RESPONSES TO DISTRIBUTED RESOURCE COALITION INTERROGATORIES

INTERROGATORY 1-DRC-1

Reference: • **Exhibit 1, Tab 5, Schedule 1**

Preamble:
Alectra notes that it anticipates an increase in demand for services upgrades driven by the increasing adoption of electric vehicles (EVs) and electric heat pumps.

a) Please discuss the impacts of the growing consumer interest in EVs and associated increase in EV penetration in Alectra's service territory, on Alectra's distribution system planning, load forecast, productivity, and OM&A costs.

b) Please identify in the record where Alectra provides details of how technological advancement and increasing adoption of electrified technology such as EVs will require training their workforce over the course of years to ensure Alectra is able to sustain a safe and reliable grid as the energy transition accelerates.

c) Please confirm and comment on whether the anticipated increased adoption of EVs and other distributed energy resources ("DERs") over the next five years and beyond will require investments in Alectra's workforce and please discuss what will be involved in training the workforce for Alectra's proposed approach (timeframes, new approaches, etc.).

d) Please comment on what training, programs, and investments will be needed if a more ambitious energy transition and EV and DER adoption scenario occurs over the next five years and beyond. In your response, please comment on what training and upgrading of workforce skills will be needed to ensure that Alectra's workforce is able to meet the challenges of an accelerated energy transition in this and the next decade and how does this compare to Alectra's current approach and the approach proposed in the Application.

e) Similarly, please discuss any disadvantages where a lower electrification scenario materializes.

RESPONSE:

a) Alectra Utilities has incorporated into its system peak demand forecast the impact of EV uptake in its service area and identified that EV uptake is one of the several growth drivers of increased peak demand within Alectra Utilities' service territory. Furthermore, Alectra Utilities has developed prudent and appropriate system expansion plans to meet the growing peak demand into the DSP. For more insight into the impact of the EVs on load forecast and distribution system planning, please refer to Exhibit 2A Tab 1 Schedule 1 Appendix J *Load Forecast & System Capacity Adequacy Assessment Report 10-Year Outlook* (page 32-38).

Alectra Utilities has determined that incremental peak-demand growth from EVs is distributed across its entire service territory, reflecting the dispersed nature of EV adoption. As such, the impact of EV adaptation to Alectra Utilities' system and operations is incorporated into the overall incremental volume and complexity of work. It is not possible for Alectra Utilities to distinctly track the impacts of EV uptake on productivity and OM&A-related functions. Alectra Utilities provided impacts on OM&A initiatives in Customer Service[1], Grid Modernization[2], Asset Management[3] and Distribution Design[4] as part of the overall OM&A impact assessment for 2027 to 2031. OM&A impacts of increased demand are addressed throughout the application evidence.

[1] Exhibit 4, Tab 2, Schedule 7
[2] Exhibit 4, Tab 2, Schedule 1, Page 29
[3] Exhibit 4, Tab 2, Schedule 1, Page 21
[4] Exhibit 4, Tab 2, Schedule 2

b) Please reference Exhibit 4 Tab 3 Schedule 1 Pages 3-4 Workforce Plan Overview.

c) Continuous learning and professional development are critical components of Alectra Utilities workforce management strategy and is further described in Exhibit 4 Tab 3 Schedule 4 Page 1 to 12 Workforce Management strategies. These strategies are designed to provide relevant specialized training as required to support changing business requirements.

d) The strategies referred to in part c) above can be adapted, as required, to either be accelerated or decelerated to remain in alignment with the requirements of the industry and the impacts of the energy transition.

e) Please see the response to 2-DRC-9 (j) and response to part d) above.

RESPONSES TO DISTRIBUTED RESOURCE COALITION INTERROGATORIES

INTERROGATORY 1-DRC-2

Reference: • Exhibit 1, Tab 2, Schedule 3

Preamble: Alectra notes that as EV adoption increases, more customers require guidance on how their new vehicle affects electricity usage, billing, and home charging.

a) Please explain what steps are required and what costs are incurred for a single residential unit to install and connect an EV home charger through the typical layout process. In your response, please discuss any known or anticipated challenges encountered by Alectra's customers.

b) Please explain what steps are required and what costs are incurred for commercial facilities or multi-unit residential buildings to carry out the necessary upgrades to connect EV chargers. In your response, please discuss any known or anticipated challenges encountered by Alectra's customers.

c) Please indicate how many of each of the following types of customer connections Alectra facilitated in its service territory in 2024-2025:
   (i) single residential unit EV charger connections;
   (ii) commercial facility EV charger connections; and
   (iii) multi-unit residential EV charger connections.

d) Please indicate how many of each of the following types of customer connections Alectra anticipates in its service territory over the 2026-2031 period:
   (i) single residential unit EV charger connections;
   (ii) commercial facility EV charger connections; and

(iii) multi-unit residential EV charger connections.

e) Please provide any and all working papers, reports, and analysis conducted to support Alectra's demand forecasts of expected EV penetration on its service territory.

f) Please provide any and all assumptions related to bidirectional, "vehicle to grid" ("V2G") flow and data considered by Alectra not provided in the Application.

RESPONSE:

Alectra Utilities seeks to clarify at the onset that the reference presented in the question, "Exhibit 1, Tab 2, Schedule 3" refers to the Cost of Service Checklist. Refer to the responses below for parts a) - f).

a) The steps required and costs incurred for a single residential unit to install and connect an EV home charger through the typical layout process are described in Exhibit 2A, Tab1, Schedule 1, Appendix B10, Page 395 lines 3-17. Residential EV related service connection requests are received by Alectra on the customer application portal. These applications follow the layout process. If Alectra determines that the existing service conductor (secondary service conductor – connection asset) is undersized based on the service request, a design layout (complete with a firm cost estimate) is performed by Alectra and provided to the customer. If Alectra determines the existing service conductor (secondary service conductor – connection asset) is adequately sized based on the service request, the service application is handled as a disconnect/reconnect and is not captured as a service layout. For residential layouts processed through Alectra's standard connection procedures, no systemic utility-side barriers have been identified. Where upgrades to the secondary service conductor or upstream assets are required, these are addressed through the normal layout and connection process. Building-side electrical upgrades beyond Alectra's demarcation point are the responsibility of the customer.

b) The steps required for commercial facilities or multi-unit residential buildings to carry out the necessary upgrades to connect EV chargers are described in Exhibit 2A, Tab1, Schedule 1, Appendix B10, Page 396 lines 7-18. ICI EV related service connection inquiries are received by Alectra through the Electric Vehicle Charging Connection Procedure (EVCCP) process. Based on the response from Alectra, the customer submits the service connection request on Alectra's customer application portal. Costs are estimated based on the specific work required to provide adequate capacity and service to the specific commercial facility or multi-unit residential building to accommodate the (EV) load, and costs are captured in the offer to connect. For ICI services (including those related to EVs), challenges that may be encountered by Alectra's customers include:

- Many existing buildings were not originally designed to accommodate additional electrical load (e.g., associated with EV charging). As a result, customers may require upgrades to building electrical infrastructure, including service entrances, transformers, switchgear, panels, and metering arrangements, before EV chargers can be installed. These upgrades can be complex and disruptive, particularly in older buildings or space-constrained facilities.

- Customers may encounter limitations in available distribution system capacity at the local level. In areas with high load density or constrained feeders, additional utility-side upgrades may be required, leading to longer connection timelines and increased costs.

- Customers may face evolving technical standards, permitting requirements, and uncertainty regarding the timing of EV adoption rates at their site, which can complicate investment decisions. Alectra continues to support customers through early engagement, capacity assessments, and coordinated planning to facilitate efficient and reliable EV charger integration.

c) In 2024-2025, the number of customer connections Alectra facilitated in its service territory is seen in Table 1.

Table 1 - EV Connections (2024 –2025)

EV Connections		
	Residential	**ICI**
2024	358	19
2025	301	45

Alectra does not separately track commercial and multi-unit residential EV charger connections within its internal systems. These projects are all tracked under ICI services and are not coded separately by end-use classification. As a result, a further breakdown is not available.

d) For 2026-2031, the number of customer connections Alectra anticipates in its service territory is seen in Table 2.

Table 2 - Forecasted EV Connections

EV Connections		
	Residential	**ICI**
2026	789	49
2027	1250	54
2028	1724	61
2029	2325	69
2030	2936	79
2031	2843	99

Alectra does not separately track commercial and multi-unit residential EV charger connections. These projects are all tracked under ICI services.

e) Please see 1-DRC-02_Attachment 1 Guidehouse Projection for EV penetration in Alectra service area. Please refer to Exhibit 2A, Tab 1, Schedule 1, Appendix J “Load Forecast & System Capacity Adequacy Assessment Report 10-Year Outlook (2024-2034)” Section 3.6 Page 32 to 38.

f) Through the V2X pilot discussed in Exhibit 1, Tab 7, Schedule 1, p. 12-13, Alectra is considering assumptions related to technical and electrical capability, operational availability, and data and metering requirements associated with bidirectional power flow.

These assumptions include that participating electric school buses identified as “V2G-capable” will be equipped with batteries capable of bidirectional power flow; that the vehicles will be available to inject energy into the distribution system during agreed-upon time periods; and that metering and telematics data will be sufficiently granular to support pilot analysis, evaluation, and reporting requirements.

1-DRC-2

Attachment 1
Guidehouse Total EV Population in Alectra Utilities Service Territory With Forecast

Guidehouse Total EV Population in Alectra Utilities Service Territory with Forecast

Vehicle	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040
LDV-BEV	23,388	31,349	44,380	70,951	113,050	171,119	249,414	348,294	444,064	555,570	681,292	820,642	973,075	1,116,665	1,253,367	1,382,463	1,504,503	1,620,000
LDV-PHEV	14,974	19,441	25,315	32,926	42,016	53,171	66,162	81,221	85,413	87,427	87,308	85,166	78,985	73,252	67,935	63,004	58,431	54,189
MDV-BEV	427	656	920	1,254	1,622	2,033	2,492	3,009	3,667	4,469	5,446	6,637	8,088	9,857	12,013	14,641	17,843	21,746
MDV-PHEV	47	73	102	139	180	226	277	334	407	497	605	737	899	1,095	1,335	1,627	1,983	2,416
HDV	100	143	192	257	332	420	525	652	798	975	1,192	1,457	1,781	2,177	2,660	3,252	3,975	4,859
Total	**38,936**	**51,663**	**70,908**	**105,527**	**157,200**	**226,969**	**318,869**	**433,511**	**534,349**	**648,937**	**775,842**	**914,639**	**1,062,828**	**1,203,045**	**1,337,310**	**1,464,986**	**1,586,734**	**1,703,211**

Note 1. Ontario LDV EV population until 2030 was from the Guidehouse Insights report
Note 2. Ontario M/HDV EV population until 2030 was obtained from Guidehouse Insights' North America forecast scaled down according to Ontario LDV EV population divided by North America LDV EV population.
Note 3. Ontario M/HDV EV population from 2031-2040 was extrapolated from the 2030 projection using the projected CAGR of 2030, which is 22% of Ontario's total vehicle population in 2020 figures were obtained from StatsCan, projected to 2040 using Ontario's Ministry of Finance's growth projection (StatsCan)
Note 4. Alectra Utilities' total vehicle population in 2020 was obtained from the Ontario vehicle population scaled down according to the population in Alectra Utilities territory divided by the Ontario population
Note 5. Projected forward to 2040 using the population forecast from the Hemson Growth Report ("GREATER GOLDEN HORSESHOE: GROWTH FORECASTS TO 2051 August 26, 2020).
Note 6. Average vehicle retirement rate of ~7%/year is obtained from StatsCan vehicle population data compared to StatsCan vehicle sales data, averaged from 2015-2019 (StatsCan).
Note 7. LDV-BEV sales in Alectra Utilities' territory from 2021-2024 are 1/3 of Guidehouse's sales forecast for Ontario, adjusted for population growth differences between Alectra Utilities and Ontario.
Note 8. LDV-PHEV sales in Alectra Utilities' territory from 2021-2030 are 1/3 of Guidehouse's sales forecast for Ontario, adjusted for population growth differences between Alectra Utilities and Ontario
Note 9. LDV-BEV sales in Alectra Utilities' territory from 2025-2035 gradually ramp up from 7% to 100% to reflect the federal ZEV mandate
Note 10. LDV-PHEV sales in Alectra Utilities' territory from 2031-2035 gradually ramp down from 5% to 0% to reflect the federal ZEV mandate
Note 11. EV retirement rate is the same as the Internal Combustion Engine (ICE) vehicle retirement rate
Note 12. Alectra Utilities' vehicle population is projected by taking the prior year's population, adding new sales, and subtracting retirements from the previous year.
Note 13. Factors that can influence EV forecast: EV Sales Data, Incentives/programs, change in government policy, availability of public charging, education, TCO.

RESPONSES TO DISTRIBUTED RESOURCE COALITION INTERROGATORIES

INTERROGATORY 1-DRC-3

Reference: • Exhibit 1, Tab 11, Schedule 2

Preamble: Alectra's rate framework provides Cost of service rebasing in 2027, followed by a Custom Price Cap Index **(CPCI)** applied in each of years two through five (2028-2031), as follows:

CPCI = In - X + RGFn

where,

- "I" is OEB's annually published Inflation Factor applicable to electricity distributors;
- "X" is the sum of the fixed productivity factor plus a fixed utility-specific stretch factor;
- "RGF" is the difference between the forecast base revenue requirement for the current year (n), and its forecast base revenue requirement for the prior year (n-1), less increases provided by "I", and billing determinant growth.

a) Please outline Alectra's assumptions in the two-component "X" productivity factor in the above equation regarding capacity, load changes, and leveraging due to EVs and other DERs in each of years two through five.

b) Please outline Alectra's assumptions in the "G" term in the above equation regarding capacity, load changes, and leveraging of EVs and other DERs in each of years two through five.

c) How were each of DERs, EVs, and EV charging infrastructure treated for the purpose of setting the “IPD” factor at which Alectra arrived?

RESPONSE:

a) The X-Factor is the sum of a base productivity factor and a utility-specific stretch factor. The base productivity factor is set at 0% consistent with the OEB standard policy. The utility-specific stretch factor of 0.15% was determined by Clearspring Energy Advisors using econometric total cost benchmarking analysis; please see Exhibit 1, Tab 6, Attachment 1-3.

The econometric model used to determine the stretch-factor considers historical and forecast total costs (inputs) and the 10-year average rolling peak demand (outputs) to assess Alectra’s cost performance relative to its peers. Inputs and outputs related to capacity, load change, EV and DERs form part of the overall model and cannot be separately identified for the purpose of the X-factor calculation.

For a full discussion of Alectra Utilities’ load forecast, inclusive of discussion concerning the adoption and growth of EVs and charging technology, please see Exhibit 3, Tab 1, Schedule 1, Attachment 3-2.

For a full discussion of capacity, EVs, and DERs from a planning perspective, please see Exhibit 2A, Tab 1, Schedule 1 as well as the associated Appendix B01-B14.

For a discussion of Alectra Utilities’ planning process and determination of peak load forecasts, please refer to Exhibit 2A, Tab 1, Schedule 1, and specifically Chapter 5.3.

b) At Section 4.2 of the Clearspring Report (Exhibit 1, Tab 6, Schedule 2, Attachment 1-3), Clearspring explains the derivation of the G-Factor as follows:

The G Factor is determined based on how the growth of the system will impact incurred costs. Cost elasticity parameters are found in the econometric cost model. These are estimates of the percentage change in cost given a percentage change in the output variable. The cost elasticity weights are the best method for estimating the impacts of output growth onto cost levels and, therefore, are used as the basis for the construction of the G Factor.

Clearspring explains further in Section 5 as follows:

Clearspring uses the cost elasticity output weights found in its econometric total cost model as the basis for weighting the projected growth in customers and system peak demands to calculate the proposed G Factor. The weight on customer growth is 52.9% and the weight on system peak demand is 47.1%. These sum to "one" and match the way the output quantity index in a proper TFP study would be calculated.

The peak demand forecast underlying the G-Factor includes consideration of capacity, load changes, EVs and DERs.

For a full discussion of Alectra Utilities' load forecast, inclusive of discussion concerning the adoption and growth of EVs and charging technology, please see Exhibit 3, Tab 1, Schedule 1, Attachment 3-2.

For a full discussion of capacity, EVs, and DERs from a planning perspective, please see Exhibit 2A, Tab 1, Schedule 1 as well as the associated Appendix B01-B14. For a discussion of Alectra Utilities' planning process and determination of peak load forecasts, please refer to Exhibit 2A, Tab 1, Schedule 1, and specifically Chapter 5.3.

c) At Section 6 of its report (Exhibit 1, Tab 6, Schedule 2, Attachment 1-3), Clearspring describes the derivation of the IPD factor as follows:

> *The IPD calculation utilizes the same inflation indexes that comprise the IPI calculation but customizes and adjusts the index to be specific to OM&A expenses. The difference is derived from using Alectra's labour and non-labour OM&A expenses to provide the weights for the inflation indexes rather than the 30% weight on labour and the 70% weight on non-labour assumed in the 4GIR IPI calculation which was designed with both capital and OM&A expenses in mind.*

The IPD relates to the impacts of inflation on Alectra's OM&A plan, which includes a consideration of capacity, load changes, EV and DERs throughout. For a full discussion of the impact on the OM&A arising from the execution of the DSP (load and capacity), as well as from EVs and DERs please see the following exhibits:

Exhibit 4, Tab 1, Schedule 1 – Operations, Maintenance, & Administration Overview;
Exhibit 4, Tab 1, Schedule 2 – OM&A Key Themes & Trends
Exhibit 4, Tab 2, Schedule 7 – Customer Service
Exhibit 4, Tab 2, Schedule 9 – System Control
Exhibit 4, Tab 2, Schedule 10 – Stations
Exhibit 4, Tab 9, Schedule 1 – Costs of Non-Wires Solutions?

Other areas of OM&A may be indirectly impacted by evolutions pertaining to load, capacity, DERs and EVs as the needs of customers and Alectra's business and priorities evolve. In particular, the resourcing needs and priorities of specific business units may be impacted. A discussion of FTE Requirements by Program can be found at Exhibit 4, Tab 3, Schedule 3.

RESPONSES TO DISTRIBUTED RESOURCE COALITION INTERROGATORIES

INTERROGATORY 1-DRC-4

Reference: • Exhibit 1, Tab 5, Schedule 2

Preamble: Alectra engaged Innovative Research Group Inc. (Innovative) to design, execute and document the results of its application-specific customer engagement process.

a) Please provide a copy of all written instructions provided by Alectra to Innovative in relation to the respective customer engagement mandate and the report provided in Exhibit 1, Tab 5, Schedule 2, Attachment 1-2.

b) Please provide a copy of all written instructions provided by Alectra to Innovative in relation to customer engagement with respect to consumer choice in integrating new technologies like EVs, solar power, and battery storage (including V2G and vehicle-to-home [“V2H”]).

c) Please describe all measures undertaken by Alectra and Innovative to invite and ensure the participation of EV stakeholders and other DER customers (including EV drivers, owners of DERs, EV associations, and DER industry associations) in the customer engagement process.

d) Please provide any and all notes relating to EVs and DERs from the customer engagement that are supplementary to the report provided in Exhibit 1, Tab 5, Schedule 2, Attachment 1-2.

e) Please discuss how the outcomes and priorities of customers have changed compared to historical equivalents and discuss any trend lines in customer priorities related to the adoption and integration of technologies like DERs, EVs, and battery storage (including V2G and V2H).

RESPONSE:

Responses prepared by Innovative Research Group:

a) There were no formal written instructions. INNOVATIVE and Alectra have been conducting customer engagements for rate applications for a decade. INNOVATIVE is aware of the customer engagements requirements set out in the Renewed Regulatory Framework for Electricity and the Handbook for Utility Rate Applications. Based on those requirements, INNOVATIVE provided Alectra with a proposal and that proposal provided the basis of the contract.

b) There were no formal written instructions. The survey was developed primarily through discussion in video calls and in person meetings to allow key team members to share information and reactions in real time and avoid unproductive email chains. Specific topics were identified by Alectra and then questions developed by INNOVATIVE.

c) Throughout Alectra's 2027-2031 rate application customer engagement, all customers had the opportunity to participate in one of two ways. The first way was through random recruitment from Alectra's complete customer list. The second way was by inviting all customers to participate in certain engagement activities. In both cases, each customer, in each rate class, had an equal opportunity to participate in this engagement – including EV stakeholders and other DER customers.

d) There are no additional notes from IRG's customer engagement relating to EVs and DERs that are supplementary to the reports provided in Exhibit 1, Tab 5, Schedule 2, Appendix 1-2.

e) The focus of this engagement is to understand Alectra customers' preference today. There was no time series analysis of changes in customers' views on outcomes and priorities conducted in this application.

RESPONSES TO DISTRIBUTED RESOURCE COALITION INTERROGATORIES

INTERROGATORY 1-DRC-5

Reference: • Exhibit 1, Tab 7, Schedule 1

Preamble: Alectra notes that the GRE&T Centre supports commitment to its customers by developing innovative products and services that help them better understand and manage their energy use, including the Ultra-Low Overnight (**ULO**) Pricing Plan, AlectraDrive@Home and AlectraDrive@Work, and EV Detection initiatives (**the Initiatives**).

a) Please provide any and all working papers, reports, and analysis conducted on or in support of the Initiatives.

b) Please identify all elements of the application (including proposed capital projects, OM&A, program designs, deferral accounts, or DER/EV-related initiatives) that were informed by the work and learnings from the Initiatives.

c) Please confirm whether Alectra has conducted any analysis of ULO adoption rates within its service territory and whether those adoption rates are being used as an input to any proposed DER, EV, or Non-Wires Solutions (NWS) related initiative in the Application. If yes, please provide the analysis and the specific application references where it is used.

d) Please provide the final evaluation results (reports, analysis, etc.) for AlectraDrive@Home and AlectraDrive@Work, including:

(i) enrolment and retention rates;
(ii) measured load shifting (kW at peak, kWh shifted, and time-of-use distribution);
(iii) customer satisfaction and opt-out rates;

:

(iv) effectiveness by customer segment (residential vs commercial; fleet vs non-fleet, if applicable); and

(v) incremental costs per kW reduced (and per kWh shifted), with any assumptions relied upon by Alectra.

e) Please explain how Alectra assessed whether the Initiatives produced net customer value (including avoided system costs) and identify whether any such quantified benefits are relied upon in the Application.

f) Please confirm, and provide details of, whether Alectra has used any results from the Initiative to support deferral of distribution capital (including stations/lines capacity) or to justify non-wires approaches.

g) Please identify whether and how EV Detection results were used to adjust peak demand assumptions, coincidence factors, or growth rates at the transformer, feeder, or station level in the Application, if at all.

h) Please confirm whether any specific capital investments proposed in this application (lines, stations, or grid modernization) were justified or accelerated based on results from the EV Detection initiative.

i) Please confirm whether EV Detection results are, or will be, shared with EV charging proponents or aggregators to support site selection and project development. If not, please explain why.

RESPONSE:

For the purposes of this interrogatory, references to the Ultra-Low Overnight Pricing Plan are interpreted to mean Alectra's Advantage Power Pricing (APP) project, operated as part of the Ontario Energy Board's RPP Roadmap Pilots initiative from 2017 to 2022, unless otherwise noted. The provincial Ultra-Low Overnight rate was informed by the APP pilot and was mandated by the OEB for implementation by all Ontario electricity distributors in 2023.

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a) Alectra respectfully notes that this interrogatory is overly broad and would require the disclosure of internal working documents that are not relevant to the determination of this proceeding. The key material and relevant information regarding the Initiatives have been provided in the attached final reports:

- 1-DRC-05_Attachment 1 _ ULO Final Report
- 1-DRC-05_Attachment 2_ ULO Optionality Report
- 1-DRC-05_Attachment 3_ AlectraDrive @Work Final Report
- 1-DRC-05_Attachment 4_ AlectraDrive @Home-GIF- Final Report

b) The following elements in this application were informed by the Initiatives:

- SEW Customer Engagement - eMobility
- Alectra Drive for Fleets
- Grid Enablement: School Bus Fleets (V2X)
- EV Detection
- Customer Non-Wires Solution Design & Development

The Initiatives provided insight into these elements by demonstrating customer interest and preferences around utility support for load management and by validating load management use cases and implementation considerations through in-field deployment. These have informed the projects listed above by validating their fitness for use as DERs; providing input data; and/or refining business models, implementation plans, project scope and/or customer engagement approaches.

Details about these elements of the Application can be found in Exhibit 1, Tab 7, Schedule 1 (Facilitating Innovation) and Exhibit 2A, Tab 1, Schedule 1, Appendix B09 Section 2.4 (DER Supporting Technologies).

The Initiatives also highlighted customer preferences for utility-provided information and support related to new technologies, which informed Alectra's ongoing Customer

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Engagement efforts, such as Supporting Electrification, the Digital First Strategy, and Supporting Customer Connections and Key Accounts.

Details of these elements can be found in Exhibit 1, Tab 5, Schedule 1.

c) Alectra Utilities tracks customer RPP rate option switching through a Rate Optionality Report. ULO adoption among Alectra's RPP-eligible customers remains at approximately 1% to date. ULO adoption rates are not used as an input to forecast DER uptake, EV load, or Non-Wires Solutions in this application.

The availability of the ULO rate has been an input into the e-Mobility Customer Engagement Pilot (see Exhibit 1, Tab 7, Schedule 1 and Exhibit 2A Tab 1, Schedule 1, Appendix B09). Among its various educational materials, the e-Mobility Customer Engagement project developed a rate selection calculator to help customers forecast the impact of optional rate plans on electricity "fuel" costs across their vehicle and driving habits, charger type and charging schedule.

The e-Mobility calculator complements Alectra's upcoming Rate Plan Calculator on the MyAlectra online customer portal. This tool will evaluate the impact of optional rates on bills by analyzing historical energy consumption patterns, including any on-site DERs, and will identify potential saving opportunities for customers. More details about this approach and these initiatives can be found in the Ongoing Customer Engagements section (Exhibit 1, Tab 5, Schedule 1, including Supporting Electrification pages 8-9, Digital First Strategy pages 3-4, and Supporting Customer Connections and Key Accounts pages 10-12).

d) Please refer to the AlectraDrive@Home and AlectraDrive@Work final reports included as attachments to this IR response.

- 1-DRC-05_Attachment 3_ AlectraDrive @Work Final Report
- 1-DRC-05_Attachment 4_ AlectraDrive @Home-GIF- Final Report

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e) Net customer value was assessed through third-party evaluations of project results.

The Initiatives were designed as time-limited demonstration projects rather than long-term system assets. As the AlectraDrive @Work, @Home and Advantage Power Pricing projects have been completed and customer participation has ended, there are no quantified benefits remaining that can be relied upon in the Application.

f) The Initiatives were designed as time-limited demonstration projects rather than long-term system assets. As the AlectraDrive @Work, @Home and Advantage Power Pricing projects have been completed and customer participation has ended, there are no quantified benefits remaining that can be relied upon in the Application

While these initiatives provided insights into customer behaviour and load management capability, they were not used to justify specific distribution capital deferrals or to support non-wires alternatives. Alectra Utilities' approach to the consideration of non-wires solutions is described in Exhibit 2A, Tab 1, Schedule 1, Section 5.3.5.

As noted above in c), customers' adoption of ULO is currently approximately 1%. EV managed charging technology for mass market adoption is still in its initial stages of commercialization and there is uncertainty pertaining to funding structures. As a result, neither is expected to have a material impact on the 2027-2031 planning period. During this period, Alectra will continue to monitor and support the development and uptake of managed charging and EV pricing initiatives and will make necessary adjustments to forecast and uptake projections in the following planning cycle.

g) The EV Detection algorithm is a planning support tool that can provide an additional source of information to system planning staff alongside other analyses. EV Detection results were not used to adjust peak demand assumptions, coincidence factors, or growth rates at the transformer, feeder, or station level in this Application.

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h) The EV Detection algorithm is a planning support tool that can provide an additional source of information to system planning staff alongside other analyses. EV Detection results were not used to justify or accelerate any specific capital investments proposed in this Application.

i) Consistent with Alectra Utilities' privacy policies and customer data agreements, the results of the EV Detection algorithm are not released externally. The detailed working documents supporting the EV transformer analysis and the EV Detection algorithm contain proprietary information and intellectual property of Alectra Utilities.

1-DRC-5

Attachment 1
ULO Final Report

Regulated Price Plan Pilot – Dynamic Pricing Final Report

Submitted to the Ontario Energy Board

Alectra Utilities with its partner BEworks

January, 2021

CONTRIBUTORS

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About Alectra

Alectra's family of energy companies distributes electricity to more than one million homes and businesses in Ontario's Greater Golden Horseshoe area and provides innovative energy solutions to these and thousands more across Ontario. The Alectra family of companies includes Alectra Inc., Alectra Utilities Corporation and Alectra Energy Solutions. Learn more about Alectra at alectrautilities.com.

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About BEworks

Founded in 2010, BEworks is an unconventional management consulting firm that applies scientific thinking to transform the economy and society. BEworks' team of experts in cognitive and social psychology, neuroscience, and marketing answer clients' most complex business questions, execute disruptive growth strategies, and accelerate innovation.

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Executive Summary

In 2016, the Ontario Energy Board (OEB), through its Regulated Price Plan (RPP) Pilots, sought to examine the impact of alternative pricing schemes and non-price interventions on conservation and demand management behaviours among utility customers. Alectra Utilities (Alectra), and its partners, have tested the impact of three separate Time-of-Use (TOU) pricing schemes (Dynamic, Overnight, and Enhanced) with two non-price interventions ("Nudge Reports", and programmable smart thermostat technology) over a 12-month reporting period (May 01, 2018 to April 30, 2019 inclusive) to achieve the OEB's RPP Pilot objectives. Collectively, the three pricing pilots were communicated and marketed to customers under the name Advantage Power Pricing (APP).

Based on findings from the impact analyses conducted at the 6-month reporting period, the OEB opted to extend the reporting period beyond the originally scoped 12 months for one of the pricing pilots (Dynamic pricing) for an additional five months. This program extension provides behavioural response impacts to Dynamic pricing over a second Summer season and also allows for the assessment of behavioural response to different frequencies of Critical Peak Period (CPP) events. To that end, Dynamic pricing participants were randomly assigned to receive either six or nine CPP events in the 5-month extension period. This report supplements the 12-month report on the impacts of Alectra's RPP Pilot by presenting the final 5-month impacts of Dynamic pricing. This report also represents a comprehensive impact analysis of the entire 17-month reporting period for Dynamic pricing and therefore also includes the 12-month impacts owing to Dynamic pricing that were previously reported in the 12-month report on the impacts of Alectra's broader RPP Pilot.

Dynamic Pricing

Under TOU pricing in Ontario, the calendar year is divided into two 6-month periods referred to as Summer months (May 01 to October 31 inclusive) and Winter months (November 01 to April 30 inclusive). Just as in the 6- and 12-month reporting periods, participants in the Dynamic pricing Treatment received variable On-Peak pricing, depending on anticipated demand forecasts, that differed from Status-Quo On-Peak TOU pricing by having High, Medium, and Low On-Peak Periods (Table 1). During the 6- and 12-month reporting periods, Dynamic pricing participants were also exposed to six CPP events in each of the Summer 2018 and Winter 2018-2019 months. Each of these events lasted for four hours and customers were subjected to an especially high On-Peak kWh price during this time.

The times of day (during weekdays) that are designated as On-Peak and Off-Peak hours vary depending on whether they fall within Summer or Winter months (Table 1). As such, we report impact estimates related to TOU price periods separately for Summer and Winter months throughout this report.

Table 1: Dynamic Pricing kWh Prices

Price Period	Hours	Price (cents/kWh)	
		Nov - April	May - Oct
Off-Peak	Weekdays: 12am-3pm and 9pm-12am Weekends: All day	4.9	4.9
Low On-Peak	50% of Weekdays: 3pm-9pm	10.0	9.9
Medium On-Peak	30% of Weekdays: 3pm-9pm	19.9	19.8
High On-Peak	20% of Weekdays: 3pm-9pm	39.8	39.7
Critical Peak	On the top six or nine system peak days in summer and winter, each event lasting four hours. Start time of events determined by peak demand hour of event day	49.8	49.8

Dynamic Pricing + 6 CPP Days and Dynamic Pricing + 9 CPP Days: In the 5-month extension period (Summer 2019), Dynamic pricing Treatment participants were subdivided and randomly assigned to receive either six or nine CPP events. These participant groups are subsequently referred to in this report as "Dynamic 6" and "Dynamic 9", or "Legacy Dynamic 6" and "Legacy Dynamic 9", respectively (the 'Legacy' groups are described further below). Given the substantial consumption reductions owing to CPP events demonstrated in the 6- and 12-month impact analyses, it is of interest to know whether these types of impacts would be again observed over a second Summer period and/or whether these impacts would be affected by an increase in CPP event frequency.

Legacy Dynamic Customers

There are two distinct customer groups in the Dynamic pricing pilot: (1) customers who enrolled in Dynamic pricing as part of the current RPP Pilot initiative, and (2) Legacy Dynamic customers who were already enrolled in prior instantiations of Dynamic pricing offered by Alectra beginning in 2015. Throughout this report, we analyze these two customer groups as separate pilots, referred to as 'Dynamic' and 'Legacy Dynamic' pricing pilots. There are three important qualitative differences between Dynamic and Legacy Dynamic customer groups that necessitate that they be treated independently for the purposes of this impact analysis:

1. **Duration of Dynamic pricing exposure:** Legacy Dynamic customers have been subjected to the Variable Peak and Critical Peak pricing events that typify Dynamic pricing for a substantially longer time than newly enrolled Dynamic customers

2. **Duration of exposure to price protection:** Legacy Dynamic customers were subjected to price protection for the entirety of the Legacy program, whereas newly enrolled

customers had, at most, a few months of price protection prior to the start of the current RPP Pilot

3. **Differences in analytic approach:** Due to the fact that Legacy Dynamic customers have been taking part in the program for, in some cases, up to 3-4 years at the commencement of the current pilot, there exists no appropriate historical baseline consumption period on which to conduct a difference-in-difference analytical approach

Status-Quo TOU (Control)

Customers assigned to the pricing Control conditions for the Dynamic pricing pilot experienced Status-Quo TOU prices. The Status-Quo TOU rates and associated price periods are shown in Table 2.

Table 2: Status-Quo TOU Pricing kWh Prices

Price Period	Summer Hours (May – October)	Winter Hours (November – April)	Price (cents/kWh)	
			Nov - April	May-Oct
Off-Peak	Weekdays: 12am-7am and 7pm-12am Weekends: All day	Weekdays: 12am-7am and 7pm-12am Weekends: All day	6.5	6.5
Medium-Peak	Weekdays: 7am-11am and 5pm-7pm	Weekdays: 11am-5pm	9.5	9.4
On-Peak	Weekdays: 11am-5pm	Weekdays: 7am-11am and 5pm-7pm	13.2	13.2

Non-Price Interventions

Nudge Reports: Half of the participants in each of the Dynamic pricing Treatment and Control groups, as well as half of the participants in the Legacy Dynamic Treatment group, were randomly assigned to receive a non-price intervention in the form of a Nudge Report. Due to delays in obtaining Legacy Dynamic Control customer data required for data disaggregation and customized feedback, participants in this condition were not distributed Nudge Reports. The Nudge Reports were a monthly report that accompanied the Shadow Bill for pricing Treatment participants (or was sent as a stand-alone report in the case of pricing Control participants). This monthly report is referred to as a 'Nudge Report' because it contains information drawn from the field of behavioural economics intended to nudge conservation behaviours among recipients. Specifically, the Nudge Report communication encouraged recipients to 'pledge' to reduce their On-Peak electricity consumption, displayed personalized tips for achieving this goal, and provided personal benchmarking feedback so that recipients could track their On-Peak consumption behaviour month-to-month.

Smart Thermostat Technology: In addition to measuring the effect of Nudge Reports as a non-price intervention, the impacts of smart thermostat technology in driving conservation and load-shifting behaviours among pilot participants was also investigated. Households were designated as "*Technology*" if they possessed or acquired an eligible smart thermostat (either independently or through incentive programs offered by Alectra Utilities) *and* registered that device with

Alectra during program enrollment to enable automatic load curtailment. Eligible devices included Honeywell, Nest, ecobee, and Energate Foundation. All of these registered devices received some form of automatic load curtailment during Critical Peak events and during Variable On-Peak events in Summer 2018 and Winter 2018-2019 (except for Nest, for which load curtailment was limited to Critical Peak events as part of the 'Rush Hour Rewards' program). Only ecobee and Energate devices retained curtailment functionality in Summer 2019.

Program Results

Sample Sizes

Sample sizes as a function of experimental condition are shown in Table 3 and Table 4 below. Detailed information concerning exclusion criteria is provided in Section 4, with detailed exclusions for each provided in Sections 5.3.1 and 5.4.1.

Table 3: Number of participants in the Dynamic Pricing Pilot

<table>
<tr><th rowspan="2"></th><th colspan="3">Summer 2018</th><th colspan="2">Winter 2018-19</th><th colspan="3">Summer 2019</th></tr>
<tr><th>Starting N</th><th>Total Exclusions</th><th>Final N</th><th>Total Exclusions</th><th>Final N</th><th></th><th>Total Exclusions</th><th>Final N</th></tr>
<tr><td rowspan="2">Dynamic Pricing, No Nudge Report</td><td rowspan="2">385</td><td rowspan="2">47</td><td rowspan="2">338</td><td rowspan="2">103</td><td rowspan="2">235</td><td>Dynamic 6 Pricing, No Nudge Report</td><td>13</td><td>107</td></tr>
<tr><td>Dynamic 9 Pricing, No Nudge Report</td><td>10</td><td>98</td></tr>
<tr><td rowspan="2">Dynamic Pricing + Nudge Report</td><td rowspan="2">385</td><td rowspan="2">40</td><td rowspan="2">345</td><td rowspan="2">110</td><td rowspan="2">235</td><td>Dynamic 6 Pricing + Nudge Report</td><td>10</td><td>105</td></tr>
<tr><td>Dynamic 9 Pricing + Nudge Report</td><td>9</td><td>118</td></tr>
<tr><td>Status-Quo TOU Pricing, No Nudge Report</td><td>385</td><td>21</td><td>364</td><td>22</td><td>342</td><td></td><td>16</td><td>326</td></tr>
<tr><td>Status-Quo TOU Pricing + Nudge Report</td><td>385</td><td>23</td><td>362</td><td>21</td><td>341</td><td></td><td>19</td><td>322</td></tr>
<tr><td>Total</td><td>1540</td><td>131</td><td>1409</td><td>256</td><td>1153</td><td></td><td>77</td><td>1076</td></tr>
</table>

Table 4: Number of Participants for Legacy Dynamic Pilot

	Summer 2018	Winter 2018-19

	Starting N	Total Exclusions[1]	Final N	Starting N	Total Exclusions	Final N
Registration Bin 1						
Legacy Dynamic	778	114	664	839	111	728
Status-Quo TOU Control	778	114	664	839	111	728
	Summer 2019					
Legacy Dynamic 6 CPP Days	327	56	271			
Legacy Dynamic 9 CPP Days	336	48	288			
Status-Quo TOU Control	663	104	559			
Registration Bin 2						
Legacy Dynamic	650	147	503	639	141	498
Status-Quo TOU Control	650	147	503	639	141	498
	Summer 2019					
Legacy Dynamic 6 CPP Days	253	49	204			
Legacy Dynamic 9 CPP Days	250	46	204			
Status-Quo TOU Control	503	95	408			

Summary of Analytical Approach

As a result of seasonal variations and year-over-year fluctuations in weather patterns, there was substantially higher overall electricity consumption in the 17-month pilot period relative to the preceding 17 months. For this reason, we employ a difference-in-difference (DID) approach for the estimation of impacts owing to Dynamic pricing (which was the condition comprised of

[1] Total Exclusions: This is simply the sum of Opt-Outs + Move-Outs + Missing Data + Outliers. Full descriptions of each of these exclusion criteria are provided in Section 4. Advantage Power Pricing Impact Analysis Methodology.

participants who enrolled in the pricing pilot in 2018 at the start of the current study; see below for distinction from Legacy Dynamic). The DID compares the year-to-year difference in consumption between Treatment and Control groups. For example, if from the pre-Treatment to the Treatment period, a given Control group consumed 0.05 kWh more electricity, but the corresponding Treatment group consumed only 0.01 kWh more electricity, we can then report that the Treatment lead to a 0.04 kWh reduction in consumption relative to the Control group. We present DID impact analysis results as mean hourly kW differences between Treatment and Control, where negative values indicate less consumption owing to Treatment (price or non-price). We subsequently derive and report percentage change equivalents from the results of the kW impact estimates. In all regression tables, mean hourly kW impact estimates represent the *additional* change in mean hourly kW consumption between periods for participants receiving an experimental Treatment, compared to the change in kW consumption exhibited by participants in the appropriate Control group. We extrapolate percent change in mean hourly kW consumption owing to a pilot Treatment variable by dividing the mean hourly kW impact coefficient by the relevant Treatment group's counterfactual consumption, which we derived by subtracting the impact coefficient from the Treatment group's observed mean hourly consumption in the relevant TOU price period in the pilot Treatment period. Thus, percent impact estimates represent the percentage by which the observed consumption in the Treatment group differs from their counterfactual consumption had they not been Treated. As these values were calculated from the kW impacts, we did not conduct statistical significance testing directly on the percentage values. Statistical significance of impacts is only reported for the mean hourly kW effects from the linear regression models.

There are two instances in which mean hourly kW impact estimates were not derived and statistically analyzed using a difference-in-difference (DID) approach: (1) all Legacy Dynamic pilot impact estimations; and (2) the Technology impact estimations for the Dynamic pilot, pertaining to the incremental impacts owing to curtailment-enabled Smart thermostats. Firstly, Alectra began offering a version of Dynamic pricing to its customers in 2015, and over the course of three separate registration periods, has been continuing to offer Dynamic pricing to a subset of its residential customer base. This means that at the commencement of the current RPP Pilot program, there existed approximately 1,500 households already enrolled in Dynamic pricing. In an attempt to gather data on the longevity of previously estimated consumption impacts owing to Dynamic pricing, Alectra and the OEB sought to retain this 'Legacy' Dynamic customer group as part of the current RPP Pilot. The start dates of this Legacy Dynamic pricing mean that the employment of a DID approach to impact estimation is problematic. Mainly, in order to compare consumption in the current pilot period (May 01, 2018 – October 30, 2019) to a pre-Treatment historical baseline period, a historical data set that is (in many cases) over four years old would have to be used. Despite the fact that this would be a very 'noisy' and arguably inappropriate historical data set with which to employ a DID approach, historical data sets for Legacy Dynamic matched Control customers was not made available to the evaluator during the implementation and evaluation stages of this pilot. This is further complicated by the fact that Legacy Dynamic pricing customers enrolled into Dynamic pricing at three different historical time periods, meaning that different historical baseline periods would have to be used for different groups of customers within the Legacy Dynamic customer group (this is discussed further below). It is for these reasons that we compare Legacy Dynamic pricing with Status-Quo TOU Control pricing in each year on record separately, without using the DID approach.

Caution should be used when making qualitative or quantitative comparisons between Dynamic and Legacy Dynamic impacts. Legacy Dynamic participants have been exposed to the Dynamic pricing structure for (in some cases) up to four years, whereas newly enrolled Dynamic participants have only been exposed to Dynamic pricing for a little over a year and a half. Even with this in mind, any comparisons made between these two groups of customers would not provide an accurate picture of the effect of exposure duration to Dynamic pricing on electricity consumption behaviour. This is because Legacy Dynamic participants enjoyed full price protection for the entirety of the Legacy program (price protection was removed only as part of the 17-month evaluation period that comprises this report). Thus, because of differences in the analytical approach, differential exposure durations to Dynamic pricing, and differences in the length of exposure to price protection, any comparisons between the Legacy and newly enrolled Dynamic customer groups should only be made with these important differences in mind.

Secondly, the smart thermostat "Technology" analysis compares households with registered smart thermostats to those without registered devices *during the 2018-2019 Treatment period only*. Exact timing of smart thermostat installation for each household is unknown, therefore Technology was analyzed comparing kWh consumption of households with and without registered smart thermostat during the Treatment period only, and we did not employ a difference-in-difference approach. All registered smart thermostats received some form of automatic load curtailment during certain peak TOU periods during the unprotected pilot period. Analyzing Technology during the Treatment period only avoids any noise introduced by potential smart thermostat usage during the pre-Treatment pricing period. Put differently, we assume that there are likely consumption reduction benefits conferred by (1) owning and using a smart thermostat, and (2) registering that thermostat for automatic load curtailment. If we were to employ a DID approach to Technology impact estimates, some Technology customers would be compared to a pre-Treatment period in which they used a smart thermostat that was not load-curtailment enabled, some would be compared to a pre-Treatment period in which they did not possess a smart thermostat at all, and still some would be compared to a pre-Treatment period in which they owned a smart thermostat for some, but not all of the pre-Treatment period. We therefore opted to simply compare those with registered smart thermostats to those without registered smart thermostats during the Treatment period only.

Impact of Pricing Structures

The impacts owing to Dynamic pricing, covering Summer 2018 (May to October 2018, inclusive), Winter 2018-19 (November 2018 to April 2019, inclusive), and Summer 2019 extension period (June to October 2019, inclusive) are summarized in Table 5. Here we present only the impact estimates for the highest and lowest priced TOU periods across pilots, however detailed TOU period impact estimates are provided in Section 5. Impact estimates represent mean hourly kW consumption differences from the pre-Treatment baseline period to the Treatment period, compared between Dynamic pricing participants and Status-Quo TOU pricing matched Control participants (i.e., impact estimates derived from the difference-in-difference methodology). Estimated average hourly electricity consumption impacts during High On-Peak hours owing to Dynamic pricing in the Summer periods amounted to -0.260 kW in Summer 2018, and -0.148 kW and -0.121 kW, per hour on average in Summer 2019 for the 6 and 9 CPP event groups respectively. The reduction in the magnitude of the estimated impacts during High

On-Peak hours from Summer 2018 to Summer 2019, likely owes at least in part to the fact that average hourly temperatures during these times of day were about 4 degrees lower in Summer 2019. The Winter 2018-2019 impact owing to Dynamic pricing was estimated to be -0.122kW . In addition, there were no differences in consumption between Dynamic pricing participants and matched Control participants during Dynamic Off-Peak hours. During Critical Peak Periods in the Summer, consumption impacts amounted to -0.354 kW in Summer 2018 and -0.38 kW and -0.35 kW per hour on average in Summer 2019 for the 6 and 9 CPP event groups respectively. Winter consumption impacts during CPP events amounted to -0.168 kW per hour on average.

Table 5: Main effects of price plans (comparing Treatment group versus Control group)

Dynamic Pricing	Main Effect of Price (Relative to Status-Quo TOU Control)										
	Summer 2018			Winter 2018-19			Summer 2019 Extension				
	High On-Peak	Off-Peak	CPP Days	High On-Peak	Off-Peak	CPP Days			High On-Peak	Off-Peak	CPP Days
kW	**-0.26*****	0.000	**-0.354*****	**-0.122*****	0.001	**-0.168*****	Dynamic 6	kW	**-0.148*****	-0.002	**-0.382*****
								%	-8.528	-0.207	-19.625
%[2]	-12.968	0	-17.239	-10.558	0.114	-12.948	Dynamic 9	kW	**-0.121*****	-0.003	**-0.35*****
								%	-7.632	-0.321	-18.802

**** $p < 0.001$; ** $p < 0.01$; * $p < 0.05$; ^ $p < 0.1$*

As discussed above, the Legacy Dynamic peak impact analyses calculated the difference in electricity consumption for the Legacy Dynamic pricing Treatment group compared to Status-Quo TOU Control pricing group during the experimental periods without the DID method. Results are reported as mean hourly kW consumption difference in Table 6. This pilot was also divided into two different sub-groups, based on different dates of registration. Two different subgroups of participants were analyzed separately, based of different periods of pilot enrollment: Registration Bin 1 (registration date on or before May 1st, 2015) and Registration Bin 2 (registration date between October 1st, 2015 and May 4th, 2016). Registration Bin 1 consumed significantly less electricity than their Status-Quo TOU matched Control group during the Summer 2018 High On-Peak period (-0.144 kW per hour on average), while neither Bin differed from Control with respect to Winter High On-Peak consumption. Neither of the Legacy Dynamic Summer 2019 Treatment groups exhibited significantly lower High On-Peak usage relative to matched Controls. Interestingly, all Registration Bin 2 participants exhibited higher Off-Peak consumption compared to their matched Controls, with the exception of Winter (2018-

[2] % impacts are calculated as kW impact / (PostTOUUsage - kW impact), where PostTOUUsage is the average consumption between the Dynamic Pricing + Nudge Report and Dynamic Pricing + No Nudge Report groups from Tables 27, 28 and 29.

2019) period. For Critical Peak Periods, both Registration Bin 1 and Registration Bin 2 exhibited lower consumption in the Summer periods than matched Controls, ranging from -0.152 kW to -0.24 kW per hour on average, however, there were no differences in Critical Peak Period consumption for the Winter (2018-2019) period compared to their matched Controls.

Table 6: Main effects of Legacy Dynamic price plan during 2018 (comparing Treatment group versus Control group)

Legacy Dynamic Pricing		Main Effect of Price (Relative to Status-Quo TOU Control)										
		Summer 2018			Winter 2018-19			Summer 2019 Extension				
		High On-Peak	Off-Peak	CPP Days	High On-Peak	Off-Peak	CPP Days			High On-Peak	Off-Peak	CPP Days
Bin 1	kW	**-0.144****	**0.108*****	**-0.241*****	-0.005	**0.057***	-0.03	Dynamic 6	kW	-0.079	**0.089****	**-0.24*****
	%	-7.496	11.878	-11.996	-0.465	6.898	-2.475		%	-5.133	10.418	-13.337
Bin 2	kW	-0.065	**0.072***	**-0.152***	-0.005	0.091	-0.021	Dynamic 9	kW	-0.067	**0.116*****	**-0.225*****
	%	-3.59	7.959	-7.851	-0.354	8.447	-1.321		%	-4.306	13.599	-12.511

**** $p < 0.001$; ** $p < 0.01$; * $p < 0.05$; ^ $p < 0.1$*

Overall, impact estimates indicate significant High On-Peak electricity consumption savings for Dynamic pricing pilot participants. Moreover, the consumption impact estimates for this pilot are more consistent with 'load clipping' than 'load shifting', as the lower High On-Peak consumption exhibited by Dynamic pricing participants, relative to Status-Quo TOU Controls, did not co-occur with higher Off-Peak consumption. For the Legacy Dynamic pricing participants, we observe lower High On-Peak consumption only for the Summer 2018 period for registration Bin 1, albeit with higher Off-Peak consumption relative to Controls, consistent with load-shifting. Given that there were several differences between Dynamic and Legacy Dynamic pilots that necessitated distinct analytic approaches to impact estimation, one might imagine that these differences may also explain why High On-Peak and Off-Peak patterns of consumption also differed qualitatively between these two pilots. Specifically, Legacy Dynamic participants have been exposed to Dynamic pricing for a much longer period of time and may therefore have decreased their responsiveness to Dynamic pricing signals over time. On the other hand, Legacy Dynamic participants have enjoyed price protection for the majority of their time in Dynamic pricing, perhaps affecting how they learned to respond to Dynamic pricing signals (i.e., that increased costs relative to Status-Quo TOU would not be incurred for High On-Peak consumption, and that the especially low Off-Peak rate could be capitalized on by increasing electricity consumption during these hours).

Importantly, for the Summer 2019 period, across both pilots, we see very similar estimated consumption impacts between the CPP 6 and CPP 9 groups, suggesting that High On-Peak and Off-Peak behavioural response was not affected by the frequency of CPP events (6 vs. 9).

Non-Price Interventions

In addition to the pricing interventions, half of the participants in each of the pricing Treatment and Control groups for the Dynamic pricing pilot and half of the participants in the pricing Treatment group for the Legacy Dynamic pricing pilot were randomly assigned to receive 'Nudge Reports'. This non-price intervention took the form of a monthly report that accompanied the Shadow Bill for pricing Treatment participants (or was sent as a stand-alone report in the case of pricing Control participants). This monthly report is referred to as a 'Nudge Report' because it contains information drawn from the field of behavioural economics intended to nudge conservation behaviours among recipients. Specifically, the Nudge Report displays personalized tips for reducing On-Peak consumption and provides personal benchmarking feedback so that recipients can track their On-Peak consumption behaviour month-to-month.

Impact estimates owing to Nudge Reports were not statistically significant for any TOU periods within the Dynamic and Legacy Dynamic pilot (an abbreviated summary of which is presented in Table 7).

Table 7: Effects of Nudge Report on Mean Hourly kW Consumption (comparing Nudge Report recipients versus non-recipients)

App Price Plan	Main kWh effect of Nudge Report (Relative to No Nudge)						
Dynamic Pricing Pilot		High On-Peak		Off-Peak		Season Total	
		kW	%[3]	kW	%	kW	%
	Summer 2018	-0.015	-0.792	0.007	0.709	0.005	0.478
	Winter 2018-19	0.024	2.206	0.011	1.246	0.01	1.094
	Summer 2019	-0.066	-4.16	-0.01	-1.075	-0.014	-1.398
Legacy Dynamic Pricing Pilot		High On-Peak		Off-Peak		Season Total	
		kW	%	kW	%	kW	%
	Summer2018	-0.005	-0.279	-0.029	-2.865	-0.024	-1.772
	Winter 2018-19	-0.005	-0.404	0.005	0.494	-0.004	-0.352
	Summer 2019	-0.1^	-6.564	-0.042	-4.306	-0.047	-4.615

*** $p < 0.001$; ** $p < 0.01$; * $p < 0.05$; ^ $p < 0.1$

In addition to measuring the effect of Nudge Reports as a non-price intervention, the impacts of smart thermostat technology in driving conservation and load-shifting behaviours among pilot participants was also of interest. Households were designated as "Technology" households if they participated in a smart thermostat incentive program offered by Alectra Utilities. Participation in such incentive programs means that "Technology" customers registered an eligible device to receive automatic load curtailment during Medium On-Peak, High On-Peak,

[3] % impacts are calculated as kW impact / (PostTOUUsage - kW impact), where PostTOUUsage is the average consumption between the Dynamic Pricing + Nudge Report and Standard TOU Pricing + Nudge Report groups from Tables 27, 28 and 29.

and Critical Peak TOU periods. Exact timing of smart thermostat installation for each household remains unknown, therefore Technology was analyzed comparing the mean hourly kW consumption of households with and without registered smart thermostats during the Treatment period only, without employing a difference-in-difference approach.

We found overall savings in mean hourly electricity consumption owing to Dynamic (-0.031 kW to -0.114 kW seasonal total) and Legacy Dynamic pricing households (-0.061 kW to 0.208 kW seasonal total) with registered smart thermostat (Table 8). These savings were largest during the Winter 2018-2019 season. In Summer 2019, participants in the Legacy Dynamic 6 group broke away from the overall pattern and saw a small but significant increase in Off-Peak electricity consumption relative to matched Controls owing to smart thermostat possession/registration (+0.122 kW per hour on average).

Table 8: Effects of smart thermostat Technology on Mean Hourly kW Consumption

APP Price Plan	Main effect of Technology in kWh (Relative to No Technology)								
Dynamic Pricing Pilot		CPP Days		High On-Peak		Off-Peak		Season Total	
		kW	%	kW	%	kW	%	kW	%
	Summer 2018	-0.150	-8.544	-0.062	-3.541	-0.015	-1.527	-0.031	-2.347
	Winter 2018-19	-0.145^	-12.344	**-0.145***	-13.704	**-0.110****	-12.241	**-0.114***	-11.531
	Summer 2019	-0.152	-9.692	-0.065	-4.314	-0.086	-8.885	-0.064	-5.532
Legacy Dynamic Pricing Pilot		High On-Peak				Off-Peak		Season Total	
		kW		%		kW	%	kW	%
	Summer 2018	**-0.127***		-6.887		0.052	5.383	-0.061	-4.379
	Winter 2018-19	**-0.281*****		-20.078		**-0.171*****	-15.283	**-0.208*****	-16.363
	Summer 2019	-0.082		-5.33		0.012	4.51	-0.064	-6.09

**** p < 0.001; ** p < 0.01; * p < 0.05; ^ p < 0.1*

Bill Savings

The impacts of Dynamic and Legacy Dynamic pricing on customers' electricity bills are shown in Table 9. The average monthly APP bills were compared to the average monthly TOU bills that participants would have paid if they showed the exact same consumption patterns but were billed as per Status-Quo TOU prices instead of APP (Dynamic) prices. Summary statistics show that Dynamic and Legacy Dynamic participants experienced small savings in the Summer 2018 period and moderate savings in the Winter 2018-19 period. However, participants in both Dynamic and Legacy Dynamic pricing experienced costs in Summer 2019 owing to participation in APP. Figures showing the distribution of the total savings per pricing pilot are shown in Appendix D.

Table 9: Monthly Bill Savings

Summer 2018	May	June	July	August	September	October	Average Monthly Savings
Dynamic	$11.93	$4.99	-$17.80	-$12.64	$2.37	$12.81	$0.28
Legacy Dynamic	$11.73	$5.22	-$16.45	-$11.01	$2.99	$12.34	$0.81
Winter 2019-19	November	December	January	February	March	April	Average Monthly Savings
Dynamic	$13.98	$10.14	-$0.79	-$14.42	-$3.19	$10.54	$2.71
Legacy Dynamic	$14.54	$10.43	-$1.31	-$16.16	-$3.84	$11.01	$2.45
Summer 2019		June	July	August	September	October	Average Monthly Savings
Dynamic 6 CPP	--	$12.25	-$12.04	-$22.28	-$2.46	$8.78	-$3.15
Dynamic 9 CPP	--	$11.40	-$13.19	-$21.56	-$1.21	$8.96	-$3.12
Legacy Dynamic 6 CPP	--	$11.44	-$12.51	-$19.64	-$0.36	$9.06	-$2.40
Legacy Dynamic 9 CPP	--	$11.57	-$12.53	-$19.67	-$0.16	$9.27	-$2.30

Bill Savings are Denoted as Positive

Conclusions

Alectra Utilities examined the impact of Dynamic pricing as an alternative pricing structure to Status-Quo TOU pricing amongst residential electricity consumers over a 17-month period. This examination was conducted as part of the Province's re-examination of the Regulated Price Plan in Ontario and included Dynamic and Legacy Dynamic pricing pilots in combination with two non-price manipulations, Nudge Reports and smart thermostat technology. Both Dynamic pricing and Legacy Dynamic pricing pilots yielded some reductions in On-Peak consumption. Over the full 17-month duration of the pilot, Dynamic pricing pilot yielded an estimated consumption reduction of 0.025 kW per hour on average (-2.47%; Table 33). However, for the Legacy Dynamic Pilot, High On-Peak reductions in consumption were offset by increases in Off-Peak electricity consumption, resulting in an increase in average hourly consumption over the 17-month duration of the pilot by these participants (Table 61).

Nudge Reports did not yield significant consumption impacts over and above the impacts of Dynamic pricing TOU periods. Smart thermostats that were registered to allow Alectra to curtail consumption during higher priced times of day were associated with electricity consumption impacts for some Summer CPP and High On-Peak periods and these impacts were largest during Winter On-Peak periods in both pilots.

The five-month extension of Dynamic and Legacy Dynamic pricing beyond the original 12-month reporting period of Advantage Power Pricing (the public-facing name of Alectra Utilities' instantiation of the Regulated Price Plan Pilot Project) was approved in order to address two primary research questions:

1. Will the responsiveness to High On-Peak and Critical Peak price events estimated for Dynamic and Legacy Dynamic customers in the Summer of 2018 persist a year later (i.e., in the Summer of 2019)?

2. Does the responsiveness to CPP events by Dynamic and Legacy Dynamic customers depend on the frequency of those events (i.e., will increasing the number of CPP events from six to nine per season result in diminished behavioural response to such events)?

With respect to the first research question, the magnitude of the consumption savings owing to High On-Peak pricing was numerically smaller for the Summer 2019 season relative to Summer 2018. This likely owes in large part to the fact that electricity consumption is variable and highly dependent on weather. High On-Peak average hourly temperatures were approximately 4 degrees Celsius lower in Summer 2019 relative to Summer 2018 (average hourly temperatures as a function of season and TOU period are provided in Table 25 later in this report). Of course, part of the quantitative reduction in High On-Peak impact across the two Summers may reflect diminished behavioural response to Dynamic pricing. It is not possible to ascertain the relative contributions of seasonal weather fluctuations and diminished behavioural response in driving the smaller estimated consumption impact in Summer 2019 relative to Summer 2018. Importantly, CPP event responsiveness was nearly identical in both Summer 2018 and Summer 2019 for households in both Dynamic and Legacy Dynamic pilots. Responsiveness to short, infrequent CPP events, therefore, shows no evidence of diminished behavioural response over a two-Summer reporting period.

With respect to the second research question, consumption impact estimates clearly indicate that average hourly consumption savings during CPP events do not differ between households who received six such events and those who received nine. We can conclude therefore, that for a given CPP event, behavioural response is not affected by the frequency at which such events occur, at least within the range of event frequencies that were manipulated here.

Contents

1. Introduction

In an effort to achieve the conservation and demand management (CDM) objectives in the province of Ontario, the Ontario Energy Board has been seeking to examine the impact of alternative electricity pricing schemes under the Regulated Price Plan (RPP) as well as the impact of non-price interventions (such as communications and technology) on electricity consumption behaviour among residential customers. Alectra Utilities participated in the RPP Pilot Program to test the impact of three separate Time-of-Use (TOU) pricing schemes and two non-price interventions on conservation, load-shifting, and peak period consumption reduction behaviours amongst a sub-set of its customers.

TOU pricing was introduced in Ontario with the goal of reducing electricity consumption among residential and commercial consumers during 'peak' times of day when demand on generation and distribution infrastructure is highest. TOU pricing charges consumers different hourly Kilowatt-Hour (kWh) prices depending on the time of day. Ontario adopted a three-period TOU pricing structure comprised of Off-Peak (when prices are lowest), Medium-Peak, and On-Peak (when prices are highest) periods. TOU pricing periods are meant to closely mirror actual system peak demand (as per the Independent Electricity System Operator). The logic behind TOU pricing is based on traditional economic theory which holds that consumption of a given commodity will decrease as the price of that commodity increases. TOU pricing is therefore intended to function as a disincentive to electricity consumption during On-Peak periods when prices are highest.

In an effort to further improve the efficacy of TOU pricing in achieving the Province's conservation and demand management objectives, the OEB has undertaken a re-examination of the RPP in an effort to uncover new ways of achieving those objectives. The OEB identified two primary areas of opportunity to better align the RPP with the province's conservation goals:

1. *Implementing Price Pilots: The OEB stated that it would work with Local Distribution Companies (LDCs) to undertake several pricing (and non-price) pilots. The pilots will run for at least one calendar year to assess whether there is persistence in the impact of the intervention.*

2. *Empowering Consumers – Enhancing energy literacy and non-price tools: The OEB stated that it intends to launch non-price pilot initiatives, such as piloting automated load control technology and behavioural interventions.*

The first prioritized opportunity area outlined by the OEB acknowledges that perhaps the price differential between On-Peak and Off-Peak TOU periods is currently insufficient to function as meaningful financial disincentive to the consumption of electricity during peak hours. It is therefore hypothesized that more severe financial disincentives for On-Peak consumption might result in On-Peak conservation and/or load-shifting behaviours among consumers. The second prioritized opportunity area outlined by the OEB acknowledges that perhaps financial levers are not the only (and perhaps not the most effective) method of promoting behaviour change. This perspective (grounded in the field of behavioural economics) holds that individuals do not always respond to pricing signals in the way that traditional economic theory would predict. This occurs because we are subject to myriad cognitive biases such as temporal discounting. In the context of electricity consumption, this means we are prone to value our comfort in the present moment (resulting in over-use of electricity consuming appliances such as air conditioners) and to discount the future costs associated with that behaviour. It is therefore hypothesized that non-price behavioural interventions that mitigate the effects of these cognitive biases may represent a complementary approach to financial disincentives in promoting conservation and/or load shifting behaviours.

One of the three pricing pilots tested within the broader RPP pilot undertaken by Alectra Utilities (the Dynamic pricing pilot) proved successful with respect to both of these objectives during the first 12 months of the RPP Pilot. Dynamic pricing as an alternative pricing scheme to Status-Quo TOU pricing yielded substantial reductions in electricity consumption during High On-Peak times of day during the Summer and Winter months as well as during all Critical Peak pricing periods. In addition, incremental consumption impacts were estimated during High On-Peak Summer hours and Critical Peak periods owing to non-price communications (Nudge Reports) and technology assets (programmable smart thermostat ownership/registration). Given the demonstrated potential of Dynamic pricing as an alternative to Status-Quo TOU pricing, a decision was made in May 2019 to extend the Dynamic pricing pilot for another five months (June 01, 2019 – October 31, 2019 inclusive). The stated goals of this extension were to: (1) obtain data for a second Summer reporting period for Dynamic pricing, and (2) test the impact of variable frequencies of Critical Peak Period (CPP) events (6 vs 9) within a given seasonal period. The consumption impacts owing to Dynamic pricing during the entire 17-month duration of the Dynamic pilot (including the original 12-month reporting period and the five-month extension period) are the subject of the remainder of this report.

In the sections that follow, we first outline the details of the Dynamic pricing pilots and the non-price interventions that were tested experimentally as part of the RPP pilot project. We then present a detailed impact analysis, separately for each of the two customer groups who took part in Dynamic pricing (i.e., newly enrolled customers, and Legacy Dynamic customers). Finally, we present the findings from customer-facing surveys distributed throughout the 17 months of the Dynamic pricing pilot program that aimed to measure TOU comprehension and motivations to conserve electricity among pilot participants.

2. Dynamic Price Plan

Customers participating in the Dynamic pricing pilot experienced variable On-Peak prices depending on anticipated demand determined by the IESO. This pricing pilot is designed to appeal to customers who are typically home in the afternoon. Participating customers were informed of the variable On-Peak price each day at 4pm (at which point they are informed of what the price will be the following day). Customers were informed of the variable peak price each day either by logging into their APP online portal or subscribing to receive SMS text and/or email alerts from Alectra at 4pm each day. These customers also experienced CPP events lasting four hours each with an especially high kWh price. For the extension period, which comprises the Summer period months of June 01, 2019 – October 31, 2019 inclusive, half of Dynamic pricing customers and Legacy Dynamic customers were subjected to a total of six CPP events, and half were subjected to nine such events. These groups are referred to in this document as Dynamic 6/Legacy Dynamic 6 and Dynamic 9/Legacy Dynamic 9, respectively. The prices and associated price periods are shown in Table 10 below.

Table 10: Dynamic Pricing TOU Periods and Associated kWh Rates in cents (CAD)

Price Period	Hours	Price (cents/kWh)	
		Nov - April	May - Oct
Off-Peak	Weekdays: 12am-3pm and 9pm-12am Weekends: All day	4.9	4.9
Low On-Peak	50% of Weekdays: 3pm-9pm	10.0	9.9
Medium On-Peak	30% of Weekdays: 3pm-9pm	19.9	19.8
High On-Peak	20% of Weekdays: 3pm-9pm	39.8	39.7
Critical Peak	On the top six or nine system peak days in summer and winter, each event lasting four hours. Start time of events determined by peak demand hour of event day	49.8	49.8

Status-Quo Time-of-Use Pricing: Customers assigned to the Control groups experienced Status-Quo TOU prices. The Status-Quo TOU prices and associated periods are shown in Table 11.

Table 11: Status-Quo TOU Pricing TOU Periods and Associated kWh Rates in cents (CAD)

Price Period	Summer Hours (May – October)	June - October
Off-Peak	Weekdays: 12am-7am and 7pm-12am Weekends: All day	6.5¢
Mid-Peak	Weekdays: 7am-11am and 5pm-7pm	9.5¢
On-Peak	Weekdays: 11am-5pm	13.2¢

Electricity costs associated with pilot participation were communicated to pricing pilot participants via Shadow Bills. Shadow Bills are a monthly electricity consumption report that communicates to pilot participants how much electricity they have consumed in the prior billing period and how the associated costs of that electricity compare with that of Status-Quo TOU pricing (i.e., what customers would have been charged if they had the exact same consumption pattern in the billing period, but were billed according to Status-Quo TOU prices). The primary function of this Shadow Bill was to communicate bill cost savings or increases as a result of pricing pilot participation. It was hypothesized that (1) positive feedback (i.e., bill cost savings) would encourage participants to further augment their consumption patterns to realize additional savings and remain in the program. It was hypothesized that (2) negative feedback (i.e., bill cost increases) would encourage participants to begin to augment their consumption behaviours in order to realize bill cost savings. The Shadow Bill was mailed in paper form to pilot participants each billing period as a separate piece of communication to the actual monthly Alectra Utilities bill. An example Shadow Bill is shown in Appendix B. All customers in Dynamic and Legacy Dynamic pricing pilots received Shadow Bills.

3. Non-Price Interventions

In order to address the second key objective of the RPP pilot program as outlined by the OEB (i.e., *Empowering Consumers: Enhancing energy literacy and non-price tools*[4]) Alectra, in collaboration with BEworks, Util-Assist, and Bidgley, created communications that were distributed to customers on a monthly basis. These reports served to provide behavioural 'nudges' to customers to drive conservation and load-shifting behaviours (Nudge Reports). In addition, Alectra, in collaboration with Nest, Ecobee, and Energate, offered smart thermostats to pricing pilot participants to help them better realize consumption savings through automatic load curtailment functionality. It was hypothesized that pricing pilot participants with programmable smart thermostats that were registered with Alectra and subject to automatic load curtailment during Variable On-Peak and Critical Peak pricing events would exhibit greater consumption reductions than pricing pilot participants without registered devices. We describe the rationale and logistics of each of the two non-price interventions (Nudge Reports and Technology) below.

3.1.1 Nudge Reports

Exactly half of customers in both the pricing Treatment groups within the Dynamic pricing pilot and Legacy Dynamic pilot were randomly selected to receive Nudge Reports[5]. In addition, half of the customers in the Dynamic pricing pilot matched Control group were randomly selected to receive Nudge Reports. No customers in the Legacy Dynamic matched Control group received Nudge Reports due to the unavailability of customer data at the time these reports were created. Nudge Reports are one-page communications that accompanied the Shadow Bills each month for Dynamic and Legacy Dynamic pricing Treatment customers and were sent as a stand-alone report each month for Dynamic Control customers (i.e., those on Status-Quo TOU pricing who do not receive Shadow Bills). Nudge Reports employed behavioural economic approaches to drive load shifting and conservation behaviours. Specifically, four different behavioural approaches – a commitment device, feedback and benchmarking, personalized recommendations, and salient reminders – were featured in the Nudge Reports. We describe each of these tactics in turn, including the behavioural approach and relevant supporting research.

Commitment device: The initial cycles of Nudge Reports included a monetary offer whereby customers were asked to take a pledge to reduce their electricity usage during On-Peak times of day. A monetary incentive ($5 rebate) was offered to consumers when they sent an SMS message indicating their intent to sign the pledge (e.g., "YES") to a short code.

Commitment devices such as pledges can be an effective strategy for changing behaviour where intention does not match action. According to cognitive dissonance theory[6], people have the tendency to keep attitudes and beliefs in line with their externalized behaviours. Consequently,

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[4] https://www.oeb.ca/sites/default/files/uploads/RPP_Roadmap_Report_of_the_Board_20151116.pdf

[5] No customers in the Overnight pricing pilot received Nudge Reports due to a lower than expected enrollment rate for that pilot. As a result, we were not able to introduce an additional experimental factor while maintaining sufficient experimental power to detect the interactive effects of both price *and* Nudge Reports on consumption behaviour.

[6] Festinger, L. (1957). A Theory of Cognitive Dissonance, Evanston, ILL, Row, Peterson.

when people perceive that they have freely chosen to commit to a behaviour, this becomes internalized within their self-concept, making it more likely that people will follow through on behaviours consistent with the initial (comparatively trivial) act of commitment. An example of this phenomenon is known as the *foot-in-the-door* technique whereby asking individuals to agree to a small request makes it more likely for them to later comply with a larger request[7]. In the present context, it was hypothesized that pledges would act as initial small requests that aimed to regulate subsequent conservation behaviours.

There is support in the scientific literature for using commitment devices to nudge individuals towards environmentally friendly behaviours including energy conservation[8,9,10]. In one study, researchers found that when hotel guests made a specific commitment at check-in and received a lapel pin as a reminder of their pledge, they were 25% more likely to reuse their towels[11]. A study on household recycling found that a commitment intervention where participants were asked to sign a pledge card and then received a sticker to remind them of their commitment resulted in a significant increase in the frequency of recycling during the pledge period, relative to a control group[12].

Additional research indicates that providing people with a financial incentive to commit to a prosocial cause can increase compliance with that cause[13]. Using a monetary reward in the present pilot was hypothesized to increase the likelihood that consumers would agree to the conservation pledge (although we did not test this experimentally since all customers who received Nudge Reports were offered the pledge with a monetary incentive). The pledge campaign ran for 3 months (bills mailed from June to August 2018). There was a total of 101 Dynamic pilot participants and 106 Legacy Dynamic pilot participants who responded to the pledge and were therefore eligible for the $5 bill credit.

Consumption feedback and benchmarks: Using Bidgely's load disaggregation data, appliance level usage feedback information was provided to customers receiving monthly Nudge Reports. A meta-analytic review of 21 unique papers on the impact of feedback on electricity consumption supports the idea that individualized feedback leads consumers to better understand and control their usage[14]. The findings revealed an average of 5% to 12% reduction in electricity

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[7] Freedman, Jonathan L., and Scott C. Fraser. "Compliance without pressure: the foot-in-the-door technique." Journal of personality and social psychology 4, no. 2 (1966): 195.
[8] Katzev, R. D., & Johnson, T. R. (1984). Comparing the Effects of Monetary Incentives and Foot-in-the-Door Strategies in Promoting Residential Electricity Conservation. Journal of Applied Social Psychology, 14(1), 12-27.
[9] Pallak, M. S., & Cummings, W. (1976). Commitment and voluntary energy conservation. Personality and Social Psychology Bulletin, 2(1), 27-30.
[10] Werner, C. M., Turner, J., Shipman, K., Twitchell, F. S., Dickson, B. R., Bruschke, G. V., & Wolfgang, B. (1995). Commitment, behavior, and attitude change: An analysis of voluntary recycling. Journal of Environmental Psychology, 15(3), 197-208.
[11] Baca-Motes, K., Brown, A., Gneezy, A., Keenan, E. A., & Nelson, L. D. (2012). Commitment and behavior change: Evidence from the field. Journal of Consumer Research, 39(5), 1070-1084.
[12] Burn, S. M., & Oskamp, S. (1986). Increasing community recycling with persuasive communication and public commitment. Journal of Applied Social Psychology, 16(1), 29-41.
[13] Katzev, R. D., & Pardini, A. U. (1987). The comparative effectiveness of reward and commitment approaches in motivating community recycling. Journal of Environmental Systems, 17(2).
[14] Fischer, C. (2008). Feedback on household electricity consumption: a tool for saving energy? Energy efficiency, 1(1), 79-104.

consumption as a result of different feedback mechanisms. Particularly, the meta-analysis examined the variable impact of feedback mechanisms and found that the most effective feedback is delivered frequently and consistently over a long period of time, includes specific appliance level information, and is presented in a clear and appealing way.

In addition, Nudge Reports included a historical benchmark visual comparing consumers' On-Peak usage in the billing cycle to their calibrated average historical On-Peak usage. The visual included a feedback message informing consumers of whether their On-Peak consumption deviated negatively or positively relative to a moving average. Research suggests that consumers typically respond well to goal-specific feedback resulting in reductions in electricity usage. For example, in a field study of residential energy use, families that were asked to set a goal to reduce their electricity consumption and were provided with frequent feedback on their progress achieved an average of 13%-15.1% in electricity savings[15]. In prior BEworks research conducted on behalf of the Ontario Energy Board, participants were more likely to understand and indicate intent to conserve electricity after receiving negative comparisons to past usage behaviour paired with a visual of a red, wide house (meant to appear as though it were 'bloated' with energy) relative to other types of feedback[16]. Together, feedback and benchmarking provide information attributable to specific actions, allowing consumers to make comparisons to standards of behaviour and exert effort towards the most effective courses of action[17].

Personalized recommendations: Nudge Reports included personalized energy saving recommendations using Bidgely's personalization algorithm. These recommendations accompanied usage feedback information to provide customers with actionable tips on how to become more energy efficient. Prior research reveals that highly personally relevant and specific information can be effective in reducing household energy consumption. In one study, home energy audits that provide tailored energy savings options to households reduced electricity consumption by 21% compared to a control group[18]. In addition to personalized information, research shows that when people have a detailed plan for when and how they intend to reach a goal, they are more likely to attain it[19]. Psychologists refer to these actionable plans as *implementation intentions*. Theories supporting the use of implementation intentions postulate that when anticipated situations are linked with a goal-directed response, people are less likely to be deterred by obstacles impeding the completion of a task[20]. By providing customers with specific load-shifting and/or consumption reduction actions that are relevant to them, it was hypothesized that customers would be more likely to follow through with these recommended conservation actions.

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[15] McCalley, L.T. & Midden, J.H. Energy conservation through product-integrated feedback: The roles of goal-setting and social orientation. Journal of Economic Psychology, 23, 589–603
[16] BEworks, 2014. https://www.oeb.ca/oeb/_Documents/EB-2004-0205/BEworks_TOU_Report.pdf
[17] Kluger, A. N., & DeNisi, A. (1996). The effects of feedback interventions on performance: a historical review, a meta-analysis, and a preliminary feedback intervention theory. Psychological bulletin, 119(2), 254.
[18] Winett, R. A., Love, S. Q., & Kidd, C. (1982). The effectiveness of an energy specialist and extension agents in promoting summer energy conservation by home visits. Journal of Environmental Systems, 12(1).
[19] Gollwitzer, P.M. & Brandstätter, V (1997). Implementation intentions and effective goal pursuit. Journal of Personality and social Psychology. 73, 186.
[20] Gollwitzer, P. M. Implementation intentions: strong effects of simple plans. American Psychologist. 54, 7, 493.

Salient reminders: Potential behavioural barriers to load shifting include failing to pay attention to and/or simply forgetting the pricing schedule when consuming electricity on a daily basis. To address these barriers, consumers received visual memory aids to act as reminders to shift consumption behaviour in accord with their pricing schedule. These took the form of a visually salient, color-coded TOU pricing schedule that consumers had the opportunity to cut out then place in a prominent area of their home, such as on their fridge or in the laundry room. This visually salient linear timeline also clearly illustrated TOU period costs and showed how much more On-Peak and Medium-Peak periods cost relative to Off-Peak periods.

3.1.2 Thermostat Technology

As part of the RPP pilot project objectives it was also of interest to measure the impacts of smart thermostat technology that allows for automatic load curtailment during high priced TOU periods in driving conservation and load-shifting behaviours. Eligible smart thermostats can be adjusted dynamically and automatically in response to weather effects and changes in price by a customer's local distribution company, and it was therefore hypothesized that pilot participants with smart thermostats that were registered to receive such curtailment would realize additional incremental consumption savings relative to those without registered devices. As such, all Technology impact estimations are restricted to customers who registered their thermostats through Alectra to receive automatic load curtailment, which reduced heating/cooling load during higher-priced TOU (i.e., Variable On-Peak and Critical Peak). Customers with eligible devices were required to opt-in to load curtailment, which was accomplished by simply registering their device. In our analysis of smart thermostat technology as a non-price manipulation, we designate customers with registered smart thermostats as 'Technology' customers. This means that the impacts of smart thermostats on consumption behaviour derive not simply from owning an eligible smart thermostat but from receiving some form of automatic load curtailment. As can be seen in Table 12, the availability and nature of load curtailment varied by thermostat type.

Table 12: Thermostat Curtailment Periods

	Curtailment Period	
Thermostat Type	Dynamic (On-Peak)	Dynamic (Critical Peak)
Energate	Based on customer-selected 'comfort' setting	Based on customer-selected 'comfort' setting
Honeywell	Based on operating time	Based on operating time
Ecobee	Based on operating time	Based on operating time
Nest	N/A	Based on Rush Hour Rewards[21]

[21] https://support.google.com/googlenest/answer/9244031?co=GENIE.Platform%3DAndroid&hl=en

Energate Foundation Thermostat Load Curtailment Functionality by Dynamic TOU Period: For Energate Foundation thermostats, the amount of load curtailment at any given time was determined by: (1) the price of electricity, with higher priced TOU periods being subjected to higher curtailment, and (2) the thermostat comfort settings chosen by the homeowner, which ranged from 'Max Comfort' (no curtailment whatsoever) to 'Max Savings' (the highest possible curtailment). The mapping of TOU period to potential curtailment (in °C) for each of the three pricing pilots are shown in Table 13 below. Also shown in Table 14 is the mapping of smart thermostat Comfort Settings to Savings Percentages.

Table 13: Dynamic Pilot - Mapping of TOU Period to Max Savings

TOU Period	Max Savings (°C)
Off-Peak	0
Low On-Peak	1
Medium On-Peak	2
High On-Peak	3
Critical Peak	4

Table 14: Curtailment Enabled Energate Thermostats - Mapping of Savings Percentage to Comfort Setting

Savings Percentage (%)	Comfort Setting
0	Max Comfort
25	Comfort
50	Balanced
75	Savings
100	Max Savings

Given the above information, this means that a Dynamic pricing customer with a curtailment-enabled registered smart thermostat who selected the 'Balanced' comfort setting, would have seen Critical-Peak curtailment of 2 degrees Celsius (50% of the Max Savings for that TOU period). The relationship between Savings Percentage and Comfort Setting is Energate thermostat-specific.

Honeywell and Ecobee Thermostat Load Curtailment Functionality: Unlike Energate curtailment functionality, curtailment settings for Honeywell and Ecobee owners was based on Air Conditioning run-time, not degree settings. The mapping of run-time curtailment to peak period within Dynamic pricing is shown in Table 15.

Table 15: Honeywell and Ecobee Thermostats – Mapping of Pricing Period to Run-Time

Pricing Period	Maximum Air Conditioner Run Time
Off-Peak	N/A
Low On-Peak	30 minutes/hour
Medium On-Peak	24 minutes/hour
High On-Peak	18 minutes/hour
Critical Peak	12 minutes/hour

4. Advantage Power Pricing Impact Analysis Methodology

4.1 General Approach

Here we outline the methodological approach for the participant sampling and experimental designs employed to assess impacts of the Dynamic and Legacy Dynamic pilot interventions on conservation and demand management behaviours. Specific design and sampling specifications unique to each pilot are included in corresponding subsections.

The first step in the sampling procedure was to isolate the sample frame from which participants would be drawn for participation in the pilot. In doing so, there were several considerations/constraints. First, only households within the PowerStream legacy service territory were considered eligible. Second, eligible participants must not have been participating in any other pilot programs with conservation and/or demand management objectives (e.g., Home Energy Report pilots). Specifically, households receiving Home Energy Reports (or designated as part of the Control group for Alectra's Home Energy Report program) were not included in the sample frame. In addition, households participating in Alectra's Advantage Planet program were also ineligible for participation. The remaining households were then recruited for participation in Dynamic pricing or assigned to the matched Control group. No recruitment or assignment of Legacy Dynamic households or associated matched Control households was conducted; their participation in Dynamic pricing was simply continued from the legacy program. For calculations and assumptions related to experimental power, see Appendix E.

In the sections that follow, we describe the sampling procedure and present participant numbers as a function of experimental condition for each of the pricing pilots. The presentation of sample size numbers is intended to provide transparency on the different criteria under which participants who originally opted in, or who were automatically assigned to matched Control conditions for the pilot, were excluded from the data set used to estimate impacts. The columns in the sample size tables should be read as follows:

Starting N: The number of participants in each experimental condition (Price Treatment, Control; Nudge Report Treatment, Control) at the beginning of the relevant reporting period (Summer or Winter Treatment period months).

Opt-Outs: The number of participants who communicated to Alectra that they wished to discontinue participation in the pilot at any point during the relevant reporting period.

Move-Outs: The number of participants who moved at any point during the relevant reporting period

Missing Data: The number of participants for whom sufficient hourly Smart Meter data was not available to allow for consumption impact estimation in the relevant reporting period.

Outliers: The number of participants for whom their average hourly kW consumption was deemed to be excessively high or low (i.e. <0.05kW/h or >15kW/h), indicating that they may not be a representative household with respect to electricity consumption within the Alectra service territory.

Total Exclusions: This is simply the sum of Opt-Outs + Move-Outs + Missing Data + Outliers.

Final N: This is simply the Starting N subtracting the Total Exclusions. Final N represents the number of households that contributed electricity consumption data to the impact analyses for the relevant reporting period.

4.1.1 Dynamic Pricing Sampling Procedure

Since the TOU pricing periods under the Dynamic pricing structure do not align with Status-Quo TOU pricing periods, customers participating in the Dynamic pilot experienced significant material changes to their TOU schedules. In addition, the inclusion of CPP events and Variable Peak pricing required that participating residential customers be notified on a daily basis of whether there would be Low-, Medium-, High-, or Critical-Peak periods. For these reasons, the Dynamic pilot was run on an opt-in basis, requiring that eligible residential customers sign-up for (opt-in to) Dynamic pricing. As such, the Dynamic plan was run as a Matched Controlled Trial, meaning that once enrollment into the pricing Treatment group was completed, a Control group was created from the remaining sample frame that matched pricing Treatment participants on historical consumption behaviours. Additional detail on the matching algorithm and the consumption metrics used to derive the matched Control group can be found in Appendix A. Once the Treatment and matched Control groups for the Dynamic pilot were established, half were randomly assigned to receive Nudge Reports. The distribution of participants to each of the four Dynamic pricing pilot groups for the Summer 2018 and Winter 2018-19 periods is shown in Table 16.

Beginning in October 2017, eligible households were contacted via direct marketing efforts to voluntarily sign up for either the Dynamic plan as part of the current instantiation of the Regulated Price Plan Pilot project. At the conclusion of the original 12-month reporting period of the RPP Pilot program, Dynamic pricing customers were notified that the program would be extended an additional five months (June – October 2019) and were reminded to opt-out of the program if they wished to be returned to Status-Quo TOU pricing. The Summer 2019 extension period covered June-October 2019 instead of the full 6-month May-October Summer season because customers were not informed of the extension of Dynamic pricing until late May[22]. Customers were then randomly assigned to receive either six or nine CPP events within the 5-

[22] The reporting period for the original pilot concluded at the end of April 2019, however Dynamic pricing was extended through May while the OEB considered implementing a full Summer 2019 extension period, with the addition of the CPP event frequency factor. For this reason, May is considered to be a 'transition month' whereby participants continued to experience Dynamic pricing, but were not informed of the longer term extension, or of their assignment to the CPP 6 vs CPP 9 groups. We could not, therefore, include consumption data for May 2019 in the extension period analysis. The official start date of the extension period is June 1, 2019, when participants were notified of the extension, given the opportunity to opt-out, and assigned to CPP 6/9 experimental groups.

month reporting period of the extension of the pilot and are hereafter referred to as the "Dynamic 6" and "Dynamic 9" groups, respectively. Participant numbers as a function of condition in the Summer 2019 pilot period are displayed in Table 17.

Table 16: Number of Participants in Dynamic Pilot, Summer 2018 and Winter 2018-19

Summer 2018 Reporting Period								
	Starting N	Opt-Outs	Move-Outs	EVs	Missing Data[23]	Outliers	Total Exclusions	Final N
Dynamic Pricing, No Nudge Report	385	34	9	0	0	4	47	338
Dynamic Pricing + Nudge Report	385	29	6	0	0	5	40	345
Status-Quo TOU Pricing, No Nudge Report	385	0	14	0	1	6	21	364
Status-Quo TOU Pricing + Nudge Report	385	1	17	0	0	5	23	362
Total	1540	64	46	0	1	20	131	1409
Winter 2018-19 Reporting Period								
	Starting N	Opt-Outs	Move-Outs	EVs	Missing Data	Outliers	Total Excls.	Final N
Dynamic Pricing, No Nudge Report	338	25	8	0	70	0	103	235
Dynamic Pricing + Nudge Report	345	38	4	0	67	1	110	235
Status-Quo TOU Pricing, No Nudge Report	364	0	20	0	0	2	22	342

[23] See Section 4.2.4 Issues or Concerns for further explanation.

Status-Quo TOU Pricing + Nudge Report	362	4	14	0	0	3	21	341
Total	1409	67	46	0	137	6	256	1153

Table 17: Number of Participants in Dynamic Pilot, Summer 2019

Summer 2019 Extension Period								
	Starting N	Opt-Outs	Move-Outs	EVs	Missing Data	Outliers	Total Excls.	Final N
Dynamic 6 Pricing, No Nudge Report	120	2	9	1	0	1	13	107
Dynamic 9 Pricing, No Nudge Report	108	5	4	1	0	0	10	98
Dynamic 6 Pricing + Nudge Report	115	3	5	2	0	0	10	105
Dynamic 9 Pricing + Nudge Report	127	6	2	1	0	0	9	118
Status-Quo TOU Pricing, No Nudge Report	342	0	12	0	0	4	16	326
Status-Quo TOU Pricing + Nudge Report	341	4	13	0	0	2	19	322
Total	1153	20	45	5	0	7	77	1076

4.1.2 Legacy Dynamic Pricing Pilot

Alectra began offering a version of Dynamic pricing to its customers in 2015, and over the course of three separate registration periods, had been continuing to offer Dynamic pricing to a subset of its residential customer base. This means that at the commencement of the most recent instantiation of the RPP pilot program, there existed approximately 1,500 households already enrolled in Dynamic pricing. In an attempt to gather data on the longevity of previously estimated behavioural response to Dynamic pricing, Alectra and the OEB sought to retain this 'Legacy' Dynamic customer group. There exist three key differences between the Legacy and 'new' Dynamic customer bases that necessitate that we treat these groups independently, both in terms of the sampling procedure and subsequent analysis.

- The Legacy Dynamic households had been subjected to Dynamic pricing for (in some cases) up to 3 years at the commencement of the reporting period of the current evaluation

- Until the start of the current pilot reporting period, Legacy Dynamic pricing was offered with full price protection, representing an important qualitative difference between the legacy and most recent instantiations of Dynamic pricing

- The Legacy Dynamic pricing pilot was created as an opt-in pricing pilot with a matched Control group; however, separate matched Control groups were created for Summer and Winter impact analyses (whereas the present evaluator has created a single matched Control group for all impact analysis pertaining to the "new" Dynamic households)

Legacy Dynamic households were not required to re-enroll into the current pilot program, but instead were informed via email and/or direct mail that Dynamic pricing was being extended until April 2019, with the removal of price protection beginning in May 2018. As with the new Dynamic customers, half of Legacy Dynamic households were then randomly assigned to receive Nudge Reports for the duration of the pilot. Unlike the New Dynamic matched Control customers however, Nudge Reports were not distributed to Legacy Dynamic matched Control customers. Procurement of household premise IDs for Legacy Dynamic Control customers (which were not known by Alectra since they were identified by an independent evaluator several years prior) was not completed in a timely enough manner to begin distributing Nudge Reports to those customers at the commencement of the pilot.

At the conclusion of the original 12-month reporting period of the RPP Pilot program, Legacy Dynamic pricing customers were notified that the program would be extended an additional five months (June – October 2019) and were reminded to opt-out of the program if they wished to be returned to Status-Quo TOU pricing. Customers were then randomly assigned to receive either six or nine CPP events within the 5-month reporting period of the extension of the pilot. After assignment, we confirmed that the two groups did not statistically differ on historical energy consumption.

4.2 Treatment of Hourly Consumption Data

4.2.1 Description of the Data

The impact analyses that follow used quantitative data to perform inferential statistical analyses to test the effects of pricing Treatments and non-price interventions on household electricity consumption. The consumption impacts were derived from hourly Smart Meter readings for each household over the course of at least two years (12 months of pre-pilot data and 17 months of pilot data) measured in kilowatt hours (kWh) and was delivered to the evaluator (BEworks Inc.) from Savage Data Systems, Alectra's Operational Data Store. For estimated consumption impacts, hourly means are reported in kilowatts (kW).

4.2.2 Preprocessing Activities

The data cleaning process to convert raw hourly data to the data used for the statistical analysis involved converting the hourly data into means tables based on the appropriate timeframe. In total, there were four means tables created for each of the two pilots (Dynamic and Legacy Dynamic) for a total of eight means tables. The means tables consisted of:

- Time-of-Use Period Impacts: Hourly means in kW for each defined peak period, for each month, for each household

- Average Conservation Impacts: Hourly means in kW for each month, for each household

Preprocessing also involved removing households based upon several exclusionary criteria. Households were excluded if they moved during the pilot, or if they actively opted-out of the program. Households were also excluded if they exhibited many consecutive missing hourly measurements. Households exhibiting missing data generally did so for several months or longer, thus a minimum threshold of one month of missing data was set for exclusion (see Section 4.2.4 Issues or Concerns for more information). Lastly, households were excluded if their mean hourly consumption was deviant relative to other households (i.e., they were classified as 'outliers', and thus not representative of a 'typical' household within the service territory). The operational definition of an outlier was any household that exhibited hourly consumption greater than 15 kWh or less than 0.05 kWh at any hour (i.e., hours 1-24, averaged across day) during the reporting period. Households that qualified under any exclusionary criteria were indexed and subsequently removed prior to statistical analyses.

4.2.3 Estimated Elasticities

The purpose of the Estimated Price Elasticity analysis is to measure the percent change in consumption relative to a percent change in price. Both own-price (daily) elasticity and inter-period substitution elasticity are computed:

- Own-Price Elasticity: Daily means in kW for each household

- Inter-Period Substitution Elasticity: Hourly means in kW for each Peak period, for each month, for each household

4.2.4 Issues or Concerns

There were issues concerning the completeness of the *Technology* data. Data was available from Alectra on households who had purchased a smart thermostat through their thermostat incentive program offerings, but this does not cover households who purchased a smart thermostat outside of Alectra and did not register those devices with Alectra at the commencement of the pilot. Households were asked about the presence of a smart thermostat in the baseline, interim, and end-of-pilot surveys. However, smart thermostats not registered with Alectra were not eligible for load curtailment. This means that all analyses related to the incremental impacts owing to smart thermostats will be restricted only to customers with registered devices that are capable of some form of load curtailment.

There was a disproportionate incidence of 'missing data' for the Dynamic Treatment (this issue only pertains to 'new' Dynamic Treatment customers, not Legacy Dynamic Treatment customers). Upon investigation, there was not enough historical baseline data for a number of customers in this group. As a result of the fact that historical data for at least one year prior to the unprotected period of the current pilot is required in order to employ our difference-in-difference methodology, customers with insufficient historical baseline data were excluded from analysis. The missing data in question was simply delivered to the evaluator by Alectra's operational data store as 'NA' values for the requested baseline period and so the evaluator cannot shed any further light on why customers were allowed to participate in the pilot without the requisite historical consumption data. We speculate, however, that customers opted-in to the pilot, not through direct solicitation by Alectra (since only customers within the eligible sample frame were subject to direct marketing) but instead through referral by neighbours, friends, or family members. Further investigation by Alectra Utilities would be required to unequivocally determine how these customers opted-in to the pricing Treatment plans offered under APP. The loss in sample size due to missing data within the 'new' Dynamic Treatment group was approximately 9.3% for the Winter 2018-2019 and Summer 2019 impact analyses.

4.3 Dependent Variables

In this section, we present the three main dependent variable categories:

- Time-of-Use Period Impacts (including Critical Peak)
- Average Conservation Impacts
- Estimated Price Elasticities

Next, we present a definition and impact estimation model specifications for each dependent variable category.

4.3.1 Time-of-Use Period Impacts

The purpose of the TOU period impact analysis is to measure the change in energy consumption for a Treatment group relative to a Control group during specific TOU periods as a function of pricing Treatment and/or non-price intervention.

We define Time-of-Use Period Impacts as: The year-over-year difference in the average hourly consumption per month, attributable to the pilot program intervention, calculated separately for each TOU period. The exception to this is the Legacy Dynamic pilot impact estimations. The primary reason for this is that no appropriate historical baseline period existed for all Legacy Dynamic participants. Consequently, Legacy Dynamic impacts were derived by simply comparing Treatment and Control customer consumption within the 17-month pilot period.

The weekdays and hours associated with each TOU period for the Dynamic pricing structure are shown below in Table 18.

Table 18: Dynamic Pricing kWh Prices (applicable for Dynamic and Legacy Dynamic)

Price Period	Hours	Price (cents/kWh)	
		Nov - April	May - Oct
Off-Peak	Weekdays: 12am-3pm and 9pm-12am Weekends: All day	4.9	4.9
Low On-Peak	50% of Weekdays: 3pm-9pm	10.0	9.9
Medium On-Peak	30% of Weekdays: 3pm-9pm	19.9	19.8
High On-Peak	20% of Weekdays: 3pm-9pm	39.8	39.7
Critical Peak	On the top six system peak days in Summer 2018 and Winter 2018-2019, and the top nine such days in Summer 2019, each event lasting four hours. Start time of events determined by peak demand hour of event day	49.8	49.8
System-Coincident Peak Impact	Nov-April	May-Oct	
	1pm-7pm (June, July, August) Weekdays and is based on the IESO's analysis of peak hourly load	6pm – 8pm (December, January, and February) Weekdays, and is based on the IESO's analysis of peak hourly load	

There was a slight deviation from the prescribed breakdown of Low, Medium, and High On-Peak days. The way Alectra determines the rate per day is based on the IESO's overall demand forecast – which is highly correlated to the weather forecast – which is variable and hard to predict. Alectra sets a threshold on the demand forecast that will determine if a day is Low, Medium, or High. Alectra adjusts the threshold to ensure that the correct number of day-types occur in each season while trying to be mindful of creating a consistent experience for customers. This means that, for example, if Alectra anticipates a very hot day late in the Summer season, they will plan to call a 'High' On-Peak price, but if it turns out to be a fairly mild day in reality, Alectra will instead call a 'Low' or 'Medium' On-Peak price in order to maintain consistency (from a customer's point of view) between actual experienced weather fluctuation and variable peak prices. For this reason, the realized percentages of Low, Medium, and High On-Peak days may differ slightly from what is prescribed by the OEB. The actual distribution of On-Peak and CPP days are presented in Table 19 through Table 21. Critical Peak day dates are listed in Table 22.

Table 19: Dynamic On-Peak and CPP Days (Summer 2018)

Dynamic On-Peak	Number of Days	% of Total	Prescribed by OEB
High	26	20%	20%
Medium	35	28%	30%
Low	66	52%	50%
CPP	6	n/a	n/a

Days are counted beginning May 1st, 2018

Table 20: Dynamic On-Peak and CPP Days (Winter 2018-2019)

Dynamic On-Peak	Number of Days	% of Total	Prescribed by OEB
High	27	22%	20%
Medium	34	27%	30%
Low	63	51%	50%
CPP	6	n/a	n/a

Days are counted beginning November 1st, 2018

Table 21: Dynamic On-Peak and CPP Days (Summer 2019)

		Dynamic 6		Dynamic 9	
On-Peak Pricing	Prescribed by OEB	Number of Days	% of Total	Number of Days	% of Total
High	20%	25	24%	24	23%
Medium	30%	38	36%	39	37%
Low	50%	42	40%	42	40%
CPP		6	n/a	9	n/a

Days are counted beginning May 1st, 2019

Table 22: Dates of Critical Peak Days

	Summer 2018	Winter 2018-19	Summer 2019
CPP Day 1	2018-06-18	2019-01-21	2019-07-04
CPP Day 2	2018-07-04	2019-01-31	2019-07-05
CPP Day 3	2018-07-05	2019-02-13	2019-07-16
CPP Day 4	2018-07-16	2019-02-19	2019-07-19
CPP Day 5	2018-08-07	2019-02-27	2019-08-13
CPP Day 6	2018-08-28	2019-03-04	2019-08-20
CPP Day 7			2019-08-21
CPP Day 8			2019-09-11
CPP Day 9			2019-09-20

4.3.2 Dynamic Pricing Pilot Analytic Approach

A difference-in-difference (DID) approach was used to measure the effect of TOU period on household energy consumption for all Dynamic pricing TOU peak impact estimations. In order to employ a DID approach for TOU period impact estimations for the Dynamic pilot, there is an additional step required in order to determine the appropriate historical baseline consumption period. This additional step deals with the fact that Dynamic pricing customers were not exposed to Dynamic On-Peak TOU periods under Status-Quo TOU pricing in the historical baseline period. We solve for this issue here by capitalizing on the fact that there was a Legacy Dynamic pricing program in effect for a separate group of Alectra customers during the historical baseline period. As a result, we are able to compute historical baseline consumption for Dynamic customers separately for High, Medium, and Low On-Peak days based on whether the weekdays contained within the historical baseline period were called as High, Medium, or Low On-Peak days for the Legacy Dynamic pricing customers at that time.

Estimated TOU period impacts are averages and were calculated separately for the Summer (May – October) and Winter (November – April) periods. Estimated impacts were calculated based on mean hourly kW consumption using linear regression models (Equations 4.1 and 4.2), with estimations of the impact as a corresponding percentage change derived from the mean hourly kW impact (discussed further below). Consumption impacts deriving from pricing manipulation, communication (i.e., Nudge Report) manipulation, and the interaction of the price and communication manipulation are estimated, as relevant.

The Dynamic pilot assessed the impact of TOU period pricing and the Nudge Report in a duel-factor model (Equations 4.1). The Nudge Reports that were distributed to randomly selected households within the Dynamic pricing pilot contained monthly consumption feedback and personalized conservation tips to recipients. The consumption feedback was delivered as a visual depiction of On-Peak electricity consumption that benchmarked households to their On-Peak consumption at the same time in the previous year. For this reason, we hypothesized that even though personalized conservation tips were not TOU period specific, the On-Peak specificity of the consumption feedback may result in Nudge Reports imparting a differential effect on On-Peak consumption. We might expect therefore, that when pricing signals are sufficient to drive motivations to reduce On-Peak consumption (as was the intention of Dynamic pricing) that Nudge Reports would convey particularly useful consumption feedback information for participants. For this reason, we may expect that the effect of Nudge Reports interacts with the effect of pricing condition *only* for higher-priced TOU periods.

Because we hypothesized a potential interaction between price Treatment and Nudge Report, we calculated models with the inclusion of an interaction term Equation 4.1. We outlined an a priori analytical procedure in (a) the case that the interaction would be significant, in which case we report all lower order factor results from the interaction model (Equation 4.1), and (b) the case that the interaction would be non-significant, in which case we re-calculate the models including only the main effects and no interaction term (Equation 4.2), and we report main effects from this model. This is a reasonable approach because the coefficients of the predictors represent difference values depending on whether the model includes or does not include an interaction term. In regression, adding interaction terms changes the coefficients of the lower order predictors from main effects to *conditional effects*[24]. Main effects describe the impact of one predictor across all levels of the other, while a conditional effect means that the effect of one predictor is conditional on the value of the other. In our models, this means that the coefficient associated with the conditional effect of Price Treatment ($\beta_1\ Price_P$) describes the impact of Price Treatment only for the No Nudge Report households (i.e. $Price_P|Communication_C$=0). This makes intuitive sense when you consider that a significant interaction indicates that $Price_P$ varies depending on $Communication_C$; therefore, it would not also be appropriate to interpret a main effect of $Price_P$ that would be consistent across all levels of $Communication_C$. Following the same rationale in the case of a non-significant $Price_P * Communication_C$ interaction, interpretation of the conditional effect of the lower order effects as the full story of the impact of those factors is obviously incomplete. In this case, it is appropriate to drop the interaction term and calculate a model with only main effects, which describe the effect of one factor independent of the other factors in the model. To minimize confusion, coefficients from non-significant interactions are not reported in the results tables to clarify that reported main effects were derived from a model that did not include the interaction. To foreshadow, none of the Price by Communication interactions reached statistical significance for any TOU period analysis for either pilot (i.e., Dynamic and Legacy Dynamic). As such, all impact estimates for the effect of Price and Communication derive from linear models that did not include the interaction term. All models calculated with and without interactions are included in Appendix I for reference, regardless of statistical significance.

$$(4.1)\qquad (PostTOUUsage_i - PreTOUUsage_i) = \alpha + \beta_1\ Price_P + \beta_2\ Communication_C + \beta_3\ Price_P * Communication_C + \varepsilon_i$$

[24] Stevens, J. (1996). *Applied Multivariate Statistics for the Social Sciences* (3rd ed.). Lawrence Erlbaum Associates.

(4.2) $(PostTOUUsage_i - PreTOUUsage_i) = \alpha + \beta_1\, Price_P + \beta_2\, Communication_C + \beta_3 + \varepsilon_i$

Where,

PostTOUUsage	=	Average hourly TOU-period kW consumed during experimental period by household *i*
PreTOUUsage	=	Average hourly TOU-period kW consumed during pre-experiment period by household *i*
Price	=	Dummy indicator denoting presence of price manipulation
Communication	=	Dummy indicator denoting presence of communication manipulation
i	=	Indicates individual household
ε	=	Indicates regression error term

It is also worth noting that the TOU period DID regression models do not cluster standard errors, compared to what has sometimes become common practice in certain disciplines when dealing with panel regression data. Clustering standard errors, and other corrections for possible biases in standard error estimation, are common in two econometric circumstances. The first is when the experimental design is such that there are within-condition sub-groups or clusters[25]. A common example of this is when researchers are examining the effects of a law compared to some States without the same law, usually by employing a difference-in-difference model. Because of the high within-State correlation in dependent variable scores, it is important to adjust the standard errors by these geographic clusters. Secondly, some researchers, such as Bertrand and colleagues[26] describe that although standard error correction in difference-in-difference studies without geographical or other a priori clusters was not common at the time of publication, it is advisable because the serial correlation of many data points in a timeseries may underestimate the true standard error. We did not make any adjustments to the standard errors in our analyses because our models do not fulfill either of these criteria. We did compute a difference-in-difference; however, we did not fit a regression line to a timeseries in order to model change across time, as would be cautioned by Bertrand. Our approach calculates one timepoint change from baseline to Treatment period for the Treatment and Control groups, aggregating over all measurements within the given time window. In this method, each participant has one difference score, and these difference scores are compared between Treatment and Control groups. The potential for standard error bias becomes apparent as the number of timepoints in the model increases to levels not modelled in the present study. Finally, Abadie and his collaborators[27] have recently argued that standard error correction as a default choice in a broad range of circumstances without strong theoretical basis is overly conservative.

[25] Cameron, A. C., & Miller, D. (2015). A Practitioner 's Guide to Cluter-Robust Inference. *The Journal of Human Resources*, *50*(2), 317–372.
[26] Bertrand, M., Duflo, E., & Mullainathan, S. (2004). How Much Should We Trust Differences-in-Differences Estimates? Quarterly Journal of Economics, 119(1), 249–275.
[27] Abadie, A., Athey, S., Imbens, G., & Wooldridge, J. (2017). When Should You Adjust Standard Errors for Clustering? *National Bureau of Economic Research, Working Paper No. 24003.*

4.3.3 Legacy Dynamic Pricing Pilot Analytic Approach

The approach used to estimate TOU period consumption impacts amongst Legacy Dynamic pricing participants differed from the difference-in-difference (DID) approach used for 'new' Dynamic pilot impact estimations. The Legacy Dynamic program began in 2014, meaning that the employment of a DID approach to impact estimation is problematic. Mainly, in order to compare consumption in the current pilot period (May 01, 2018 – April 30, 2019) to a pre-Treatment historical baseline period, a historical data set that is (in many cases) over four years old would have to be used. Aside from the fact that hourly consumption data dating back this far was not provided to the evaluator for both Legacy Dynamic Treatment and matched Control participants at the time of impact evaluation, the logistics of employing a DID approach is further complicated by the fact that Legacy Dynamic pricing customers enrolled into Dynamic pricing at three different historical time periods, meaning that different historical baseline periods would have to be used for different groups of customers within the Legacy Dynamic customer group (this is discussed further below). It is for these reasons that we compare Legacy Dynamic households with Status-Quo TOU Control households in each year on record separately, without using the DID approach. Given this, caution should be used when making qualitative or quantitative comparisons between Dynamic and Legacy Dynamic impacts. Legacy Dynamic participants have been exposed to the Dynamic pricing structure for (in some cases) up to four years, whereas newly enrolled Dynamic participants have only been exposed to Dynamic pricing for a little over a year and a half. Even with this in mind, any comparisons made between these two groups of customers would not provide an accurate picture of the effect of exposure duration to Dynamic pricing on electricity consumption behaviour. This is because Legacy Dynamic participants enjoyed full price protection for the entirety of the Legacy program. Thus, because of differences in the analytical approach, differential exposure durations to Dynamic pricing, and differences in the length of exposure to price protection, making any comparisons between the Legacy and newly enrolled Dynamic customer groups inappropriate.

Because of the inherited legacy nature of the Legacy Dynamic group, none of the Status-Quo TOU Control participants received Nudge Reports (recall that premise IDs for Summer and Winter matched Control households for the Legacy group were not available in time to generate custom reports for this group). Therefore, the effect of TOU price structure (Dynamic vs. Status-Quo TOU) was examined between Treatment and Control participants (Equation 4.3), and separate linear analyses examined the effect of Nudge Reports within the Legacy Dynamic Treatment group only (Equation 4.4). Full results of all models are reported in Appendix I.

(4.3) $$PostTOUUsage_i = \alpha + \beta_1\, Price_P + \varepsilon_i$$

(4.4) $$PostTOUUsage_i = \alpha + \beta_1\, Communication_C + \varepsilon_i$$

Where,

PostTOUUsage	=	Average hourly TOU-period kW consumed during experimental period by household *i*
Price	=	Dummy indicator denoting presence of price manipulation

Communication	=	Dummy indicator denoting presence of communication manipulation
i	=	Indicates individual household
ε	=	Indicates non-clustered regression error term

Estimated impacts are averages and are calculated separately for the Summer 2018 (May – October), Winter 2018-19 (November – April) and Summer 2019 (June-October 2019) periods.

4.3.4 Average Conservation Impacts

The purpose of the Average Conservation Impact analysis is to measure the difference in electricity consumption between the Treatment and Control groups during each seasonal period and the entire duration of the pilot as a function of TOU price plan and/or non-price intervention.

We define Average Conservation Impact for the Dynamic pilot as the year-over-year difference in the average hourly consumption per month, calculated in the Summer 2018, Winter 2018-19, Summer 2019, and 17-month pilot period. For the Legacy Dynamic pilot, Average Conservation Impact is calculated within the 17-month Treatment period only (i.e., not a year-over-year change as per the DID approach used for 'new' Dynamic). The Summer period is defined as May 1st to October 31st (Summer 2019 analysis begins in June), and the Winter period is November 1st – April 30th. Average Conservation Impacts are collapsed across TOU periods. Note that the use of different Legacy Dynamic matched Control groups during the different seasonal periods precludes a year-round or full 17-month analysis of average conservation.

The analytical approach mirrored that of the TOU period impact estimation for each pilot. Impacts for Summer, Winter, 12-months, and 17-months are estimated based on mean kW consumption differences for pricing Treatment, communication Treatment (i.e., Nudge Reports), and the interaction between price and communication Treatments, as relevant for each pilot. The linear regression models for the Dynamic pilot used to estimate average conservation impacts with and without interaction terms are represented algebraically in Equations 4.5 and 4.6, and Legacy Dynamic linear models are represented in Equations 4.7 and 4.8.

(4.5) $$\left(PostAvgHourlyUsage_i - PreAvgHourlyUsage_{i,}\right) = \alpha + \beta_1\,Price_P + \beta_2\,Communication_C + \beta_3\,Price_P * Communication_C + \varepsilon_i$$

(4.6) $$\left(PostAvgHourlyUsage_i - PreAvgHourlyUsage_{i,}\right) = \alpha + \beta_1\,Price_P + \beta_2\,Communication_C + \varepsilon_i$$

(4.7) $$PostAvgHourlyUsage_i = \alpha + \beta_1\,Price_P + \varepsilon_i$$

(4.8) $$PostAvgHourlyUsage_i = \alpha + \beta_1\,Communication_C + \varepsilon_i$$

Where,

PostAvgHourlyUsage	=	Average kWs consumed per hour in each month for household *i*, averaged over all experimental period months
PreAvgHourlyUsage	=	Average kWs consumed per hour in each month for household *i*, averaged over all pre-experimental period months
Price	=	Dummy indicator denoting presence of price manipulation
Communication	=	Dummy indicator denoting presence of communication manipulation
i	=	Indicates individual household
ε	=	Indicates regression error term

4.3.5 Smart Thermostat Technology

Separate analyses are performed to assess the impacts of smart thermostat technology within each of the pricing pilots. Our estimation of consumption impacts owing to smart thermostats is completed using verified thermostat registration data obtained from Alectra. However, exact timing of smart thermostat installation for each household remains unknown; therefore, Technology impacts are analyzed with linear models (Equation 4.9) comparing mean hourly kW consumption of households with and without registered smart thermostats during the Treatment period only, and we did not employ a difference-in-difference approach.

Since we do not have data regarding thermostat acquisition dates for many of the customers classified as belonging to the 'Technology' groups in this pilot, it means that 'Technology' customers (those who registered a device as part of the pilot) fall into three distinct categories during the relevant historical baseline period:

1. Households who did not possess a smart thermostat at any point during the baseline (pre-pilot) period but acquired one for the start of the pilot period

2. Households who acquired a smart thermostat at some point during the baseline period, meaning they could benefit from programmable settings for some but not all of the baseline period used for differencing

3. Households who possessed a smart thermostat for the entirety of the baseline period, and simply registered that device at the commencement of the pilot

Given the heterogeneity of smart thermostat ownership status for the Technology group in the historical baseline period, we wanted to avoid introducing this 'noise' into the analysis via a difference-in-difference methodology. Put another way, if we employed a DID approach, then for some individuals, the estimated Treatment effect would be that of thermostat ownership AND registration, for others it would represent the effect of thermostat ownership AND registration for some but not all time periods, and yet for others, the DID method would deliver an effect solely of thermostat registration. By simply comparing customers with registered devices during the pilot period to customers without registered devices it ensures that at least our Treatment group consumption derives entirely from both thermostat ownership AND registration. The linear model used to estimate Technology impacts is shown algebraically in Equation 4.9.

$$(4.9) \quad PostTOUUsage_i = \alpha + \beta_1\, Technology_T + \varepsilon_i$$

PostAvgHourlyUsage	=	Average hourly kW consumed during experimental period by household *i*
Technology	=	Dummy indicator denoting presence of smart thermostat technology
i	=	Indicates individual household
ε	=	Indicates regression error term

4.3.6 Estimated Price Elasticity

The purpose of the Estimated Price Elasticity analysis is to measure the percent change in consumption relative to a percent change in price. Both own-price (daily) elasticity and inter-period substitution elasticity will be measured over the 17-month Treatment period.

We define Own-Price (Daily) Elasticity as: The percent change in hourly electricity consumption relative to the percent change in hourly electricity price.

We define Inter-Period Substitution Elasticity as: The percent change in the ratio of On-Peak to Off-Peak electricity consumption relative to the percent change in the ratio of On-Peak to Off-Peak electricity price.

The regression models for the Estimated Price Elasticity analysis is represented algebraically in Equation 4.14 for own-price elasticity and Equation 4.15 for inter-period substitution elasticity.

$$(4.14) \quad ln\,(Q_d) = \alpha + \eta\, ln\,(P_d) + \delta_1\, CDH_d + \delta_2\, HDH_d + \sum_{i=1}^{N} \theta_i D_i + \varepsilon_{i,d}$$

$$(4.15) \quad ln\left(\frac{Q_{on-peak,d}}{Q_{off-peak,d}}\right) = \alpha + \sigma\, ln\left(\frac{P_{on-peak,d}}{P_{off-peak,d}}\right) + \delta_1\,(CDH_{on-peak,d} - CDH_{off-peak,d}) + \delta_2\,(HDH_{on-peak,d} - HDH_{off-peak,d}) + \sum_{i=1}^{N} \theta_i D_i + \varepsilon_{i,d}$$

Where,

Q	=	kW consumed per hour averaged across day *d*
P	=	Electricity Price per hour averaged across day *d*
CDH	=	Cooling Degree hours per hour averaged across day *d*
HDH	=	Heating Degree hours per hour averaged across day *d*
D	=	Dummy indicator for each individual day
i	=	Indicates individual household
ε	=	Indicates regression error term

4.3.7 Estimated Percentage Impacts

In all Dynamic pilot results summary tables, mean hourly kW Treatment estimates represent the difference in year-over-year kW consumption in each TOU period for participants receiving a price/non-price Treatment, relative to participants in the appropriate Control group. We extrapolate percent impact from these mean hourly kW consumption estimates by dividing the impact coefficient by the relevant Treatment group's counterfactual consumption, which we derived by subtracting the impact coefficient from the Treatment group's observed consumption in the unprotected pilot period. From Equation 4.1:

$$\%\ impact = \frac{\widehat{\beta_1}}{(PostTOUUsage_i - \widehat{\beta_1})}$$

As such, percent impact estimates represent the percentage in the pilot period by which the observed consumption in the Treatment group differs from their counterfactual consumption had they not been exposed to the Treatment.

4.3.8 Estimation of Dynamic Pilot Summer vs. Winter Impacts Analysis

Beginning in October 2017, eligible households from the sample frame were contacted via direct marketing efforts to voluntarily sign up for the Dynamic pricing plan (again, marketed as Advantage Power Pricing). All Advantage Power Pricing (APP) participants were then placed into a full price protection period meaning that bill savings accrued as a result of participation in the APP program (relative to what charges for consumption would have been under Status-Quo TOU pricing) were credited to their subsequent electricity invoices, but any additional costs owing to APP participation were not charged. This protected period lasted until March 31, 2018 (Table 23).

Due to the difference-in-difference methodology employed to estimate consumption impacts for the Dynamic pilot, pre-Treatment baseline consumption data is required for each household. The Summer 2018 Treatment and the Summer 2019 Treatment extension period use the pre-Treatment period of Summer 2017 as baseline for the DID calculations. For example, a household's On-Peak consumption during May 2018 is compared to their consumption in May 2017, when they were not in the pilot. Since the price protection period ran from October 2017 to March 2018, this time period could not be used as a pre-Treatment baseline period for the Winter impact analysis (which covers November 2018 to April 2019). In order to circumvent this issue, we obtained consumption data from the year previous to the protected period for all participants (November 2016 – April 2017). In short, this means that the pre-Treatment historical baseline data used for the DID impact estimation for the Summer periods is one year prior to the current pilot, whereas for the Winter impact estimation, the pre-Treatment historical baseline data is two years prior to the current pilot.

Winter impact analyses derive from a comparison of consumption data from the unprotected-Treatment period (Nov 2018 – April 2019) to the pre-Treatment period (Nov 2016 – April 2017). However, we do not present data from the protected-Treatment period (Nov 2017 – April 2018) as we do not have any a priori hypotheses regarding the effects of the pricing pilots on price-protected consumption and due to the fact that the duration of the protected period is variable across customers in the Dynamic pilot depending on enrollment date (since enrollment continued throughout the entire protected period).

Table 23: Treatment period names

Winter Season Analysis		
Pre-Treatment Period	Protected-Treatment Period	Unprotected-Treatment Period
November 2016 – April 2017	November 2017 – April 2018	November 2018 – April 2019

5. Results

5.1 Bill Savings

Here we present customers' bill savings (or additional costs) owing to APP participation (shown in Table 24). These values are calculated by taking the difference between Dynamic and Legacy Dynamic customers' APP bill amounts and what customers would have paid if they exhibited the same consumption behaviour but had been billed as per Status-Quo TOU. Monetary savings are denoted as positive and costs are denoted as negative. This method of calculating bill savings is how Alectra determined whether or not a given customer was saving money as a result of pilot participation (which would appear as a bill credit on the next billing cycle) or is paying more (which was reflected as the billable amount on their billing cycle invoice). Average monthly bill savings indicate that Dynamic participants experienced small savings in the Summer period and moderate savings in the Winter period, with Legacy Dynamic customers seeing slightly larger savings. However, all participants experienced costs in Summer months (July and August), indicating that electricity-saving behaviours in particularly hot months, during On-Peak times of day were less frequent. Figures showing the distribution of the total bill savings amounts per pricing pilot are shown in Appendix D.

Table 24: Monthly Bill Savings

Summer 2018	May	June	July	August	September	October	Average Monthly Savings
Dynamic	$11.93	$4.99	-$17.80	-$12.64	$2.37	$12.81	$0.28
Legacy Dynamic	$11.73	$5.22	-$16.45	-$11.01	$2.99	$12.34	$0.81
Winter 2019-19	November	December	January	February	March	April	Average Monthly Savings
Dynamic	$13.98	$10.14	-$0.79	-$14.42	-$3.19	$10.54	$2.71
Legacy Dynamic	$14.54	$10.43	-$1.31	-$16.16	-$3.84	$11.01	$2.45
Summer 2019	May	June	July	August	September	October	Average Monthly Savings
Dynamic CPP 6	--	$12.25	-$12.04	-$22.28	-$2.46	$8.78	-$3.15
Dynamic CPP 9	--	$11.40	-$13.19	-$21.56	-$1.21	$8.96	-$3.12
Legacy Dynamic CPP 6	--	$11.44	-$12.51	-$19.64	-$0.36	$9.06	-$2.40
Legacy Dynamic CPP 9	--	$11.57	-$12.53	-$19.67	-$0.16	$9.27	-$2.30

Bill Savings are Denoted as Positive

5.2 Seasonal Temperatures

Average seasonal temperatures for each Dynamic TOU price period are presented in Table 25.

Table 25: Average seasonal temperature in degrees Celsius per Time-of-Use Pricing Period

Average temperature in degrees Celsius	Summer 2018	Winter 2018-19	Summer 2019	
			Dynamic 6[28]	Dynamic 9
High On-Peak	27.38	-6.35	23.17	23.07
Medium On-Peak	24.06	-0.88	19.41	19.41
Low On-Peak	16.34	4.8	13.25	13.25
Off-Peak	18.16	-0.81	18.49	18.54
Total CPP	26.63	-10.35	23.49	
CPP Day 1	27.3	-13	25.35	
CPP Day 2	28.03	-17.03	25.73	
CPP Day 3	25.68	-4.5	24.53	
CPP Day 4	23.45	-6.23	26.9	
CPP Day 5	26.3	-10.9	22.5	
CPP Day 6	29.03	-10.43	23	
CPP Day 7	--	--	23.95	
CPP Day 8	--	--	19.8	
CPP Day 9	--	--	19.65	

5.3 Dynamic Pricing Pilot

5.3.1 Sample Size and Summary Statistics

The number of participants in the Dynamic pricing pilot is displayed in Table 26. The Dynamic pilot began with 1,540 participants evenly distributed between the four Treatment and Control groups. At the end of the pilot extension period (October 30th, 2019) the number of participants was 1,076. Participant drop off was due to either households moving out of the service territory, households opting out of the program, missing data[29], or the household consumption was deemed to be an outlier[30]. In addition, there were a small number of households participating in a

[28] Note that for the Dynamic 6 group, CPP days 4, 5, & 7 were called as High On-Peak days, whereas for the Dynamic 9 group all CPP days (1 through 9) were called as Critical Peak Pricing events.
[29] See Section 4.2.4 Issues or Concerns for further explanation.
[30] An outlier was defined as any household who consumed more than 15kWh or less than 0.05kWh during any hour in the analysis period

separate Electric Vehicle (EV) usage pilot that began in September 2019, these households were also excluded from impact analyses pertaining to Dynamic pricing.

Table 27 through Table 29 present a summary of average hourly kW consumption for the Dynamic pilot for the pre-Treatment baseline periods of 2016-17 and the Treatment period of 2018-19.

Table 26: Number of Participants for Dynamic Pilot

Summer 2018 Reporting Period								
	Starting N	Opt-Outs	Move-Outs	EVs	Missing Data[31]	Outliers	Total Exclusions	Final N
Dynamic Pricing, No Nudge Report	385	34	9	0	0	4	47	338
Dynamic Pricing + Nudge Report	385	29	6	0	0	5	40	345
Status-Quo TOU Pricing, No Nudge Report	385	0	14	0	1	6	21	364
Status-Quo TOU Pricing + Nudge Report	385	1	17	0	0	5	23	362
Total	1540	64	46	0	1	20	131	1409
Winter 2018-19 Reporting Period								
	Starting N	Opt-Outs	Move-Outs	EVs	Missing Data	Outliers	Total Excls.	Final N
Dynamic Pricing, No Nudge Report	338	25	8	0	70	0	103	235
Dynamic Pricing + Nudge Report	345	38	4	0	67	1	110	235

Winter 2018-19 Reporting Period

[31] See Section 4.2.4 Issues or Concerns for further explanation.

	Starting N	Opt-Outs	Move-Outs	EVs	Missing Data	Outliers	Total Excls.	Final N
Status-Quo TOU Pricing + Nudge Report	362	4	14	0	0	3	21	341
Total	1409	67	46	0	137	6	256	1153
Summer 2019 Extension Period								
	Starting N	Opt-Outs	Move-Outs	EVs	Missing Data	Outliers	Total Excls.	Final N
Dynamic 6 Pricing, No Nudge Report	120	2	9	1	0	1	13	107
Dynamic 9 Pricing, No Nudge Report	108	5	4	1	0	0	10	98
Dynamic 6 Pricing + Nudge Report	115	3	5	2	0	0	10	105
Dynamic 9 Pricing + Nudge Report	127	6	2	1	0	0	9	118
Status-Quo TOU Pricing, No Nudge Report	342	0	12	0	0	4	16	326
Status-Quo TOU Pricing + Nudge Report	341	4	13	0	0	2	19	322
Total	1153	20	45	5	0	7	77	1076

Table 27: Summary of Consumption in Mean Hourly kW per Condition for Dynamic Pilot (Summer 2017/18 Periods)

Summer Period (kWh)	Status-Quo TOU Pricing, No Nudge Report	New Dynamic Pricing, No Nudge Report	Status-Quo TOU Pricing + Nudge Report	New Dynamic Pricing + Nudge Report

High-Peak 2017	Mean	1.185	1.225	1.252	1.175
	SD	0.855	0.974	1.012	0.736
High-Peak 2018	Mean	1.974	1.802	2.072	1.688
	SD	1.204	1.276	1.319	0.994
Medium-Peak 2017	Mean	1.243	1.276	1.301	1.212
	SD	0.817	0.972	0.986	0.702
Medium-Peak 2018	Mean	1.647	1.509	1.718	1.427
	SD	1.011	1.100	1.175	0.852
Low-Peak 2017	Mean	1.102	1.145	1.154	1.078
	SD	0.710	0.870	0.866	0.607
Low-Peak 2018	Mean	1.088	1.053	1.131	0.995
	SD	0.722	0.803	0.860	0.607
Off-Peak 2017	Mean	0.851	0.902	0.892	0.850
	SD	0.545	0.706	0.725	0.475
Off-Peak 2018	Mean	0.966	1.021	1.017	0.971
	SD	0.608	0.726	0.781	0.588
Total 2017	Mean	1.084	1.126	1.137	1.068
	SD	0.750	0.892	0.911	0.648
Total 2018	Mean	1.397	1.331	1.462	1.256
	SD	0.994	1.042	1.131	0.828

Table 28: Summary of Consumption in Mean Hourly kW per Condition for Dynamic Pilot (Winter Period)

Winter Period (kWh)	Status-Quo TOU Pricing, No Nudge Report	New Dynamic Pricing, No Nudge Report	Status-Quo TOU Pricing + Nudge Report	New Dynamic Pricing + Nudge Report

High-Peak 16-17	Mean	1.194	1.170	1.181	1.104
	SD	0.754	0.829	0.799	0.599
High-Peak 18-19	Mean	1.198	1.059	1.216	1.008
	SD	0.733	0.703	0.905	0.523
Medium-Peak 16-17	Mean	1.121	1.085	1.126	1.030
	SD	0.667	0.727	0.760	0.521
Medium-Peak 18-19	Mean	1.154	1.041	1.175	0.985
	SD	0.698	0.699	0.831	0.515
Low-Peak 16-17	Mean	1.047	1.028	1.082	0.986
	SD	0.615	0.723	0.732	0.527
Low-Peak 18-19	Mean	1.096	1.019	1.125	0.949
	SD	0.663	0.696	0.771	0.492
Off-Peak 16-17	Mean	0.864	0.838	0.854	0.800
	SD	0.531	0.604	0.583	0.416
Off-Peak 18-19	Mean	0.918	0.896	0.922	0.865
	SD	0.566	0.578	0.670	0.454
Total 16-17	Mean	1.040	1.014	1.046	0.966
	SD	0.646	0.725	0.725	0.524
Total 18-19	Mean	1.076	0.996	1.094	0.944
	SD	0.666	0.669	0.790	0.496

Table 29: Summary of Consumption in Mean Hourly kW per Condition for Dynamic Pilot (Summer 2019 Period)

Summer Period 2019 (kWh)	Status-Quo TOU Pricing, No Nudge Report	Dynamic 6, No Nudge Report	Dynamic 9, No Nudge Report	Status-Quo TOU Pricing + Nudge Report	Dynamic 6 + Nudge Report	Dynamic 9+ Nudge Report

High-Peak 2019	Mean	1.696	1.568	1.542	1.696	1.479	1.387
	SD	1.077	1.343	1.171	1.077	0.964	0.823
Medium-Peak 2019	Mean	1.33	1.238	1.223	1.33	1.17	1.098
	SD	0.89	1.203	1.008	0.89	0.71	0.688
Low-Peak 2019	Mean	0.991	0.992	0.956	0.991	0.93	0.886
	SD	0.629	0.977	0.689	0.629	0.513	0.508
Off-Peak 2019	Mean	0.926	0.986	0.969	0.926	0.938	0.896
	SD	0.618	0.925	0.737	0.618	0.534	0.522
Total 2019	Mean	1.232	1.196	1.149	1.232	1.13	1.046
	SD	0.882	1.146	0.933	0.882	0.739	0.663

5.3.2 Time-of-Use Period Impacts, Seasonal Impacts, and Elasticities

Because of the difference-in-difference methodology employed here to estimate consumption impacts, there is an additional step required in order to determine the appropriate historical baseline consumption period for the estimation of TOU period impacts for Dynamic pricing customers. During the pilot period, customers participating in Dynamic pricing experienced either a High, Medium, or Low On-Peak price on any given day according to the breakdown in Table 19 and Table 20. This slightly complicates the derivation of historical baseline consumption for each of these three variants of On-Peak pricing since, of course, these customers were not exposed to Dynamic On-Peak prices under Status-Quo TOU pricing in the historical baseline period. We solve for this issue here by capitalizing on the fact that there was a Legacy Dynamic pricing program in effect for a separate group of Alectra customers (results of which are reported in the next section) during the historical baseline period. As a result, we are able to compute historical baseline consumption for Dynamic customers separately for High, Medium, and Low On-Peak days based on whether the weekdays contained within the historical baseline period were called as High, Medium, or Low On-Peak days for the Legacy Dynamic pricing customers at that time.

TOU period impacts owing to Dynamic pricing are displayed in Table 30 to Table 32. For the Summer 2018 period during the three On-Peak periods (High, Medium, and Low), the estimated consumption impacts for participants exposed to Dynamic pricing are -0.260 kW, -0.186 kW, and -0.069 kW per hour, respectively. For the Winter 2018-19 period during the three On-Peak periods (High, Medium, and Low), estimated consumption impacts for participants exposed to Dynamic pricing are -0.122 kW, -0.085 kW and -0.069 kW per hour, respectively. During the Summer 2019 extension period, the estimated impact of High On-Peak pricing is -0.148 kW for the Dynamic 6 group and -0.121 kW for the Dynamic 9 group, while the impact of Medium On-

Peak pricing is -0.155 kW (Dynamic 6) and -0.100 kW (Dynamic 9). There was no significant impact of Off-Peak pricing in either Summer 2018, Winter 2018-2019, or Summer 2019.

Any differences in energy consumption associated with the Nudge Report during On- or Off-Peak periods were not found to be statistically significant.

Table 30: Dynamic Pilot Impact Analysis Results – Summer 2018

Summer 2018	Dynamic Pricing (Main Effect)		Nudge Report (Main Effect)	
	Mean Hourly kW	%[32]	Mean Hourly kW	%[33]
High On-Peak Effects	**-0.26*****	-12.968	-0.015	-0.792
Medium On-Peak Effects	**-0.186*****	-11.245	-0.002	-0.127
Low On-Peak Effects	**-0.069*****	-6.313	0.000	0
Off-Peak Effects	0.000	0	0.007	0.709
System-Coincident Peak	**-0.161*****	-10.651	-0.003	-0.207

*** $p < 0.001$; ** $p < 0.01$; * $p < 0.05$; ^ $p < 0.1$

Table 31: Dynamic Pilot Impact Analysis Results – Winter 2018-19

Winter 2018-19	Dynamic Pricing (Main Effect)		Nudge Report (Main Effect)	
	Mean Hourly kW	%	Mean Hourly kW	%

32 % impacts are calculated as kW impact / (PostTOUUsage - kW impact), where PostTOUUsage is the average consumption between the Dynamic Pricing + Nudge Report and Dynamic Pricing + No Nudge Report groups from table 27.

33 % impacts are calculated as kW impact / (PostTOUUsage - kW impact), where PostTOUUsage is the average consumption between the Dynamic Pricing + Nudge Report and Standard TOU Pricing + Nudge Report groups from table 27.

High On-Peak Effects	**-0.122*** **	-10.558	0.024	2.206
Medium On-Peak Effects	**-0.085*** **	-7.741	0.009	0.84
Low On-Peak Effects	**-0.069*** **	-6.553	-0.016	-1.519
Off-Peak Effects	0.001	0.114	0.011	1.246
System-Coincident Peak	-0.027	-2.738	0.008	0.824

**** p < 0.001; ** p < 0.01; * p < 0.05; ^ p < 0.1*

Table 32: Dynamic Pilot Impact Analysis Results - Summer 2019

Summer 2019		High On-Peak Effects	Medium On-Peak Effects	Low On-Peak Effects	Off-Peak Effects	System-Coincident Peak
Dynamic 6 Pricing (Main Effect)	Mean Hourly kW	**-0.148*** **	**-0.115*** **	-0.045	-0.002	**-0.159*** **
	%	-8.528	-8.719	-4.473	-0.207	-11.015
Dynamic 9 Pricing (Main Effect)	Mean Hourly kW	**-0.121*** **	**-0.1*** **	-0.038	-0.003	**-0.133*** **
	%	-7.632	-7.933	-3.962	-0.321	-9.661
Nudge Report (Main Effect)	Mean Hourly kW	-0.066	-0.036	-0.005	-0.01	**-0.057***
	%	-4.16	-2.914	-0.532	-1.075	-4.169

**** p < 0.001; ** p < 0.01; * p < 0.05; ^ p < 0.1*

During the System-Coincident Peak hours, results differed between Summer and Winter (Table 30 to Table 32). In the Summer 2018 period, we estimated a -0.161 kW average hourly consumption impact attributable to Dynamic pricing. Similarly, Summer 2019 yielded -0.159 kW and -0.133 kW mean hourly impacts for the Dynamic 6 & 9 groups respectively during the System-Coincident Peak hours. In the Winter 2018-19 Period, consumption during System-

Coincident Peak hours did not differ between Dynamic pricing and Status-Quo TOU Control households. System-Coincident Peak hours during the Summer were from 1-7pm whereas they were from 6-8pm in the Winter. We postulate that individuals are more likely to be home between the hours of 6-8pm (vs. 1-7pm) resulting in a lower likelihood of conserving energy during these hours.

The Nudge Reports delivered consumption reductions of -0.057 kW per hour during the Summer 2019 System-Coincident Peak hours.

Seasonal Average Conservation Impacts are shown in Table 33. Overall, there was a marginally significant main effect of Dynamic pricing on total Summer 2018 electricity consumption amounting to approximately -0.024 kW per hour, and no significant effect during the Winter 2018-2019 or Summer 2019 seasons. Overall impacts of Dynamic pricing across the entire 17-month Treatment period, amount to significant consumption savings of approximately -0.025 kW per hour. The 12-month and 17-month impacts were calculated for participants who remained in the pilot for the full relevant period. Participants who left the pilot were removed from these multi-season analyses. Details are included in Appendix I.

In comparing Dynamic pricing pilot participants who received monthly Nudge Reports to those who did not receive Nudge Reports over the entire 17-month Treatment period, there were no significant differences in electricity consumption.

Table 33: Dynamic Pilot Seasonal Average Conservation Impact Analysis Results

		Dynamic Pricing		Nudge Report	
	n[34]	Mean Hourly kW	%	Mean Hourly kW	%

[34] The 17-month impact is larger than the un-weighted average of the seasonal averages because the 17-month impact is calculated for only the households who continued through the full 17-month duration of the program. For example, if the 12-month impact were calculated only for the 1076 households who continued to the end of the

Summer 2018 Impact	1409	-0.024^	-2.256	0.005	0.478
Winter 2018-19 Impact	1153	-0.014	-1.528	0.01	1.094
12-Month Impact	1153	-0.021	-2.126	0.007	1.226
Dynamic 6 Pricing Summer 2019	1076	-0.023	-2.242	-0.014	-1.398
Dynamic 9 Pricing Summer 2019	1076	-0.022	-2.219		
17-Month Impact	1076	**-0.025****	-2.47	0.000	0

**** $p < 0.001$; ** $p < 0.01$; * $p < 0.05$; ^ $p < 0.1$*

Average hourly kW consumption for each CPP event is presented in Table 34. In order to compute the appropriate historical baseline consumption required to employ a difference-in-difference approach to the calculation of consumption impacts owing to CPP events, we once again capitalize on the existence of the Legacy Dynamic pricing pilot that was being run with a separate group of customers during the historical baseline period. This means that consumption impacts were calculated for each specific CPP day in the present pilot by first computing the difference between consumption for a given customer during a given CPP day in the current pilot (e.g., Winter, CPP Day 1) and their consumption during the corresponding CPP day in the baseline period. The three extra days marked as CPP for the Dynamic 9 group were marked as High On-Peak pricing for the Dynamic 6 group.

Table 34: Summary of Consumption in Mean Hourly kW per Dynamic Pilot Critical Peak Day (Summer 2018 Period)

Summer 2018 CPP		Status-Quo TOU Pricing, No Nudge Report	New Dynamic Pricing, No Nudge Report	Status-Quo TOU Pricing + Nudge Report	New Dynamic Pricing + Nudge Report
CPP Day 1	Mean	1.977	1.696	2.077	1.582
	SD	1.441	1.600	1.568	1.254
CPP Day 2	Mean	2.500	2.181	2.556	2.014
	SD	1.664	1.636	1.62	1.346

program (not the 1153 households who were still enrolled at the end of the 12-monht reporting period), the 12-month impact estimate would be -0.27 kW.

CPP Day 3	Mean	2.113	1.819	2.075	1.676
	SD	1.473	1.503	1.58	1.242
CPP Day 4	Mean	1.562	1.309	1.804	1.26
	SD	1.277	1.246	1.571	1.044
CPP Day 5	Mean	1.914	1.612	2.068	1.562
	SD	1.461	1.391	1.588	1.326
CPP Day 6	Mean	2.208	1.906	2.346	1.777
	SD	1.523	1.65	1.663	1.295
Total	Mean	2.046	1.754	2.154	1.645
	SD	1.505	1.534	1.616	1.276

Table 35: Summary of Consumption in Mean Hourly kW per Dynamic Pilot Critical Peak Day (Winter 2018-19 Period)

Winter 2018-2019 CPP		Status-Quo TOU Pricing, No Nudge Report	New Dynamic Pricing, No Nudge Report	Status-Quo TOU Pricing + Nudge Report	New Dynamic Pricing + Nudge Report
CPP Day 1	Mean	1.488	1.269	1.583	1.23
	SD	1.125	0.949	1.359	0.91
CPP Day 2	Mean	1.454	1.265	1.497	1.193
	SD	1.096	0.983	1.255	0.776
CPP Day 3	Mean	1.289	1.062	1.333	1.064
	SD	0.966	0.833	1.177	0.741
CPP Day 4	Mean	1.228	1.103	1.322	1.039
	SD	0.956	0.866	1.062	0.704
CPP Day 5	Mean	1.33	1.108	1.347	1.135
	SD	1.222	0.872	1.129	0.786
CPP Day 6	Mean	1.201	1.097	1.245	1.04
	SD	0.894	0.955	1.14	0.746
Total	Mean	1.326	1.146	1.383	1.113
	SD	1.052	0.911	1.193	0.783

Table 36: Summary of Consumption in Mean Hourly kW per Dynamic Pilot Critical Peak Day (Summer 2019 Period)

Summer 2019 CPP		Status-Quo TOU Pricing, No Nudge Report	Dynamic 6 Pricing, No Nudge Report	Dynamic 9 Pricing, No Nudge Report	Status-Quo TOU Pricing + Nudge Report	Dynamic 6 Pricing + Nudge Report	Dynamic 9 Pricing + Nudge Report
CPP Day 1	Mean	2.303	1.76	1.893	2.429	1.839	1.759
	SD	1.494	1.677	1.438	1.48	1.194	1.173
CPP Day 2	Mean	2.324	1.901	1.908	2.49	1.805	1.709
	SD	1.475	1.722	1.385	1.47	1.292	1.161
CPP Day 3	Mean	2.029	1.633	1.69	2.138	1.427	1.426
	SD	1.308	1.46	1.457	1.501	0.964	0.99
CPP Day/ High On-Peak	Mean	2.262	1.828	1.889	2.374	1.774	1.652
	SD	1.339	1.721	1.526	1.447	1.095	1.148
CPP Day 5/ High On-Peak	Mean	1.944	1.68	1.551	2.086	1.535	1.433
	SD	1.323	1.604	1.416	1.456	1.131	1.141
CPP Day 6	Mean	1.834	1.572	1.477	1.908	1.577	1.434
	SD	1.307	1.309	1.358	1.428	1.162	1.074
CPP Day 7/ High On-Peak	Mean	2.006	1.674	1.716	2.155	1.636	1.427
	SD	1.294	1.397	1.407	1.435	1.119	0.98
CPP Day 8	Mean	1.397	1.279	1.222	1.523	1.276	1.088
	SD	1.126	1.359	1.23	1.305	0.852	0.756
CPP Day 9	Mean	1.093	1.052	0.995	1.212	0.915	0.939
	SD	0.896	1.282	0.968	1.153	0.769	0.683
Total	Mean	1.91	1.598	1.593	2.035	1.531	1.43
	SD	1.353	1.528	1.39	1.467	1.108	1.053

The results for CPP events are shown in Table 37 to Table 39, and graphical representations of mean hourly consumption on each individual of the CPP event day are shown in Appendix G. Total CPP event impacts are show for both groups for both the 6 and the 9 CPP days. Calculating the average impact of the Dynamic 6 and Dynamic 9 groups over the 9 days allows for examination of the effect of the 3 additional CPP days over and above them being called as High On-Peak days. Impact estimates owing to Dynamic pricing during CPP hours amounted to -0.354 kW per hour on average in the Summer 2018 period and -0.168 kW per hour in the Winter period. In the Summer 2019 period, we looked at impact of Dynamic CPP pricing for the Dynamic 6 and the Dynamic 9 groups over both 6 days that were commonly CPP days, as well as for both groups over the additional 3 days that were marked as High On-Peak for the Dynamic 6 group and CPP events for the Dynamic 9 group. Over the 6 common CPP days, Dynamic 6 and Dynamic 9 pricing yielded significant average impacts of -0.367 and -.328 kW per hour, respectively. Impacts over the 9 days was -.382 kW per hour for the Dynamic 6 group and -0.349 kW per hour for the Dynamic 9 pricing. Importantly the two pricing Treatment groups did not significantly differ from each other (non-significant analyses comparing Dynamic 6 and 9 are included in Appendix I).

Nudge Reports delivered additional consumption impacts only on CPP Day 3 (-0.136 kW per hour) in Summer 2018. No other significant impacts were estimated owing to Nudge Reports. All Nudge Report impacts for CPP days can be found in Appendix I.

Table 37: Dynamic Pilot Critical Peak Day Impact Analysis Results (Summer 2018)

Summer 2018 CPP	Dynamic Pricing (Main Effect)	
	Mean Hourly kW	%
CPP Day 1	**-0.375*** **	-18.62
CPP Day 2	**-0.329*** **	-13.559
CPP Day 3	**-0.282*** **	-13.895
CPP Day 4	**-0.407*** **	-24.061
CPP Day 5	**-0.361*** **	-18.532
CPP Day 6	**-0.365*** **	-16.542
Total	**-0.354*** **	-17.239

**** $p < 0.001$; ** $p < 0.01$; * $p < 0.05$; ^ $p < 0.1$*

Table 38: Dynamic Pilot Critical Peak Day Impact Analysis Results (Winter 2018-19)

Winter 2018-2019 CPP	Dynamic Pricing (Main Effect)

	Mean Hourly kW	%
CPP Day 1	**-0.319*** **	-20.338
CPP Day 2	**-0.113***	-8.42
CPP Day 3	**-0.139*** **	-11.564
CPP Day 4	**-0.189*** **	-15
CPP Day 5	**-0.158*** **	-12.349
CPP Day 6	-0.094^	-8.086
Total	**-0.168*** **	-12.948

*** $p < 0.001$; ** $p < 0.01$; * $p < 0.05$; ^ $p < 0.1$

For Summer 2019 CPP event impact estimates, (Table 39) CPP days 4, 5, and 7 were CPP days only for households assigned to the Dynamic 9 group. These three CPP days were called as High On-Peak days for households assigned to the Dynamic 6 group. CPP days 1, 2, 3, 6, 8, and 9 were called as CPP event days for households in both the Dynamic 6 and Dynamic 9 groups.

Table 39 : Dynamic Pilot Critical Peak Day Impact Analysis Results (Summer 2019)

Summer 2019 CPP	Main Effects of Price

	Dynamic 6 Pricing		Dynamic 9 Pricing	
	Mean Hourly kW	%	Mean Hourly kW	%
CPP Day 1	**-0.496*** **	-21.607	**-0.42*** **	-18.7
CPP Day 2	**-0.467*** **	-20.129	**-0.433*** **	-19.317
CPP Day 3	**-0.54*** **	-26.087	**-0.405*** **	-20.632
CPP Day 4	**-0.484*** **	-20.903	**-0.405*** **	-15.967
CPP Day 5	**-0.391*** **	-20.217	**-0.416*** **	-18.617
CPP Day 6	**-0.426*** **	-21.295	**-0.436*** **	-23.05
CPP Day 7	**-0.360*** **	-17.866	**-0.358*** **	-15.609
CPP Day 8	**-0.206*** **	-13.886	**-0.218** **	-15.878
CPP Day 9	-0.069	-6.556	-0.057	-5.566
Dynamic 6, 6 CPP Days	**-0.367*** **	-19.001	**--**	---18.802
Dynamic 9, 9 CPP Days	**--**	--	**-0.349*** **	-18.758
Total Impact Over 6 Common CPP Days	**-.367*** **	-19.001	**-.328*** **	-17.831
Total Impact Over 9 CPP Days	**-0.382*** **	-19.625	**-0.349*** **	-18.802

**** $p < 0.001$; ** $p < 0.01$; * $p < 0.05$; ^ $p < 0.1$;*

5.3.3 Elasticity

Daily and Substitution Elasticities for the full 17-month pilot Treatment period are reported in Table 40. Daily elasticity of demand was estimated at -0.107, whereas substitution elasticity of demand was estimated at -0.019; small changes in percent consumption per percent increase in price.

Table 40: Dynamic Pilot Daily and Substitution Elasticities of Demand

	Elasticity Estimate
Daily Elasticity	**-0.107*** **
Substitution Elasticity On/Off-Peak	**-0.019*** **

*** $p < 0.001$; ** $p < 0.01$; * $p < 0.05$; ^ $p < 0.1$

5.3.4 Technology Impacts

Dynamic pricing households were designated as "*Technology*" if they participated in a smart thermostat incentive program offered by Alectra Utilities. Exact timing of smart thermostat installation for each household remains unknown, therefore Technology is only analyzed comparing kWh consumption of households with and without registered smart thermostats (capable of receiving automatic load curtailment during On-Peak and CPP event periods) during the Treatment period, and we did not employ a difference-in-difference approach. Analyzing Technology only during the Treatment period avoids any noise introduced by potential smart thermostat usage during the pre-Treatment pricing period.

The distribution of registered smart thermostats as a function of pilot group and device type is presented in Table 41. Due to sample size restrictions, the Summer 2019 Dynamic 6 and 9 groups were combined into one Dynamic pricing group for all Technology analyses. Registered Honeywell and Nest thermostats were not capable of receiving load curtailment signals from Alectra for the Summer 2019 reporting period and therefore the 'Technology' group for Summer 2019 impact estimates includes only customers with registered Energate or Nest devices. Honeywell and Nest customers with registered devices were excluded entirely from the Summer 2019 Technology impact analysis, that is, they were not added to the control group. Summaries of average electricity consumption for Technology households are presented in Table 42, and the results of the Technology impact analysis are shown in Table 43, with Technology impacts during CPP events presented in Table 44 to Table 46.

Table 41: Number of Dynamic Pilot participants with registered smart thermostats

Summer 2018	Energate	Ecobee	Nest	Honeywell	Unknown[35]
Dynamic Pricing + Nudge Report	35	22	29	0	3

[35] A small number of households had duplicate smart thermostat registrations for different thermostat types. These households were included a single time in all analyses comparing households with and without smart thermostats but are classified as unknown when the evaluator was certain of registration but unable to determine the exact model.

Dynamic Pricing, No Nudge Report	37	9	24	0	1
Status-Quo TOU Pricing + Nudge Report	6	2	0	0	0
Status-Quo TOU Pricing, No Nudge Report	2	0	0	0	0
Winter 2018-2019	Energate	Ecobee	Nest	Honeywell	Unknown
Dynamic Pricing + Nudge Report	24	14	10	0	1
Dynamic Pricing, No Nudge Report	24	5	13	0	0
Status-Quo TOU Pricing + Nudge Report	6	2	0	0	0
Status-Quo TOU Pricing, No Nudge Report	2	0	0	0	0
Summer 2019	Energate	Ecobee			
Dynamic Pricing + Nudge Report	20	13	--	--	--
Dynamic Pricing, No Nudge Report	23	5	--	--	--
Summer 2019	Energate	Ecobee			
Status-Quo TOU Pricing + Nudge Report	4	2	--	--	--
Status-Quo TOU Pricing, No Nudge Report	2	0	--	--	--

Table 42: Dynamic Pricing Technology (smart thermostats) Consumption Summary Statistics

		Summer 2018		Winter 2018-19		Summer 2019	
		Mean Hourly kW	SD	Mean Hourly kW	SD	Mean Hourly kW	SD
High-Peak	Technology	1.710	1.052	0.927	0.488	1.488	0.976
	No Technology	1.912	1.234	1.156	0.769	1.508	1.046
Medium-Peak	Technology	1.454	0.884	0.931	0.498	1.192	0.807
	No Technology	1.595	1.068	1.119	0.728	1.191	0.896
Low-Peak	Technology	1.005	0.649	0.904	0.489	0.897	0.455
	No Technology	1.076	0.769	1.074	0.691	0.955	0.700
Off-Peak	Technology	0.979	0.608	0.790	0.392	0.926	0.481
	No Technology	0.996	0.690	0.915	0.595	0.965	0.671
Total	Technology	1.272	0.866	0.883	0.469	1.126	0.749
	No Technology	1.376	1.026	1.053	0.694	1.155	0.871

We estimated small impacts on electricity consumption associated with Technology ownership/registration during On- and Off-Peak periods; however, these impacts were only reached statistical significance during Winter 2018-19 (-0.145 kW per hour; Table 43). Similar results were obtained during CPP events (Table 44 to Table 46) with estimated impacts in the range of 0.089 kW to -0.370 kW per hour on average and only reaching significance or marginal significance ($p < .10$) on a few occasions.

Table 43: Dynamic Pricing Technology Impact Analysis Results (Mean Hourly kW)

Technology Impacts (kWh)	Summer 2018		Winter 2018/2019		Summer 2019	
	Mean Hourly kW	%	Mean Hourly kW	%	Mean Hourly kW	%
High-Peak Effects	-0.062	-3.541	**-0.145***	-13.704	-0.021	-1.363
Medium-Peak Effects	-0.023	-1.538	**-0.110***	-10.626	0.002	0.137
Low-Peak Effects	-0.022	-2.131	**-0.110***	-10.894	-0.057	-6.061
Off-Peak Effects	-0.015	-1.527	**-0.110****	-12.241	-0.038	-3.951

Total Effects	-0.031	-2.347	**-0.114***	-11.531	-0.029	-2.488

*** $p < 0.001$; ** $p < 0.01$; * $p < 0.05$; ^ $p < 0.1$

Table 44: Dynamic Pricing CPP Days Technology Impact Analysis (Summer 2018)

Summer 2018 CPP Consumption (Mean Hourly kW)						
	Technology		No Technology		Technology Impact Analysis Results	
	Mean	SD	Mean	SD	kWh	%
CPP Day 1	1.573	1.231	1.875	1.514	-0.107	-6.379
CPP Day 2	1.966	1.42	2.367	1.605	-0.227^	-10.351
CPP Day 3	1.683	1.296	1.959	1.487	-0.109	-6.1
CPP Day 4	1.15	0.993	1.536	1.352	**-0.177***	-13.321
CPP Day 5	1.5	1.321	1.835	1.475	-0.146	-8.876
CPP Day 6	1.765	1.477	2.106	1.563	-0.118	-6.276
Total	1.606	1.322	1.946	1.523	-0.150	-8.544

*** $p < 0.001$; ** $p < 0.01$; * $p < 0.05$; ^ $p < 0.1$

Table 45: Dynamic Pricing CPP Days Technology Impact Analysis (Winter 2018-19)

Winter 2018-19 Consumption (Mean Hourly kW)						
	Technology		No Technology		Technology Impact Analysis Results	
	Mean	SD	Mean	SD	kWh	%
CPP Day 1	1.190	0.853	1.441	1.159	-0.071	-5.613
CPP Day 2	1.131	0.742	1.399	1.099	-0.139	-10.43
CPP Day 3	0.939	0.630	1.236	1.000	**-0.169***	-15.216

CPP Day 4	0.976	0.733	1.212	0.947	-0.137^	-12.323
CPP Day 5	1.047	0.744	1.270	1.078	-0.133	-11.301
CPP Day 6	0.904	0.711	1.184	0.980	**-0.219***	-19.523
Total	1.027	0.745	1.286	1.048	-0.145^	-12.344

*** $p < 0.001$; ** $p < 0.01$; * $p < 0.05$; ^ $p < 0.1$

Table 46: Dynamic Pricing CPP Days Technology Impact Analysis (Summer 2019)

Summer 2019 CPP Consumption (Mean Hourly kW)						
	Technology		No Technology		Technology Impact Analysis Results	
	Mean	SD	Mean	SD	kWh	%
CPP Day 1	1.678	1.292	1.859	1.399	-0.181	-9.727
CPP Day 2	1.531	1.313	1.900	1.425	-0.370^	-19.462
CPP Day 3	1.357	1.122	1.584	1.278	-0.227	-14.355
CPP Day 4	1.520	1.183	1.862	1.444	-0.342^	-18.360
CPP Day 5	1.529	1.183	1.559	1.372	-0.029	-1.891
CPP Day 6	1.360	1.174	1.538	1.236	-0.178	-11.566
CPP Day 7	1.464	1.236	1.642	1.251	-0.178	-10.821
CPP Day 8	1.287	1.075	1.198	1.082	0.089	7.437
CPP Day 9	0.935	0.694	0.986	0.994	-0.052	-5.235
Total	1.407	1.005	1.570	1.114	-0.163	-10.387

*** $p < 0.001$; ** $p < 0.01$; * $p < 0.05$; ^ $p < 0.1$

5.3.5 Pledge Analysis

Finally, we examined consumption impacts between households who responded to the On-Peak conservation pledge on the Nudge Report versus households who received the Nudge Reports but did not respond to the pledge. Recall that households had the option to respond to the pledge via SMS text message to commit to reducing their On-Peak electricity consumption. Households who chose to respond to the pledge were offered a $5 rebate. The number of participants in each of the comparison groups and the resulting impacts are shown in Table 47. Unfortunately, there were insufficient numbers of pledge participants to conduct an analysis that would allow for the derivation of meaningful impacts.

Table 47: Pledge Numbers

	Status-Quo TOU Control, Pledge Not Signed	Status-Quo TOU Control, Pledge Signed	Dynamic Pricing, Pledge Not Signed	Dynamic Pricing, Pledge Signed
Summer 2018	362	0	318	27
Winter 2018-19	341	0	219	16
Summer 2019	648	0	414	14

5.3.6 Summary of Dynamic Pricing Impacts

Given that the ratio of Off-Peak price to High On-Peak and CPP event kWh price is quite high relative to Status-Quo TOU pricing, it was hypothesized that this would provide a strong incentive for Dynamic pricing customers to curtail their electricity consumption behaviour in order to realize bill savings. The estimated impacts were highly consistent with this hypothesis as customers in Dynamic pricing exhibited lower electricity consumption relative to matched Control participants during all High and Medium Peak periods, with Summer 2018 and Winter 2018-19 seeing additional consumption savings during Low-Peak periods. Impacts during these periods ranged between -0.069 kW and -0.260 kW per hour on average. Estimated consumption impacts were not significant during the Off-Peak hours.

Significant conservation impacts were estimated during the initial six CPP events, in which Dynamic pricing Treatment customers exhibited -0.069 kW to -0.540 kW per hour relative to matched Controls during those same hours. Additionally, the electricity consumption impacts owing to Dynamic pricing during On-Peak and CPP events yielded net savings in overall average hourly consumption of 1.5% over the entire 17-month Treatment period.

In terms of non-price communications, impact estimates owing to Nudge Reports did not reach statistical significance.

Finally, Dynamic pricing customers who registered a smart thermostat through participation in Alectra's thermostat incentive program exhibited additional incremental consumption reductions relative to Dynamic pricing customers who did not report smart thermostat ownership; however, those reductions were statistically significant during only the Winter 2018-19 season (-0.145 kW per hour). Similar results were obtained during CPP events: small impacts of smart thermostat ownership/registration, with those impacts only reaching significance on a few occasions.

Overall, Dynamic pricing resulted in dramatic reductions in On-Peak electricity consumption relative to Status-Quo TOU pricing. These impacts were largest during High On-Peak days and CPP event days, indicating that strong pricing signals can act as a meaningful incentive for the curtailment of residential electricity consumption. Importantly, these savings were enhanced in some instances as a result of non-price communications, in the form of Nudge Reports, as well as ownership of smart thermostat Technology. These peak reductions were not offset by increases in Off-Peak consumption, resulting in relatively small but reliable overall conservation impacts.

With respect to the 5-month extension period (June – October 2019), there were two primary research questions that the extension period pilot was designed to address:

1. ***Would the On-Peak and CPP event impacts estimated for the Summer 2018 season still be present a year later in Summer 2019?*** Consumption impacts during High On-Peak TOU periods did in fact persist from Summer 2018 to Summer 2019. The magnitude of these impacts is observed to be smaller in Summer 2019 however, likely owing to cooler High On-Peak temperatures in Summer 2019 relative to Summer 2018. In terms of CPP event responsiveness, we see very similar impacts across the Summer 2018 and Summer 2019 seasons.

2. ***Would an increase in the frequency of CPP events from 6 to 9 impact responsiveness to CPP events?*** In assessing consumption impacts across each of the CPP events called in the Summer 2019 season, we see that consumption impacts for the six events that the Dynamic 6 and Dynamic 9 groups shared in common, are very similar. In addition, while we also see significant consumption impacts on the 3 CPP days that were unique to the Dynamic 9 group, the magnitude of these impacts is not statistically different from those obtained for the Dynamic 6 group on those three days (despite the fact that those days were called as High On-Peak days for the Dynamic 6 group).

5.4 Legacy Dynamic Pricing Pilot

5.4.1 Sample Size and Summary Statistics

The results of the Dynamic pilot estimated the effects of Dynamic pricing on 'newly' enrolled households during the enrollment period beginning in November 2017 and ending in March 2018. These "new" Dynamic participants were recruited via APP marketing materials, and Dynamic pricing impacts related to these newly enrolled customers were described in detail in the previous section. However, there existed approximately 1,500 households who enrolled in Dynamic pricing between 2015-2016 as part of previous instantiations of Alectra's APP program ('Legacy Dynamic' customers) and have been exposed to Dynamic pricing over a longer period of time. These Legacy Dynamic customers were encouraged to remain in Dynamic pricing as part of the 17-month pilot reported here. We analyze Legacy Dynamic pricing impacts independently of 'new' Dynamic pricing impacts for three important reasons:

1. The former (Legacy) Dynamic pricing initiative offered to customers by Alectra was run with full price protection. This means that as of their enrollment date in Dynamic pricing until the beginning of the most recent pilot reporting period, all participants were not financially penalized if their APP bill amounts were greater than what they would have been billed under Status-Quo TOU. Because it is unknown how extended exposure to price protection affects customer responsiveness to alternative pricing schemes, we consider Legacy Dynamic customers to be a qualitatively distinct group relative to new Dynamic customers.

2. The Legacy Dynamic pricing program began in 2014, meaning that the employment of a difference-in-difference approach to impact estimation is problematic. Mainly, in order to compare consumption in the pilot period (May 01, 2018 – October 31, 2019) to a pre-Treatment historical baseline period, a historical data set that is (in many cases) over five years old would have to be used. This is further complicated by the fact that Legacy Dynamic pricing customers enrolled into Dynamic pricing at three different historical time periods, meaning that different historical baseline periods would have to be used for different groups of customers within the Legacy Dynamic customer group (this is discussed further below).

3. Legacy Dynamic customers are compared to a separate matched Control group than the "new" Dynamic customers. Moreover, whereas the new Dynamic customers are compared to a single matched Control group, the Legacy Dynamic customers are compared to distinct matched Control groups in the Summer and Winter seasons.

The longevity of Legacy Dynamic pricing customers in the program affords us the opportunity to estimate how Dynamic pricing affects customers over an extended period of time in order to determine whether consumption impacts were sustained, increased, or decreased over time. Due to missing data, impact estimates for Winter seasons 2015-2016 and 2016-2017 were not available.

As discussed throughout this report, (e.g. Section 4.3.3), the procedure for measuring effects of Dynamic pricing on consumption for the Legacy households is distinct form the difference-in-difference methodology employed for the estimation of "new" Dynamic pricing impacts. Instead, the Legacy Dynamic impact estimates derive from a comparison of consumption between the Treatment and Control groups for each year between 2014-2019. Furthermore, as participants in the Legacy Dynamic pricing group enrolled into the pilot at different time-points, a procedure for measuring the varying durations of exposure to Dynamic pricing within the Legacy group is required. Registration dates for Legacy Dynamic customers are shown in Table 48**.**

Table 48: Breakdown of Registration Dates for Legacy Dynamic Participants

	On or Before May 1st, 2015	October 1st, 2015 – May 4th, 2016	After June 1st, 2016
Number of Registrations	978	787	55

The observed registration dates in Table 48 reveal three natural groups, or 'waves', of customer enrollment. 992 households enrolled on or before May 1st, 2015 (the first instantiation of

Dynamic pricing offered to customers by Alectra). The next major registration period was between October 1st, 2015 – May 4th, 2016. These 816 households would not have been exposed to Dynamic pricing in the Summer of 2015 but would have been exposed to Dynamic pricing during the Summer of 2016. The remaining 55 households signed up after June 1st, 2016, meaning that 2017 would have been the earliest full summer exposure to Dynamic pricing for this group. Based on these observations, we define two distinct bins of households for which consumption impacts will be estimated: **Registration Bin 1** (registration date on or before May 1st, 2015) and **Registration Bin 2** (registration date between October 1st, 2015 and May 4th, 2016). Households in **Registration Bin 3** (registration after June 1st, 2016) were excluded from the analysis as the sample size was too small to allow for the derivation of meaningful impacts.

The sample sizes used for impact estimation for the Legacy Dynamic pilot are displayed in Table 49 for Bin 1 and Table 50 for Bin 2. These tables also the breakdown of attrition rates due to either households moving out of the service territory, households opting out of the program, missing data[36], or because household consumption was deemed to be an outlier[37]. Furthermore, we observed that some households signed up for, or were erroneously assigned to, more than one pilot group (i.e. overlap with other RPP pilots being conducted by Alectra during the relevant reporting period). As a result of this, these "conflict with other pilot" households were removed from the present impact analysis; however, the number of these households was relatively small. Note that unlike in the "new" Dynamic pilot, separate matched Control groups were created for Summer and Winter periods (as per Potter et al., 2016)[38]. We conducted Control and Treatment pairwise elimination. This means that if a Treatment participant was removed, we removed their corresponding matched Control, and vice versa. In the present case, this method led to higher numbers of Legacy Dynamic pricing participants in the Winter 2018-19 period compared to Summer 2018, and Summer 2019. These participants were excluded when their Summer matched Control was removed and were added back into the Winter analysis with a new matched Control. Due to the reduction in sample size after subdividing the Treatment group into Legacy 6 and Legacy 9 for the extension period, analysis of the Summer 2019 extension period combined the two Registration Date Bins. For clarity, the final number of participants for the Summer 2019 extension period with bins combined is presented in Table 51.

Table 49: Number of Participants for Legacy Dynamic Pilot Bin 1

Bin 1 (registration date on or before May 1st, 2015)									
	Initial N	Opt-Outs	Move-Outs	Conflict with Other Pilots	Missing Data	Outliers	Removal of Matched Exclusions	Total Exclusions	Final N

[36]See Section 4.2.4 Issues or Concerns for further explanation.
[37]An outlier was defined as any household who consumed more than 15kWh per hour, less than 0.05kWh per hour during any hour in the analysis period
[38] Potter, Candice., Jain, Ankit., Thompson, Daniel., and Cumming, Trevor., (2016) "peaksaverPLUS Program 2015 Load Impact Evaluation" *Nexant, Inc.*

Summer 2018 Reporting Period									
Legacy Dynamic	778	3	34	5	15	4	53	114	664
Status-Quo TOU Control	778	4	0	30	13	9	58	114	664
Winter 2018-19 Reporting Period									
Legacy Dynamic	839	2	36	7	18	6	42	111	728
Status-Quo TOU Control	839	7	2	26	6	5	65	111	728
Summer 2019 Extension Period									
Legacy Dynamic 6 CPP Days	327	47	7	0	1	0	1	56	271
Legacy Dynamic 9 CPP Days	336	40	6	0	2	0	0	48	288
Status-Quo TOU Control	663	1	0	0	0	1	102	104	559

Table 50: Number of Participants for Legacy Dynamic Pilot Bin 1

Bin 2 (registration date between October 1st, 2015 and May 4th, 2016)									
	Initial N	Opt-Outs	Move-Outs	Conflict with Other Pilots	Missing Data	Outliers	Removal of Matched Exclusions	Total Exclusions	Final N
Summer Period									
Legacy Dynamic	650	41	34	6	9	16	41	147	503
Status-Quo TOU Control	650	2	2	21	9	19	94	147	503

Winter Period									
Legacy Dynamic	639	36	37	8	13	8	39	141	498
Status-Quo TOU Control	639	1	1	29	10	9	91	141	498
Summer 2019 Extension Period									
	Initial N	Opt-Outs	Move-Outs	Conflict with Other Pilots	EVs	Missing Data	Outliers	Removal of Matched Exclusions	Total Exclusions	Final N
Legacy Dynamic 6 CPP Days	253	34	10	0	3	0	0	2	49	204
Legacy Dynamic 9 CPP Days	250	36	4	0	4	0	1	1	46	204
Status-Quo TOU Control	503	0	0	0	0	1	2	92	95	408

Table 51: Final Number of Summer Extension Period Legacy Dynamic Participants

Summer 2019 Legacy Dynamic Participants	Final N
Legacy Dynamic 6	475
Legacy Dynamic 9	492
Status-Quo TOU Control	967
Total	1934

Next, we present a summary of average hourly kW consumption for the Legacy Dynamic pilot from 2014 through 2018 shown separately for the two registration bins for Summer (Table 52) and Winter (Table 53). Despite the fact that we do not employ a difference-in-difference approach to impact estimation for Legacy Dynamic customers, we present summary statistics for consumption in the year(s) prior to program participation (the 'baseline' year) for customers in both registration bins. Note that for Registration Bin 1, the Summer baseline year was 2014 and the Winter baseline year was 2014-2015, whereas for Registration Bin 2, the Summer baseline years were 2014 and 2015, and the Winter baseline year was 2014-2015. Summary statistics for the Summer 2019 period are presented in
Table 54.

Table 52: Legacy Dynamic Pilot Summary Statistics of Mean Hourly Consumption (kW) (Summer 2018 Period)

Summer 2014-2018 Period (kWh)		Registration Bin 1			Registration Bin 2		
		Status-Quo TOU Control, No Nudge Report	Dynamic Pricing, No Nudge Report	Dynamic Pricing + Nudge Report	Status-Quo TOU Control, No Nudge Report	Dynamic Pricing, No Nudge Report	Dynamic Pricing + Nudge Report
High-Peak 2014	Mean	1.217	1.316	1.257	1.178	1.254	1.190
	SD	0.700	0.822	0.726	0.775	0.822	0.805
High-Peak 2015	Mean	1.860	1.538	1.489	1.750	1.844	1.820
	SD	0.939	0.914	0.858	1.012	1.096	1.055
High-Peak 2016	Mean	2.032	1.702	1.671	1.887	1.747	1.729
	SD	1.056	1.005	1.002	1.065	1.112	1.134
High-Peak 2017	Mean	1.535	1.232	1.285	1.463	1.426	1.340
	SD	0.845	0.795	0.829	0.874	0.997	0.928
High-Peak 2018	Mean	1.921	1.759	1.795	1.811	1.775	1.718
	SD	1.044	1.036	1.077	1.050	1.235	1.090
Medium-Peak 2014	Mean	1.273	1.376	1.316	1.223	1.295	1.237
	SD	0.725	0.846	0.750	0.795	0.855	0.832

Summer 2014-2018 Period (kWh)		Registration Bin 1			Registration Bin 2		
		Status-Quo TOU Control, No Nudge Report	Dynamic Pricing, No Nudge Report	Dynamic Pricing + Nudge Report	Status-Quo TOU Control, No Nudge Report	Dynamic Pricing, No Nudge Report	Dynamic Pricing + Nudge Report
Medium-Peak 2015	Mean	1.327	1.247	1.193	1.264	1.384	1.328
	SD	0.828	0.820	0.754	0.881	0.961	0.922
Medium-Peak 2016	Mean	1.553	1.431	1.389	1.452	1.407	1.403
	SD	0.907	0.909	0.869	0.926	0.965	0.985
Medium-Peak 2017	Mean	1.134	1.013	1.038	1.113	1.146	1.061
	SD	0.707	0.671	0.661	0.749	0.821	0.786
Medium-Peak 2018	Mean	1.570	1.489	1.502	1.488	1.488	1.410
	SD	0.894	0.892	0.889	0.910	1.046	0.909
Low-Peak 2014	Mean	1.190	1.283	1.225	1.159	1.235	1.161
	SD	0.675	0.790	0.700	0.752	0.803	0.779
Low-Peak 2015	Mean	1.030	1.038	1.008	1.002	1.116	1.045
	SD	0.631	0.659	0.630	0.691	0.769	0.754
Low-Peak 2016	Mean	1.017	1.046	0.992	0.974	1.021	0.992
	SD	0.639	0.702	0.630	0.656	0.720	0.731
Low-Peak 2017	Mean	0.916	0.881	0.881	0.909	0.963	0.898
	SD	0.540	0.573	0.534	0.585	0.644	0.662
Low-Peak 2018	Mean	0.996	1.028	1.021	0.970	1.044	0.982
	SD	0.613	0.638	0.617	0.647	0.733	0.680
Off-Peak 2014	Mean	0.852	0.902	0.876	0.853	0.903	0.840
	SD	0.480	0.569	0.511	0.577	0.596	0.591
Off-Peak 2015	Mean	0.875	0.961	0.953	0.872	0.949	0.887
	SD	0.500	0.569	0.574	0.590	0.610	0.608
Off-Peak 2016	Mean	0.941	1.053	1.035	0.912	1.021	0.963
	SD	0.542	0.653	0.601	0.593	0.656	0.639
Off-Peak 2017	Mean	0.796	0.914	0.925	0.799	0.905	0.848
	SD	0.465	0.609	0.536	0.520	0.600	0.610

Summer 2014-2018 Period (kWh)		Registration Bin 1			Registration Bin 2		
		Status-Quo TOU Control, No Nudge Report	Dynamic Pricing, No Nudge Report	Dynamic Pricing + Nudge Report	Status-Quo TOU Control, No Nudge Report	Dynamic Pricing, No Nudge Report	Dynamic Pricing + Nudge Report
Off-Peak 2018	Mean	0.909	1.022	1.013	0.905	1.005	0.952
	SD	0.527	0.626	0.582	0.590	0.662	0.620
Total Consumption 2014	Mean	1.116	1.200	1.150	1.088	1.156	1.091
	SD	0.664	0.777	0.691	0.737	0.782	0.765
Total Consumption 2015	Mean	1.325	1.178	1.142	1.263	1.356	1.305
	SD	0.937	0.834	0.792	0.957	1.011	1.011
Total Consumption 2016	Mean	1.502	1.361	1.319	1.410	1.364	1.341
	SD	1.032	0.954	0.913	1.015	1.006	1.030
Total Consumption 2017	Mean	1.145	1.040	1.060	1.115	1.141	1.066
	SD	0.786	0.729	0.721	0.799	0.856	0.824
Total Consumption 2018	Mean	1.412	1.361	1.373	1.355	1.378	1.307
	SD	0.939	0.909	0.922	0.945	1.036	0.935

Table 53: Legacy Dynamic Pilot Summary Statistics of Mean Hourly Consumption (kW) (Winter 2018-19 Period)

Winter 2018-19 Period (kWh)		Registration Bin 1			Registration Bin 2		
		Status-Quo TOU Control, No Nudge Report	Dynamic Pricing, No Nudge Report	Dynamic Pricing + Nudge Report	Status-Quo TOU Control, No Nudge Report	Dynamic Pricing, No Nudge Report	Dynamic Pricing + Nudge Report
High-Peak 2014-2015	Mean	1.224	1.211	1.182	1.6	1.7	1.62
	SD	0.623	0.626	0.555	1.35	1.45	1.268
High-Peak 2015-2016	Mean	1.027	1.063	1.021	1.27	1.24	1.208
	SD	0.501	0.559	0.528	0.96	0.88	0.831
High-Peak 2016-2017	Mean	0.995	0.992	0.979	1.24	1.2	1.2
	SD	0.482	0.551	0.496	1.02	0.92	0.908
High-Peak 2017-2018	Mean	1.068	1.087	1.079	1.4	1.4	1.347
	SD	0.571	0.706	0.613	1.32	1.2	1.135
High-Peak 2018-2019	Mean	1.076	1.07	1.071	1.41	1.43	1.389
	SD	0.559	0.586	0.598	1.34	1.26	1.21

Winter 2018-19 Period (kWh)		Registration Bin 1			Registration Bin 2		
		Status-Quo TOU Control, No Nudge Report	Dynamic Pricing, No Nudge Report	Dynamic Pricing + Nudge Report	Status-Quo TOU Control, No Nudge Report	Dynamic Pricing, No Nudge Report	Dynamic Pricing + Nudge Report
Medium-Peak 2014-2015	Mean	1.216	1.23	1.188	1.55	1.61	1.544
	SD	0.615	0.626	0.555	1.23	1.32	1.167
Medium-Peak 2015-2016	Mean	--	--	--	--	--	--
	SD	--	--	--	--	--	--
Medium-Peak 2016-2017	Mean	--	--	--	--	--	--
	SD	--	--	--	--	--	--
Medium-Peak 2017-2018	Mean	1.023	1.062	1.051	1.29	1.3	1.275
	SD	0.504	0.601	0.555	1.12	0.99	0.966
Medium-Peak 2018-2019	Mean	1.032	1.05	1.049	1.27	1.3	1.274
	SD	0.54	0.583	0.584	1.11	1.03	1.056
Low-Peak 2014-2015	Mean	1.112	1.14	1.091	1.35	1.41	1.349
	SD	0.559	0.591	0.522	0.98	1.03	0.934
Low-Peak 2015-2016	Mean	--	--	--	--	--	--
	SD	--	--	--	--	--	--
Low-Peak 2016-2017	Mean	--	--	--	--	--	--
	SD	--	--	--	--	--	--
Low-Peak 2017-2018	Mean	0.956	1.008	1.005	1.15	1.16	1.144
	SD	0.485	0.577	0.564	0.92	0.81	0.813
Low-Peak 2018-2019	Mean	0.997	1.022	1.023	1.18	1.21	1.181
	SD	0.52	0.57	0.551	0.95	0.89	0.886
Off-Peak 2014-2015	Mean	0.923	0.933	0.904	1.24	1.28	1.233
	SD	0.489	0.481	0.44	1.14	1.19	1.095
Off-Peak 2015-2016	Mean	0.807	0.891	0.857	1.06	1.09	1.059
	SD	0.404	0.48	0.427	0.9	0.86	0.858
Off-Peak 2016-2017	Mean	0.788	0.873	0.85	1.03	1.09	1.073
	SD	0.392	0.506	0.403	0.94	0.92	0.933

Winter 2018-19 Period (kWh)		Registration Bin 1			Registration Bin 2		
		Status-Quo TOU Control, No Nudge Report	Dynamic Pricing, No Nudge Report	Dynamic Pricing + Nudge Report	Status-Quo TOU Control, No Nudge Report	Dynamic Pricing, No Nudge Report	Dynamic Pricing + Nudge Report
Off-Peak 2017-2018	Mean	0.812	0.896	0.89	1.08	1.17	1.137
	SD	0.408	0.539	0.453	1.06	1	1.037
Off-Peak 2018-2019	Mean	0.826	0.883	0.883	1.08	1.17	1.164
	SD	0.432	0.511	0.462	1.05	1.03	1.069
Total 2014-2015	Mean	1.065	1.073	1.038	1.38	1.44	1.37
	SD	0.585	0.597	0.549	1.2	1.28	1.13
Total 2015-2016	Mean	0.932	0.974	0.939	1.2	1.19	1.154
	SD	0.488	0.549	0.509	1.01	0.94	0.913
Total 2016-2017	Mean	0.916	0.948	0.93	1.17	1.16	1.164
	SD	0.48	0.562	0.479	1.04	0.94	0.953
Total 2017-2018	Mean	0.965	1.011	1.004	1.24	1.27	1.228
	SD	0.507	0.613	0.56	1.14	1.03	1.012
Total 2018-2019	Mean	0.999	1.019	1.02	1.26	1.3	1.269
	SD	0.545	0.584	0.579	1.16	1.1	1.091

Table 54: Legacy Dynamic Pilot Summary Statistics of Mean Hourly Consumption (kW) (Summer 2019 Period)

Summer 2019 Period (kWh)	Status-Quo TOU Control, No	Legacy Dynamic 6 Pricing, No	Legacy Dynamic 9 Pricing, No	Legacy Dynamic 6 Pricing +	Legacy Dynamic 9 Pricing +

		Nudge Report	Nudge Report	Nudge Report	Nudge Report	Nudge Report
High-Peak 2019	Mean	1.547	1.533	1.516	1.403	1.445
	SD	0.972	1.014	1.058	0.902	0.99
Medium-Peak 2019	Mean	1.187	1.228	1.198	1.112	1.181
	SD	0.78	0.84	0.846	0.726	0.795
Low-Peak 2019	Mean	0.887	0.982	0.953	0.864	0.932
	SD	0.534	0.62	0.58	0.536	0.603
Off-Peak 2019	Mean	0.85	0.981	0.965	0.896	0.965
	SD	0.55	0.681	0.626	0.557	0.655
Total 2019	Mean	1.115	1.181	1.159	1.071	1.133
	SD	0.785	0.837	0.834	0.729	0.803

5.4.2 Time-of-Use Period Impacts and Seasonal Results with Elasticities

Impact estimates for On-Peak (High, Medium, Low) and Off-Peak TOU periods, CPP Days, and System-Coincident Peak hours are displayed in Table 55 to Table 59. In order to derive impacts for High, Medium, and Low On-Peak hours during the baseline (pre-pilot) years, we used the following approach: For Registration Bin 1, we used temperature data for Summer and Winter weekdays in the baseline year to rank order the days and then assigned the warmest 20% to 'High On-Peak', the next warmest 30% to 'Medium On-Peak', and the next warmest 50% to 'Low On-Peak' for Summer months (for Winter months, the days were ranked in reverse from coldest to warmest). For Registration Bin 2, we capitalized on the pre-existing assignment of On-Peak days to Low, Medium, and High for the Legacy Dynamic participants in Registration Bin 1 where possible, and where this was not possible, we again relied on temperature data to infer whether a given day would have been assigned to Low, Medium, or High On-Peak.
Legacy Dynamic households consumed less Summer 2018 High On-Peak electricity than Status-Quo TOU Control households during all Treatment years (Bin 1 - 2015-2019; Bin 2 - 2016-2019). For Registration Bin 1, households in the Treatment group consumed on average -0.35kW, -0.35kW, -0.28kW, and -0.14kW less energy per hour on average (relative to Control) during High-Peak hours in 2015, 2016, 2017, and 2018 respectively. For Registration Bin 2, the effect was -0.15kW, -0.08kW, and -0.07kW in 2016, 2017, and 2018 respectively. Summer 2019 did not see significant differences in High On-Peak energy consumption between Legacy Dynamic customers and matched Controls. We did however observe a significant difference during the Summer baseline periods between Control and Treatment groups. In both Registration Bins, High On-Peak consumption was higher in the Treatment group before the program began. This would suggest that the derived impacts of Dynamic pricing on Legacy Dynamic customers could be underestimates the true Treatment impact. No differences between pricing groups were observed for any of the High On-Peak Winter periods.

With respect to the Summer Medium On-Peak hours in Registration Bin 1, the effects were similar to those estimated during the High On-Peak hours. Treatment households had higher electricity consumption at baseline than the Control group, followed by lower consumption for the Legacy Dynamic Treatment customers relative to Control in all Treatment years (-0.075 to 0.143 kW per hour). However, there were no significant differences in consumption between Legacy Dynamic pricing Treatment and Control households during Summer 2018 or 2019 Medium On-Peak TOU periods. Similar to the High On-Peak results, there was only one impact estimate reaching statistical significance during the Winter Medium On-Peak periods for either Registration Bin (i.e. only +0.034 kW per hour in Bin 1 during 2017-2018).

With respect to Low On-Peak electricity consumption, both registration bins had higher consumption than Status-Quo TOU Control household during the Summer baseline year. Differences between Treatment and Control customers during all three Summer and Winter Treatment periods ranged between -0.035 kW per hour and +0.076 kW per hour, with estimated consumption impacts being positive more often than negative for Legacy Dynamic Treatment households relative to Control households, and most years showing no significant differences between pricing groups.

Legacy Dynamic households exhibited higher consumption (ranging between +0.037 to +0.123 kW per hour on average) during Off-Peak TOU periods in most Treatment years.

Table 55: Legacy Dynamic Pricing TOU Peak Impact Analysis Results (Mean Hourly kW, Summer 2014-18)

Summer 2014-18 Period	Baseline	Bin 1 Dynamic Pricing / Bin 2 Baseline	Dynamic Pricing Main Effect		
	2014	2015	2016	2017	2018
High-Peak - Bin 1	0.070^	**-0.347*** **	**-0.345*** **	**-0.276*** **	**-0.144** **
High-Peak - Bin 2	0.042	0.081	**-0.149***	-0.082	-0.065
Medium-Peak - Bin 1	0.073^	**-0.107** **	**-0.143** **	**-0.109** **	-0.075^
Medium-Peak – Bin 2	0.042	0.091^	-0.048	-0.012	-0.041
Low-Peak - Bin 1	0.064	-0.007	0.002	-0.035	0.028
Low-Peak - Bin 2	0.037	0.076^	0.032	0.020	0.041
Off-Peak - Bin 1	0.037	**0.082** **	**0.103*** **	**0.123*** **	**0.108*** **
Off-Peak - Bin 2	0.017	0.044	**0.078***	**0.076***	**0.072***
CPP - Bin 1	--	**-0.756*** **	**-0.721*** **	**-0.421*** **	**-0.241*** **
CPP - Bin 2	--	0.029	**-0.37*** **	**-0.159** **	**-0.152***
System-Coincident-Peak - Bin 1	0.009	**-0.162*** **	**-0.256*** **	-0.064^	**-0.087***
System-Coincident-Peak – Bin 2	0.011	0.035	**-0.118***	-0.037	-0.060

*** $p < 0.001$; ** $p < 0.01$; * $p < 0.05$; ^ $p < 0.1$

Table 56: Legacy Dynamic Pricing TOU Peak Impact Analysis Results (Summer, % Difference in Mean Hourly kW)

Summer 2018 Period (%)	Baseline	Bin 1 Dynamic Pricing / Bin 2 Baseline	Dynamic Pricing Main Effect (Mean Hourly %)		
	2014	2015	2016	2017	2018
High-Peak - Bin 1	5.752	-18.653	-16.98	-17.986	-7.496
High-Peak - Bin 2	3.564	4.627	-7.897	-5.607	-3.59
Medium-Peak - Bin 1	5.732	-8.061	-9.206	-9.609	-4.776
Medium-Peak – Bin 2	3.435	7.202	-3.305	-1.078	-2.755
Low-Peak - Bin 1	5.379	-0.679	0.197	-3.821	2.81
Low-Peak - Bin 2	3.192	7.583	3.286	2.2	4.225
Off-Peak - Bin 1	4.344	9.367	10.951	15.447	11.878
Off-Peak - Bin 2	1.993	5.044	8.548	9.507	7.959
CPP - Bin 1	--	-35.383	-28.749	-22.868	-11.996
CPP - Bin 2	--	1.466	-15.865	-9.195	-7.851
System-Coincident-Peak - Bin 1	4.556	-13.034	-16.98	-5.405	-6.019
System-Coincident-Peak – Bin 2	0.95	2.931	-7.897	-3.212	-4.336

*** $p < 0.001$; ** $p < 0.01$; * $p < 0.05$; ^ $p < 0.1$

Table 57: Legacy Dynamic Pricing TOU Peak Impact Analysis Results (Average Hourly kW, Winter 2014-19)

Winter 2018-19 Periods	Baseline	Bin 1 Dynamic Pricing / Bin 2 Baseline	Dynamic Pricing Main Effect		
	2014-2015	2015-2016	2016-2017	2017-2018	2018-2019
High-Peak – Bin 1	-0.028	0.016	-0.01	0.015	-0.005
High-Peak – Bin 2	0.057	-0.045	-0.043	-0.026	-0.005
Medium-Peak – Bin 1	-0.007	--	--	0.034	0.018
Medium-Peak – Bin 2	0.032	--	--	-0.005	0.014
Low-Peak – Bin 1	0.004	--	--	**0.05***	0.025
Low-Peak – Bin 2	0.03	--	--	0.003	0.02
Off-Peak – Bin 1	-0.004	**0.068****	**0.074*****	**0.081*****	**0.057***
Off-Peak – Bin 2	0.016	0.012	0.048	0.07	0.091
CPP – Bin 1	--	**-0.067***	**-0.076***	0.006	-0.03
CPP – Bin 2	--	-0.095	-0.146^	-0.029	-0.021
System-Coincident-Peak – Bin 1	-0.007	0.01	-0.007	0.028	0.014
System-Coincident-Peak - Bin 2	0.033	-0.071	-0.064	-0.02	-0.004

*** $p < 0.001$; ** $p < 0.01$; * $p < 0.05$; ^ $p < 0.1$

Table 58: Legacy Dynamic Pricing TOU Peak Impact Analysis Results (Winter, % Difference in Mean Hourly kW)

Winter 2018-19 Period (%)	Baseline	Bin 1 Dynamic Pricing / Bin 2 Baseline	Dynamic Pricing Main Effect (Mean Hourly %)		
	2014	2015	2016	2017	2018
High-Peak - Bin 1	-2.287	1.558	0.812	1.405	-0.465
High-Peak - Bin 2	3.554	-3.552	-4.63	-1.858	-0.354
Medium-Peak - Bin 1	-0.575	--	--	3.324	1.745
Medium-Peak – Bin 2	2.071	--	--	-0.387	1.1
Low-Peak - Bin 1	0.36	--	--	5.231	2.507
Low-Peak - Bin 2	2.225	--	--	0.261	1.702
Off-Peak - Bin 1	-0.434	8.427	9.389	9.97	6.898
Off-Peak - Bin 2	1.289	1.129	4.644	6.468	8.447
CPP - Bin 1	--	-6.227	-6.305	0.589	-2.475
CPP - Bin 2	--	-6.808	-9.165	-2.076	-1.321
System-Coincident-Peak - Bin 1	-0.487	0.812	-0.59	2.351	1.17
System-Coincident-Peak – Bin 2	1.807	-4.63	-4.259	-1.329	-0.267

**** $p < 0.001$; ** $p < 0.01$; * $p < 0.05$; ^ $p < 0.1$*

Table 59: Legacy Dynamic Pricing TOU Peak Impact Analysis Results (Summer 2019; Mean Hourly kW and % differences)

Summer 2019 Period	Dynamic Pricing Main Effect (Mean Hourly kW)			
	Dynamic Pricing (6 CPP)		Dynamic Pricing (9 CPP)	
	Mean Hourly kW	%	Mean Hourly kW	%
High-Peak	-0.079	-5.133	-0.067	-4.306
Medium-Peak	-0.018	-1.533	0.002	0.169
Low-Peak	0.036	4.004	0.056	6.267^
Off-Peak	**0.089****	10.418	**0.116*****	13.599
CPP	**-0.24*****	-13.337	**-0.225*****	-12.511
System-Coincident-Peak	-0.068	-5.123	-0.055	-4.108

**** $p < 0.001$; ** $p < 0.01$; * $p < 0.05$; ^ $p < 0.1$*

CPP events occurred at different frequencies across each year and season of Legacy Dynamic pricing (Table 60).

Table 60: Number of Critical Peak Events by Year

	Summer	Winter
Year 1	--	--
Year 2	5	4
Year 3	5	1
Year 4	7	3
Year 5	6	6
Year 6	6/9	NA

With respect to CPP events in the Summer months across years, the pattern was consistent across the two Registration Bins, and the two CPP pricing groups during Summer 2019. We estimated lower electricity consumption (-0.152 to -0.756 kW per hour) for Legacy Dynamic Treatment customers relative to Control customers during CPP event hours across all Treatment years.

CPP events were less impactful in the Winter months across the years analyzed here, with small effects in mean hourly kW consumption only obtained during Treatment Years 1 and 2 for Registration Bin 1(-0.067 kW and -0.076 kW respectively), and no differences between Treatment and Control for Registration Bin 2.

The differential distribution of the number of CPP events and their duration limits potential inferences of about the effects of CPP impacts across different years. Specifically, the larger number of CPP events in Year 5 (the most recent instantiation of Dynamic pricing) relative to Years 2 and 3, likely yield better estimates of the impact of CPP events on consumption relative to historical impact estimates derived from smaller sets of observations. This is further complicated by the fact that only in Year 5 was price protection removed. Again, while it is possible, and potentially insightful to examine CPP responsiveness over time for Legacy Dynamic pricing households given the data available, caution should be used when interpreting the reduction in magnitude of these effects over time (i.e., in the Summer CPP impact estimates across year).

There were no significant differences between Legacy Dynamic pricing Treatment and Control households during any of the Summer or Winter System-Coincident Peak periods.

From a descriptive perspective, we do observe that the magnitude of Summer Legacy Dynamic pricing consumption effects (for High On-Peak, Medium On-Peak, and CPP events) between Treatment and Control households diminish across time (

Table 55 to Table 59). For example, the High On-Peak registration Bin 1 impacts for Treatment years 2015-2018 are -0.347 kW, -0.345 kW, -0.276 kW, and -0.144 kW mean hourly consumption, respectively, with significant consumption impact estimates obtained for Legacy Dynamic Treatment households relative to Control households in all years. It is important to note that inferential statistical modelling of pricing Treatment impacts over time, incorporating seasonal variations in temperature, are necessary to confirm that these magnitude changes in Summer impacts represent a significant trend rather than natural variability in the data. The magnitudes of all other periods of measurement, including Low On-Peak, Off-Peak, as well as overall Summer do not exhibit this descriptive trend. The effects of Summer 2019 appear descriptively similar to Summer 2018; however, a direct comparison is made more difficult because Summer 2019 analyses combined the Registration Bins. Further discussion of this potential effect is included in Section 5.4.7.

Seasonal average conservation impacts are shown in Table 61 and Table 62. Overall, Legacy Dynamic pricing Treatment customers consumed slightly more electricity than Status-Quo TOU Control customers, and this effect only reached significance for Bin 1 (and in the Summer 2019 period in which Bin 1 and 2 were combined). The use of different matched Control groups during the Summer and Winter periods precludes a year-round or full 17-month analysis of average conservation impacts.

Table 61: Legacy Dynamic Seasonal Average Hourly kW Consumption Impacts

	2014 Summer 2014-15 Winter	2015 Summer 2015-16 Winter	2016 Summer 2016-17 Winter	2017 Summer 2017-18 Winter	2018 Summer 2018–19 Winter	Summer 2019	
Summer Bin 1	0.042	0.051^	**0.063***	**0.081****	**0.084****	Legacy Dynamic 6	**0.068***
Summer Bin 2	0.02	0.049	0.057	0.06^	0.059		
Winter Bin 1	-0.004	**0.059****	0.059	**0.073****	**0.05***	Legacy Dynamic 9	**0.0932****
Winter Bin 2	0.02	0.003	0.032	0.058	0.077		

*** $p < 0.001$; ** $p < 0.01$; * $p < 0.05$; ^ $p < 0.1$; ^ $p < .10$

Table 62: Legacy Dynamic Seasonal Average Hourly % Consumption Impacts

	2014 Summer 2014-15 Winter	2015 Summer 2015-16 Winter	2016 Summer 2016-17 Winter	2017 Summer 2017-18 Winter	2018 Summer 2018–19 Winter	Summer 2019	
Summer Bin 1	4.615	5.433	6.165	9.459	8.601	Legacy Dynamic 6	7.436
Summer Bin 2	2.208	5.278	5.787	7.025	6.115		
Winter Bin 1	-0.415	6.983	7.163	8.634	5.809	Legacy Dynamic 9	10.236
Winter Bin 2	1.562	0.273	2.993	5.215	6.949		

*** $p < 0.001$; ** $p < 0.01$; * $p < 0.05$; ^ $p < 0.1$; ^ $p < .10$

5.4.3 Elasticity

Daily and Substitution Elasticities are reported for the 17-month Treatment period in Table 63. Daily elasticity of demand was estimated at -0.072. The daily elasticity of demand was negative and less than 1, indicating only a small change in percent consumption per percent change in price. Substitution elasticity of demand was estimated at -0.004 again indicating a relatively small change in percent consumption per percent change in price.

Table 63: Legacy Dynamic Pilot Daily and Substitution Elasticities of Demand

	Elasticity Estimate
Daily Elasticity	**-0.072*** **
Substitution Elasticity On/Off-Peak	**-0.004*** **

**** $p < 0.001$; ** $p < 0.01$; * $p < 0.05$; ^ $p < 0.1$*

5.4.4 Communication Analysis

In this section, we report consumption impacts attributable to the Nudge Reports that were distributed to households in the Legacy Dynamic Group. Starting in May 2018, we randomly selected half of the Legacy Dynamic Treatment group to receive Nudge Reports (Table 64). We report the effects of the Nudge Reports between Legacy Dynamic households who did not receive Nudge Reports to the households who did receive Nudge Reports. To preserve statistical power, we combined both Registration Date Bins (1 and 2). In addition, we did not use a difference-in-difference methodology (for the same rationale outlined in the analytic approach to TOU period impact estimates) but instead analyzed consumption behaviour during the Treatment period only.

Summary statistics of hourly consumption for Legacy Dynamic households with and without Nudge Reports were previously shown in Table 55 to Table 59. Consumption impacts owing to Nudge Reports are shown in Table 65. None of the estimated impacts of Nudge Reports reached statistical significance.

Table 64: Number of Legacy Dynamic participants who received Nudge Reports

	Summer 2018 Final N	Winter 2018-19 Final N	Summer 2019 Final N
Legacy Dynamic, No Nudge Report	574	615	--
Legacy Dynamic + Nudge Report	593	611	--
Legacy Dynamic 6, No Nudge Report	--	--	235
Legacy Dynamic 9, No Nudge Report	--	--	240
Legacy Dynamic + Nudge Report	--	--	242
Legacy Dynamic + Nudge Report	--	--	250

Table 65: Legacy Dynamic Nudge Report Communication Impact Analysis Results

	Nudge Report Main Effect (Mean Hourly kW)					
	Summer 2018 Period		Winter 2018-19 Period		Summer 2019	
	Mean Hourly kW	%	Mean Hourly kW	%	Mean Hourly kW	%
High-Peak	-0.005	-0.279	-0.005	-0.404	-0.1^	-6.564
Medium-Peak	-0.027	-1.842	-0.005	-0.424	-0.065	-5.387
Low-Peak	-0.031	-2.997	-0.007	-0.628	-0.068^	-7.053
Off-Peak	-0.029	-2.865	0.005	0.494	-0.042	-4.306
CPP	-0.03	-1.71	-0.013	-0.986	-0.098	-6.061
System-Coincident-Peak	-0.011	-0.815	0.007	0.562	-0.063	-4.869
Total	-0.024	-1.772	-0.004	-0.352	-0.047	-4.615
12-Month Total	-	-	-0.012	-1.641	-	-
17-Month Total	-	-	-	-	-0.035	-3.328

*** $p < 0.001$; ** $p < 0.01$; * $p < 0.05$; ^ $p < 0.1$

5.4.5 Technology Impacts

As with the Dynamic pricing pilot, Legacy Dynamic pricing households were designated as "Technology" if they participated in a smart thermostat incentive program offered by Alectra Utilities. Objectively verifiable data on smart thermostat ownership exists only for customers who registered their devices through Alectra and therefore our estimation of consumption impacts owing to smart thermostats could only be completed using this verified data. Recall that registered devices were equipped with some form of load curtailment during peak pricing events and so the estimated impacts of smart thermostats (i.e., "Technology") reported here are a measure of the (likely) additive effects of both owning a smart thermostat *and* receiving automatic load curtailment signals. For the Technology analysis, we again combined both Registration date bins.

Frequency of smart thermostat ownership/registration is presented in Table 66. None of the Status-Quo TOU matched Control households owned registered smart thermostats with Alectra Utilities; therefore, we compared Technology and No Technology within the Legacy Dynamic pricing Treatment group only. Registered Honeywell and Nest thermostats were not capable of receiving load curtailment signals from Alectra for the Summer 2019 reporting period and therefore the 'Technology' group for Summer 2019 impact estimates includes only customers with registered Energate or Nest devices. Honeywell and Nest customers with registered devices were excluded entirely from the Summer 2019 Technology impact analysis, that is, they were not added to the control group.

Table 66: Frequency of registered smart thermostat ownership by Legacy Dynamic condition

	Energate	Ecobee	Nest	Honeywell	Unknown
Summer Period					
Legacy Dynamic Pricing	690	5	4	62	38
Status-Quo TOU Control	0	0	0	0	0
Winter Period					
Legacy Dynamic Pricing	731	6	7	66	36
Status-Quo TOU Control	0	0	0	0	0
Summer 2019 Period					
Legacy Dynamic Pricing	615	4	--	--	--
Status-Quo TOU Control	0	0	0	0	0

For the Legacy Dynamic pricing pilot, results of the Technology impact analysis are shown in Table 67 to Table 69. For Summer 2018 High On-Peak hours, we estimated a statistically significant mean hourly consumption effect of -0.127kW owing to smart thermostat possession/registration. Technology was associated with lower electricity consumption for all of the Winter Legacy Dynamic TOU periods, ranging between -0.151 kW (Low On-Peak) and -0.281 kW (High On-Peak), including an overall effect of -0.208 kW for the Winter months. Analysis of the Summer 2019 consumption data yielded an estimated consumption impact of -0.082 kw during High On-peak hours. In this period, the effects of technology ranged from 0.012 kw (during Off-Peak hours) to -0.082 kw during the High On-Peak hours.

Table 67: Legacy Dynamic Technology Impact Analysis Results (Mean Hourly kW; Summer 2018)

Summer Period (Mean Hourly kW)		Technology	No Technology	Estimates	
				Mean Hourly kW	%
High-Peak	Mean	1.723	1.85	**-0.127***	-6.887
	SD	1.058	1.191		
Medium-Peak	Mean	1.449	1.529	-0.08	-5.211
	SD	0.894	0.998		
Low-Peak	Mean	1.014	1.03	-0.016	-1.59
	SD	0.645	0.698		
Off-Peak	Mean	1.016	0.964	0.052	5.383
	SD	0.613	0.636		
Total	Mean	1.336	1.397	-0.061	-4.379
	SD	0.91	1.017		

**** $p < 0.001$; ** $p < 0.01$; * $p < 0.05$; ^ $p < 0.1$*

Table 68: Legacy Dynamic Technology Impact Analysis Results (Mean Hourly kW; Winter 2018-19)

Winter Period (Mean Hourly kW)		Technology	No Technology	Estimates	
				Mean Hourly kW	%
High-Peak	Mean	1.12	1.402	**-0.281*** **	-20.078
	SD	0.706	1.261		
Medium-Peak	Mean	1.081	1.291	**-0.21*** **	-16.289
	SD	0.652	1.073		
Low-Peak	Mean	1.046	1.197	**-0.151*** **	-12.628
	SD	0.605	0.907		
Off-Peak	Mean	0.946	1.117	**-0.171*** **	-15.283
	SD	0.621	1.04		
Total	Mean	1.062	1.27	**-0.208*** **	-16.363
	SD	0.672	1.111		

**** $p < 0.001$; ** $p < 0.01$; * $p < 0.05$; ^ $p < 0.1$*

Table 69: Legacy Dynamic Technology Impact Analysis Results (Mean Hourly kW; Summer 2019)

Summer 2019 Period			Technology	No Technology	Estimates	
					Mean Hourly kW	%
Legacy Dynamic	High-Peak	Mean	1.46	1.545	-0.082	-5.33
		SD	0.957	1.003		
	Medium-Peak	Mean	1.181	1.192	-0.031	-2.59
		SD	0.783	0.805		
	Low-Peak	Mean	0.93	0.901	-0.024	-2.54
		SD	0.573	0.558		
	Off-Peak	Mean	0.966	0.865	0.012	4.51
		SD	0.614	0.582		
	Total	Mean	1.136	1.124	-0.064	-6.09
		SD	0.778	0.808		

*** $p < 0.001$; ** $p < 0.01$; * $p < 0.05$; ^ $p < 0.1$

5.4.6 Pledge Analysis

We sought to examine consumption impacts between households who responded to the On-Peak conservation pledge on the Nudge Report versus households who received the Nudge Reports but did not respond to the pledge. Recall that households had the option to respond to the pledge via SMS text message to commit to reducing their On-Peak electricity consumption. Households who chose to respond to the pledge were offered a $5 rebate. The number of participants in each of the comparison groups is shown in Table 70. Unfortunately, there is insufficient cell size to derive statistically meaningful impacts owing to customers signing versus not signing the pledge within the Legacy Dynamic pricing Treatment group.

Table 70: Pledge Numbers – Legacy Dynamic Customers Who Received Nudge Reports

	Pledge Not Signed	Pricing Pledge Signed
Summer 2018	555	38
Winter 2018-19	571	40
Summer 2019	462	28

5.4.7 Overall Summary of Legacy Dynamic Impacts

Overall, Legacy Dynamic participants consumed less High On-Peak, Medium On-Peak, and CPP electricity during Summer months than the Status-Quo TOU Control households. However, these differences appear to decrease across time and there were no significant differences between Treatment and Control households during On-Peak periods in Summer 2019. Similar to the "new" Dynamic pricing pilot, large consumption impacts were estimated during CPP events, but no overall differences were observed between impact estimates for those Legacy Dynamic participants who received six CPP events or those who received 9 CPP events. Diminished On-Peak hour savings were partially offset by higher Low and Off-Peak usage, leading to some increases in seasonal consumption in the Treatment relative to the Control group.

In terms of non-price interventions, Nudge Reports were not associated with significant consumption impacts and smart thermostat ownership/registration yielded significant electricity consumption impacts for Summer High On-Peak periods and all Winter On-Peak periods.

In terms of the diminishing magnitude of the impact estimates during High On-Peak and Critical Peak events in the Summer months, we offer two interpretations of this hypothesized diminishing behavioural response to peak pricing:

Hypothesis 1 - Impact of prior extended price protection: Customers in Legacy Dynamic pricing have been enrolled in Advantage Power Pricing since 2015 or 2016 (depending on whether they are in registration bin 1 or 2) and have been enjoying full price protection until the start of the current pilot program in April 2018. It is therefore possible that these customers decreased responsiveness to pricing signals over time precisely because there was no material financial penalty associated with doing so. In other words, customers may have learned that failure to maintain On-Peak consumption reductions would not end up costing them more (at least in terms of total bill amount) than they were used to paying under Status-Quo TOU.

Hypothesis 2 - Impact of declining technology use: Over the course of the Legacy Dynamic pricing initiatives undertaken by Alectra Utilities, formerly branded and marketed as Advantage Power Pricing, as well as in the current instantiation, participating customers have been offered subsidized smart thermostats (including procurement and installation). The rationale behind these thermostat incentive programs was that customers would exhibit greater demand response to High On-Peak and Critical Peak pricing events. Response to these events for customers owning eligible devices (i.e., Energate) could be achieved by adjusting the devices 'comfort' settings during programming, and/or by consenting to load curtailment. The latter involves allowing the utility to remotely adjust thermostat settings to lower consumption during high-demand times of day, thus allowing the customer to realize bill savings without having to take any action. The decline in the magnitude of estimated consumption impacts owing to Dynamic pricing for Legacy customers, may therefore be driven, at least in part, by differential use/acquisition of smart thermostat devices over the four to five years in which participating Legacy customers have been enrolled.

There are two ways in which differential use of Technology may have mitigated behavioural response to CPP events:

1. *Lower uptake of devices across the three Dynamic pricing enrollment periods:* While it is true that update of the smart thermostat incentives offered in the current instantiation of Dynamic pricing is lower than the historical uptake observed in the Legacy programs, this is unlikely to be a major factor in driving lower CPP responsiveness. If lowered behavioural response was due to a drop-in device acquisition, we would expect to see sharp declines in behavioural response to CPP events that coincide with the program registration periods. Instead we see a fairly steady decline over the course of the program.

2. *Increasing use of thermostat comfort settings:* It is possible that as time in the Dynamic pricing program increases, customers become increasingly likely to increase the comfort settings on their thermostats, thus increasing consumption during Peak hours in order to enjoy warmer or cooler homes (in Winter and Summer respectively). At the time of the submission of this report, we do not possess thermostat settings data from registered devices and so cannot speak to the reality of this hypothesis.

In summary, the apparent change in impact of Dynamic pricing across time is an interesting potential area of future investigation and should include statistical evaluation of any such effects. Note that such an analysis would not be particularly informative here owing to the fact that the switch from full price protection to unprotected participation in Year 5 represents a significant qualitative change in program design. In addition, differential exposure duration to Dynamic pricing (owing to different registration periods) and inconsistency in the frequency of CPP events across season and year further complicates what would otherwise be a simple time-series analysis. Although we have posited several potential mechanisms to explain a potential reduction in behavioural response to Dynamic pricing over time, a detailed analysis of these mechanisms is not possible at present.

With respect to the 5-month extension period (June – October, 2019), there were two primary research questions that the extension period pilot was designed to address:

1. ***Would the On-Peak and CPP event impacts estimated for the Summer 2018 season still be present a year later in Summer 2019?*** We observed that the trend towards diminished High On-Peak consumption savings observed from 2015-2018 continued into 2019 for Legacy Dynamic households, with consumption impacts failing to reach statistical significance in Summer 2019. With respect to CPP event responsiveness, we estimated similar impacts in the Summer 2018 and Summer 2019 seasons.

2. ***Would an increase in the frequency of CPP events from 6 to 9 impact responsiveness to CPP events?*** In assessing consumption impacts across each of the CPP events called in the Summer 2019 season, we see that consumption impacts for the six events that the Dynamic 6 and Dynamic 9 groups shared in common, are very similar. Thus, as with the 'new' Dynamic pilot, increasing the frequency of CPP events does not seem to impact behavioural response to any one particular CPP event.

6. Survey Findings

In service of the broader objectives of the RPP Pilot Program, customer-facing surveys were administered to all Dynamic and Legacy Dynamic customers along with households in the matched Control groups. The purpose of the surveys was to measure overall levels of comprehension of TOU pricing plans, motivation to change behaviour, subjective experience with APP price plans, and to capture relevant demographic data and household characteristics (e.g. electric vehicle (EV) ownership and use of a programmable thermostat).

To estimate the effects of participation in Dynamic pricing over time on the above metrics, surveys were deployed at the beginning of the pilot (April 2018) (*baseline*), at the six-month mark (October 2018) (*midterm/interim*), and at the end of the Dynamic pilot extension period (November 2019) (*final*). Each of these surveys remained active for approximately one month in order to gather as much participant response data as possible without sacrificing the temporal specificity of each survey (i.e., if the baseline survey were active for too long, it would no longer be a valid 'baseline' survey). Unfortunately, a single survey link was distributed to all Dynamic pricing pilot participants regardless of whether they were newly enrolled or part of the Legacy Dynamic program. This means that survey results for the Dynamic pricing plan comprise a mixture of responses from both "new" and Legacy participants. This section of the report will discuss the results of all three surveys in order to assess potential changes in comprehension, motivation, and self-reported behaviour change (1) across time, and (2) between Treatment and Control groups within Dynamic pricing, where applicable and feasible. Note that survey responses were solicited via direct mail and email marketing initiatives undertaken by Alectra and therefore the evaluator had no control over the response rate. In some instances (particularly for Control participants within each pilot), response rates were too low to allow for any meaningful analyses.

Since survey data was provided in an anonymous form, we cannot determine how many households provided unique responses. That is, some households may have responded to surveys at just a single time-point, any two of the three time-points, or all three time-points. Table 71 shows the number of survey completions across all conditions. Table 72 shows the number of survey completions across all conditions *and* survey timepoints.

Table 71: Total Number of Survey Responses per Condition Overall

Pricing Pilot Group	No Nudge Report	Nudge Report	**Total**
Dynamic Pricing Control	17	8	**25**
Dynamic Pricing Treatment	541	58	**599**
Total			**624**

Table 72: Number of Survey Responses per Condition Baseline, Midterm, and Final

Number of Completions for Baseline Survey

Treatment Group	No Nudge Report	Nudge Report	**Total**
Dynamic Pricing Control	12	8	**20**
Dynamic Pricing Treatment	83	58	**141**
Total			**161**
Number of Completions for Midterm Survey			
Dynamic Pricing Control	5	0	**5**
Dynamic Pricing Treatment	235	166	**401**
Total			**406**
Number of Completions for Final Survey			
Dynamic Pricing Control	0	0	**0**
Dynamic Pricing Treatment	223	0	**223**
Total			**223**

6.1 Comprehension

The first research question was whether households who received a Nudge Report had higher levels of comprehension regarding electricity prices and the TOU period structure in the Province of Ontario relative to those who did not receive Nudge Reports. It was hypothesized that with prolonged exposure to Nudge Reports over the duration of the pilot, that customers would increase their level of comprehension of prices and TOU period times relative to customers who were not exposed to these reports. To answer this question, households were asked the same four comprehension questions on the baseline (before Treatment), midterm (six months after receiving pricing Treatment/Nudge Report), and final surveys (17 months after receiving pricing Treatment/Nudge Report). The four comprehension questions that appeared on all three surveys are listed below as well as in Appendix K:

1. Please select the pricing model that you think best describes how electricity is currently priced for the majority of residential customers in Ontario **(Answer: "Time-Of-Use: The price of electricity varies depending on the time of day")**

2. Electricity usage is split into different Time-Of-Use periods. The cost of electricity varies between these periods. What do you think the daily Time-Of-Use Periods are called in Ontario? **(Answer: "Three different TOU periods: Off-Peak, Mid-Peak, On-Peak")**

3. Select the top 3 household items that you believe consume the most electricity **(Answer: "Washing machine / Dryer, Heating and Cooling unit, Fridge")**

4. What do you think is the most effective way to reduce your electricity bill in the Summertime? **(Answer: Raise the temperature on your A/C unit by 2 degrees Celsius between the hours of 1pm and 7pm during hot months)**

Each survey response was coded as correct or incorrect and a comprehension score out of 4 was obtained for each respondent. Survey respondents were given one mark for correct answers on questions 1, 2, and 4 and 1/3 of a mark for each correctly listed item in question 3. The final comprehension score was then converted into a percentage.

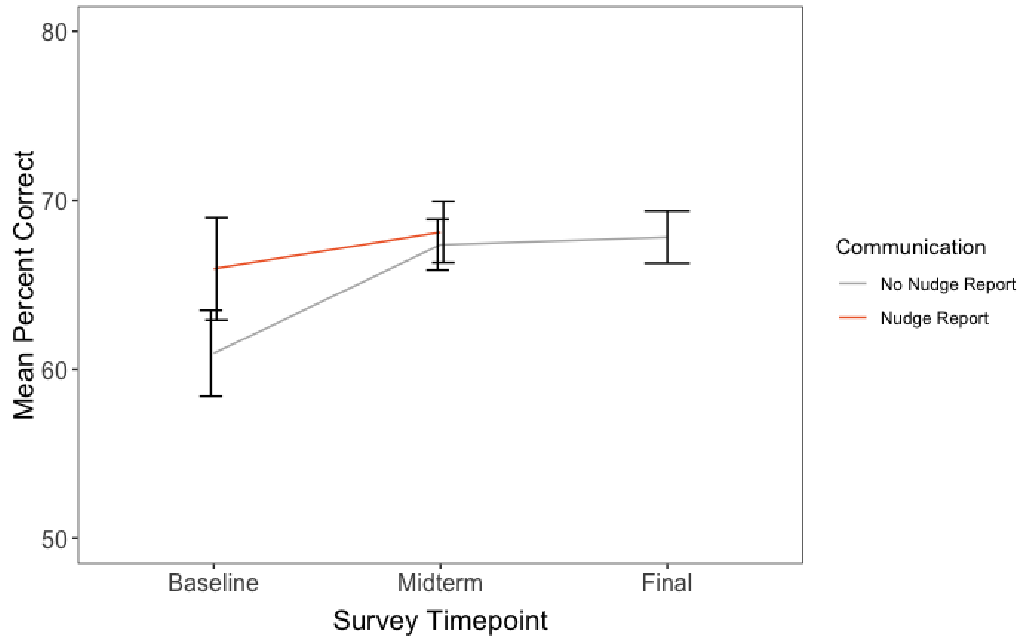
This section will compare percentage of correct responses between the Baseline, Midterm (Interim), and Final Surveys by communication condition (i.e. whether or not they received a Nudge Report).

Table 73 and Figure 1 show the comprehension scores (mean percent correct responses) for the Dynamic pricing pilot. There were too few survey completes for Dynamic pricing Controls at baseline and midterm, therefore comprehension was analyzed in the Dynamic pricing Treatment group only. There was a significant effect of timepoint on comprehension scores for all participants in the Dynamic pricing Treatment group. Overall, participants performed significantly better on comprehension at the midterm and final timepoints compared to baseline. There was no effect of communication (i.e. Nudge Report) on comprehension scores.
In summary, participants in the Dynamic pricing pilot performed significantly better on the comprehension portion of the survey over time. Results of the statistical model for the Dynamic pricing pilot are shown in Table 1 of Appendix J.

Table 73: Comprehension Scores for Dynamic Pricing Pilot (Mean Percent Correct)

	Dynamic Pricing Control		Dynamic Pricing Treatment	
Survey Timepoint	No Nudge	Nudge	No Nudge	Nudge
Baseline	70.8%	78.1%	60.9%	65.9%
Midterm	68.3%	N/A	67.4%	68.1%
Final	N/A	N/A	67.8%	N/A

Figure 1: Comprehension Scores for the Dynamic Pricing Pilot (Mean Percent Correct)



6.2 Motivation

The second research question addressed by the customer-facing surveys pertains to whether pricing Treatment and/or the Nudge Report were able to increase household motivation to alter electricity consumption behaviour. Households were asked for their opinions regarding their motivation to either shift or not shift their electricity usage in accordance with their TOU schedule (APP TOU schedule for pricing Treatment customers and Status-Quo TOU schedule for pricing Control customers). The purpose of this assessment was to determine whether any of pricing Treatments and/or Nudge Report communications had any effect on these motivations. To measure motivation, respondents were asked the following six questions (note: questions are also listed in Appendix K):

1. Rate your level of agreement with the following statement on a scale from 1: "Strongly Disagree" to 7: "Strongly Agree": I don't think it is fair for the utility company to ask me to change my energy consumption behaviour.

2. Rate your level of agreement with the following statement on a scale from 1: "Strongly Disagree" to 7: "Strongly Agree": I feel like I am already doing everything I can to conserve energy.

3. Rate your level of agreement with the following statement on a scale from 1: "Strongly Disagree" to 7: "Strongly Agree": I feel motivated to conserve On-Peak electricity and/or shift my electricity usage to Off-Peak.

4. Respond with "Yes" or "No": Has TOU pricing affected how you consume energy?

5. How much do you agree or disagree with each of the following reasons for why you have NOT shifted your consumption behaviour from On-peak to Off-peak (on a scale from 1: “Strongly Disagree” to 7: “Strongly Agree”)?

    a. I didn’t know Ontario had a Time-of-use pricing structure for electricity consumption
    b. It is too difficult for me to schedule electricity consuming activities during Off-Peak hours (such as overnight)
    c. I don’t think the cost savings are worth the effort
    d. I don’t think it contributes much to the province’s electricity conservation efforts
    e. I’m not too concerned about the environmental impact of my electricity consumption
    f. I don’t think anyone else does it, so I don’t either
    g. It’s too complicated for me to understand

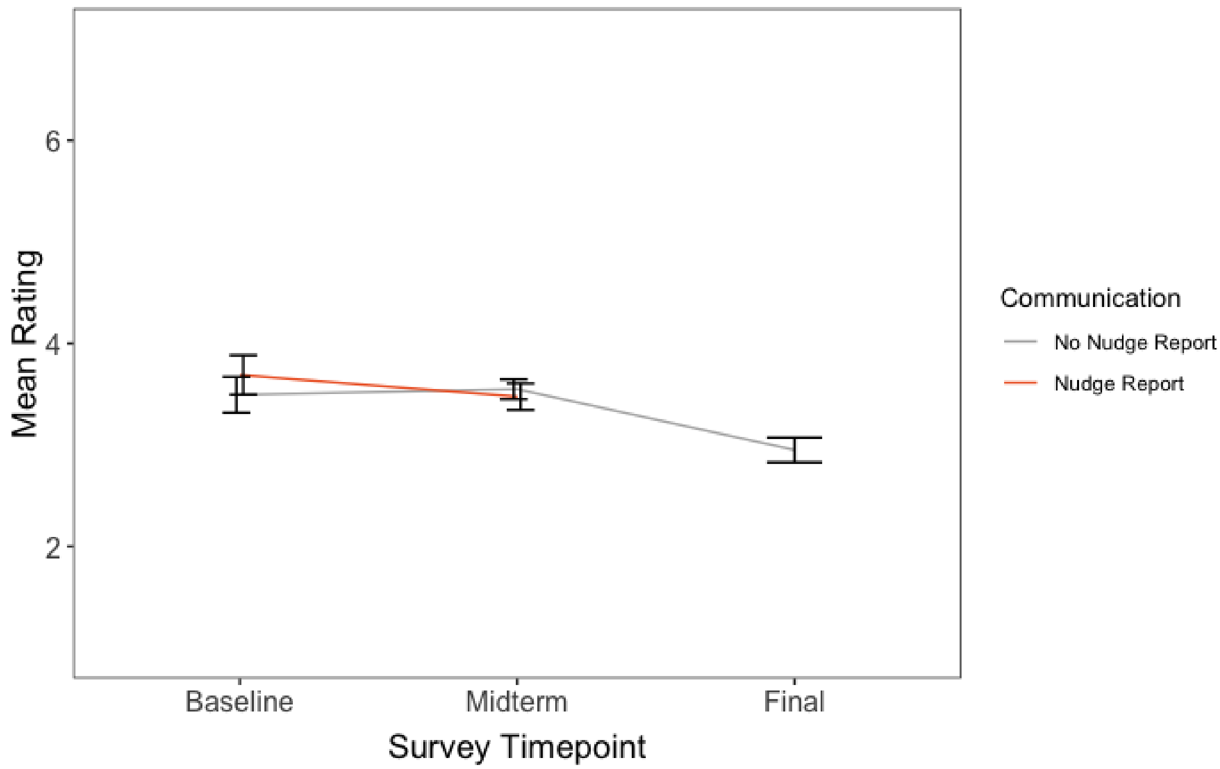
6. How much do you agree or disagree with each of the following reasons for why you have shifted your consumption behaviour from On-peak to Off-peak? (on a scale from 1: “Strongly Disagree” to 7: “Strongly Agree”):
    a. To save money on my monthly bills
    b. It was the environmentally responsible thing to do
    c. To be a good role model for others
    d. Because others I know were also doing it
    e. It was convenient for me to shift my electricity consumption
    f. I purchased smart thermostats to automatically shift my electricity consumption

There were not enough survey completions at the baseline and midterm survey timepoints for Dynamic pricing Control households, and therefore we only analyzed survey responses for the Dynamic pricing Treatment respondents over time.

Question 1: *Rate your level of agreement with the following statement on a scale from 1: "Strongly Disagree" to 7: "Strongly Agree": I don’t think it is fair for the utility company to ask me to change my energy consumption behaviour.*

Participants in the Dynamic pricing Treatment group had lower ratings of agreement with the statement ‘I don’t think it is fair for the utility company to ask me to change my energy consumption behaviour’ at the final survey timepoint compared to baseline (Figure 2; Table 2 of Appendix J).

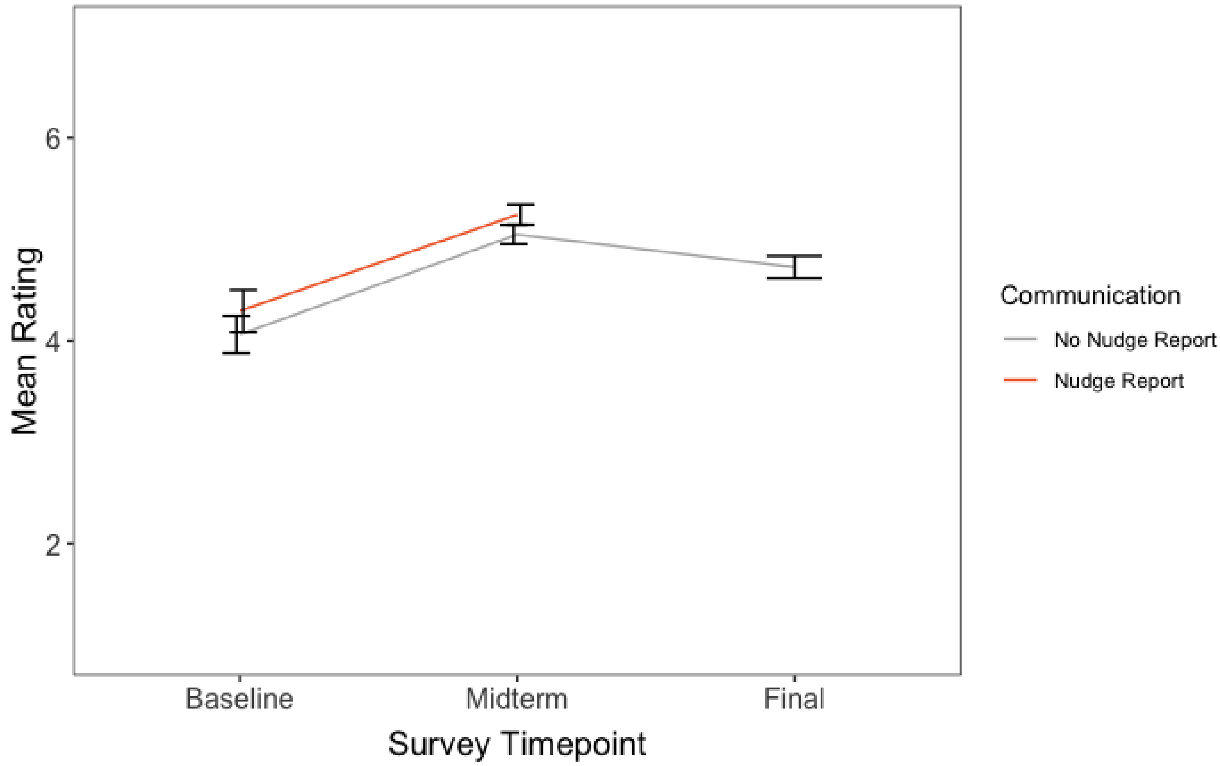
Figure 2: Participants mean ratings for agreement with the statement 'I don't think it is fair for the utility company to ask me to change my energy consumption behaviour' (1-7 scale)



Question 2: *Rate your level of agreement with the following statement on a scale from 1: "Strongly Disagree" to 7: "Strongly Agree": I feel like I am already doing everything I can to conserve energy.*

There was a significant effect of timepoint on level of agreement with the statement 'I feel like I am already doing everything I can to conserve energy' whereby participants in the Dynamic pricing Treatment group had higher levels of agreement with this statement at the midterm and final survey timepoints compared to baseline (Figure 3; Table 3 of Appendix J).

Figure 3: Participants mean ratings for agreement with the statement 'I feel like I am already doing everything I can to conserve energy' (1-7 scale)



Question 3: *Rate your level of agreement with the following statement on a scale from 1: "Strongly Disagree" to 7: "Strongly Agree": I feel motivated to conserve On-Peak electricity and/or shift my electricity usage to Off-Peak.*

There were no differences between Dynamic pricing groups on responses to Question 3. Participants agreed with this statement on average, with a mean level of agreement of 5.70 (+/- 1.25) on a scale of 1 to 7.

Question 4: *Has TOU affected your energy consumption?*

There were no significant differences between groups in terms of likelihood of reporting that TOU pricing affected electricity consumption. Proportion who reported 'Yes' for each group/condition are recorded in Table 74.

Table 74: Percentage of participants for each condition who responded that TOU pricing has affected their energy consumption

	Dynamic Pricing Control		Dynamic Pricing Treatment	
Survey Timepoint	No Nudge	Nudge	No Nudge	Nudge
Baseline	100.0%	100.0%	95.2%	86.2%
Midterm	100.0%	N/A	90.2%	85.5%
Final	N/A	N/A	91.0%	N/A

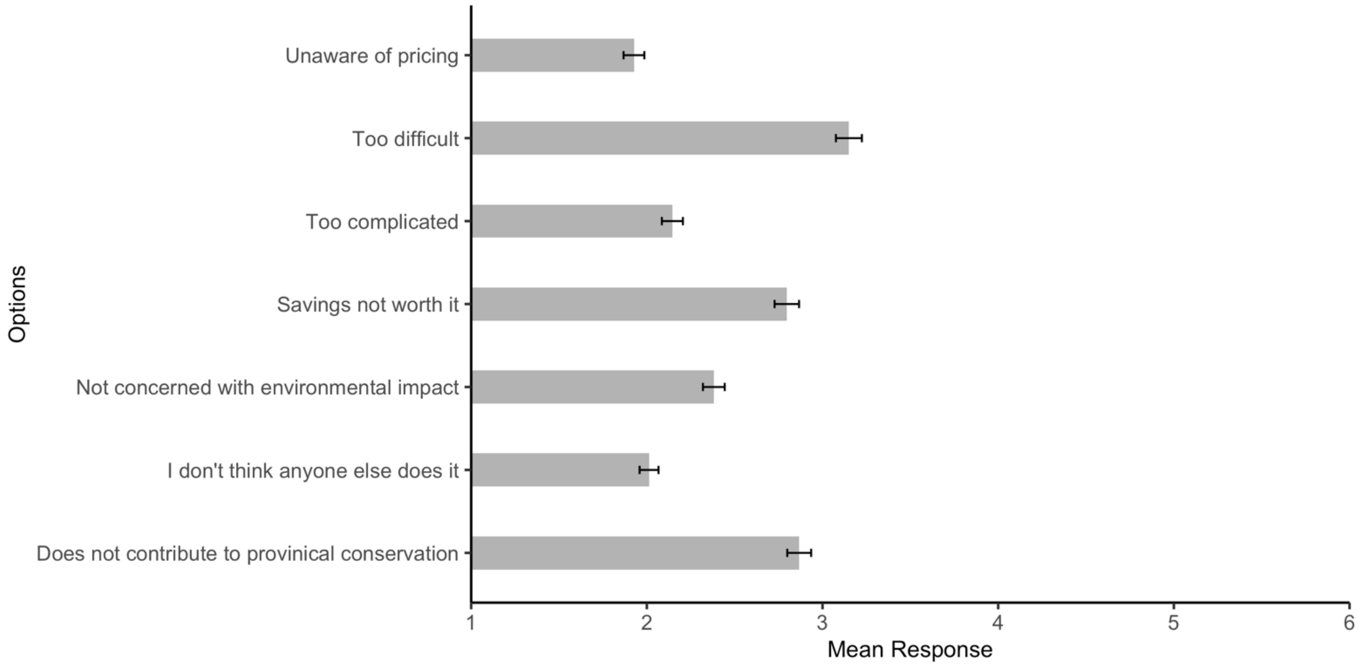
Question 5: *Factors that influence why participants reported that they did not shift their energy consumption behaviour.*

Overall, mean ratings for various motivational factors affecting why Dynamic pricing Treatment participants claim they did not shift their electricity consumption behaviour in response to Dynamic pricing significantly differed from one another (Table 6 of Appendix J). Difficulty in shifting energy consumption behaviour was rated most highly as a factor for why participants did not shift their behaviour followed by Provincial reasons (i.e. does not contribute to Provincial energy conservation). Mean ratings for each factor are displayed in Figure 4 and summarized in Table 75.

Table 75: Mean levels of agreement (1-7 scale) with motivational factors for not shifting energy behaviour in Dynamic Pricing Treatment participants

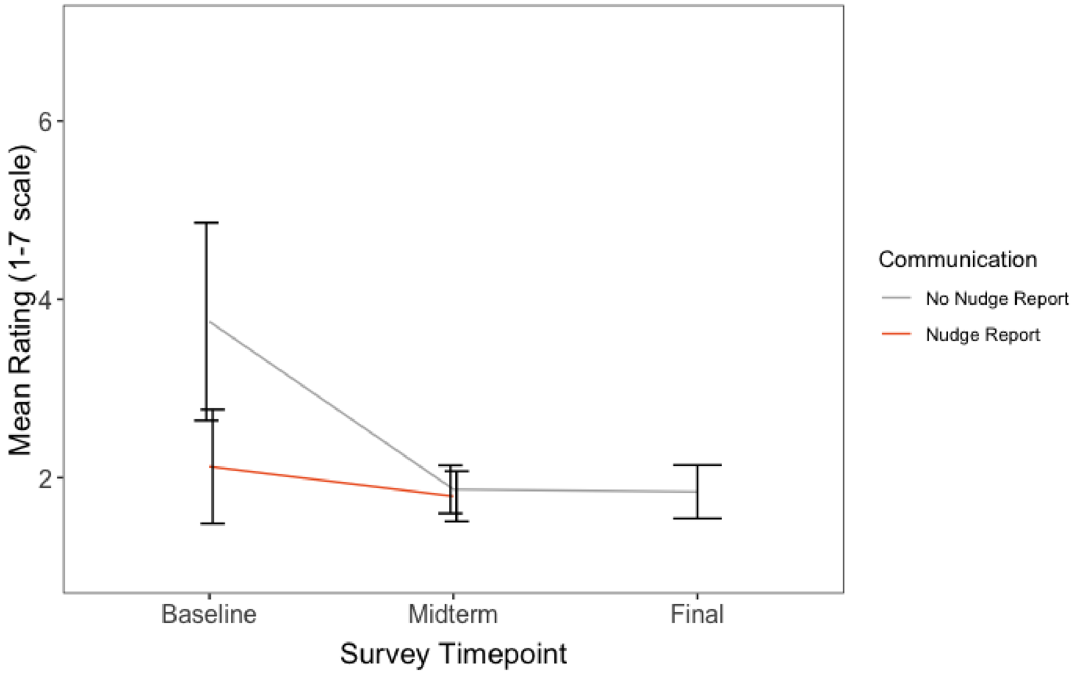
Motivation	Timepoint	Dynamic Pricing Treatment
Awareness	Baseline	2.7
	Midterm	1.8
	Final	1.8
Difficulty	Baseline	3.0
	Midterm	3.9
	Final	3.7
Cost	Baseline	2.5
	Midterm	3.8
	Final	3.7
Provincial	Baseline	3.3
	Midterm	3.7
	Final	3.8
Environment	Baseline	2.3
	Midterm	3.1
	Final	2.3
Social	Baseline	2.0
	Midterm	2.3
	Final	2.1
Comprehension	Baseline	2.8
	Midterm	3.0
	Final	2.5

Figure 4: Participants mean ratings for how much each factor influenced them to not shift energy consumption behaviour (1-7 scale)



Participants in the Dynamic pricing pilot had reduced feelings of 'lack of awareness' as a motivation for why they did not shift their electricity consumption behaviour over the course of the Dynamic pricing pilot. Specifically, their level of agreement with the statement 'I didn't know Ontario had a Time-of-use pricing structure for electricity consumption' decreased at the midterm and final survey timepoints compared to baseline (Figure 5; Table 7 of Appendix J).

Figure 5: Participants mean ratings for how much 'lack of awareness' influenced them not to shift energy consumption behaviour (1-7 scale)



No other responses to Question 5 differed significantly different between groups (Nudge Report, no Nudge Report) or across time in the Dynamic pricing pilot.

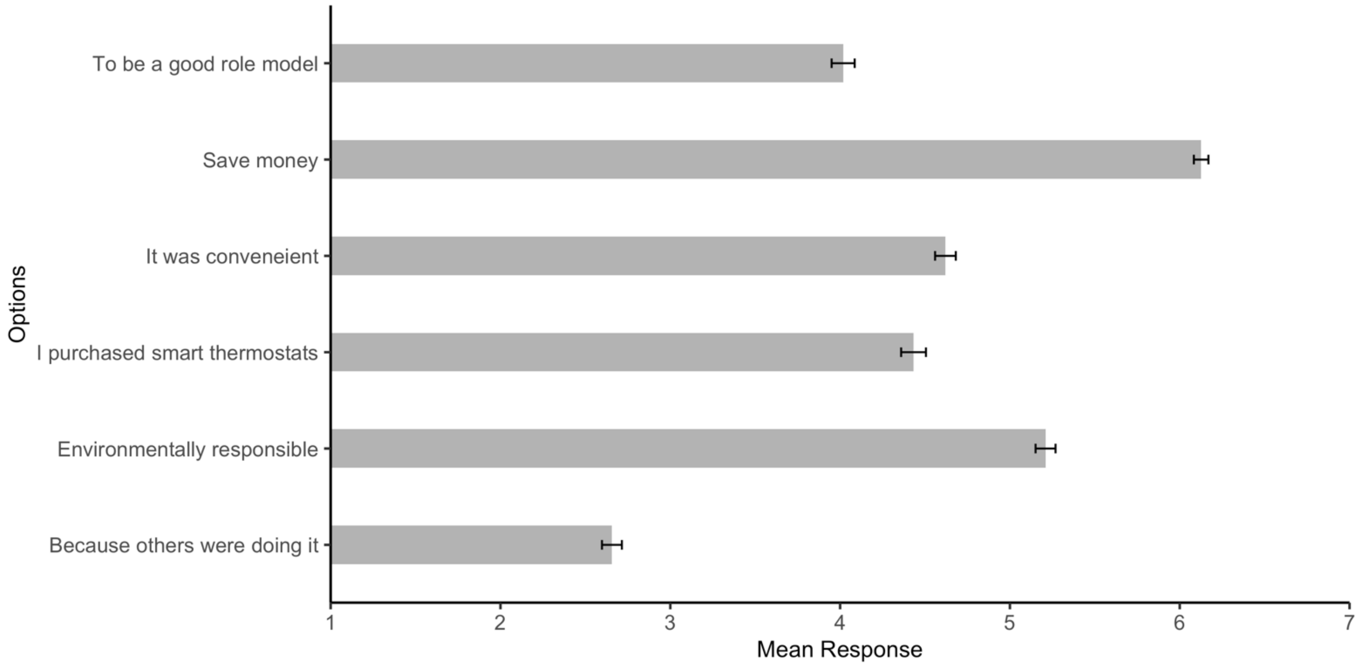
Question 6: *Factors that influence why participants reported that they did shift their energy consumption behaviour.*

Overall, mean ratings for various motivational factors affecting why Dynamic pricing pilot Treatment participants feel they *did* shift their electricity consumption behaviour significantly differed from one another (Table 14 of Appendix J). 'Saving money' was rated most highly as factor for why participants shifted their behaviour followed by environmental responsibility. Mean ratings for each factor are presented in Figure 6 and summarized in Table 76.

Table 76: Mean levels of agreement (1-7 scale) with motivational factors for shifting energy behaviour in Dynamic Pricing Treatment participants

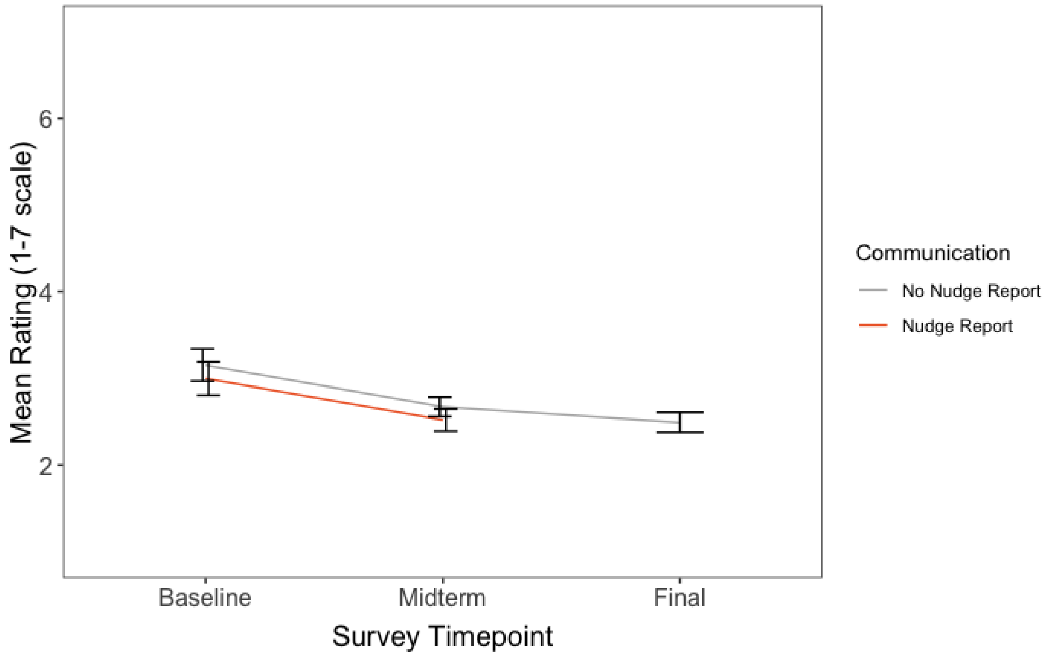
Motivation	Timepoint	Dynamic Pricing Treatment
Cost	Baseline	6.2
	Midterm	6.1
	Final	6.3
Environment	Baseline	5.3
	Midterm	5.1
	Final	5.4
Role model	Baseline	4.2
	Midterm	4.0
	Final	4.1
Social	Baseline	3.1
	Midterm	2.6
	Final	2.5
Convenience	Baseline	4.8
	Midterm	4.4
	Final	5.1
Smart Thermostat	Baseline	4.8
	Midterm	4.3
	Final	4.6

Figure 6: Participants mean ratings for how much each factor influenced them to shift energy consumption behaviour (1-7 scale)



There was a significant effect of timepoint on agreement levels with social motivation (i.e. 'because others I know were also doing it') as a reason for why participants in the Dynamic pricing pilot shifted their electricity consumption behaviour (Table 18 of Appendix J). Participants in the Dynamic pricing Treatment group had significantly lower agreement ratings for this factor at the midterm survey compared to baseline and even lower agreement at the final survey timepoint compared to baseline (Figure 7).

Figure 7: Participants mean ratings for how much social factors influenced them to shift energy consumption behaviour (1-7 scale)



There was a significant effect of timepoint on agreement with convenience (i.e. 'it was convenient for me to shift my energy consumption') and purchasing smart thermostats as motivational factors for why participants in the Dynamic pricing Treatment group shifted their electricity consumption behaviour. Agreement ratings with both of these factors were lower at the midterm survey timepoint compared to baseline (Figure 8, Table 19 of Appendix J, and Figure 9, Table 20 of Appendix J).

Figure 8: Participants mean ratings for how much convenience influenced them to shift energy consumption behaviour (1-7 scale)

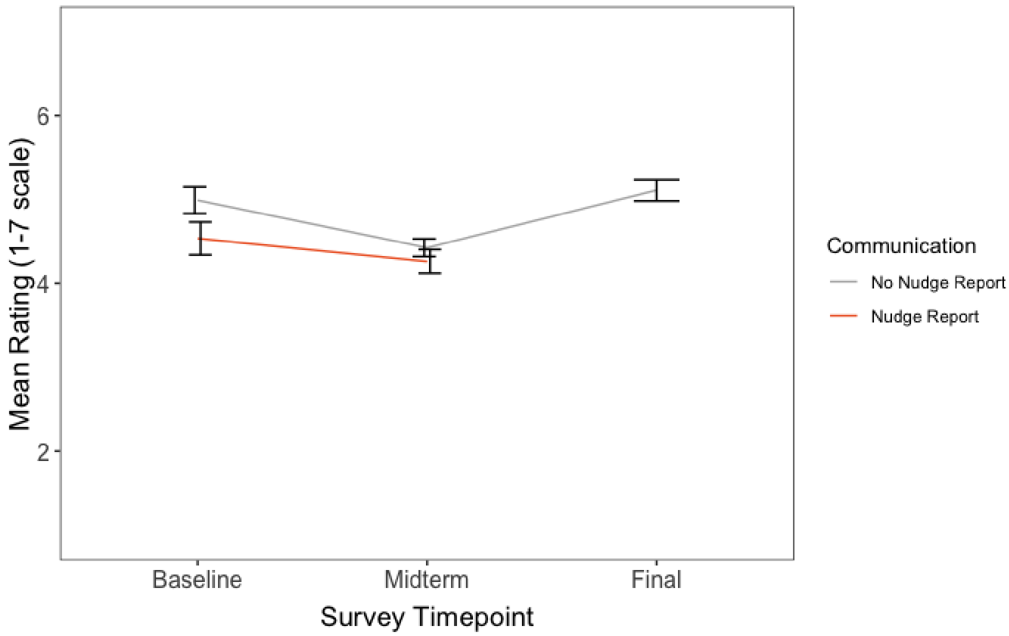
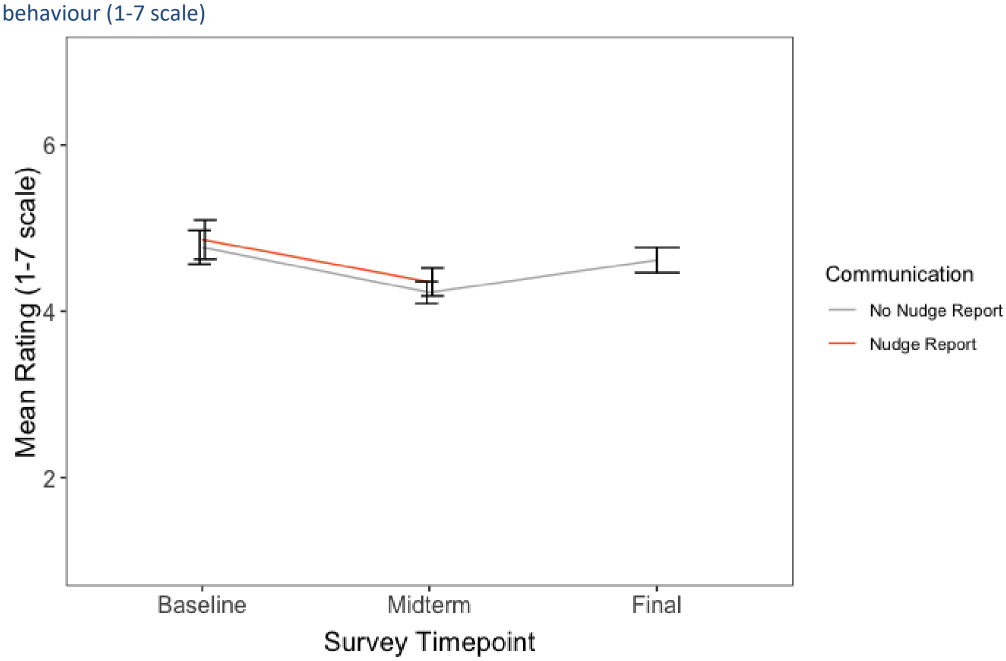


Figure 9: Participants mean ratings for how much purchasing a smart thermostat influenced them to shift energy consumption behaviour (1-7 scale)



Based on the small number of surveys completed by the Dynamic pricing Control group, we were only able to examine Dynamic pricing Treatment participant responses *over time*. Dynamic pricing Treatment participants had lower agreement with the statement ‘I don’t think it is fair for the utility company to ask me to change my energy consumption behaviour’ over time and also felt more strongly that they were ‘doing everything they can’ to conserve electricity over the course of the Dynamic pilot. Most Dynamic pricing participants felt that TOU pricing did affect their consumption behaviour. For those who reported that TOU pricing did not affect their consumption behaviour, ‘difficulty shifting energy consumption to Off-Peak hours’ and ‘doesn’t contribute to provincial energy conservation’ were rated most highly as motivations for not shifting their behaviour.

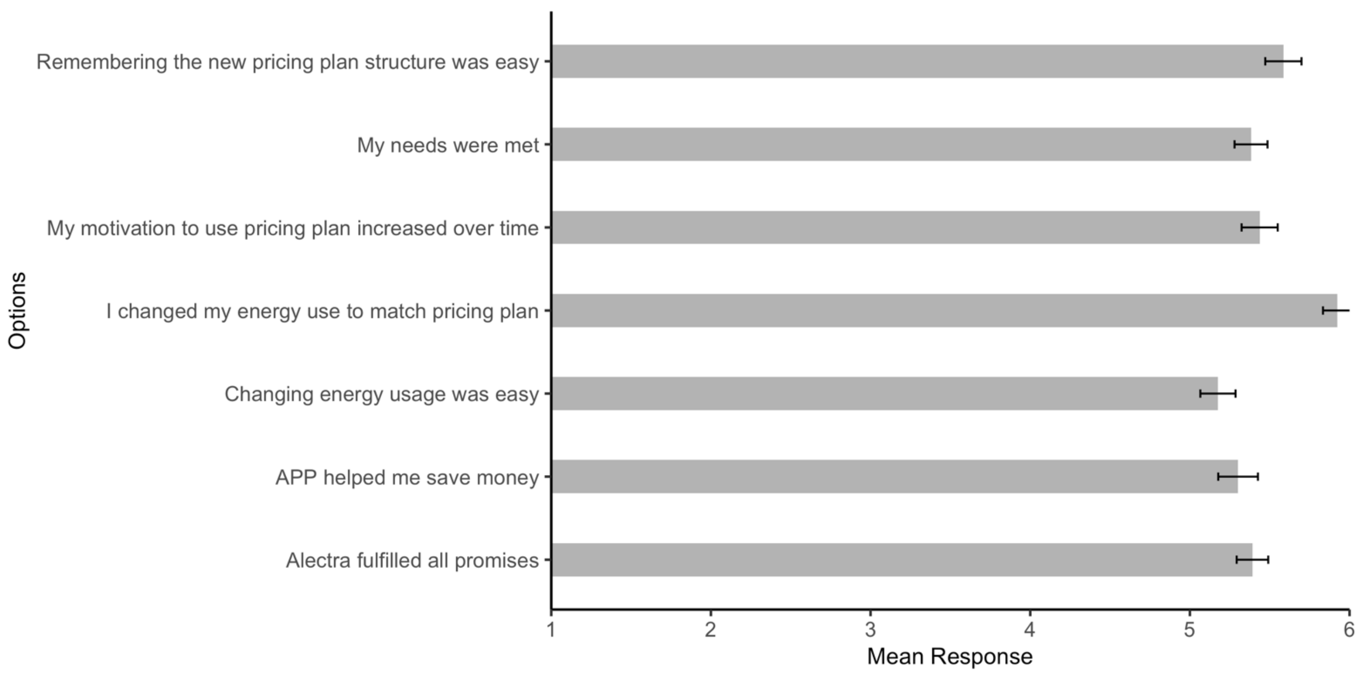
In terms of what Dynamic pricing participants felt *did* affect their electricity consumption behaviour, saving money and environmental responsibility were rated most highly as reasons for shifting behaviour. Participants rated social reasons for shifting their behaviour lower over the course of the pilot, and also reported convenience and the use of smart thermostats lower at the midterm survey timepoint compared to baseline and final survey timepoints.

6.3 Participant Experience

Participants in Dynamic pricing were asked several questions related to their experience in the APP program at the final survey timepoint (questions are listed in Appendix K). Here we review responses to these questions in order to quantify participants’ subjective experience with APP.

There were significant differences in the degree to which participants in the Dynamic pricing pilot agreed with the seven statements related to their subjective experience (Figure 10; Table 21 of Appendix J). Overall, participants had the highest ratings of agreement with the statement ‘I changed my energy use behaviour to match my new pricing plan’ and ‘Remembering the new pricing plan structure was easy’ suggesting that they were able to successfully remember and adopt new electricity consumption behaviours.

Figure 10: Dynamic Pricing participant mean levels of agreement with key subjective aspects of Alternative Pricing Plan participation



Overall, the participants exposed to Dynamic pricing had the high numerical levels of satisfaction with their experience in APP, with a mean rating of 5.64 (+/- 1.55) on a scale of 1 to 7. Participants in the Dynamic pricing Treatment group were also likely to recommend (i.e. above neutral) APP to others, with a mean rating of 5.64 (+/- 1.66) on a 1 to 7 scale. Most survey respondents (76.7%) in the Dynamic pricing Treatment group did not contact Alectra with any issues over the course of the pilot.

6.4 Participant Demographics

Dynamic pricing participants were asked a series of demographic questions at the end of each survey. The primary purpose of these questions was to provide a comprehensive picture of the make-up of the APP participants. These demographic responses should provide useful information for the scalability of the APP price plans to other markets. As with any pilot project, the interpretability and generalizability of the behavioural findings are limited to the characteristics of the sample with whom the pilot was conducted. A few of the noteworthy observations from the demographic questionnaire: (1) 89% of respondents report owning some type of programmable thermostat, (2) less than 6% of respondents indicate heating their homes primarily with electricity, (3) over 90% of respondents indicate having central Air Conditioning, and (4) only 7% of respondents indicate owning an electric vehicle, indicating that Dynamic pricing is perhaps not optimized to attract this particular sub-population. We note that since survey responses were completely voluntary, sample characteristic data from respondents may be somewhat skewed due to selection bias; caution should be used when interpreting the demographic responses as well as all other survey-derived insights reported here. A full list of demographic survey questions can be found in Appendix K.

Table 77: Dynamic Pricing Pilot Demographics

	Dynamic Pricing Control (N=25)	Dynamic Pricing Treatment (N=765)	Total (N=790)
Residence			
N-Missing	0 (0.0%)	1 (0.1%)	1 (0.1%)
Duplex or two-family home	0 (0.0%)	28 (3.7%)	28 (3.5%)
High-rise apartment or condo building	0 (0.0%)	3 (0.4%)	3 (0.4%)
Low-rise apartment or condo building	0 (0.0%)	6 (0.8%)	6 (0.8%)
Other (please enter)	0 (0.0%)	12 (1.6%)	12 (1.5%)
Single-family home	22 (88.0%)	613 (80.1%)	635 (80.4%)
Townhouse or row-house	3 (12.0%)	100 (13.1%)	103 (13.0%)
Other (please indicate)	0 (0.0%)	2 (0.3%)	2 (0.3%)
Year Home Built			
N-Missing	0 (0.0%)	1 (0.1%)	1 (0.1%)
1920 or before	0 (0.0%)	13 (1.7%)	13 (1.6%)
1921 - 1945	0 (0.0%)	3 (0.4%)	3 (0.4%)
1946 - 1960	2 (8.0%)	20 (2.6%)	22 (2.8%)
1961 - 1970	2 (8.0%)	42 (5.5%)	44 (5.6%)
1971 - 1980	3 (12.0%)	89 (11.6%)	92 (11.6%)

	Dynamic Pricing Control (N=25)	Dynamic Pricing Treatment (N=765)	Total (N=790)
1981 - 1985	1 (4.0%)	64 (8.4%)	65 (8.2%)
1986 - 1990	2 (8.0%)	90 (11.8%)	92 (11.6%)
1991 - 1995	2 (8.0%)	45 (5.9%)	47 (5.9%)
1996 - 2000	2 (8.0%)	89 (11.6%)	91 (11.5%)
2001 - 2005	1 (4.0%)	103 (13.5%)	104 (13.2%)
2006 - 2011	4 (16.0%)	110 (14.4%)	114 (14.4%)
2012 - 2016	4 (16.0%)	24 (3.1%)	28 (3.5%)
2012 - 2017	1 (4.0%)	65 (8.5%)	66 (8.4%)
Unsure	1 (4.0%)	7 (0.9%)	8 (1.0%)
Thermostat			
N-Missing	0 (0.0%)	1 (0.1%)	1 (0.1%)
No	2 (8.0%)	84 (11.0%)	86 (10.9%)
Yes	23 (92.0%)	680 (88.9%)	703 (89.0%)
Thermostat Type			
N-Missing	1 (4.0%)	46 (6.0%)	47 (5.9%)
ecobee	4 (16.0%)	96 (12.5%)	100 (12.7%)
Energate Foundation	0 (0.0%)	246 (32.2%)	246 (31.1%)
Honeywell UtilityPRO or ExpressStat	6 (24.0%)	133 (17.4%)	139 (17.6%)
Nest	6 (24.0%)	130 (17.0%)	136 (17.2%)
Other (please enter)	8 (32.0%)	114 (14.9%)	122 (15.4%)
Primary Heating Method			
N-Missing	0 (0.0%)	6 (0.8%)	6 (0.8%)
Boiler with hot water or steam radiators	0 (0.0%)	4 (0.5%)	4 (0.5%)
Primary Heating Method			
Electric baseboard heaters	0 (0.0%)	20 (2.6%)	20 (2.5%)
Electric furnace	1 (4.0%)	25 (3.3%)	26 (3.3%)
Natural gas furnace	24 (96.0%)	693 (90.6%)	717 (90.8%)
Other	0 (0.0%)	7 (0.9%)	7 (0.9%)
Propane furnace	0 (0.0%)	3 (0.4%)	3 (0.4%)
Other (please indicate)	0 (0.0%)	7 (0.9%)	7 (0.9%)
Appliances			
Central air conditioning	23 (92.0%)	694 (90.7%)	717 (90.8%)
Electric clothing dryer	17 (68.0%)	526 (8.8%)	543 (68.7%)
Electric water heater	9 (36.0%)	190 (24.8%)	199 (25.2%)
Room or window air conditioner	0 (0%)	0 (0%)	0 (0%)
Electric space heater	0 (0%)	155(20.3%)	155 (19.6%)
Swimming Pool	0 (0%)	0 (0%)	61 (8.0%)
Electric Vehicle Ownership			
N-Missing	0 (0.0%)	6 (0.8%)	6 (0.8%)
No	24 (96.0%)	702 (91.8%)	726 (91.9%)
Yes	1 (4.0%)	57 (7.5%)	58 (7.3%)
Number of Adults 18+			

	Dynamic Pricing Control (N=25)	Dynamic Pricing Treatment (N=765)	Total (N=790)
N-Missing	0	1	1
Mean (SD)	2.400 (0.707)	2.356 (0.987)	2.357 (0.979)
Range	1.000 - 4.000	0.000 - 7.000	0.000 - 7.000
Number of Adults 60+			
N-Missing	0	6	6
Mean (SD)	0.320 (0.690)	0.705 (0.887)	0.693 (0.883)
Range	0.000 - 2.000	0.000 - 3.000	0.000 - 3.000
Number of Children			
N-Missing	1	2	3
Mean (SD)	0.542 (0.884)	0.699 (0.999)	0.694 (0.996)
Range	0.000 - 2.000	0.000 - 9.000	0.000 - 9.000
Income Level			
N-Missing	0 (0.0%)	7 (0.9%)	7 (0.9%)
$10,000 to less than $20,000	2 (8.0%)	9 (1.2%)	11 (1.4%)
Income Level			
$100,000 to less than $150,000	5 (20.0%)	120 (15.7%)	125 (15.8%)
$150,000 or more	4 (16.0%)	122 (15.9%)	126 (15.9%)
$20,000 to less than $30,000	0 (0.0%)	19 (2.5%)	19 (2.4%)
$30,000 to less than $40,000	0 (0.0%)	31 (4.1%)	31 (3.9%)
$40,000 to less than $75,000	1 (4.0%)	103 (13.5%)	104 (13.2%)
$75,000 to less than $90,000	3 (12.0%)	83 (10.8%)	86 (10.9%)
$90,000 to less than $100,000	0 (0.0%)	53 (6.9%)	53 (6.7%)
Less than $10,000	2 (8.0%)	5 (0.7%)	7 (0.9%)
Prefer not to say	8 (32.0%)	213 (27.8%)	221 (28.0%)
Education			
N-Missing	1 (4.0%)	7 (0.9%)	8 (1.0%)
College or other non-university certificate or diploma	5 (20.0%)	140 (18.3%)	145 (18.4%)
None, or grade 1-8	0 (0.0%)	5 (0.7%)	5 (0.6%)
Post-graduate or professional schooling after university (e.g., Master's degree or Ph.D; law or medical school)	8 (32.0%)	197 (25.8%)	205 (25.9%)
Registered Apprenticeship or other trades certificate or diploma	0 (0.0%)	19 (2.5%)	19 (2.4%)
Secondary (high) school graduate	0 (0.0%)	56 (7.3%)	56 (7.1%)
Secondary (high) school incomplete	0 (0.0%)	8 (1.0%)	8 (1.0%)
University certificate, diploma, or degree	11 (44.0%)	333 (43.5%)	344 (43.5%)
What is the last grade or class you completed in school?	0 (0.0%)	0 (0.0%)	0 (0.0%)
Number of People in House			

	Dynamic Pricing Control (N=25)	Dynamic Pricing Treatment (N=765)	Total (N=790)
N-Missing	0 (0.0%)	2 (0.3%)	2 (0.3%)
0	2 (8.0%)	214 (28.0%)	216 (27.3%)
1	5 (20.0%)	240 (31.4%)	245 (31.0%)
2	17 (68.0%)	261 (34.1%)	278 (35.2%)
3	0 (0.0%)	31 (4.1%)	31 (3.9%)
4+	1 (4.0%)	17 (2.2%)	18 (2.3%)
Someone Home Mon-Fri			
N-Missing	0 (0.0%)	1 (0.1%)	1 (0.1%)
No	5 (20.0%)	51 (6.7%)	56 (7.1%)
Yes	20 (80.0%)	713 (93.2%)	733 (92.8%)

7. Summary and Conclusions

This report assessed the impacts of Dynamic pricing in combination with two non-price interventions (communications in the form of Nudge Reports as well as technology in the form of programmable smart thermostats with load curtailment enablement). Originally, Dynamic pricing was intended to run for 12 months, in parallel with two other pricing pilots offered as part of Advantage Power Pricing by Alectra Utilities. However, in May 2019, the Ontario Energy Board opted to extend the reporting period for the Dynamic pricing plan for an additional five months based on a desire to obtain additional insights after reviewing the impacts reported during the interim reporting period (April 2018 – October 2018 inclusive). This extension was also intended to allow for the exploration of customer response to a greater number of CPP events by splitting Dynamic pricing participants into two groups, one receiving six CPP events (which is the number of events called for each of the Summer and Winter seasons in the original 12-month reporting period), and the other receiving nine CPP events. For completeness, the consumption impacts owing to Dynamic pricing as well as the non-price interventions, were reported for the entire 17-month duration of Dynamic pricing (the originally scoped 12-month APP pilot plus the 5-month Dynamic pricing extension period).

Below, we first summarize the key behavioural findings with respect to electricity consumption impacts stemming from Dynamic pricing (both "new" and Legacy Dynamic pilots), followed by the non-pricing interventions. We then summarize the findings obtained from the three customer-facing surveys administered over the course of this pilot. Finally, we make some general conclusions and recommendations pertaining to the future of the Regulated Price Plan in the Province of Ontario.

Summary of Pricing Interventions

Dynamic Pricing

It was hypothesized that the high On- to Off-Peak pricing differential in the Dynamic pricing pilot would provide a strong incentive for customers to reduce their electricity consumption behaviour during On-Peak periods in order to realize bill savings. This could be accomplished either through simple curtailment of On-Peak consumption, or through load shifting behaviours in which customers perform certain actions (such as laundry, pre-cooling air conditioning etc.) during Off-Peak as opposed to On-Peak hours. The estimated consumption impacts were highly consistent with the former, as Dynamic pricing customers exhibited lower electricity consumption relative to matched Control participants during Low, Medium, and High-On-Peak hours, without exhibiting an increase in Off-Peak consumption.

The largest consumption impacts in this pilot owe to the CPP events in which Dynamic pricing customers were subjected to six 4-hour events in each of the Summer 2018 and Winter 2018-2019 reporting periods, and either six or nine such events in Summer 2019. These customers were notified via email or SMS text (according to each customer's preference) of upcoming CPP events, provided a minimum of two hours in advance of such events. Customers were charged an hourly kWh price of 49.8 cents during these event hours. Dynamic pricing Treatment customers substantially less electricity during CPP event hours compared to matched Controls during those same hours. The overall electricity consumption impacts owing to Dynamic pricing during Peak and CPP events also yielded a small net decrease in overall average consumption in the Summer and Winter periods respectively.

Based on preliminary (i.e., 6-month interim) impact analyses showing that Dynamic pricing is an effective means to reduce household electricity consumption during High and Critical Peak TOU periods in Summer months, Dynamic and Legacy Dynamic pilots were extended over a second Summer season. With respect to this 5-month extension period (June – October 2019), there were two primary research questions:

1. Will the responsiveness to High On-Peak and Critical Peak price events by Dynamic and Legacy Dynamic customers in the Summer of 2018 persist a year later (i.e., in the Summer of 2019)?

2. Does the responsiveness to CPP events by Dynamic and Legacy Dynamic customers depend on the frequency of those events (i.e., will increasing the number of CPP events from 6 to 9 per season result in diminished behavioural response to such events)?

With respect to the first research question, there were no qualitative differences in the estimated magnitude of responsiveness to High On-Peak TOU periods between the Summer 2018 and Summer 2019 seasons for either the Dynamic or Legacy Dynamic pilots. The magnitude of the consumption savings owing to High On-Peak pricing was numerically smaller however for the Summer 2019 season relative to Summer 2018. This likely owes in large part to the fact that electricity consumption is variable and highly dependent on weather. High On-Peak average hourly temperatures were approximately 4 degrees Celsius lower in Summer 2019 relative to Summer 2018 (average hourly temperatures as a function of season and TOU period are provided in Table 25 later in this report). Of course, part of the quantitative reduction in High On-Peak impact across the two Summers may reflect diminished behavioural response to Dynamic pricing. It is not possible to ascertain the relative contributions of seasonal weather fluctuations and diminished behavioural response in driving the smaller estimated consumption impact in Summer 2019 relative to Summer 2018. Importantly, CPP event responsiveness was nearly identical in both Summer 2018 and Summer 2019 for households in both Dynamic and Legacy Dynamic pilots. Responsiveness to short, infrequent CPP events, therefore, shows no evidence of diminished behavioural response over a two-Summer reporting period.

With respect to the second research question, consumption impact estimates clearly indicate that average hourly consumption savings during CPP events do not differ between households who received six such events and those who received nine. We can conclude therefore, that for a given CPP event, behavioural response is not affected by the frequency at which such events occur, at least within the range of event frequencies that were manipulated here.

Summary of Non-Pricing Interventions

Nudge Reports

One of the aims of the current RPP Pilot program is to explore the potential impacts of non-price means by which to drive conservation and demand management behaviours. To that end, Alectra and its partner BEworks designed and distributed monthly communications in the form of Nudge

Reports to randomly selected pricing Treatment and Control customers in the Dynamic pricing pilots. These reports featured a mix of (1) conservation pledges, (2) salient TOU schedules, (3) personalized conservation tips (derived from load disaggregation data by Bidgely), and (4) personalized On-Peak consumption feedback. These Nudge Reports were designed based on the principles of behavioural economic theory which holds that individuals do not always respond rationally to pricing signals, act in their own best interests, or follow through with intended actions. For randomly selected customers in the Dynamic pricing Treatment conditions, these Nudge Reports appeared on the back page of the monthly Shadow Bills. For randomly selected Dynamic pricing matched Status-Quo TOU Control participants (i.e., customers who remained on Status-Quo TOU pricing), these reports were distributed via direct mail as single-page monthly communications under the program name Power Insights.

Nudge Reports were not successful at delivering incremental consumption impacts over and above the impacts attributable to Dynamic pricing, except for a -0.057 kW per hour effect during system-coincident peak times of day in Summer 2019 for the Dynamic pilot. Given that the Nudge Reports deployed in the current pilot program contained several behavioural interventions, it is impossible to disentangle the independent or interactive effects of each feature of the Nudge Reports on customer behaviour. Future work would be needed to better understand the potential of behavioural interventions to further impart conservation impacts in pricing schemes in which the pricing manipulation itself delivers large impacts. It is likely the case that Nudge Reports are more appropriate and impactful when price is either not manipulated, or does not function as a sufficient incentive on its own to drive conservation and demand management behaviours among residential consumers.

Smart Thermostats

The effects of programmable smart thermostats on conservation and load shifting behaviours in the present pilot program were assessed quasi-experimentally. That is, these devices were not randomly assigned to Treatment and Control customers, but instead, we relied on data regarding ownership *and* registration of these devices within the pilot population. Importantly, only customers with eligible devices that were registered to receive automatic load curtailment were included in our Technology Treatment group. The Energate Foundation thermostat had the most ability in this regard, being able to respond to varying price levels with different levels of response, with a sophisticated and flexible setting that allowed customers to specify their preferred level of price-response.

Dynamic pricing costumers, both "new" and Legacy, who were registered for automatic load curtailemnt generally exhibited reduced electricity consumption relative to Dynamic pricing customers who did not register an eligible device for load curtailment.

It seems therefore, that smart thermostats provide an additional non-price means of driving electricity consumption reductions among populations who choose to purchase these devices and register them to receive automatic load curtailment. However, we recommend caution when interpreting the effects of smart thermostats on consumption behaviour. Specifically, households were not randomly assigned to receive smart thermostats. Instead, all pricing participants had the opportunity to self-select themselves into smart thermostat ownership by taking advantage of thermostat incentive offers. Due to this inherent selection bias, we cannot attribute a causal relation between smart thermostat ownership and incremental sensitivity to pricing signals displayed by the subset of households designated as 'Technology' households. Indeed, some unknown proportion of the observed variance in consumption behaviour owing to smart thermostat ownership/usage is almost certainly driven by the fact that individuals who choose to acquire such devices are likely different from individuals who do not acquire such devices in many other material ways. Specifically, smart thermostat owners are likely more engaged, motivated, tech-savvy etc. than their non-technology adopting counterparts, and it may be these inherent individual difference characteristics that drive incremental changes in consumption behaviour. Only a true RCT or a recruit-and-deny experimental approach would be able to quantify the unique contribution of smart thermostat technology to demand response among residential electricity consumers.

Summary of Customer-Facing Surveys

Customer-facing surveys were administered to Dynamic and Legacy Dynamic program participants at three time-points during the course of the 17-month reporting period: within the registration period and first two months of the pilot (baseline), at the 6-month mark (mid-term) and at the conclusion of the pilot at the 17-month mark (final). There were three primary objectives of these surveys: (1) to capture relevant demographic and socio-economic information about the samples, (2) to assess whether comprehension of TOU pricing differs among Treatment and Control groups, and whether there are any changes in comprehension of TOU pricing over time, and (3) to assess whether motivations to alter electricity consumption behaviour differs among Treatment and Control groups, and whether there are any changes in stated motivations to alter consumption behaviour over time.

In terms of comprehension of TOU pricing, we found that comprehension scores increased over the duration of the Dynamic pricing pilot, which likely comes as a result of increasing exposure to Nudge Reports and Shadow Bill communications throughout the duration of the pilot. In addition, participants reported an increase in feeling that 'they were doing everything they can' to conserve electricity from the beginning of the pilot to the end, likely owing to sustained attempts to reduce bill amounts under Dynamic pricing. In general, Dynamic pricing participants reported being highly satisfied with their experience in Dynamic pricing over the 17-month duration of the pilot.

Final Conclusions and Recommendations

The current RPP Pilot program undertaken by Alectra Utilities and its partners has produced important and novel insights regarding the future of the Regulated Price Plan in the Province of Ontario. It is clear that strong pricing signals, in the form of the Variable Peak and Critical Peak pricing events that typify Dynamic pricing, are in fact sufficient to drive electricity conservation behaviours during peak-demand times of day. This raises two important considerations when considering the scalability of new pricing structures such as Dynamic pricing. (1) Electricity is a basic commodity to which all Ontario residents have a reasonable expectation of access. Given this, there must be careful consideration given to the use of price as the sole or primary lever to achieve conservation objectives. Specifically, there will be limits on the extent to which LDCs are able or willing to increase the price of peak electricity during certain times of day (even if across all hours of the day pricing remains the same on average) and there are surely limits on consumers' willingness to pay for On-Peak electricity as well as limits on their tolerance to frequent Critical Peak events, despite the fact that the increase in CPP event frequency from 6 to 9 seems to have had no adverse effects on either behavioural response or participant experience. (2) Dynamic pricing, as tested here, required that participants had to actively 'opt-in', suggesting that providing rate-payers with choice regarding their TOU pricing plan may be necessary in the future in order to realize maximum conservation and/or load shifting impacts. In order to further validate this latter point, future pilots could experimentally manipulate whether Variable Peak pricing plans are administered on an opt-in vs. opt-out basis.

Finally, non-price interventions such as behaviourally informed customer communications and availability of smart thermostat technology hold promise as additional, complementary methods for further realizing On-Peak consumption reductions among Ontarians. LDCs should seek to optimize their current customer communications with respect to consumption feedback (either through existing electricity invoices or through separate communications) as well as potentially devoting more resources to the marketing and provision of automated load control devices such as smart thermostats.

How to contact us

To learn more about Alectra, please visit **https://alectrautilities.com**

To learn more about BEworks, please visit **www.BEworks.com** or call (416) 920-1921

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1-DRC-5

Attachment 2
ULO Optionality Report

Optionality Report: Switches

Last Refreshed
2026-01-26 10:04:16 AM

Account Type

- [ ] Select all
- [ ] Commercial
- [ ] Residential

Application Status

- [ ] Select all
- [ ] CANCELLED
- [x] COMPLETE
- [x] MTRCFGCHG
- [x] REQINPROC
- [x] REQRECVD
- [ ] REQREJECT

Date

- [ ] Select all
- [ ] 2020
- [ ] 2021
- [ ] 2022
- [ ] 2023
- [ ] 2024
- [ ] 2025
- [ ] 2026

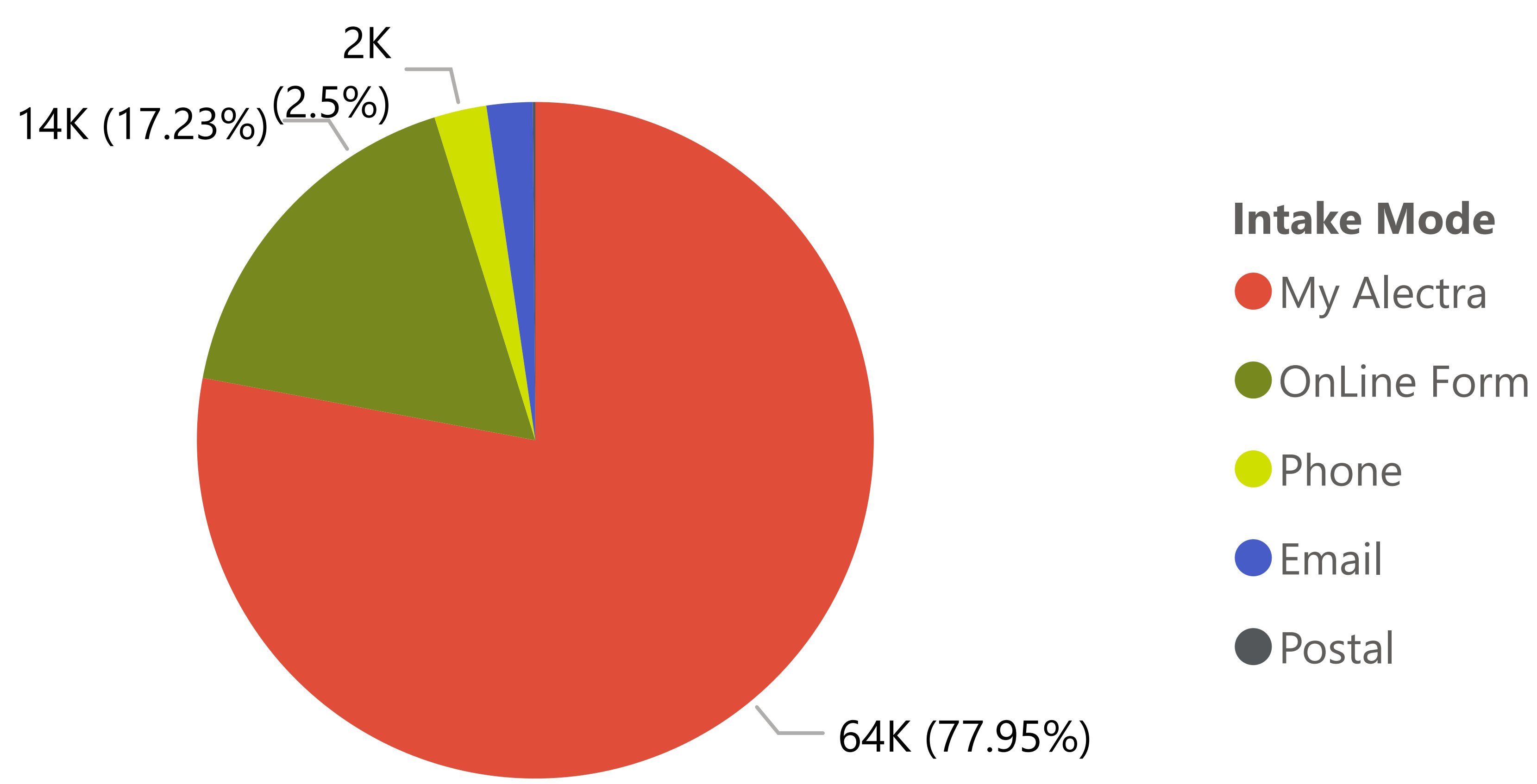
Account Type	Tiered	TOU	ULO	Total
Total # of COM Rate Switch Applications	1,137	167	61	**1,365**
Total # of RES Rate Switch Applications	66,540	9,663	4,917	**81,120**
Total # of Rate Switch Applications	**67,677**	**9,830**	**4,978**	**82,485**

Data is cumulative from rate go live

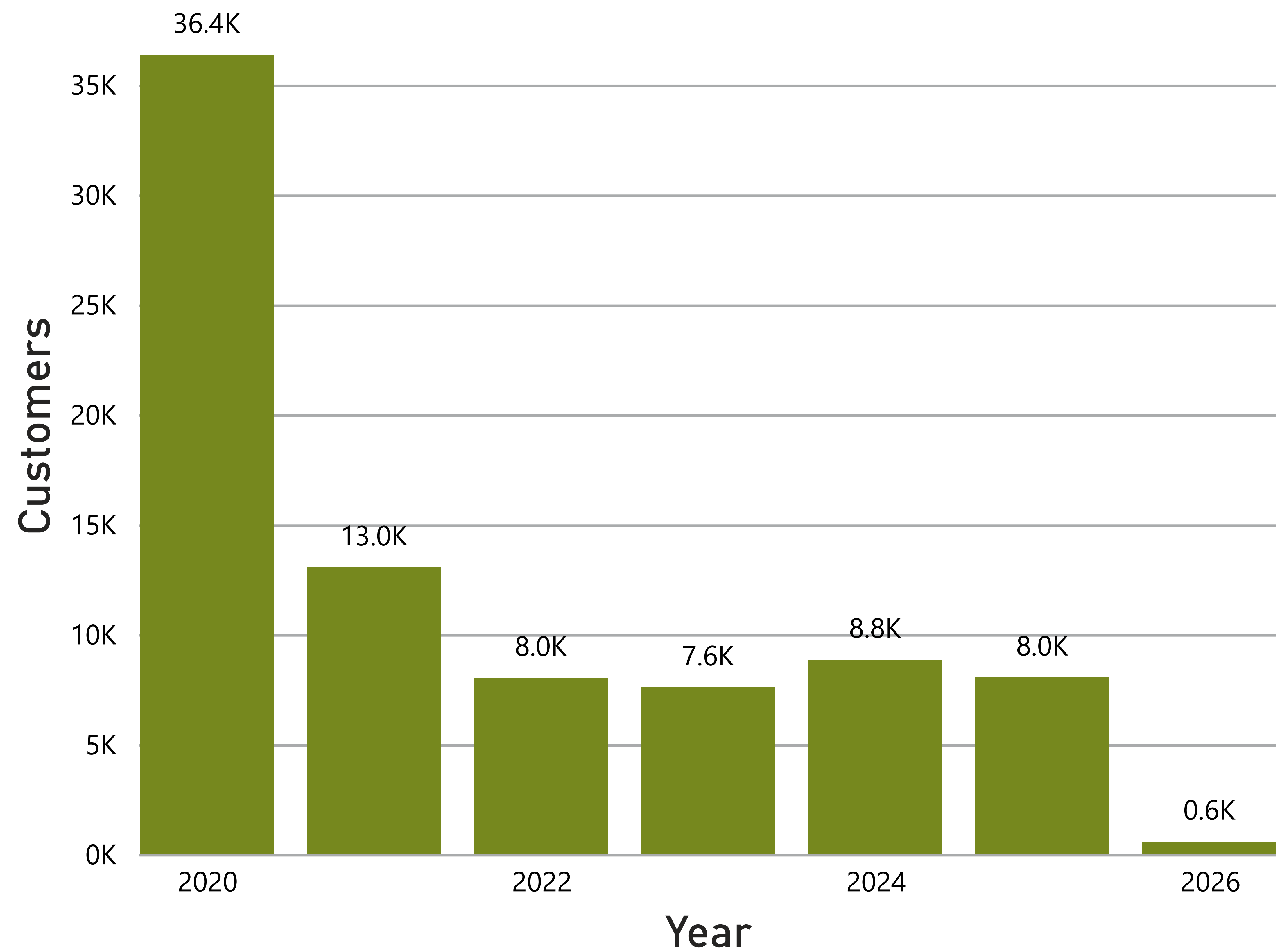
From \ To	Tiered	TOU	ULO	Total
Tiered		8,857	1,167	**10,024**
TOU	67,151		3,811	**70,962**
ULO	526	973		**1,499**
Total	**67,677**	**9,830**	**4,978**	**82,485**

Data is cumulative from rate go live

Application Intake Mode Breakdown



Rate Switches Trend



Optionality Report: ULO

Last Refreshed
2026-01-26 10:04:16 AM

Account Type

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- [ ] Residential

Application Status

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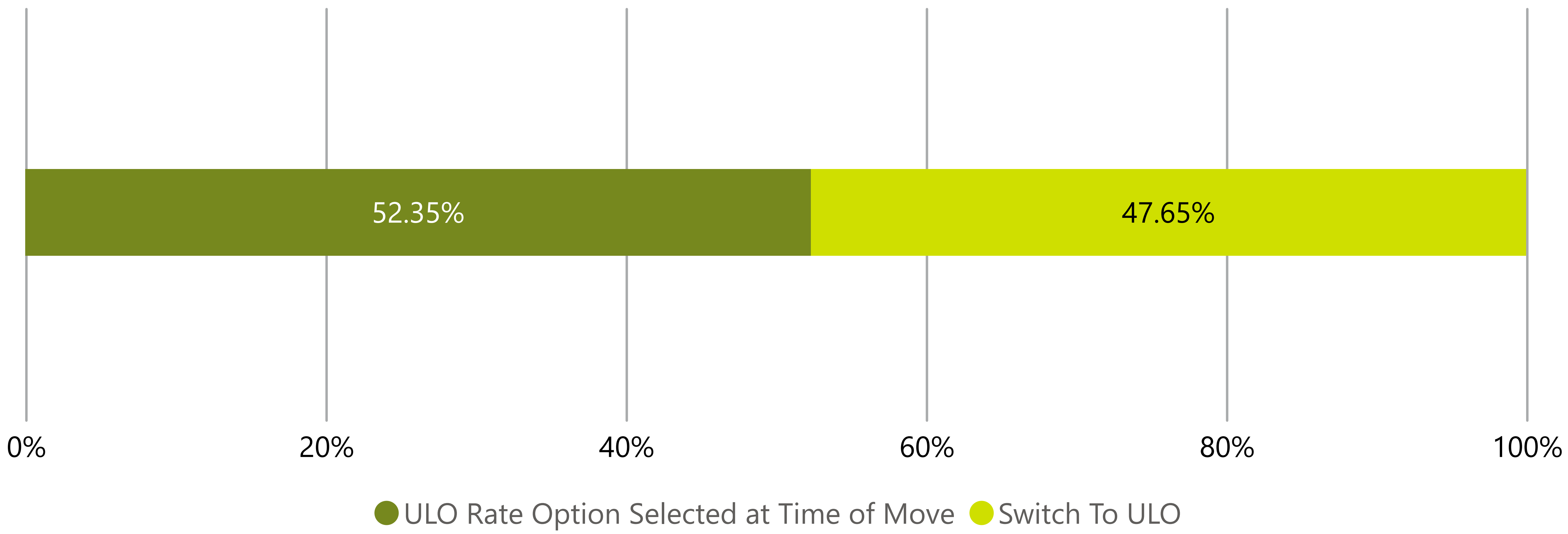
- [ ] CANCELLED
- [x] COMPLETE
- [x] MTRCFGCHG
- [x] REQINPROC
- [x] REQRECVD
- [ ] REQREJECT

Date

- [ ] Select all
- [ ] 2020
- [ ] 2021
- [ ] 2022
- [ ] 2023
- [ ] 2024
- [ ] 2025
- [ ] 2026

ULO Customers - Moves vs Switches

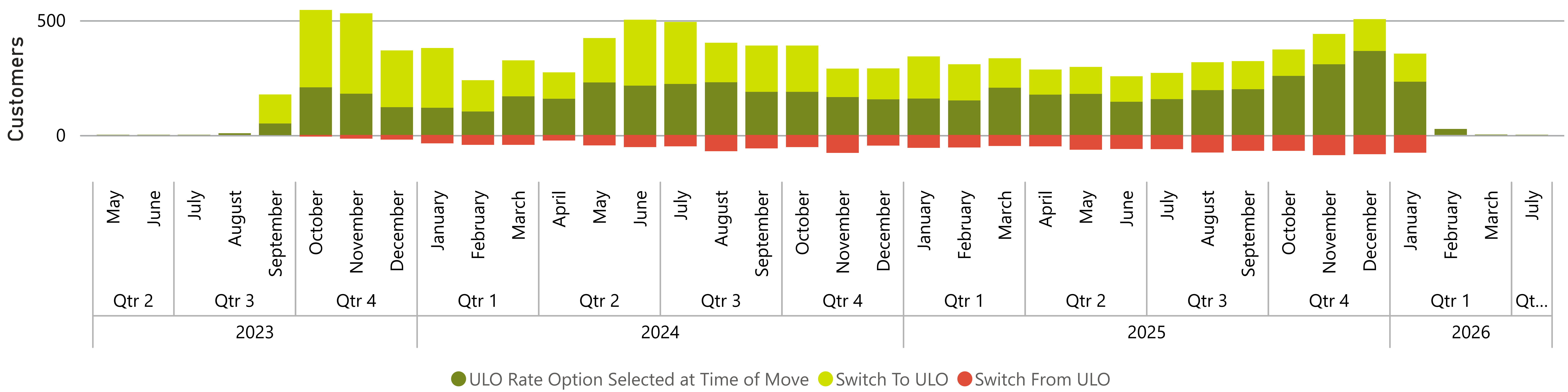


ULO Movement

Type	Customers
ULO Rate Option Selected at Time of Move	5,470
Switch To ULO	4,978
Switch From ULO (Negative)	-1,499
TOTAL ULO	8,949

Data is cumulative from rate go live

All ULO Customers



1-DRC-5

Attachment 3
AlectraDrive@Work Final Report

alectradrive @work

Final Report

Delivered On	Prepared By	Prepared For
July 28, 2022	Geotab Energy	Alectra Utilities Corporation

alectra utilities

GEOTAB

Table of Contents

Executive Summary

The AlectraDrive @Work program is a workplace electric vehicle (EV) charging pilot that was created by the Alectra Utilities Corporation, in collaboration with Geotab Energy, and with support from Natural Resources Canada and the Independent Electricity System Operator (IESO). The program was designed to collect and monitor EV charging data from program participants at various workplace locations using the FleetCarma System, and compare that data to the data collected directly from the charging stations at those locations. The two workplace charging locations are the Alectra Utilities Corporate Head Office (referred to as the Derry Rd facility) and the Markham Civic Centre.

The purpose of this final report is to provide a summary of the overall program findings from the FleetCarma System, including all EV charging and trip data collected from program participants starting on October 31, 2018 until June 30, 2022. Any data related to demand response or FleetCarma's SmartCharge Manager™ system is outside the scope of this report.

EV data was collected from a total of 28 vehicles with three different powertrains: long-range battery electric vehicles (7 LR BEVs), short-range battery electric vehicles (11 SR BEVs) and plug-in hybrid electric vehicles (10 PHEVs). An analysis of the load curves of the three powertrains showed that the load for SR BEVs has a gradually increasing power draw during the morning followed by a fairly consistent load until it peaks in the evening, while PHEVs have a consistently low draw all throughout the day. LR BEVs proved to be the most volatile, with more fluctuations throughout the day and a large spike in the evening caused by one individual who charges consistently at 8 pm. In terms of average driving distance, PHEVs have the longest overall average driving distances (combining distance traveled using gasoline and electricity) on a calendar day but the shortest average electric distances, while LR BEVs have higher driving distances than SR BEVs due to their larger battery capacity.

When examining location-based charging, it was observed that during general business hours (8 am to 5 pm), charging was highest at both the Markham Civic Centre and Derry Rd facilities. This corresponds to participants using workplace charging while at work. It was also observed that charging at other locations is highest at around 7 pm, which may correspond with home charging as participants take advantage of Ontario's off-peak time-of-use rate.

Analyzing the average daily load on weekdays compared to weekends showed the load is generally higher on weekdays than on weekends. This is most notable during business hours on weekdays when participants are at work and utilizing workplace chargers. When comparing the load curves across all seasons, the load generally increases throughout the workday and then peaks at the times coinciding with Ontario's off-peak time-of-use hours. Winter, the season that generally requires more vehicle cabin conditioning, has a higher load associated with it.

An analysis of the impacts of the COVID-19 pandemic indicated that there was a substantial decrease in both driving distances and charge energy starting in Q1 2020, which coincides with the declaration of the global pandemic. This led to an overall reduction in workplace charging for the remainder of the program as more participants were working from home.

A survey that was delivered to participants at the start of this program showed that participants primarily joined the AlectraDrive @Work program in order to obtain access to workplace charging to provide sufficient charge to their EVs prior to driving home. Additionally, it was noticed that the availability of workplace charging is likely to have an impact on a person's decision to drive an EV, in addition to their overall charging habits.

Introduction

The AlectraDrive @Work program was a workplace electric vehicle (EV) charging pilot that was sponsored by the Alectra Utilities Corporation, in collaboration with Geotab Energy. The program was launched on November 6, 2017, with vehicle data collection starting on October 31, 2018. The program was designed to monitor participant charging data at various workplace locations using the FleetCarma System, and compare vehicle-side charging data to the data collected directly from the charging stations at those locations. The objectives of the AlectraDrive @Work program are as follows:

1. Demonstrate the value of smart EV workplace charging that balances building and EV load, while mitigating potential cost increases and enabling EV adoption;
2. Provide participants with access to charging;
3. Mitigate demand charges & manage transformer loading; and
4. Create added value for customers and Alectra Utilities in terms of commodity cost management and market services.

The program was supported by Natural Resources Canada and the Independent Electricity System Operator (IESO). The purpose of this final report is to provide a summary of the overall program findings, including all participant EV charging and trip data throughout the duration of the data collection period, October 31, 2018 until June 30, 2022. Any data related to demand response or FleetCarma's SmartCharge Manager™ system is outside the scope of this report.

All participants in the AlectraDrive @Work program received a C2 connected car device, which can be seen in Figure 1. This device is installed by inserting the device into the vehicle's on-board diagnostic port (OBD) or using a similar process for vehicles that are not equipped with the standard diagnostics port (i.e. Tesla vehicles). Once installed, the C2 device transmits data from the vehicle to the FleetCarma system servers. A total of 45 devices were purchased by Alectra Utilities for use in this program.

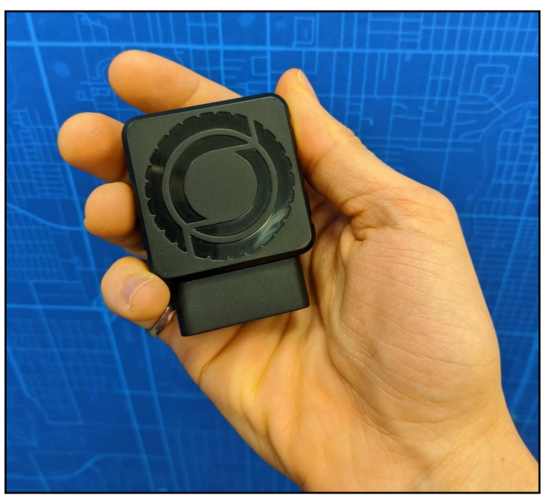


Figure 1: C2 Connected Car Device

Program Design

The AlectraDrive @Work program was designed to recruit participants that work and charge their electric vehicles at one of the following two sites:

- Alectra Utilities Corporate Head Office (Derry Rd Facility)
- Markham Civic Centre

Of the 45 devices that were purchased by Alectra Utilities, 10 were assigned to the Derry Rd facility, 22 were assigned to the Markham Civic Centre, and 13 were never assigned. Data from a total of **28 distinct vehicles** was collected and included in this report.

Between October 31, 2018 and March 31, 2021, this program had two components to it:

1. Vehicle-side data collection of all participant charging and trip data.
2. Implementation of demand response (DR) activities and collection of the relevant DR data.

After the sunset of the FleetCarma System on March 31, 2021, the program focused solely on vehicle-side data collection for load profiling, with charge and trip data from the participants being shared with Alectra Utilities on a monthly basis. At the end of the program on June 30, 2022, a total of 22 devices were still active in the program.

Participant Journey and Enrollment

Participants in the AlectraDrive @Work program were recruited at each location. The participants consisted primarily of employees of Alectra Utilities at the Derry Rd facility location and City of Markham employees at the Markham Civic Centre location. All participants owned or leased an electric vehicle and charged them regularly at their workplace location. Included in this program was a City of Markham fleet which consisted of 7 PHEV vehicles. In order to be eligible to participate in the program, participants needed to own/lease an electric vehicle, as defined below:

- **Long range battery electric vehicle (LR BEV)**: any fully electric vehicle that has a battery capacity greater than 50 kWh.
- **Short range battery electric vehicle (SR BEV)**: any fully electric vehicle that has a battery capacity less than 50 kWh.
- **Plug-in hybrid electric vehicle (PHEV)**: any vehicle that has both an internal combustion engine and an externally rechargeable battery that can be used to drive the vehicle.

Once participant eligibility was confirmed, participants were then sent an application package detailing their participation in the program and the terms and conditions of the program. Once the package was signed and completed, the participants were provided with their C2 connected car device in order to get started collecting vehicle data with the program. This included details on how to get set up in the FleetCarma System and how to set their preferences for any future DR events that were being run by Alectra Utilities.

Program Data Analysis

This section of the report will discuss the various data analyses conducted by Geotab Energy. All analyses discussed in this section will include data collected between October 31, 2018 and June 30, 2022 from participants at both the Derry Rd facility and the Markham Civic Centre. Each section will include a selection of load curves, which are significant in helping understand the variation in the average electrical load over time.

Data from a total of 28 distinct vehicles was collected and is included in this section. It should be noted that due to the limited number of vehicles in this program, the load curves displayed below may have been influenced by the charging habits of a select few participants. This could also lead to volatility in the load curves depending on how the data was aggregated.

Vehicle Powertrain Analysis

Figure 2 illustrates the average daily load curve for each of the three powertrains in this program: LR BEVs (7 vehicles), SR BEVs (11 vehicles), and PHEVs (10 vehicles). The load curve for SR BEVs increases at around 6 am and generally trends upwards until about 10 am, and then stays fairly consistent until an increase at 7 pm, after which it slowly starts to decrease. PHEVs have a gradual increase in charging throughout the morning until 12 pm then it stays relatively the same throughout the rest of the day, followed by a decrease starting at around 10 pm.

The load curve for LR BEVs is the most volatile of the powertrains. It starts increasing at around 7 am and starts to trend slightly downwards at about 11 am, followed by a large spike at around 8 pm. Looking at the underlying data, this is the result of one individual who charges consistently at 8 pm, which has led to the data looking slightly skewed. This one vehicle is highly influential, accounting for 56% of the 8 pm charging data, and 16% of all total charging.

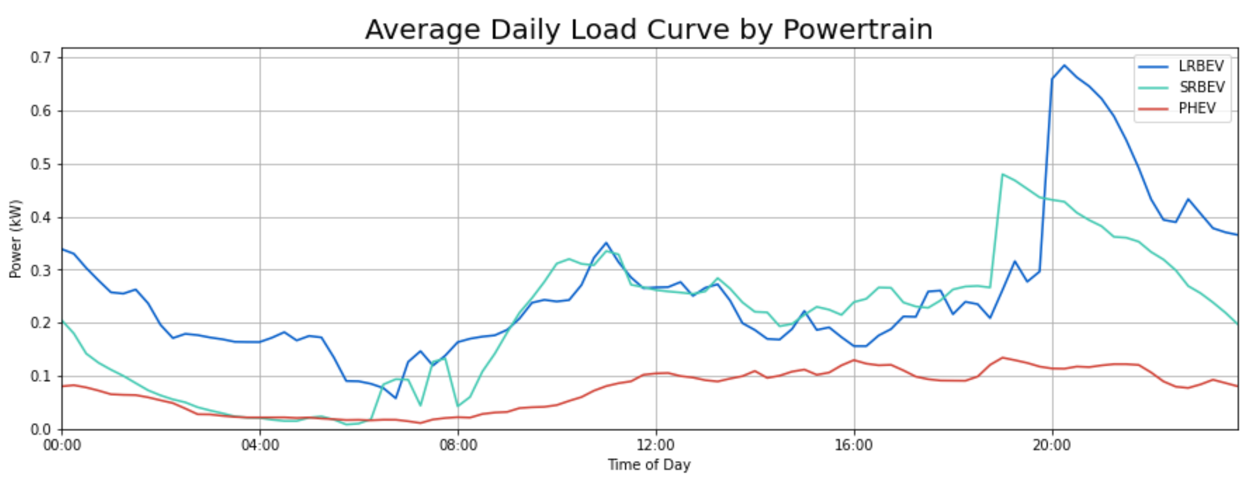


Figure 2: Average Daily Load Curve by Powertrain

Figure 3 shows what the average daily load curve by powertrain would look like if that one vehicle was removed. It can be seen that LR BEVs still have the highest overall load, but the 8 pm spike is no longer present. There is a slight increase in evening charging at 7 pm, which corresponds to a reduced residential electricity rate. This suggests that the participants will wait until 7 pm to begin charging at home in order to leverage cost savings on their electric bill.

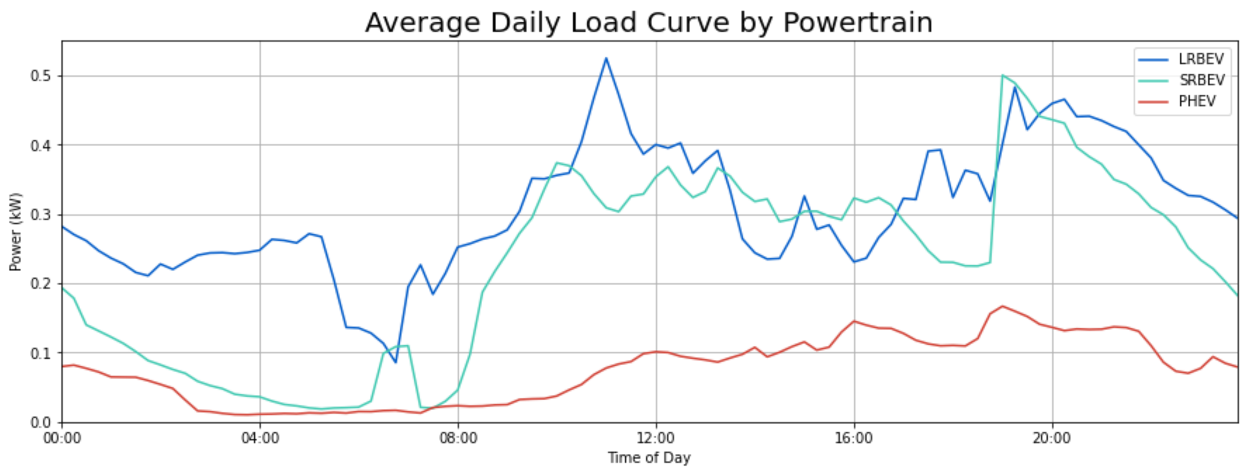


Figure 3: Average Daily Load Curve by Powertrain with Outlier Removed

Table 1 shows a breakdown of the average driving distance travelled by each powertrain. Average distances were calculated using either calendar days or driving days. The calendar day averages refer to the average driving distance for every day since program launch. Driving day averages refer to only days that the individual vehicles were actually driven. It can be seen that PHEVs have the longest overall average driving distances per calendar day, but the shortest average electric distances (~43.8% electric driving). LR BEVs have farther driving distances than SR BEVs by roughly 3 kilometers each calendar day and almost 13 kilometers each driving day. This may be the result of LR BEVs having longer range capabilities compared to the SR BEVs.

Table 1: Average Driving Distances for Each Powertrain

Powertrain	Average Distance [km]		Average Electric Distance [km]	
	Calendar Day	Driving Day	Calendar Day	Driving Day
LR BEV	27.09	53.54	27.09	53.54
SR BEV	24.04	40.95	24.04	40.95
PHEV	31.14	58.7	12.71	26.61
Total	**27.34**	**50.44**	**20.76**	**38.98**

Geographic Analysis

As part of the AlectraDrive @Work program setup, the Markham Civic Centre and the Derry Rd facility had reporting geofences created in order to monitor whether charging was taking place at the facility locations or if charging was occurring elsewhere (i.e. participants' homes, public charging stations, etc.). This analysis, demonstrated by the load curves in Figure 4, shows that charging at the two locations is highest during general business hours (8 am to 5 pm), indicating that participants are most likely to charge at these locations while they are at work. This is especially true for the Derry Rd facility, as they had fewer overall charge sessions (~10% of the number of charge sessions at the Markham Civic Centre), but roughly three times more LR BEV charge sessions than the Markham Civic Centre. This significantly impacted the load curve at Derry Rd to be much higher than at any other locations.

It is noticeable that charging at other locations exceeds the workplace charging after 4 pm, indicating that participants are charging away from the workplace outside of business hours. Additionally, non-workplace charging started to increase at around 7 pm, which may be due to participants choosing to charge at home in accordance with Ontario's off-peak time-of-use rate (7 pm to 7 am, Monday - Friday, all day on weekends and holidays).

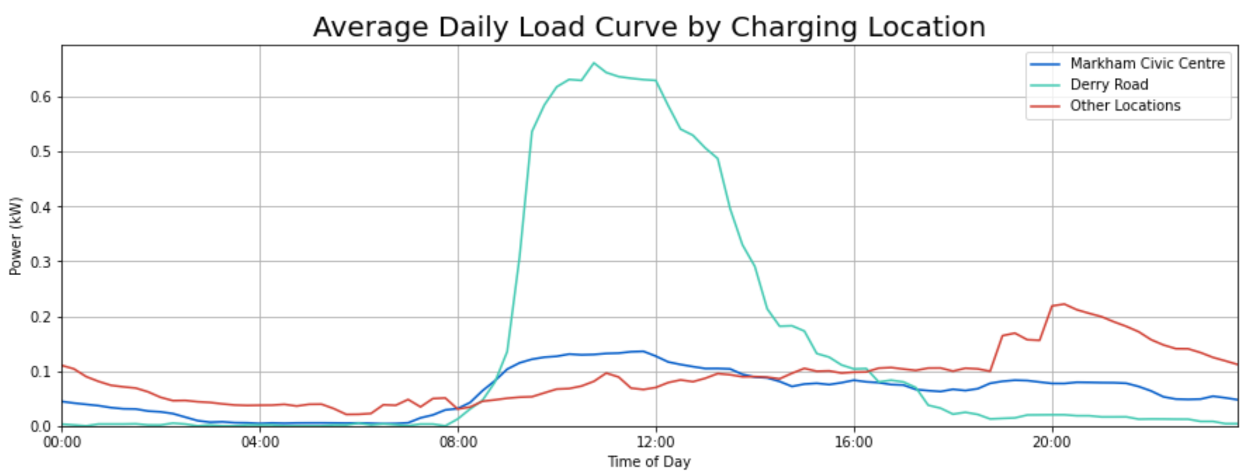


Figure 4: Average Daily Load Curve by Charging Location - All Vehicles

Given the difference in the sample size between the two workplace locations being analyzed, Figure 5 shows the same charging location analysis but normalized with a similar sample size and vehicle composition (i.e. 4 LR BEVs, 4 SR BEVs, 1 PHEV) in each load curve. The vehicles were randomly selected for this analysis. The same general trend can be found in both Figures 4 and 5, with the increase in charging outside the workplace after 7 pm.

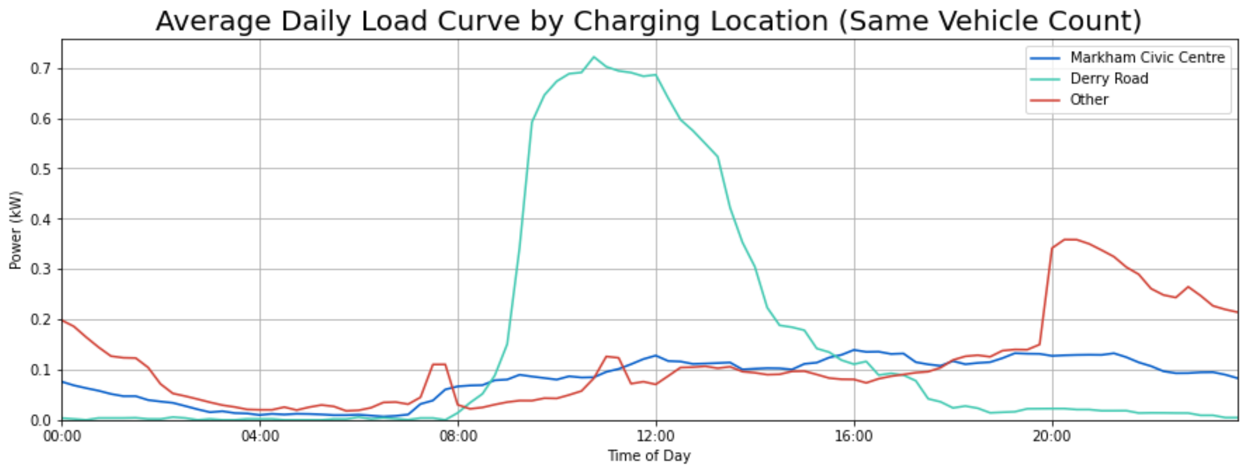


Figure 5: Normalized Average Daily Load Curve by Charging Location (4 LR BEVs, 4 SR BEVs and 1 PHEV per group)

Temporal Analysis

The average daily load curve for weekdays compared to weekends can be seen in Figure 6. This figure includes all 28 EVs and demonstrates that participants, at most points in a day, are more likely to charge on weekdays than on weekends. There is a higher load during general business hours on weekdays than on weekends, which corresponds to increased workplace charging when participants are at work. There were also peaks on both weekdays and weekends at 7 pm and 8 pm, likely due to participants charging at home during Ontario's off-peak time-of-use hours, or participants scheduling their charging to start at those particular times in order to maximize the benefit of a lower electrical cost.

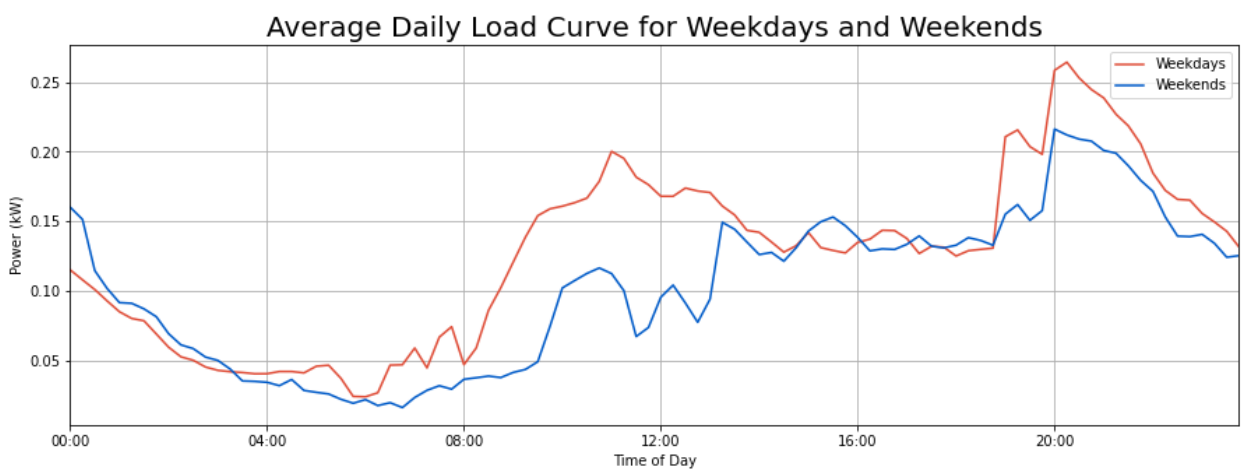


Figure 6: Average Daily Load Curve by Weekdays and Weekends

Figure 7 shows the average load for each of the four seasons: Spring (March - May), Summer (June - August), Fall (September - November) and Winter (December - February). Across all seasons, in general, the load increases throughout the work day, decreases slightly after 5 pm, and then peaks at around 7 pm and 8 pm. This coincides with Ontario's off-peak time-of-use hours, likely the time that certain participants schedule their charging to start. It can be seen that winter generally requires more vehicle cabin conditioning and has a higher load associated with it. Additionally, colder temperatures tend to reduce the overall efficiency of a vehicle's battery, which could explain the slight increase in charging during the winter months compared to the other seasons.

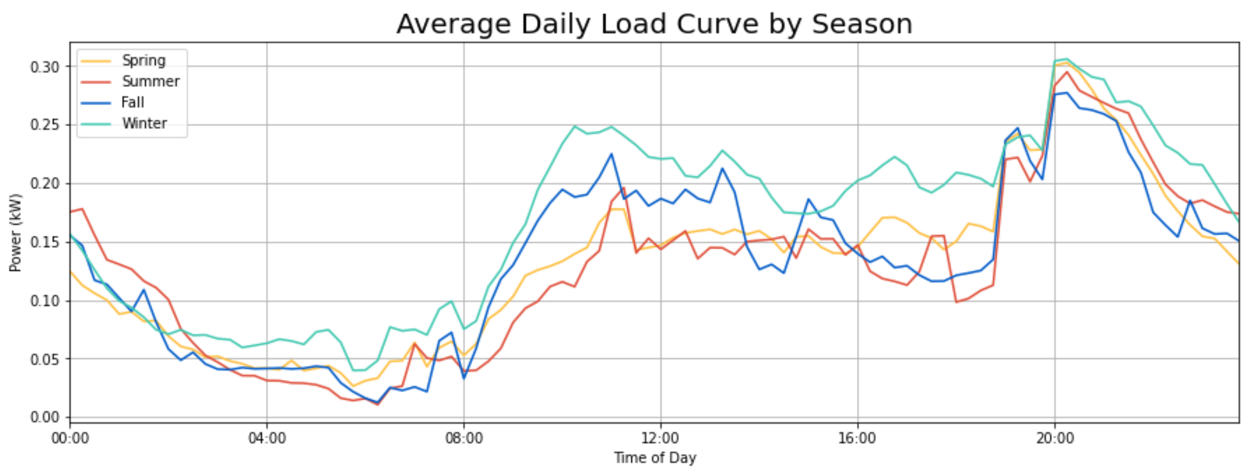


Figure 7: Average Daily Load Curve by Season

A further analysis of the seasonal impacts on EV charging can be seen in Figure 8, where the average daily load of the hottest and coldest months of the year are analyzed. For this analysis, all January data was used for the coldest month, and all July data was used for the hottest month. It can be seen that the hottest month had a higher load between roughly 11 pm and 3 am, but the coldest month had higher load during general business hours and into the evening.

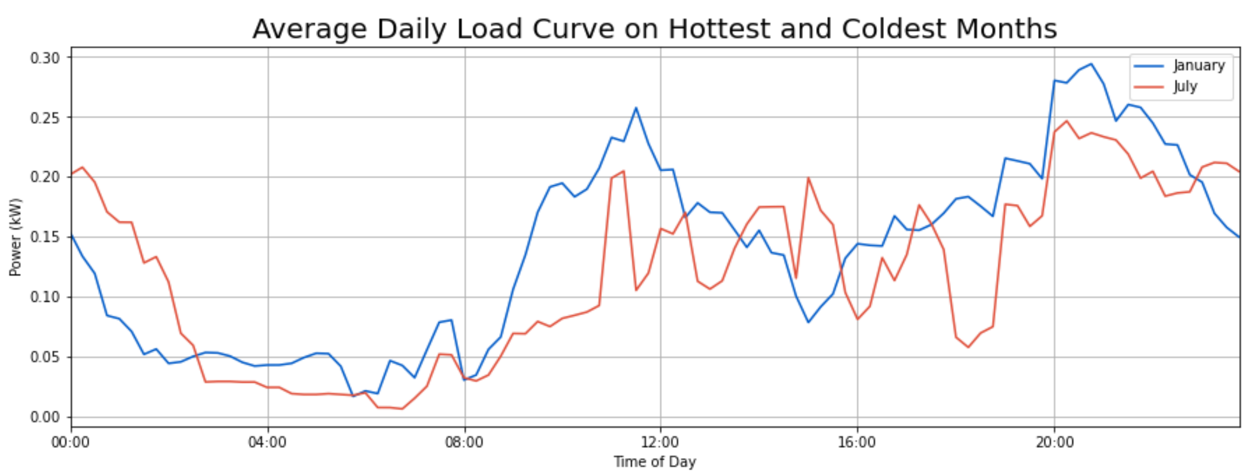


Figure 8: Average Daily Load Curve on Hottest and Coldest Month

Impacts of the COVID-19 Pandemic

On March 11, 2020, the COVID-19 global pandemic was declared, and shortly thereafter Ontario went into a province-wide lockdown. There were noticeable impacts on the driving and charging behaviours of the participants in this program. Table 2 shows the average driving distance of all program vehicles broken down quarterly. It can be seen that prior to Q4 2019, the average total and electric distances were equal as there were no PHEVs in the program yet. Once the Derry Rd facility launched and additional vehicles were recruited for the Markham Civic Centre, the overall distances increased and the total distance and electric distance values differed due to the inclusion of PHEVs.

There is a noticeable decrease in all driving distances starting in Q1 2020, likely a direct result of the stay-at-home orders and the transition to working from home caused by the COVID-19 pandemic. Q3 2021 and onwards shows an increase in driving distances, which could correspond to the province reopening as the pandemic progressed and the negative societal impact of COVID-19 start to diminish over time.

Table 2: Quarterly Breakdown of Driving Distances for All Program Vehicles

Time Period	Average Distance [km]		Average Electric Distance [km]	
	Calendar Day	Driving Day	Calendar Day	Driving Day
Q4 2018*	44.5	48.5	44.5	48.5
Q1 2019	35.5	43.2	35.5	43.2
Q2 2019	29.3	32.8	29.3	32.8
Q3 2019	26.9	31.6	26.9	31.6
Q4 2019	43.9	51.9	43.6	50.7
Q1 2020	30.6	40.5	25.5	33.1
Q2 2020	21.6	34.5	13.7	22.8
Q3 2020	25.0	37.3	15.8	24.6
Q4 2020	21.3	33.6	17.7	27.4
Q1 2021	18.3	30.7	14.6	25.1
Q2 2021	22.0	45.8	17.0	35.7
Q3 2021	26.6	81.5	22.6	68.0
Q4 2021	27.5	51.5	23.4	42.0
Q1 2022	39.9	55.1	28.3	38.0
Q2 2022	46.1	64.0	36.0	48.6

*Does not include all data from the quarter; program data collection began on October 31, 2018

To analyze the impacts of the pandemic on the charging energy, Figure 9 was created to compare the total charge energy across all months of the program, broken down by charging location. It can be seen that following March 2020, the overall charge energy decreased significantly, and the charging that took place at the Derry Rd facility became negligible until the last 3 months of 2022. It should also be noted that the percentage of charging away from the workplace increased as most people started working from home. This led to a reduction in workplace charging for the remainder of the program. Additionally, since the start of the pandemic, over 70% of all Markham Civic Centre charging was performed by the fleet vehicles, indicating that individual EV owners were likely to have been charging at home during the pandemic.

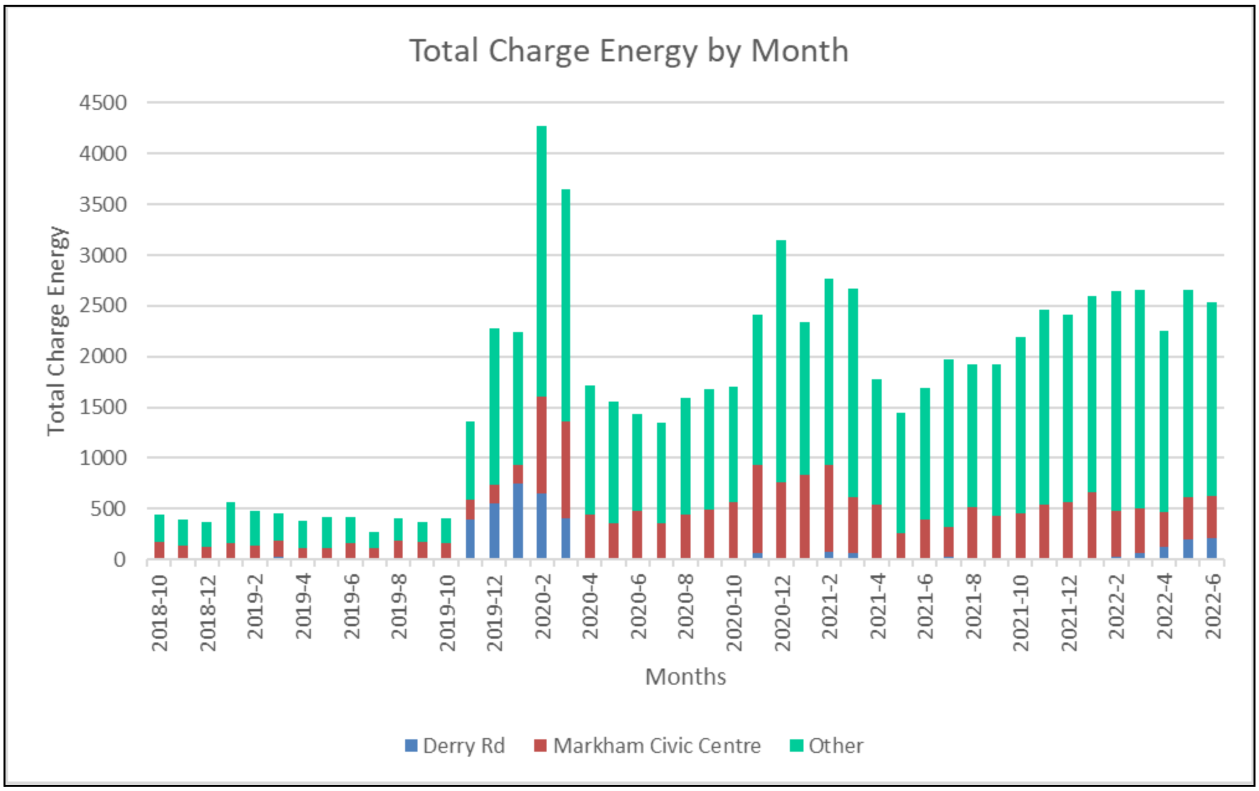


Figure 9: Total Charge Energy by Month

Participant Experience

In 2019, a survey was sent out to all participants of the AlectraDrive @Work program at both the Markham Civic Centre and Derry Rd sites. A total of 20 participants submitted responses for the survey, with 13 of those participants completing all survey questions. This section will highlight some of the results of the survey, particularly regarding feedback on why participants joined the program and its impact on their charging habits. A significance statement is included at the end of each section to highlight the main takeaway from the results collected.

Why did you sign up for the AlectraDrive @Work Program?

Answer	1st Choice	2nd Choice	3rd Choice	4th Choice	5th Choice	6th Choice	7th Choice
To have access to chargers at work so I can leave work with sufficient charge	58.8%	17.7%	0.0%	0.0%	20.0%	0.0%	0.0%
To help the environment	29.4%	11.8%	12.5%	18.8%	6.7%	13.3%	7.7%
To get free charging	5.9%	35.2%	12.5%	18.8%	13.3%	13.3%	7.7%
To support my utility and employer understand how to manage EV charging	0.0%	23.5%	31.2%	12.5%	6.7%	0.00%	15.4%
To get access to additional insights through the web portal	5.9%	11.8%	6.3%	31.2%	13.3%	26.7%	15.4%
To be more innovative	0.0%	0.00%	25.0%	12.5%	13.3%	20.0%	23.0%
To receive the participant incentives	0.0%	0.00%	12.5%	6.2%	26.7%	26.7%	30.8%

Significance: Access to workplace charging to provide sufficient charging energy to EVs is the main motivator for participating in the AlectraDrive @Work program.

So far, does the EV charging available at your workplace affect your decision to drive an EV?

Answer	1st Choice
Major Influence	30.0%
Some Influence	40.0%
Not at All	30.0%

Significance: The availability of workplace charging will likely have an impact on a person's decision to drive an electric vehicle.

Do you expect that workplace EV charging will change your driving habits in the future?

Answer	1st Choice
Major Change	10.0%
Some Change	65.0%
Not at All	25.0%

Significance: Workplace charging will likely change the way an EV owner charges their electric vehicle.

Conclusion

The AlectraDrive @Work program is a workplace charging pilot that is created by the Alectra Utilities Corporation, in collaboration with Geotab Energy and support from Natural Resources Canada and the IESO. The program was designed to monitor participant EV charging data at specific workplace locations using the FleetCarma Portal System, and compare vehicle-side data to the data collected directly from the charging stations at those locations. The data that was collected was used to assess the overall demand and feasibility of workplace charging at different facilities. The two workplace charging locations included are Alectra Utilities Corporate Head Office (referred to as the Derry Rd facility) and the Markham Civic Centre. The data analyzed in this report was collected between October 31, 2018 and June 30, 2022.

The analysis conducted looked at the data from a variety of perspectives to provide program insights. When comparing the load curves of the three different vehicle powertrains in this program (LR BEVs, SR BEVs and PHEVs), it was noticed that SR BEVs have a gradually increasing power draw during the morning, followed by a fairly consistent load until it peaks at around 7 pm. PHEVs meanwhile have a consistently low draw all throughout the day.

The LR BEV load curve proved to be the most volatile, with more fluctuations throughout the day and a large spike in the evening caused by one individual who charges consistently at 8 pm. By removing the data from this individual, it was observed that LR BEVs still have the highest overall load, but the 8 pm spike is no longer present. This demonstrates the volatility of load curves with small numbers of EVs where individual behaviour can have a significant impact, but could also provide some indication of how load could be impacted in the future as more EVs are on the road.

In terms of average driving distance, PHEVs have the longest overall average driving distances on a calendar day but the shortest average electric distances. It was also observed that LR BEVs have higher driving distances than SR BEVs, which is due to their larger battery capacities.

Both the Markham Civic Centre and the Derry Rd facility were geofenced to track location-based charging. It was observed that during general business hours (8 am to 5 pm) is when charging at the two locations is highest, especially for the Derry Rd facility, which corresponds to participants utilizing their workplace chargers while at work. It was observed that the charging at other locations (e.g. home, public charging stations, etc.) exceeds the charging at the workplaces after 4 pm and peaks after 7 pm, which aligns with when participants are likely not at work and with Ontario's off-peak time-of-use rate.

The average load on weekdays compared to weekends showed that at most points in a day, the load is higher on weekdays than on weekends. This is most notable during general business hours on weekdays as increased workplace charging takes place when participants are at work. When comparing the load curves across all seasons, the load generally increases throughout the workday, and then peaks at around 7 pm and 8 pm, coinciding with the Ontario's off-peak time-of-use hours. Winter, the season that generally requires more vehicle cabin conditioning, has the highest load associated with it.

When analyzing the impacts of the COVID-19 pandemic, it became evident that there was a substantial decrease in both driving distances and charge energy starting in Q1 2020, which coincides with the declaration of the global pandemic. This led to an overall reduction in workplace charging for the remainder of the program as more participants were working from home.

A survey that was delivered to participants at the start of this program showed that participants primarily signed up for the AlectraDrive @Work program in order to obtain access to workplace charging to provide sufficient charge to their EVs prior to driving home. Additionally, it was noticed that the availability of workplace charging is likely to have an impact on a person's decision to drive an EV, as well as their overall charging habits.

Overall, the introduction of EV charging stations at workplaces has proven to have an impact on EV charging habits. Most charging took place at the workplace prior to the start of the pandemic, and EV owners are likely to adapt their driving and charging habits based on the availability of workplace charging. This supports the managed charging/DERM integration initiatives that have been tested in the past, and can prove to be a very valuable resource for the future of active load control.

1-DRC-5

Attachment 4
AlectraDrive@Home - GIF- Final Report

Final Project Report

AlectraDrive @HOME

Managed Charging Program for Single & Multi Family Homes

GROUP 1: Smart Charging- Time-variant pricing and load control

Project Partners

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Natural Resources Canada

Disclaimer: This project is supported by the financial contribution of the Independent Electricity System Operator (IESO), through its Grid Innovation Fund. However, the views, opinions and learnings expressed in this report are solely those of Alectra Utilities Corporation.

Public Report – AlectraDrive @Home (Smart Charging)

Group 1: Smart Charging: *Time-variant pricing and load control (30 customers)*

Executive Summary

The AlectraDrive @Home project targeted the need for affordable and effective EV charging solutions in both multi-residential and single-family homes. By evaluating both passive (pricing) and active (utility-managed charging) models, the AlectraDrive @Home program aimed to provide access to affordable EV charging options while also optimizing charging behaviours that would mitigate potential strain on the electrical grid caused by unmanaged charging and give insights into future program design. Customer feedback indicated strong satisfaction with this project, with 82% of participants expressing being content with the program and finding value for their money. Moreover, 80% of charging was shifted to off-peak times when compared to baseline data. These stats indicated the project's efficacy in providing grid management solutions as well as understanding customer needs. Additional key findings indicated high price elasticity of electric vehicle (EV) charging behaviours, and that demand response (DR) events are an effective method to reduce EV charging demand during peak hours.

Challenges exist in managing EV charging in both multi-unit residential buildings (MURBs) and single-family homes (SFHs) due to technical complexities. Consistent with other studies, MURBs encountered more complex technical issues related to installation and management of EV charging equipment, where SFHs were simpler due to a less complex installation, billing and communications needs. The pilot demonstrated that current and prospective EV drivers require more support from their electrical utilities. This work should include support for customers in the form of guides for acquiring an EVSE, communication of best practices for EV charging, and additional programs that reward customers for shifting their charging to off-peak times.

Future initiatives stemming from the findings of this project include highlighting opportunities for regulatory changes, enhancing community engagement, and streamlining enrollment processes for future programs. Overall, AlectraDrive @Home laid the groundwork for customer-facing EV support programs, while showcasing that managed charging of EVs works and is a viable method for electrical utilities to reduce demand across their service territories.

The project was set up with 3 customer groups: Group 1 (managed charging group), Group 2 (rewards groups) and Group 3 (control group). This program has been made possible through the provision of funds by Ontario's Independent Electricity System Operator (IESO) and the Government of Canada, through Natural Resources Canada (NRCan). The IESO's financial contributions relate to Group 1, whereas NRCan's contributions relate to both program treatment groups (Group 1 and 2/3).

Note that some content for this public report was sourced from Guidehouse's process and impact evaluation reports.

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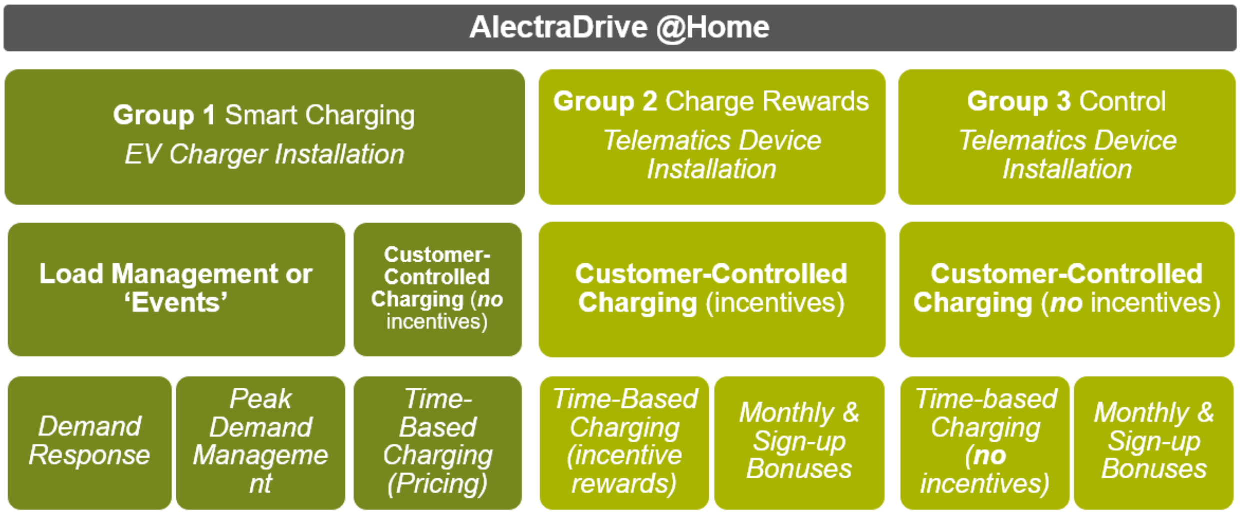

Figure 1 - High-level pilot program group architecture.

Project Objectives & Pilot Architecture

In 2020, Alectra initiated the AlectraDrive @Home project which was designed to explore a variety of strategies to ensure that consumer EV charging was timed to maximize the cost-effectiveness of EVs and complement an increasingly distributed electricity system. The program targeted solutions that met these criteria for residential consumers, including both multi-unit residential buildings (MURBs) and single-family homes (SFHs).

There were two goals for Group 1 in this pilot:

1. The first goal of this the project was to test the effectiveness of automatic technological electric vehicle supply equipment (EVSE) control for drivers charging at home.
2. The second goal of the impact evaluation was to test the effectiveness of the time-varied pricing treatment at reducing EV demand during the project on-peak periods.

Note that for the purpose of the pilot, on-peak time was considered all hours outside of 1 to 9 pm on non-holiday weekdays.

Group 1 – Detailed Architecture & Description

All Group 1 participants, part of the smart charging group, were provided access to subsidized FLO CoRe+ Level 2 EVSE at their residence, including the installation, in return for paying a monthly fee for the duration of the project (see Figure 2 below). There were 9 installations of EVSE in 4 MURBs, and 17 EVSE installed in 17 single-family homes, for a total of 26 participant EV chargers. There were 12 drivers in the MURB portion of the pilot, and 18 drivers in SFHs. Note that no analysis was completed on non-participant chargers installed at MURB buildings. These chargers were installed to provide access to EV charging at buildings that had EV drivers not enrolled in the pilot.

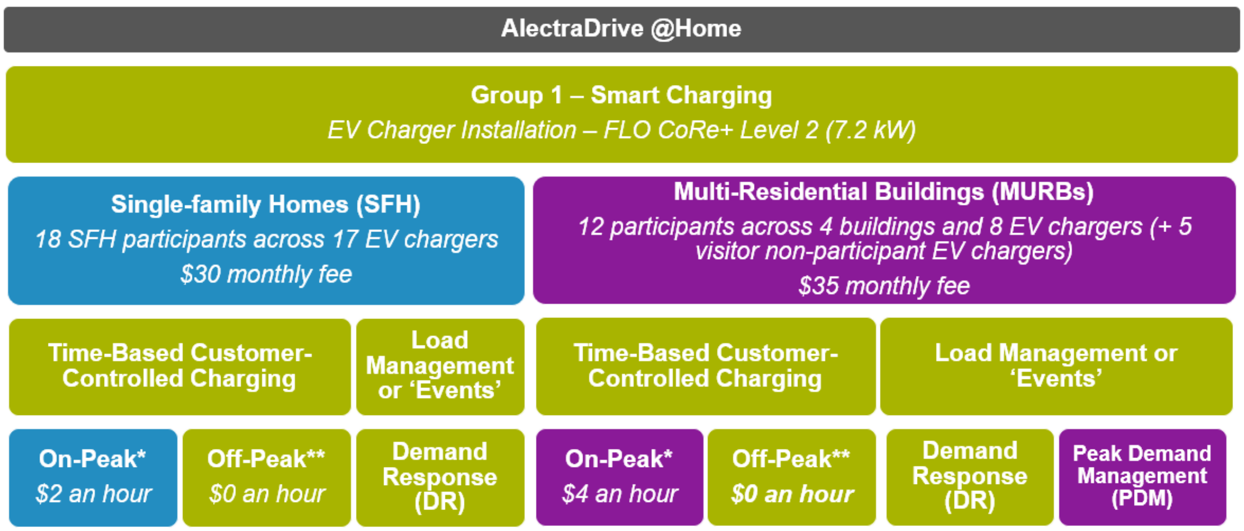

Figure 2 - Group 1 pilot architecture.

Active and Passive Controls – Description & Findings

The AlectraDrive @Home pilot program had two components core to the managed charging process:

- **Pricing signals or *passive control***: Participants were subjected to daily peak period charges intended to reduce average demand during the project on-peak period (1pm – 9pm on non-holiday weekdays). This charge was applied as a $/hour surcharge to use the EVSE during this peak period. MURBs paid $4 an hour for any charging done during on-peak hours, whereas SFH drivers paid $2 an hour. The reasoning behind the difference in costs was to account for the fact that SFH drivers paid for their electrical usage on their own utility bills, while MURB drivers only paid the on-peak costs. All energy commodity costs used by the MURB drivers were remitted to the condo corporation or building owner.

- **Automatic EVSE managed charging or *technological Control***: Demand Response (DR), which for the purpose of this project is the reduction of power to the charging station during a pre-determined time, was completed across the project to test the effectiveness of the technology and how customers react to reduce power to their charging station during peak hours. Peak Demand Management was also tested across the 4 MURBs, showcasing how demand can be reduced based on historical demand profiles to avoid increasing demand charges caused by concurrent EV charging during peak times.

As described above, passive control was performed through a pre-established per hour price when charging during on-peak times (1 pm to 9 pm on non-holiday weekdays) to test whether pricing was a strong enough driver to move charging to off peak times (9 pm to 1 pm on holidays and weekends).

Technological or active control was completed automatically using a custom API connection from FLO's EV chargers to Generac's (formerly Enbala) Concerto platform acting as a DERMS. Through the FLO API integration, the project team was able to customize the degree to which the EV charger should be curtailed as well as the frequency and timing. During each DR event, power to the station was throttled to 80% of the original 7 kW output. In simpler terms, a typical 7 kW station will charge an EV in 4 to 8 hours, whereas the 80% reduction increases this to about 9 to 15 hours. Note that DR events were not ran for the entire overnight period, so the time to charge will vary depending on the DR length and the type of EV being charged. Impacts were estimated for a series of pre-planned DR events covering a range of day-types, and the most appropriate estimated event impact (or aggregation of impacts) was considered to provide an ex-ante estimate of the equipment's DR capability.

Each participant was given two free opt-out opportunities to remove themselves from the DR event, and each opt-out above that cost them $10. DR events were scheduled every other week across 9 months, on predetermined days. Participants became aware of the DR event on the day-of, at 7 am via a text message and/or an email describing the event timing and instructions regarding opting out. Each participant was expected to plan accordingly to ensure they had enough charge for any trips required following the DR event. The project team saw only a single instance of opting out during the pilot across both SFH and MURB drivers.

Initially, the DR window was from 5 pm to 9 pm every other week on a predetermined day. The project team saw very minimal charging during this initial DR period due to the strength of pricing signals (passive control). To ensure the team had access to DR data, the DR window was changed to occur between 10 pm to 12 am based on the same schedule as the previous window timing. This resulted in proper testing availability and collection of data needed for the impact evaluation.

This pilot also tested the efficacy of a DERMS deployed in MURBs which worked to reduce building distribution demand charges through the deployment of a form of automated DR: Peak Demand Management (PDM). As with the DR events, participants could opt out of PDM events for a fee, with both DR and PDM opt-outs counting towards the same allotment of freebies. The goal of the pilot for PDM was to quantify to which degree PDM can mitigate increases in the monthly non-coincident peak demands of MURBs. This relates but also expands on DR's goal of quantifying to what degree EVSE curtailment DR events could reduce the IESO-coincident summer peak demand when applied to residential L2 EVSE in single and multi-family buildings.

Project Partners

The table below outlines the project partners involved with AlectraDrive @Home along with their roles and responsibilities.

Table 1 - Project Partners.

Partner	Role	Responsibilities
Alectra	Project Lead	Overall project design, management, execution, and reporting; vendor and budget management; overall customer experience and reporting to funders
Geotab (formerly known as FleetCarma)	Telematics device provider; data acquisition and analysis	Equipment deployment (C2); customer recruitment, data collection, analysis, and reporting on findings from incentive models and control groups; customer support and engagement related to C2 device; program administration; participation in rewards structure and access to web portal; note that Group 2/3 received C2 devices, not Group 1.
Flo	EVSE provider and operations manager	Integration with Generac DERMS platform; development of Time of Use (TOU) pricing and DR software features for Flo CoRe+ EVSE; sales support with MURBs (condos) and residential customer support; site plans and technical designs for EVSE installations, overseeing site deployment process with RBI and/or other contractors as required by Alectra; managing pricing/customer billing interface for end-user and support for Alectra admin portal for TOU/CPP pricing/scheduling; overall EVSE technology solution and project management as per Alectra-Flo SOW.
Generac (formerly known as Enbala)	DERMS provider	Installation and operation of DERMS at participating sites; integration of pricing signals and real-time usage data with demand curtailment to manage EVSE loads; use-case testing, analysis and reporting as per UAT and Alectra-Generac SOW.
Smith & Long/Robertson Bright (RBI) + Bracer EV	Electrical contractors	Virtual and physical MURB + SFH site assessments, EVSE installations, including additional equipment as required, required electrical upgrades, and related electrical work at participating sites.
Alectra Energy Solutions/Services.	Key account management /MURB recruitment	Key account management, customer care, and support recruitment of MURB participants

Plug'n Drive	Customer engagement and insights	Marketing and customer engagement support through design of messaging, materials, and engagements for participants; webinars and info sessions (Ride & Drives as required/circumstances allow)
Guidehouse	Pilot design and evaluation	Pilot design and evaluation consultant; pricing model development, evaluation, data analysis and reporting.
Laszlo Energy Services	Project management	Project budgeting, reporting, customer management, and evaluation support.

Impact Evaluation Approach & Results

As per the final evaluation report for Group 1 completed by Guidehouse, both impact and process evaluations were undertaken for the managed charging (Group 1) pilot. Impacts were evaluated using a regression analysis, applied to the quarter hourly individual EVSE data. Guidehouse estimated a separate regression model for each EVSE, controlling for the month, day of the week, and hour of day. Additional variables were included to capture the impact of pricing treatment and events (DR and PDM).

For event period impacts, Guidehouse used interval data from participant EVSE during the pilot period. The week-on-week-off approach provided a nearly contemporaneous baseline period for evaluating the impacts of the use-cases; the regression-based approach compares each EVSE's demand during the "on" weeks with the same EVSE's demand during the "off" weeks. The on/off design applies only to the automatic interventions (the "use-cases"). Impacts for pricing were estimated through a regression-based comparison of individual EVSE charging profiles before and after the application of prices. Each EVSE's profile in the initial baseline period (i.e., before prices or use-cases were deployed) was compared to the same EVSE's charging profile in the "off" weeks in the period in which the on/off design is deployed.

Guidehouse applied a seasonal charging profile and charging consumption adjustment factor to demand in the baseline period to account for seasonal differences between the baseline and pilot periods. Seasonal adjustments were estimated using data from the Group 2 (Rewards) pilot evaluation, which includes a control group (known as Group 3) of EV drivers whose vehicles' charging was logged from November of 2020 through the end of December 2022. Group 3 drivers were not subject to any pilot treatment.

Impact Evaluation Results (Demand Response)

The original event schedule included a series of DR events from 5 pm – 9 pm, coinciding with the on-peak pricing period from 1 pm – 9 pm. Based on preliminary results estimated approximately halfway through the pilot period, Guidehouse determined that given the response to pricing, little to no demand remained during the 5 pm – 9 pm window to curtail with DR. This is illustrated by Figure 3, which shows total demand across the SFH participants (green line) and MURB participants (blue line) for the DR event from 5 pm – 9 pm on May 25th. Demand was close to zero for both MURB and SFH participants leading up to the event and remained at the same level during the event. Demand increased at 9 pm, once the event and on-peak pricing period had both ended.

Following a recommendation from Guidehouse, Alectra worked with the vendor to shift remaining DR events to the 2-hour period from 10 pm to midnight. This illustrated an important challenge in planning EVSE DR events: for on-demand capacity to be achieved, there must be existing load to curtail.

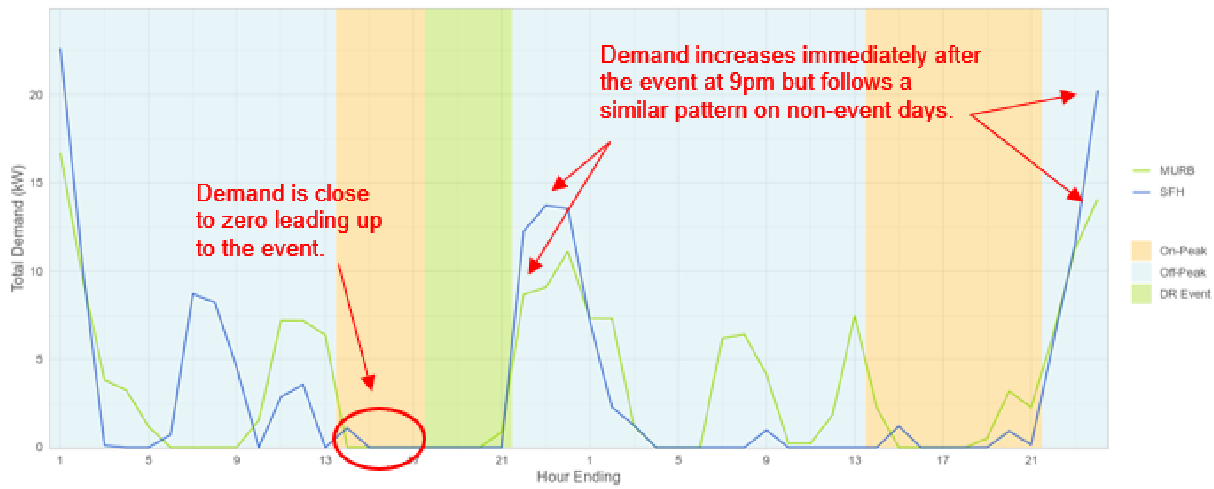

Figure 3 - Total Demand by Building Type, 5 pm to 9 pm DR on May 25, 2023. (Source: Generac data, Guidehouse analysis.)

Like the previous figure, Figure 4 shows the event from 10 pm – midnight on July 17th, 2023, with total demand across the SFH participants (green line) and MURB participants (blue line). In contrast to the May 25th, 2023, event, the on-peak pricing period had already ended at the time of the event start (10pm), so demand was non-zero leading up to the event. Demand fell to near zero for MURBs and SFHs during the event, then rose immediately after.

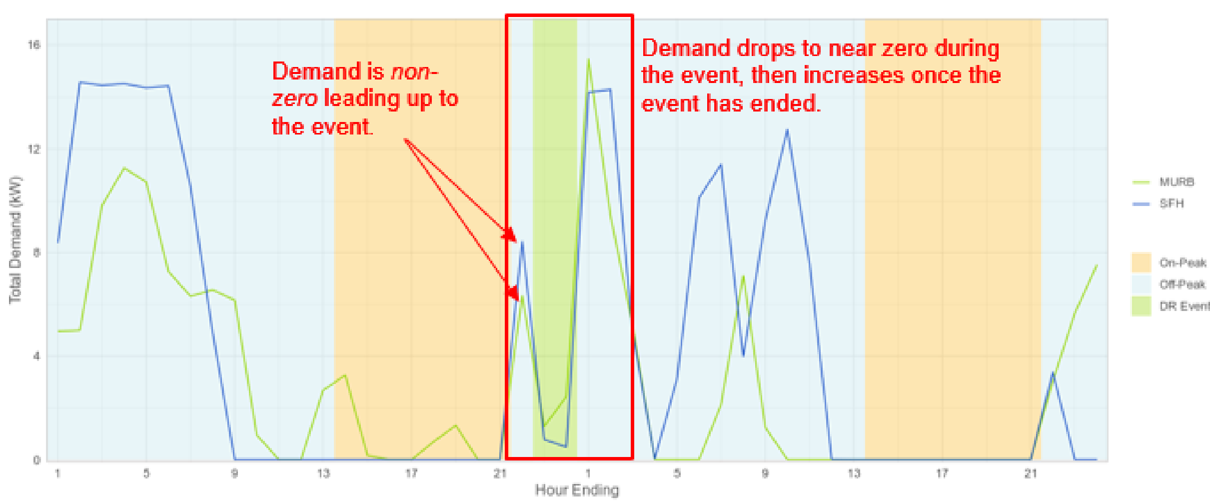

Figure 4 - Total Demand by Building Type, 10 pm to 12 am DR on July 17, 2023. (Source: Generac data, Guidehouse analysis.)

Guidehouse estimated average event impacts for each building type and event time, as well as individually for each event. DR delivered consistent and meaningful load reductions in periods which EVSE are normally in use. During events overlapping with the on-peak pricing period (5 pm – 9 pm events), DR delivered low or zero savings, as most pilot participants had already shifted charging at this window in response to pilot pricing. For events from 10 pm to midnight, MURB and SFH participants reduced demand by an average of 0.92 kW and 0.65 kW per EVSE, respectively. DR impacts were higher in hours in which baseline demand is higher; dispatching DR events outside of the on-peak pricing period for testing purposes did yield much higher impacts than DR events dispatched during hours in which drivers are already responding to prices.

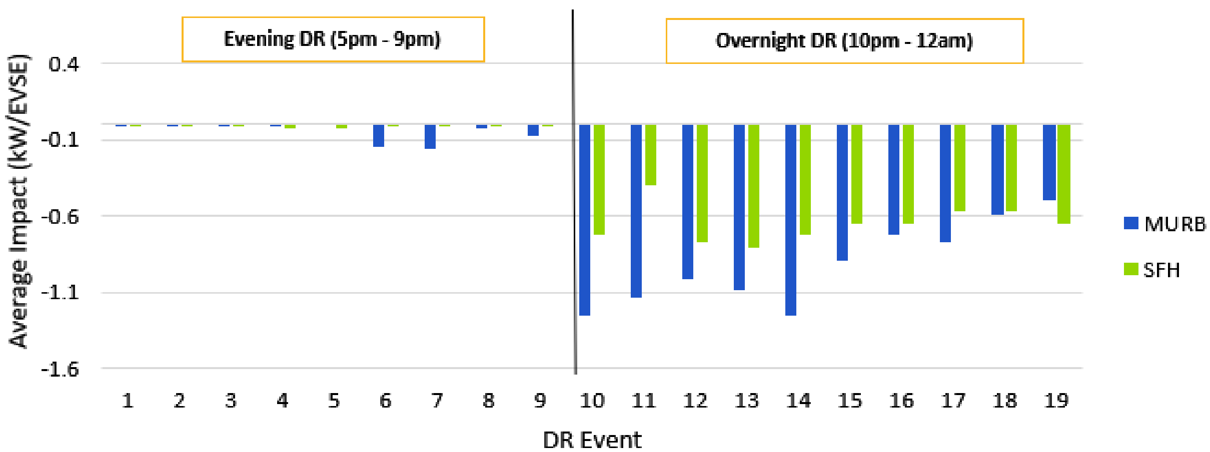

Figure 5 – Avg. impacts per DR event by building type. (Source: Generac data, Guidehouse analysis.)

Figure 5 shows average impact per EVSE by building type for each of the 19 DR events. Impacts for the first nine events (5 pm – 9 pm) were low, but in almost all cases, were directionally in alignment with expectations. For the first 9 events, impacts for MURBs ranged from 0 to -0.16 kW per EVSE, compared to 0 to -0.03 kW per EVSE for SFH participants. For events 10 – 18 (10 pm – midnight), impacts were larger, ranging from -0.5 to -1.25 kW per EVSE for MURBs and -0.4 to -0.81 kW per EVSE for SFH participants.

Clear demand reductions were estimated for events from 10 pm – midnight for both SFH and MURB participants. Average impacts were -0.92 kW per EVSE for MURBs and -0.65 kW per EVSE for SFHs, representing demand reductions of 86% and 89% of baseline demand for MURBs and SFHs, respectively. While none of the impacts represented statistically significant estimates, impacts for the later event time (10 pm – midnight) were less uncertain and may provide a more accurate estimate of on-demand capacity. The statistical uncertainty in these cases appeared to be driven by the highly binary nature of EV loads, which are typically either on or off, and the small number of events and participating EVSE.

For SFH participants, almost no charging occurred from 8 am – 5 pm on weekdays, coinciding both with a standard workday but also with the highest-priced periods in the Regulated Price Plan (RPP) time of use (TOU) price schedule. Charging is most concentrated after 9 pm. For MURB participants, demand is slightly higher during the day (MURB drivers are not subject to the default RPP TOU price) and increases from midday through midnight.

In planning future EVSE DR events, Alectra will consider the type of participants and their existing charging patterns when developing expectations around the potential for demand reductions. If EVSE are normally in use during a given period, DR dispatched at this time can be expected to deliver meaningful load reductions.

Impact Evaluation Results (Pricing)

A simple comparison of baseline period and pilot period average charging profiles was sufficient to identify that the program had an impact in shifting vehicle charging later into the evening, reducing demand from 1 pm – 9 pm to nearly zero on weekdays. This shift was expected given the existing RPP TOU incentive for status quo charging to begin after 7 pm, and the pilot treatment pricing further disincentivizing charging between 1 pm and 9 pm.

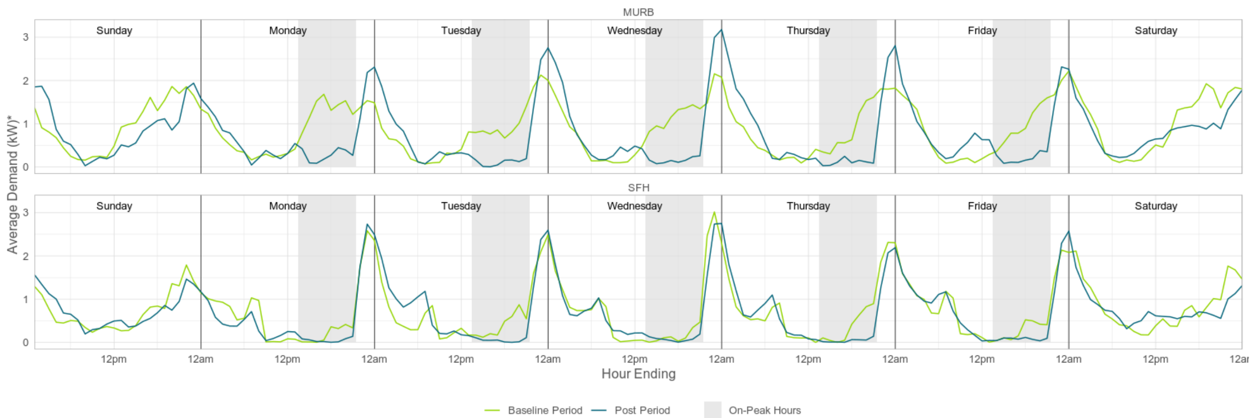

Figure 6 - Weekly Avg. Charging Profiles. (Source: Generac interval data, Guidehouse analysis.)

Figure 6 captured average charging demand per vehicle by day of week during the pilot period and in the baseline period. During the pilot on peak periods from 1 pm to 9 pm (shaded grey), post-period demand in blue was consistently below baseline period demand in green.

The top panel shows the average profile for MURB drivers, the bottom panel shows the average profile for SFH drivers. The key difference in the baseline profiles (green) between MURB and SFH can likely be attributed to the fact that the SFH drivers were already subject to RPP TOU, whereas the MURB drivers are not.

This was evidence of a consistent shift in participant charging patterns. The regression-estimated parameters yielded a contemporaneous baseline (very similar to, but not identical to, average demand in the pre-pilot period). This too clearly illustrated the impact of the program, as may be seen in Figure 7, which contrasts the average estimated participant baseline (dashed green line) with the average observed charging demand (solid orange line) for MURBs.

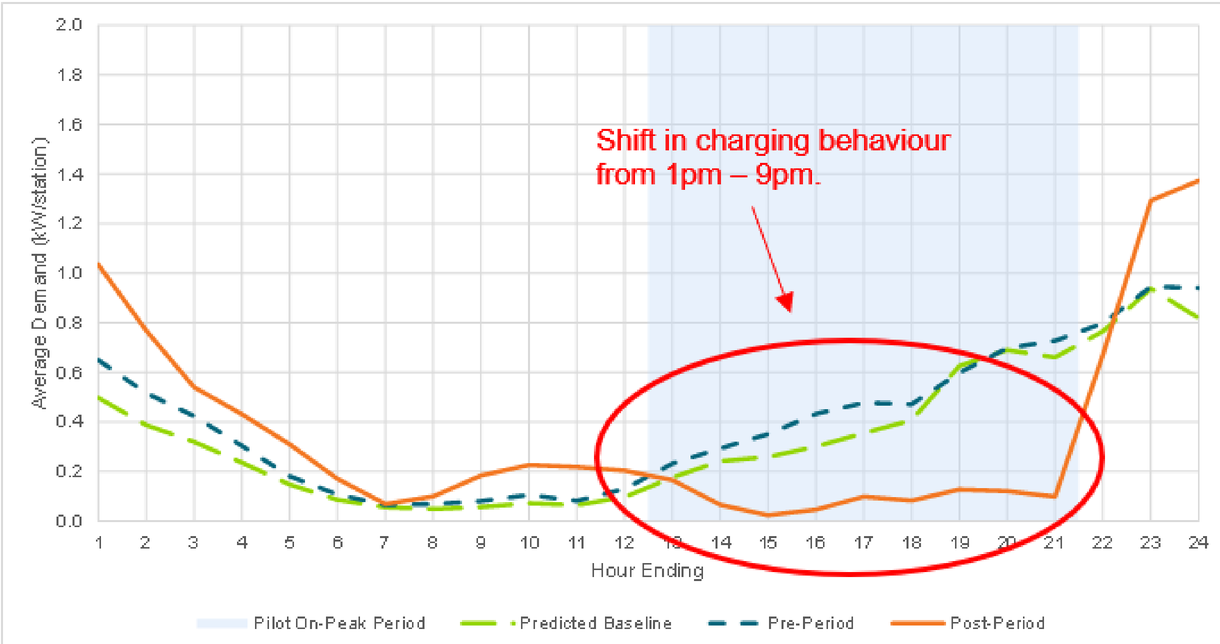

Figure 7 - Avg. Non-Holiday Weekday Observed & Baseline Demand for MURBs. (Source: Generac interval data, Guidehouse analysis.)

An equivalent figure for SFHs is included in Figure 8. Prior to the pilot, charging activity at MURBs was more concentrated during the 1 pm to 9 pm period than at SFHs, as illustrated by the dashed blue lines in Figure 7 and Figure 8. MURB participants were not subject to RPP TOU electricity pricing, whereas SFH participants were. This difference in initial charging patterns contributed to a more dramatic shift in charging behaviour observed for MURB participants.

In reviewing this, and all other figures showing estimated charging profiles, the reader must remember that average profiles are averages across all vehicles, including those charging and those not charging in any given interval. Put another way, although the estimation sample included approximately 25 EVSE across the two building types, there were at most 10 vehicles charging at any one time. Load profiles were therefore averages across a few vehicles with high demand (charging) and many with no demand (not charging).

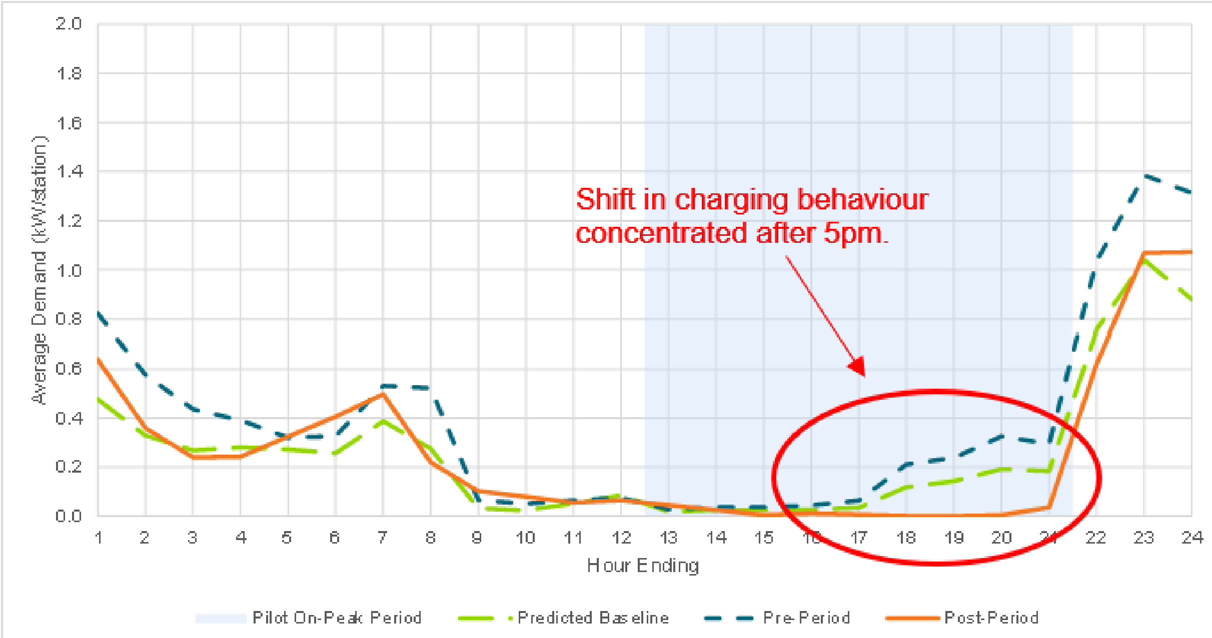

Figure 8 - Avg. Non-Holiday Weekday Observed & Baseline Demand for SFHs. (Source: Generac interval data, Guidehouse analysis.)

During on-peak periods, MURB participants delivered an average of 0.37 kW in savings per EVSE, compared to 0.08 kW per EVSE for SFH participants. For both participant types, this represented close to 85% of estimated baseline demand, indicating that participants shifted almost all charging activity outside of the 1pm – 9pm window.

On-peak impacts were relatively consistent throughout the pilot period. Both MURB and SFH participants showed the greatest response relative to baseline demand in April, reducing over 95% of load during the on-peak period. Off-peak impacts were smaller, with an estimated increase of 0.18 kW and 0.03 kW of demand per EVSE for MURB and SFH participants, respectively. The smaller off-peak impact was likely a reflection of the pricing structure – on a non-holiday weekday, there are 8 on-peak hours and 16 off-peak hours, so load shifted outside of the on-peak window can be spread more evenly throughout the day. For example, some participants may have shifted charging to start at 9 pm, while others may have charged in the morning of the following day.

Average impacts by building type, season, and pilot period are presented in Table 2, below. All impacts were directionally consistent with expectations (increases in demand during off-peak periods, reductions in demand during on-peak periods). However, MURB participants showed a much greater response to pricing during off-peak weekdays, with an average increase in demand of 0.18 kW (62% of baseline demand) compared to just 0.03 kW for SFH participants in the same period (10% of baseline demand).

Table 2 - Average Pilot Period Impacts. (Source: Generac interval data, Guidehouse analysis.)

Building Type	Day Type	Pilot Period	Average Impact (kW / EVSE)	Baseline	Percent Savings	Standard Error	Relative Precision
MURB	Weekday	On-Peak	-0.37	0.44	83%	0.09	39%
		Off-Peak	0.18	0.30	-62%	0.09	78%
	Weekend/ Holiday	Off-Peak	0.05	0.44	-11%	0.13	451%
SFH	Weekday	On-Peak	-0.08	0.09	88%	0.06	122%
		Off-Peak	0.03	0.34	-10%	0.06	304%
	Weekend/ Holiday	Off-Peak	0.05	0.33	-15%	0.09	300%

In general, the evaluation team was inclined for this evaluation to interpret most statistically non-significant results as indicating that the result is present, but highly uncertain. As mentioned in the evaluation plan, uncertain estimates are an expected outcome of this evaluation given the small sample size (<15 EVSE in each group), nature of the estimation approach, and granularity of the baseline. Moreover, survey results corroborated the finding that results were present for both MURB and SFH participants – participants at both building types reported shifting charging behaviour in response to the pilot.

Regardless of statistical significance. as anticipated, the pilot did significantly impact vehicle charging, shifting almost all demand from the on-peak period to other times of day.

Impact Evaluation Results (Peak Demand Management)

Average kW impacts were estimated for PDM events to which MURB Group 1 participants were subject, by pilot period (on-peak, off-peak). As with DR events, these impacts were derived from an event-specific baseline derived from each EVSE's charging behaviour during the pilot period, i.e., these impacts were incremental to existing vehicle response to the pilot on-peak pricing. Given the large number of PDM events that occurred, results were not reported on a per event basis.

During on-peak periods, there was virtually no impact at Building A and Building B, driven by low EVSE usage during on-peak periods. Estimated impacts at Building C were larger, 0.16 kW per EVSE. This impact is relatively uncertain given only a single event took place during the on-peak period at Building C. During off-peak periods, average impacts were highest magnitude at Building B and Building D, representing savings of 0.7 kW and 0.88 KW per EVSE, respectively.

At Building A, Guidehouse estimated demand savings of 0.12 kW per EVSE, slightly higher than the 0.09 kW in savings estimated for the EVSE at Building C.

Figure 9 presents the average PDM impacts. Given the low frequency of events at the Building C and Building D sites, impacts are highly uncertain and should be interpreted with caution. Events were more frequent at Building A and Building B, but no estimates are statistically significant at the 90% confidence level.

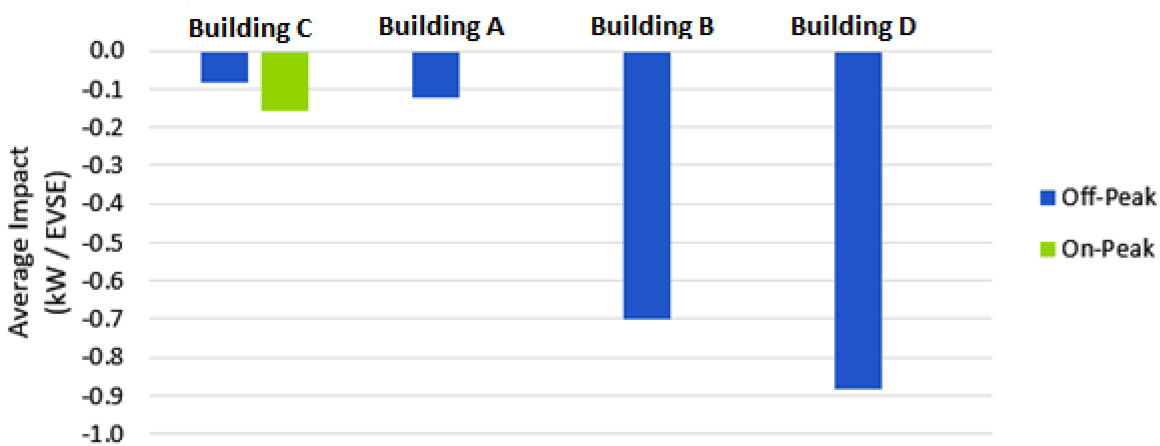

Figure 9 – Avg. PDM impacts by pilot period and building. (Source: Generac data, Guidehouse analysis.)

Despite relatively uncertain point estimates, the consistency of results across sites suggests estimated impacts represented real demand savings achieved by PDM. On average, PDM delivered modest but clear demand reductions during off-peak periods. PDM also appeared to have delivered on-peak demand reductions, but impacts were low and highly uncertain. Low impacts during the on-peak period were likely a result of the response to pricing treatment. Since EVSE were rarely in use during the on-peak periods, this reduced the ability of PDM to deliver savings in that window.

Impacts by IESO Cost-Effectiveness Period and Avoided Cost Benefits of EV Charging Response

In Ontario, the provincial benefits of energy efficiency (also known as conservation and demand management, or CDM) are measured using the estimated value of avoided generation costs. Unit values of avoided costs are published by the Independent Electricity System Operator (IESO) as part of that organization’s Cost-Effectiveness Tool. Avoided energy costs are provided by year, for eight different time periods. These are identified in the table below, drawn directly from the IESO’s Cost Effectiveness Guide (see reference below in Figure 10).

TOU Period	Winter	Summer	Shoulder
On-Peak	0700 – 1100 and 1700 – 2000 weekdays (602 Hours)	1100 – 1700 weekdays (522 hours)	None
Mid-Peak	1100 – 1700 and 2000 – 2200 weekdays (688 hours)	0700 – 1100 and 1700 – 2200 weekdays (783 hours)	0700 – 2200 weekdays (1,305 hours)
Off-Peak	0000 – 0700 and 2200 – 2400 weekdays; All hours weekends and holidays (1,614 hours)	0000 – 0700 and 2200 – 2400 weekdays; All hours weekends and holidays (1,623 hours)	0000 – 0700 and 2200 – 2400 weekdays; All hours weekends and holidays (1,623 hours)

Figure 10 – IESO avoided cost TOU periods. (Source: IESO).

The estimated impacts of pricing by IESO TOU period were presented in Table 3 below. As previously, impacts were presented as average kW and average percent of baseline impacts and are accompanied by an estimate of the relative precision. Estimated energy impacts were applied to the average number of hours per TOU period in a calendar year to calculate average annual energy savings by TOU period.

Table 3 – Avg. impacts by IESO avoided cost TOU period. (Source: Generac interval data, Guidehouse analysis.)

Season	Day Type	Cost Period	Average kW Impact	Relative Precision (+/- % at 90% Confidence)	Average % Savings	Energy Impact (kWh/EVSE/year)
Summer	Non-Holiday Weekday	On-Peak	-0.06	185%	60%	-34
		Mid-Peak	-0.02	500%	17%	-19
		Off-Peak	0.05	289%	-14%	86
	Weekend/Holiday	Off-Peak	-0.06	176%	51%	-84
Shoulder	Non-Holiday Weekday	Mid-Peak	0.05	285%	-14%	87
		Off-Peak	-0.08	154%	46%	-45
	Weekend/Holiday	Off-Peak	-0.07	163%	65%	-49
Winter	Non-Holiday Weekday	On-Peak	0.02	792%	-5%	33
		Mid-Peak	-0.06	185%	60%	-34
		Off-Peak	-0.02	500%	17%	-19
	Weekend/Holiday	Off-Peak	0.05	289%	-14%	86

Avoided generation capacity costs were also provided. The IESO cost-effectiveness tool assumed some value for avoided transmission and distribution capacity costs through 2018 but assigns these benefits a $0 value in subsequent years. Guidehouse applied these costs to the average combined impact of pricing and DR, weighted based on the number of historical 5CP occurring in each hour. The IESO cost effectiveness guide defined the peak demand reduction period as 1 pm to 7 pm during June, July, and August. Guidehouse used the IESO defined costs because they provided the best publicly available estimate of benefits but included all hours in which pricing and DR were in effect.

Table 4 - Avg. peak demand impact. (Source: Generac interval data, Guidehouse analysis.)

Hour Ending	Percent of 5CP in Hour	Average DR Impact (kW / EVSE)	Average Pricing Impact (kW / EVSE)	Weighted Average (kW / EVSE)
14	0%	-	-0.07	0.00
15	10%	-	-0.10	-0.01
16	5%	-	-0.11	-0.01
17	5%	-	-0.11	-0.01
18	52%	-0.02	-0.20	-0.11
19	19%	-0.03	-0.28	-0.06
20	0%	-0.02	-0.33	0.00
21	5%	-0.03	-0.30	-0.02
23	0%	-0.70	-	0.00
24	0%	-0.78	-	0.00
Total:				**-0.21**

The average demand savings from DR and pricing may be applied to the annual avoided capacity costs to deliver an estimate of generation capacity benefits. The product of the energy benefits in Table 4 and the IESO avoided cost in each period delivered generation energy benefits. Guidehouse combined these benefits and calculated the net present value. For the purposes of this analysis, Guidehouse has assumed a "measure lifetime" of 7 years, a social discount rate of 4%, and that the first year of savings was 2023. Applying these estimated impacts and other assumed values **delivered a lifetime avoided cost benefit of EV charging behaviour changes from the program of approximately $113 ($2021) per EV**. This value did not include any estimated value associated with deferred distribution or transmission capacity upgrades, and, as noted above substantially understated its likely value as a resource for providing provincial coincident peak capacity.

EVSE Utilization & Curtailment Capability

Pricing was effective at shifting EV loads in a block. Simple TOU-style pricing and the availability of vehicle charging scheduling options to drivers resulted in convergent migration of charging profiles to periods of lowest cost (typically periods in which demand imposes the lowest system costs). As EV adoption grows, event-based solutions such as DR may be required to manage load if EV adoption is sufficiently pronounced that the rate-driven load migration defines a new local or system peak that cannot be easily addressed through an appropriate adjustment of the price signal.

It is highly uncertain, however, at what point simply allowing pricing to push EV loads off-peak is insufficient and managed charging is required. Assuming that all EVSE are being exercised at their maximum delivery capacity simultaneously delivers very large estimates of EV-driven peak demand. Such estimates are often used in strategic discussions of energy transition concerns. The reality is that EV loads are temporally diverse, even within their least expensive pricing windows. Planning exercises based on projected EV (and especially level 2 EVSE) adoption must de-rate peak EVSE delivery capability values or risk over-investing in infrastructure.

Process Evaluation Methods & Findings

The Guidehouse team employed a comprehensive process evaluation methodology, analyzing different facets of the program to gauge its effectiveness and impact. This approach ensured a holistic understanding of the program's operations, participant engagement, and overall outcomes.

- **Program Materials Review.** Guidehouse conducted a document review, reviewing a range of materials utilized by the pilot. This included educational content, email outreach communications, and promotional materials. This step was crucial in understanding the informational context and outreach strategies employed, providing insights into how participants perceived and interacted with the program.

- **Program Staff Interviews.** Guidehouse interviewed four staff members involved in the pilot, including program implementers, between August and September 2023. These interactions helped delineate the program's internal workings and staff perspectives on its execution.

- **MURB Interview Analysis.** Alectra undertook a series of interviews with MURB participants in September and October 2023, which was analyzed by Guidehouse. The notes from these discussions provided nuanced, insight into participant experiences.

- **Participant Survey and Analysis.** Guidehouse reviewed surveys disseminated by Alectra to pilot participants at different stages of the pilot. These included a baseline survey (February 2023), an interim survey (June 2023), and a concluding survey (September 2023), encompassing feedback from 12 MURB and 16 SFH participants. These surveys captured the evolving perceptions and attitudes of participants throughout the pilot.

The process evaluation team compared its findings against the impact evaluation results, cross-verifying them with the qualitative data from the interviews and surveys. This approach ensured consistency and validity in our findings.

Effectiveness of Models (Process Evaluation)

Across the surveys with MURBs and SFHs, there were a few key similarities and differences. Both MURB and SFH participants indicated high levels of satisfaction with the program's overall management, the reliability of the charging technology, and the clarity of communications they received. A notable difference lay in the complexity of installations and ongoing management of

EV charging in MURBs, requiring more robust communication strategies and coordination with property management.
In contrast, SFH participants enjoyed more straightforward experiences. Both groups shared concerns about the pricing structures and would prefer to avoid paying the premium during peak periods. However, there was a general openness to participating in future initiatives, especially those offering financial incentives.

There were four main differences between the groups.

Table 5 – Key differences in EV installation between SFHs and MURBs. (Source: Guidehouse Analysis of Survey and Interview data.)

Topic	SFH	MURB
Installation Logistics	**SFH installations were typically more straightforward** because they usually involve a single homeowner's decision and direct coordination with the installers. There was no need to negotiate with multiple stakeholders, making the process quicker and more efficient. Homeowners had greater freedom in choosing the location of the chargers, and there were fewer restrictions concerning electrical capacity and parking arrangements.	**MURBs faced more complex logistics**, requiring coordination with property management, condo boards, and potentially other residents. The installation must often accommodate multiple vehicles. The process can be slower due to the need for approvals and potential electrical upgrades to support the additional load, especially in larger MURBs. Parking arrangements can also be more complex, requiring designated spaces for EV charging.
Ongoing Management	**Homeowners had direct control over their EV charging stations,** with little need for ongoing coordination with third parties. This autonomy can lead to higher satisfaction rates and less administrative overhead. However, the homeowner was solely responsible for maintenance and any required troubleshooting.	**MURBs required a more structured management approach** to ensure fair access to charging stations, handle maintenance, and resolve any user disputes. This may have involved scheduling systems, communication protocols, and designated personnel to manage the EV charging program. While more complex, this structured approach was necessary to maintain order and satisfaction among multiple residents.

Topic	SFH	MURB
User Satisfaction	**SFH participants often reported high satisfaction,** likely due to the ease of installation and autonomy over charging systems. They were able to manage their charging schedules, maintenance, and any upgrades directly, with no need to coordinate with neighbors or management entities.	**Satisfaction levels in MURBs did vary significantly**, influenced by factors like charging station availability, ease of access, and property management communication effectiveness. Successful MURB installations featured clear guidelines, robust support, and effective communication channels, enhancing resident satisfaction.
Feasibility and Cost-Effectiveness	**SFH participants reported a positive experience**, citing the ease of installation and management of charging times. They appreciated the reliability of the hardware and the clarity of program communications. Like MURB participants, the reaction to rate changes was mixed, with some participants expressing caution about increased costs during specific periods.	**Many MURB respondents appreciated the program but indicated a perceived need for more accessible charging solutions within their living arrangements.** While some MURB participants noted the program was "game-changer" for EV drivers in condos, others expressed desires for the program's extension or expansion. The introduction of new rates, especially the Ultra-Low Overnight (ULO) rate, was met with interest, though some participants were still evaluating its value for their specific situations

Regulatory Barriers and Solutions

The pilot highlighted several complex challenges in retrofitting EVSE into existing MURBs. This was primarily due to logistical hurdles such as the strategic placement near designated parking spaces, the augmentation of power supply in locations where existing infrastructure was insufficient, and the establishment of reliable Wi-Fi connectivity in subterranean garages, which was essential for the operation of the EVSE use-cases and pricing.

It was challenging for MURB managers to provide pilot participants charging station access near their allotted parking spot or provide reliable access to a shared spot to charge their EV. Navigating the regulatory landscape to address these challenges was nontrivial. While electrical codes serve as non-negotiable safety standards, there was latitude for policy innovation in other areas to help MURB managers mitigate these barriers.

For example, providing additional financial incentives would have helped MURBs afford the costs necessary to upgrade electrical systems when installing multiple EV charging stations. More proactive measures like advocating for building code policies that mandate the inclusion of EV charging facilities in new building designs would help reduce those expensive future retrofit costs in the longer term.

MURB Technical Issues

While interview data shared generally positive feedback regarding the pilot, MURBs faced some unique challenges. Addressing these pain points may help to improve delivery for future scaled programs.

Table 6 - Technical issues for MURB participants. (Source: Guidehouse Analysis of survey and interview data

Technical Challenge for Participation	Details
Connectivity Issues	Participants noted internet connectivity variations, especially in underground garages, as sometimes experiencing less consistent connections. This made it challenging for consumers to respond to price signals by program their EV remotely to avoid charging in the on-peak period. This influenced the ease of ongoing pilot participation.
Hardware Challenges	Participants encountered instances of device malfunctions or interactions with existing infrastructure that required additional troubleshooting. These occurrences were part of the pilot's technological adaptation phase and influenced various activities and engagement levels.
Navigating New and Intricate Software	Feedback included mentions of challenges navigating the software platforms, from encountering unexpected bugs to adapting to user interface (UI) designs. These learning opportunities were part of familiarizing with the digital tools provided and occasionally influenced the smoothness of user experience.
Accessing Technical Support	Access to technical support was a highlighted aspect, with suggestions for enhancing the responsiveness of this service. Timely assistance was identified as a key factor in maintaining steady program engagement and effectively addressing participant queries or concerns.
Security Awareness	Awareness of digital security within online platforms was evident, with participants mindful of data privacy and unauthorized access risks. Ensuring a secure digital experience was important for maintaining confidence in the program's technological aspects.
Resource Utilization Guidance	There was desire for more comprehensive guidance or training to fully leverage the program's technological resources and tools. Enhanced educational support could further empower participants to maximize the benefits and functionalities offered.

Ensuring EVSE installations were compliant with building and electrical codes was costly and logistically challenging. Alectra should therefore focus on enhancing its "soft services" like outreach and communication to encourage more participation, or by being more proactive: advocating for policies that require installation of EV chargers during the development of

MURBs (rather than as an afterthought when it would have to be retrofitted, as was the case during this pilot).

Table 7 highlights these key recommendations to encourage MURB participation.

Table 7 - Key recommendations to increase MURB participation. (Source: Guidehouse analysis of survey data.)

Category	Key Recommendations
Address Financial Constraints	**Offer Financial Incentives:** Many MURB participants cited budget constraints has a primary concern. Therefore, providing financial incentives such as discounts, rebates, or financing options could encourage participation. This could be facilitated by pursuing grants and funding for installations.
	Demonstrate ROI: Create clear case studies showing the return on investment (ROI) from program participation, emphasizing long-term savings and value.
Resolve Technical Issues	**Ensure Connectivity:** Wi-Fi connectivity is vital for EVs as it enables smart charging management, allowing EVs to charge during off-peak hours enabling remote monitoring and control of the charging process, enhancing user convenience and grid management. Ensuring this connectivity in MURBs (in basement parking garages) will be crucial for allowing those drivers to participate in managed charging.
	Provide Technical Support: Establish a robust technical support system to assist participants with any issues they encounter, ensuring quick and effective resolutions.
	Simplify Technology: If participants faced difficulties with the technology, consider simplifying or offering alternative, more user-friendly solutions.
	Work with new and upcoming condos to integrate EV infrastructure in planning phase: To avoid the retrofit complications from MURB physical and electrical infrastructure, and to ensure that EV infrastructure is available and integrated into new buildings, partner with designers and contractors during project planning.
Enhance Communication and Outreach	**Tailored Communication:** Communicate program benefits and procedures clearly and effectively. Tailor your message to address the specific needs and concerns of MURB managers or owners.
	Engage Community Leaders: Use MURB community leaders to advocate for the program, as they can relate better to residents and provide more personalized encouragement.
Offer Customization and Flexibility	**Flexible Options:** Recognize that one size doesn't fit all. Offer options that cater to different budgets, preferences, and building capacities.
	Custom Solutions: Provide opportunity for MURBs to have a say in the program's specifics, ensuring it fits their needs and constraints.
Provide Education and Training	**Workshops and Seminars:** Organize educational sessions to inform participants about the importance and benefits of the program and train them on any technical aspects.

Category	Key Recommendations
	Resource Materials: Offer guides, FAQs, and other resources that participants can refer to at any time. Focus on providing easily understood information to an audience with limited to no technical understanding.
Build Trust with Transparency	**Share Success Stories:** Highlight successful case studies from other MURBs that have benefited from the program.
	Transparent Processes: Be clear about costs, expectations, processes, and the support available, so there are no surprises.
Streamline the Participation Process	**Simplify Enrollment:** Make it easy to join the program, with minimal paperwork and red tape.
	Dedicated Support Team: Have a team ready to help new participants through the enrollment process and any initial hurdles.
Feedback Loop	**Regular Surveys:** Continue to gather feedback to understand ongoing challenges and successes participants are experiencing.
	Adapt and Improve: Show that you are listening by adapting the program based on the feedback received.

Based on the interview responses from various MURB participants involved in the pilot, several insights emerged regarding best practices, successful approaches, and strategies for effective communication and collaboration with condo boards and property managers. Guidehouse synthesized three practices to encourage MURB participation:

- **Inclusive Decision-Making:** Engaging all stakeholders, including tenants, owners, and board members, in the decision-making process was crucial. This approach ensured broad support and facilitated smoother implementation. Participants who were decision-makers or had a significant influence, such as property managers and board members, played a pivotal role in advancing these initiatives.

- **Proactive Communication:** Effective communication strategies, including distributing notices and holding informative meetings, were essential in promoting the EV charging programs. These efforts helped in addressing misinformation, setting expectations, and enhancing the acceptance of the program.

- **Leveraging Incentives:** Financial incentives or support programs, such as those offered by the pilot, were significant motivators. They not only made participation financially attractive but also encouraged stakeholders by offsetting some installation costs and adding perceived value to the property.

Through our analysis of interview responses and survey data, Guidehouse identified success stories of addressing the program implementation and any challenges. Those successful approaches included:

- **Collaborative Planning:** Successful implementations were often those where there was close collaboration between the property management, condo board, and service providers. This collaboration was particularly important during the installation phase, addressing technical or regulatory hurdles, and ensuring the solutions met specific building requirements.

- **Addressing Technical Challenges:** Buildings that anticipated and effectively managed technical barriers, such as internet connectivity for chargers or electrical infrastructure limitations, avoided delays and ensured a better experience for end-users.

- **Regulatory Navigation:** Understanding and navigating through regulatory requirements, including zoning, permitting, and building codes, were critical factors in the timely and compliant installation of EV charging stations.

To enable effective communication and collaboration with MURBS, Guidehouse identified the following three best practices:

- **Transparency:** Open lines of communication between the board members, property managers, and residents helped in pre-empting opposition, especially concerning changes in common spaces or alterations affecting individual units.

- **Education and Information Sharing:** Providing clear and accessible information helped alleviate concerns from residents. This strategy was particularly effective in countering misinformation regarding safety or financial implications.

- **Responsive Feedback Mechanisms:** Establishing a system for addressing feedback, both positive and negative, contributed to the program's success. This approach included dealing with technical issues promptly and having clear protocols for residents to report problems or concerns.

Considering the challenges in navigating condo boards and property managers, the following activities would be necessary in scaled projects:

- **Building Consensus:** For initiatives requiring collective agreement, such as MURB by-law changes, successful strategies involved early board member engagement and comprehensive information dissemination to build consensus.

- **Facilitating External Engagements:** Some participants found value in external engagements, such as consultations with installation experts or interactions with other condos that had successfully implemented similar programs. These engagements provided valuable insights and reassured stakeholders.

- **Managing Expectations:** It was important to set realistic timelines and be transparent about potential disruptions during installation. Effective communication about the scope, benefits, and procedural aspects of the program helped in managing expectations and reducing dissatisfaction or resistance.

Value of the Program and Participation

Several MURB respondents expressed satisfaction with the program, noting it as a "game changer" and appreciating the ease of charging at home. As noted earlier in this report, 82% of respondents indicated they were satisfied with the value for their money. MURB respondents also highlighted the importance of having management with forward-thinking goals.

Concerns were raised about the need for better internet connectivity especially in underground parking areas, the desire for the special program rates to be made permanent, and access to EV charging stations (in MURBs where there wasn't 1:1 EV to charger ratios). These points suggested that ongoing costs and the permanence of favourable rates are significant factors in customer decisions.

Some SFH respondents mentioned the importance of clear communication and the need for earlier notice about charging events, which points to the value placed on transparency and predictability in program participation. MURB and SFH respondents appreciated the charging experience reliability and Alectra's clear communications. However, there were suggestions for improvements, such as better explanations at the start of the program and more responsive support.

Overall, the survey results reflect a general willingness to engage with EV charging programs, particularly when they are accompanied by clear benefits, such as convenience and cost savings. However, the data also highlights the need for programs to address potential barriers, such as technical issues and the need for better communication and support.

Program Improvement Recommendations

The recommendations presented below are designed to enhance future EV program operational frameworks, participant engagement, and overall impact. By addressing the financial, technical, and educational aspects of the program, and advocating for forward-thinking policy changes, Alectra can ensure a more scalable transition to sustainable electric transportation solutions for both SFH and MURB residents. Further research should be conducted to monitor the long-term effectiveness of these recommendations and to explore their applicability to other regions and programs. Please see Table 7: Key Recommendations to Increase MURB Participation for an exhaustive list of key improvement recommendations.

- **Financial Accessibility and Incentivization**
    - A recurrent theme across participant feedback was the financial barrier to entry. A robust incentive framework would support continued expansion of MURB installations. This could include targeted discounts, rebates, and flexible financing options, all designed to lower the participation threshold. Additionally, by presenting clear, demonstrable case studies articulating the ROI, Alectra can reinforce the program's value proposition and long-term economic advantages. Perhaps these financial incentives can also be achieved through securing grants, rebates, or subsidies that target MURBs to enable more economic options.

- **Advocate for Regulatory Changes to Building Code**
    - Technical challenges, particularly retrofitting EV charging stations within existing MURB infrastructures, have been a notable concern. To address this, Alectra should consider advocating for policies to mandate that EV-ready electric systems be included in the construction of new MURBs.

- **Community Engagement and Educational Resources**

- The evaluation underscores the necessity for communication strategies that are tailored to the needs of MURB stakeholders. To facilitate this, improved community engagement and educational resources will be crucial.
- Engaging with community leaders and leveraging their influence can enhance program advocacy, driving deeper engagement and participation. For SFHs, where decision-making is typically less complex, maintaining clear and consistent communication channels will continue to be essential for program transparency and participant satisfaction.
- To empower participants with the knowledge and skills required to navigate the program, Guidehouse recommends that Alectra consider developing educational resources that are accessible and easily understood by a non-technical audience. These could include user-friendly guides and FAQs, or short instructional videos designed to support both SFH and MURB participants. To adapt resources that will be understood by customers, Alectra should consider using focus groups to probe for preferred modalities of accessing information. This approach will facilitate a better understanding of the program's benefits and ensure that participants are well-equipped to leverage the technology effectively.

- **Streamlining Enrollment and Support**
  - The enrollment process should be as frictionless as possible. Alectra should consider ways of simplifying the enrollment process to minimize administrative effort. A full deployment of the program to Alectra’s service territory would benefit from a dedicated support team, tasked with guiding potential participants through the initial program stages and addressing preliminary concerns. MURB stakeholder interviews demonstrated the importance of focusing enrollment with the MURB management rather than with tenants who would need to work through MURB leadership to have a charger installed.
  - This further underscores the idea that working with MURBs *before* construction, rather than retrofitting EVSE to the MURB would reduce costs and administrative overhead. Pre-construction engagement would ensure that EV Charging stations meet electrical, zoning and building codes, are more likely to be situated in areas that are more useful for tenants, and is coordinated by the MURB leadership, thereby making the enrollment and setup as seamless as possible for prospective customers.

- **Feedback Mechanisms and Continuous Improvement**
  - A structured feedback mechanism is vital for capturing participant’s evolving needs and experiences. Regular surveys and feedback channels should be instituted, with the dual aim of gauging participant sentiment and identifying areas for programmatic refinement. Demonstrating adaptability by evolving the program in response to this feedback will be critical to its ongoing success.

Summary of Process Evaluation Results

Process evaluation findings aligned with those of the impact evaluation; survey respondents stated that adjustments in pricing would drive their charging habits. Other key process findings include:

- **Unlocking Potential.** MURB drivers referred to being provided access to EVSE in parking as a "game-changer". Although these (and SFH) drivers expressed dissatisfaction with time-varied pricing, price response (as documented by the impact evaluation) was very strong, exceeding pilot expectations.

- **MURB Barriers.** It is more costly and more challenging to implement managed charging in MURBs than in SFHs. This has impacts on customer satisfaction and perceived value, with MURB drivers generally less positive than SFH drivers.

- **Technology Development and Support.** Device malfunctions, problems with inter-operability across platforms and coordination across vendors impacted the perceived value and customer satisfaction; for example, Wi-Fi connectivity problems due to EVSE installation locations appears to have constrained MURB driver price response and program satisfaction.

- **Communication is King.** Participants and stakeholders indicated a high level of satisfaction with the degree of consultation, communication, and transparency provided by Alectra. Expanding the pilot to a wider deployment will challenge the delivery team. To build on the pilot's success and manage the costs of communication and education, Alectra will require a communications strategy that is structured for scale, but one that provides the team with the flexibility to address client-specific challenges as they arise.

Table 8 shows which motivators most influenced MURB and SFH participants.

For each motivator, responses for each group were analyzed in two categories: motivated versus least motivated. The strongest motivators for charging behaviour (75% of respondents or higher) are highlighted in bright green cells, and least important motivators (75% of respondents or higher) in pink cells.

Table 8 shows that monetary incentives are the strongest motivators for both MURBs and SFH. The least important motivators were social incentives such as comparing charging behaviour with peers and reducing environmental impacts.

Table 8 - Charging Behaviour Motivations. (Source: Guidehouse analysis of survey data.)

Question: To what extent would the following motivate you to change your current charging behaviour? Please rank the below from most motivated […] to least motivated […]

		MURB		SFH	
Motivator	Type of Motivation	Most Motivated	Least Motivated	Most Motivated	Least Motivated
Knowing that my changes would enable the grid to better support more EVs	Social / Environmental	64%	36%	69%	31%
Knowing that my changes would help enable more EV charging infrastructure	Social / Environmental	55%	45%	31%	69%
Changes to Alectra's Time of Use electricity rates that charge less for charging overnight, for example.	Financial	73%	27%	81%	19%
Monthly monetary incentives to charge my EV at certain times of day	Financial	73%	27%	81%	19%
Monthly monetary incentives to avoid charging my EV at certain times of day	Financial	82%	18%	87%	13%
Comparison of my electricity use with others in my community	Social / Environmental	9%	91%	0%	100%
Reduction in environmental impacts	Social / Environmental	18%	82%	25%	75%
Lower electricity charges for everyone	Social / Environmental	27%	73%	25%	75%

The program demonstrated the potential for sustainability and scalability. Sustainability is closely tied to the program's ability to present an attractive value proposition to customers, to continue to influence consumer behaviour. The introduction of financial incentives and a technical support framework has proven effective and will remain integral as the program expands. Additionally, the program's focus on education has laid a foundation for sustained participant engagement and informed decision-making.

The feasibility of scaling up the pilot may depend on the evolution of EV policy within the relevant regulatory bodies, and the support these provide for EV adoption. For instance, as and when building codes grow to encourage or require the inclusion of EV charging infrastructure in new MURB developments, the opportunity and potential for applying the pilot design to manage distribution system costs will grow.

Conclusions and Recommendations

The evaluation identified several findings that carry implications for the future of EV infrastructure installation in both SFHs and MURBs. Notably, the pilot illuminated the important role of pricing structures to influence participant behaviours. Survey respondents stated that adjustments in pricing would drive their charging habits, with a marked shift to prioritize charging during off-peak hours. This behavioural adaptation has important ramifications for managing peak demand and ensuring the stability of the electrical grid as EV adoption escalates.
The most material conclusions of Guidehouse's evaluation of the Group 1 component of the "@Home" EV Rewards program are:

1. **EV drivers' charging behaviours were highly price-elastic.**
    a. Pilot participants reduced EV charging demand by over 80% during the on-peak period (1 pm-9 pm on non-holiday weekdays). This was the period in which the price of EV charging increased – participants were subject to a fee of $2 - $4 per hour (depending on building type) to charge their vehicle during this time, incremental to the cost of electricity.
    b. MURB and SFH participants were more motivated by financial incentives than environmental or social incentives to change charging behaviour. Most SFH (87%) and MURB (82%) participants reported that monetary incentives to avoid charging their EV at certain times of day would affect their behaviour.
    c. This finding was consistent with the Group 2 evaluation, as well as recent professional literature, including the work recently conducted by the Ontario Energy Board (OEB) that resulted in the development of the new ULO voluntary RPP TOU rate that became available to RPP consumers as of May 1, 2023.

2. **DR events were an effective mechanism for reducing load during periods *when pricing is not in place*. Reliable Wi-Fi connectivity was essential for ensuring efficacy.** During DR events that did not overlap with the on-peak pricing period, MURB and SFH participants reduced demand by an average of -0.92 kW and -0.65 kW per EVSE, respectively. DR events consistently delivered meaningful demand reductions, typically over 70% of estimated baseline demand. However, for events overlapping with the on-peak period from 5 pm – 9 pm, demand reductions were close to zero for all participants due to low baseline demand, due to the pricing response.

3. **Managed charging in MURBs faced many logistical challenges.** Wi-Fi connectivity was essential for EVs and charging stations to participate in DR programs and ensure its efficacy. MURB sub-terranean parking garages presented challenges in accessing Wi-Fi and may have prevented drivers from remotely managing charging schedules, which was critical when charging is disrupted by DR events. The Alectra program team experienced challenges with some pilot implementations (e.g., PDM dispatch, pricing applied to drivers, etc.) and drivers themselves encountered device malfunctions or other hardware problems that impacted engagement.

4. **PDM events delivered modest demand reductions but may not be an effective tool for materially reducing non-coincident peak load for a building or delivering value for the distributor.**
    a. PDM events delivered modest demand reductions, with projected ex-ante non-coincident peak demand impacts of less than 0.15% of peak building load. Even if a customer specific non-coincident peak demand reduction is achieved, this delivers value only if a customer's demand is coincident with the peak demand experienced by the distribution asset that serves it.
    b. PDM dispatch does not guarantee a MURBs monthly demand charge will be reduced. Customers' peak demand is a highly dynamic and volatile moving target, and EV loads are generally a small component of peak load.

As of December 2022, the OEB has amended the Standard Supply Service Code and RPP to allow RPP consumers the option to enroll the RPP ULO TOU price plan as of May 1, 2023. This new price plan, if adopted by individual EV owners, provides a substantial incentive to drivers to shift their charging behaviours even further away from existing patterns than did this pilot.

Given these findings, Guidehouse recommends current and future programs consider the following:

- **Focus on Pricing:** Pricing is very effective at shifting EV charging loads. Pricing leaves control in the hands of drivers (several drivers referenced concern about allowing Alectra direct control over their charging). When pricing reflects upstream costs, drivers will make decisions that efficiently balance their preferences with system costs. Alectra may wish to consider (in future implementations) allowing individual MURBs to define their own on-peak period to control their building specific demand and wholesale electricity costs more effectively.

- **Continue to Test Active EV Managed Charging.** Pricing is effective at shifting EV loads as a group, but if EV adoption grows to the point that EV loads define local peaks additional solutions will be required to manage distribution and bulk energy system costs. As shown by this pilot, and others, active EV charging is a much more complex implementation than (e.g.,) A/C direct load control due to the proliferation in control avenues (OEM telematics, EVSE, third-party devices) and major and on-going interoperability challenges. However, solutions such as DR offer predictable and consistent demand reductions when properly implemented. Continued testing of different ways to dispatch EV loads will allow Alectra to refine and develop the technology into a satisfactory non-wires solution for use on its network and others.

- **Promote Pricing Models that Emphasize Money Savings:** Pilot participants reported their charging behaviour is more motivated by financial *incentives* than *disincentives*. More than half of MURB participants reported that they are "Uncomfortable" or "Very uncomfortable" with being charged a higher rate in the peak charging model. Off-peak benefits should be promoted and messaging the consequential increased on-peak costs should be refined with the assistance of market research professionals.

- **Tailored Communication and Technical Support:** Alectra's communications must cater to the diversity in customer comprehension of EV technologies and time-varied pricing. For example, participants reported the most successful MURB installations featured clear guidelines, robust support, and effective communication channels, enhancing resident satisfaction. For instance, one MURB respondent appreciated the "Process [was] explained clearly step by step. Even when there were hurdles in the process, Alectra was flexible in pivoting to other solutions to continue the process of getting the charging hubs to reality. (I can think of other organizations that would have ground to a halt or abandon altogether." SFH and MURB tenants cited the importance of emails, clear instructions, and direct contact with Alectra. Adopting a tailored communication strategy will enhance customer satisfaction, streamline service delivery, and foster an informed, engaged community, leading to efficient query resolution and improved customer interaction.

- **Feedback Integration**: Considering the transition from pilot to program, Alectra should continue to provide an ongoing mechanism for collecting EV driver feedback to refine and adapt its offerings to support cost-effective EV adoption. This feedback is crucial for maintaining understanding and buy-in, can help in identifying unforeseen issues, and offer continued program improvement opportunities. Alectra should consider providing participants opportunities to provide feedback through surveys, focus groups, and interviews to capture greater insights. To encourage participation, consider offering small incentives (especially when there is apathy or reluctance to engage) to acknowledge the effort and time that was given by customers who provide feedback. Models that promote immediate rewards (digital gift card upon completion of survey or focus group discussion) may be most effective for encouraging feedback.

- **Engage with MURB Management During Pre-Construction Design Phases; Advocate for Policy Supportive of EV Infrastructure in all New Builds:** Findings from the process evaluation underscored the challenges of retrofitting EV charging stations into existing infrastructure, especially in MURBs. Policies that result in the installation of charging stations during the construction phase of MURBs would provide Alectra, EV drivers, and MURBs with more efficient, cost-effective, and conveniently located charging stations.

RESPONSES TO DISTRIBUTED RESOURCE COALITION INTERROGATORIES

INTERROGATORY 1-DRC-6

Reference: • Exhibit 1, Tab 7, Schedule 1

Preamble: Alectra's SEW Customer Engagement - eMobility Pilot is designed to support residential customers considering EV adoption by offering targeted tools, information, and engagement around load management.

a) Please provide any and all working papers, reports, and analysis conducted on or in support of the eMobility Pilot.

b) Please provide a detailed description of the managed charging pilot (SmartCharge).

c) Please explain how the SmartCharge pilot differs from AlectraDrive@Home and AlectraDrive@Work, and identify what incremental learning objectives this pilot is intended to address.

d) Please explain how Alectra defines and measures "avoided" or "deferred" customer service upgrades within the eMobility Pilot.

e) Please describe the quantitative metrics being tracked to assess grid impacts from the eMobility Pilot (peak demand reduction, load shifting by time period, etc.).

f) Please describe the two recruitment approaches being tested and how differences in recruitment outcomes (participation, retention, satisfaction) will be translated into scalable program design assumptions, including expected participation rates for future managed charging or EV flexibility programs.

g) Please identify which eMobility Pilot functionalities are proposed for integration into the customer experience platform.

h) Please confirm whether Alectra will file the final evaluation results of the eMobility Pilot with the OEB.

RESPONSE:

a) Alectra respectfully notes that this interrogatory is overly broad and would require the disclosure of internal working documents that are not relevant to the determination of this proceeding. The key material and relevant information regarding the eMobility Pilot Project has been provided in the attached project charter in 1-DRC 6_Attachment 1_Charter SEW eMobility.

b) The SmartCharge pilot is a limited-scope residential managed charging initiative designed to assess the feasibility and customer acceptance of electric vehicle charging load management. The pilot is available to up to 50 residential Alectra Utilities customers who own an electric vehicle.

Participating customers are provided with a connected Level 2 EV charger, with charger capacity options of 32A, 48A, or 80A, subject to customer requirements and site conditions. Participants are required to download and use an Alectra-provided mobile application, which enables charger connectivity, visibility of charging activity, and participation in managed charging events.

The pilot evaluates managed charging as a form of demand-side load management by temporarily reducing EV charging load during periods of system demand. During a managed charging event, the charging power of participating chargers may be reduced by up to 75%, allowing charging to continue at a reduced rate. Managed charging events are limited to no more than two events per week, with each event lasting no more than four hours.

Participation in managed charging events is voluntary. Customers may opt out of individual events through the mobile application. Participants are notified in advance of scheduled events through email and or push notifications delivered via the eMobility application.

The SmartCharge pilot is intended to inform Alectra Utilities' understanding of customer response and operational considerations associated with managed EV charging as a load management tool.

c) The SmartCharge pilot builds on earlier learnings from AlectraDrive@Work and AlectraDrive@Home, but differs in customer segment, delivery approach, and learning focus.

AlectraDrive@Work targeted commercial facilities and evaluated managed charging alongside other controllable distributed energy resources, including solar generation, battery storage, and HVAC-based demand response. Load control was implemented through a Distributed Energy Resource Management System and focused on site-level and portfolio-level DER coordination rather than individual EV drivers.

AlectraDrive@Home targeted residential customers in single-family and multi-family dwellings and evaluated two approaches to EV load management: incentive-based managed charging using vehicle telematics data, and managed charging using connected EV chargers combined with time-of-use pricing signals. The pilot focused on testing technology options and validating customer interest in residential managed charging.

The SmartCharge pilot differs from both projects by focusing on the customer experience and operational feasibility of managed EV charging delivered through Alectra Utilities' existing customer engagement platform. Rather than testing multiple technology pathways, SmartCharge assesses whether simplifying enrollment, communication, and ongoing customer interaction supports a more scalable and user-friendly approach.

A key distinction of SmartCharge is the integration of managed EV charging functionality into Alectra's customer platform, enabling enrollment, equipment selection, eligibility screening, installation planning, and ongoing visibility and control of charging activity through a single interface.

The incremental learning objectives of the SmartCharge pilot include:

- Assessing customer experience across enrollment, installation, and ongoing operation
- Evaluating customer willingness to participate in utility-sponsored EV charging load management events
- Assessing the feasibility and operational considerations of integrating managed EV charging into Alectra's customer engagement platform, and
- Evaluating the effectiveness of eMobility educational tools in supporting informed customer decisions

d) The eMobility Pilot does not establish a formal definition or quantitative metric for "avoided" or "deferred" customer service upgrades.

An avoided or deferred customer service upgrade refers to situations where a customer is able to install and use a Level 2 EV charger without needing upgrades to their electrical panel or secondary service, where such upgrades would otherwise have been required without load management measures.

As part of the eligibility and enrollment process, participating customers were asked to submit photographs of their electrical panels to support an assessment of available capacity to accommodate EV charging load. Customers were offered Level 2 chargers rated at 32A, 48A, or 80A, subject to the assessed capacity of their existing electrical service.

Customer applications were screened and grouped into three categories:

1. Customers whose existing electrical service could accommodate a Level 2 EV charger at one or more amperage levels without any service upgrade
2. Customers who could accommodate EV charging load only through the use of an EV Energy Management System (EMS) to manage load
3. Customers whose electrical service could not accommodate EV charging load, even with the use of an EV EMS.

Customers in the third category were excluded from the pilot. Customers in the first category were eligible to participate without additional equipment. Customers in the second category were eligible to participate if they accepted the installation of an EV EMS, which was provided at no additional cost. For these customers, the use of an EV EMS avoided the need for an otherwise required customer service upgrade.

The pilot does not attempt to quantify avoided or deferred upgrades beyond this eligibility-based assessment.

e) The eMobility Pilot is primarily intended to assess customer response and experience with managed EV charging delivered through a connected customer platform.

Within the scope of this pilot, the following quantitative metrics related to grid impacts and load management are being tracked:

- Hourly interval electricity consumption
- EV charger capacity (amperage rating)
- Number of managed charging (demand response) events issued
- Number of managed charging events participated in
- Number of managed charging events opted out of
- Timing and duration of managed charging events
- Curtailment limits applied during events
- Estimated energy curtailed during managed charging events

- Participation rates in managed charging events

In addition, customer-related metrics are collected to support interpretation of participation and operational results, including customer satisfaction with managed charging events and customer attitudes toward charging curtailment.

The pilot does not seek to quantify system-level peak demand reduction or deferral impacts.

f) The pilot is testing two customer participation approaches for managed EV charging:

- A utility-provided charger offered under a monthly subscription model
- A bring-your-own device model supported through customer incentives

Both approaches use the same recruitment method. Customers were invited by email to register their interest through Alectra Utilities' customer engagement portal. Using a common recruitment channel allows differences in participation, retention, and satisfaction to be assessed based on the program offering rather than the outreach method.

The pilot also evaluates elements of the recruitment and onboarding process, including:

- Convenience of the application process
- Relevance of the information provided
- Communication preferences
- Usability of the customer engagement platform
- Simplicity of the onboarding process

Recruitment outcomes, participation, retention, and customer satisfaction will be assessed by a third-party evaluator. Findings and recommendations will inform future program design considerations.

Future scaling of the SmartCharge pilot would be subject to the development of a separate business case demonstrating program cost-effectiveness. Such a business case would consider expected participation rates, recruitment and operating costs, and the value of managed EV charging as a resource, and would be informed by the findings of the eMobility Customer Engagement pilot.

g) The purpose of the eMobility pilot is to assess the merits of the customer engagement approach, supporting technology, and business model associated with these integrated functionalities. Data required to support this assessment are being collected throughout the project and will be evaluated by a third-party evaluator.

As the project is ongoing and data collection is still underway, no conclusions or recommendations regarding future investment in the customer experience platform have been made at this time.

h) Yes. The OEB is funding this project through the OEB Innovation Sandbox Challenge. Alectra Utilities will file the final evaluation results of the eMobility Pilot with the Ontario Energy Board as part of its reporting obligations.

1-DRC-6

Attachment 1
Charter SEW eMobility

PROJECT BRIEF

SEW Customer Engagement eMobility_152574

1.0 PROJECT IDENTIFICATION

Project Lead/Manager	[redacted]	**Project Sponsor**	[redacted]
Project Start Date	1/2/2025	**Project End Date**	12/31/2026
Division Name	GRE&T Centre	**Document Version**	1

2.0 PROJECT DESCRIPTION

The project seeks to create a connected utility e-Mobility customer engagement platform (provided by SEW, CX platform provider) that supports residential customer engagement and participation in DER programs. It will include the provision of affordable EV charging equipment compatible with utility load management programs through an online storefront.

The goal is to assess the value of information/tools provided to customers on their electrification journey, and the value customers find in a program designed to support and enable them to become prosumers through enabling managed EV charging.

Customers-sited DERs can play a meaningful role in providing flexibility & capacity to the distribution system. Electrification (i.e., EV charging and eventually heating) creates new loads which in some cases leads to loads being greater than the designed service infrastructure. Unmanaged infrastructure can fail before its end of life, meaning earlier replacement, leading to higher costs for customers. Using DERs effectively means loads can be curtailed/shifted to off-peak times; meaning load growth due to electrification can be managed within existing limits or expansion can be deferred closer to end of life and upgraded as part of planned capital programs.

Alectra will deploy real-world customer engagement strategies/solution tools, while offering customers affordable choices of prequalified Level 2 EV chargers. Once customers have the charger, we will offer a smart charging solution and analyze the business and technical considerations that make this an economical service to offer to all of Alectra's customers. Alectra will be better positioned to manage grid reliability and meet customers' needs when we can influence customers to buy EV chargers compatible with managed charging, which supports the economical and reliable operation of the grid.

The project aims to:

- Enhance Alectra's customer relationships (i.e., increase customer satisfaction and support customers along their electrification journey).
- Influence customers' charging habits and technology selection decisions to enable managed EV charging and other load management through a connected experience.

- Create a program structure that can be validated and expanded upon with new provincial funding for electricity DSM (Stream 2)

The project is supported in part by the OEB Innovation Sandbox Challenge ($325k) for the period 2024-2026.

3.0 BENEFITS

Goals:
The project aims to:
- Enhance Alectra's customer relationships (i.e., increase customer satisfaction and support customers along their electrification journey).
- Influence customers' charging habits and technology selection decisions to enable managed EV charging and other load management through a connected experience.

Outcomes:
- Create the technical and behavioral conditions for managed EV charging and other load management through a connected experience.
- EV demystification
- Improved customer satisfaction and customer relationship
- Identified characteristics of business models (e.g., convenience, affordability, and choice) and financing features (e.g. ability customer pays vs Utility pays in exchange for DER controllability) that customers best respond to.

*Further details regarding benefits can be found within the Copperleaf Business Case.

4.0 FINANCIAL SUMMARY

Benefits	OM&A	Capital
Project Costs	OM&A = $868,088	Capital = $1,145,124

*Further details regarding the financial breakdown can be within the Copperleaf Business Case budgets tab.

5.0 PROJECT DEFINITION

Project Scope	**IN SCOPE - Scope Inclusions & High Level Requirements:**
	• Provide the eMobility module to participants, operate the system, and assess functionality and satisfaction. The eMobility module will provide interactive tools and test innovative outreach strategies for customer recruitment for EV-related utility programs with a focus on facilitating ZEV (electric light duty vehicle) adoption for residential customers; • Recruit single-family home residential customers to participate in a utility-sponsored EV Charger load management for approximately 1.5 to 2 years (targeting 18months). The eMobility module will be used as a customer care tool over the course of the pilot;

	• Conduct demand response/managed charging tests and test customers' willingness to participate in utility-sponsored load management;
	• Analyze and evaluate the feasibility and dependencies of launching a full deployment of the eMobility module into Alectra's customer engagement platform;
	• Enhance Alectra's customer relationships (i.e., increase customer satisfaction and support customers along their electrification journey); and
	• Influence customers' charging habits and technology selection decisions to enable managed EV charging and other load management through a connected experience.
	
	• **Phase 1: eMobility module deployment**
	  ◦ Deploy an **eMobility CX application** (i.e., micro-website) that hosts e-mobility **education and awareness material**. Bring customers onto the platform.
	
	  <u>Deploy various tools:</u>
	    ▪ GHG reduction calculator showcasing savings of going electric.
	    ▪ Energy wallet – tool showcasing potential dollar savings associated with electrification transition – switching from L1 to L2, or ICE vehicle to EV.
	    ▪ Utility rate comparison calculator that guides customers toward the right rate plan fit based on their charging behaviours.
	    ▪ Public charging map locator
	  ◦ **Test group** – all Alectra account holders that choose to disclose the Alectra Utilities account number. Logging in will enable a customized experience using Utility metering data inputs.
	  ◦ **Control group** – Non-Alectra account holders/those who don't provide their Alectra Utilities account number will have a guest view experience. These customers will still have visibility into the tools, but certain tool (e.g., rate plan comparison) will not be customized using their metering data. We will seek to capture guest experience though a pop-up survey.
	
	• **Phase 2: Infrastructure deployment**
	  ◦ Host a marketplace through the eMobility module that allows residential customers to acquire smart L2 EVSE that are compatible with Utility load management program.
	  ◦ Subscription fee model, where Alectra owns the EV charger and leases the equipment to the customer for a monthly fee that spans the life of the pilot (~2 years).
	  ◦ Alectra customers go through a screening process to be selected for Group A, all other Alectra customers would fall into Group B. Group B recruitment only opens once Group A is fully subscribed.
	  ◦ **Group A - (Subscription plan, Alectra owns EVSE, utility provides EVSE and installation payment support):**
	  ◦ **Group B - Control group (no utility EVSE/installation payment support, customer owns EVSE)**
	
	• Phase 3: **Grid optimization**
	• Optimize the grid & enable grid services
	  ◦ **Activate EVSE to provide demand response load shifting** based on customers' present preferences.
	  ◦ Provide incentives for customers enrolled in the pilot to shift their load.

- Demonstrate how residential EV chargers can provide grid flexibility.
- **Group A (Subscription group, Alectra owns the equipment)**
- **Group B – Control group (Customer owned equipment)**

OUT OF SCOPE - Scope Exclusions:

- System integration in Alectra's CX project. Pilot will be a separate instance independent of the CX project; however, the pilot will explore what the needs will be for CX platform integration. Data will be pulled through APIs
- Customers bring their own 3rd party device (not from the marketplace)
- Telematics integration
- Payment terminal on the EVSE
- MURBs, fleets or commercial deployments
- No L3
- No V2G capability
- No battery storage

Project Deliverables

Deliverable Number	Deliverable Name	Deliverable Description
M1.1	**Detailed Project Plan document**	* Budget * Schedules (including timelines, milestones) * Reporting mechanisms (including internal approval documentation and performance metrics documentation) * Definition of requirements and milestones which will allow the Parties to confirm the scope of work and provide a checkpoint for the Services to validate the scope of work.
M1.2	**Statement of Work (SoW)**	Contract with SEW
M1.3	**Program Conceptualization and Design document**	* Defines the program objectives and desired outcomes * Identifies target customer segments for the pilot program * Document the program eligibility criteria and customer selection process * Documents the scope of the pilot program (number of charging stations, geographic area, etc.). * List of KPIs to monitor

	M1.4	**Discovery workshops**	workshops to gather all relevant information to prepare the deliverables required for this Milestone involves reviewing all requirements, business processes, Alectra specific business rules and validations, to inform the technical requirements needed from the EVSE. Provide workshop records summarizing the relevant information obtained from the workshops
	M1.5	**Customer Journey Maps**	Customer journey description, engagement touchpoints points and mapping against SEW-provided capabilities.
	M1.6	**Stakeholder register and communication plan**	document which identifies key stakeholders (internal and external) and communication plan which identifies how communication with each stakeholder group will occur at various stages of the pilot.
	M1.7	**Governance model**	Points of escalation
	M1.8	**Target Customer Segment Analysis**	Identify which customers we are targeting, why, how and when
	M1.9	**Eligibility criteria and participant selection process document**	Customer recruitment plan and pilot landing page to detail the process.
	M1.10	**Pilot Participant Engagement and Policy Assessment**	List of all requirements which Client will need to address in its Terms & Conditions for Program Enrollment (Participant Agreement) Ensure that the Services offer and facilitate an opt out/removal policy
	M1.11	**EVSE monitoring plan**	a system for monitoring charging station usage and energy consumption. Ensuring the EVSE Charging Management System is running and operating as intended and establishing a trouble shooting plan that complies with SLAs.
	M1.12	**Customer service support script, material & issue escalation plan**	Train the Trainer training and related materials provided to Alectra

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	M1.13	**Marketing plan**	An operational document that shows how the team is planning to use advertising and outreach to target a specific target audience. Includes a strategic roadmap that will be used to organize, execute, and track the marketing strategy over the life of the pilot.
	M1.14	**Marketing material**	Development of materials for program marketing (brochures, website content, social media posts, etc.) and customer enrollment including all Website Content and Campaign materials contemplated in Appendix B (collectively, the "Marketing Materials") including all collateral acceptable to Client acting reasonably, including: • Website EV Content (EV overview and benefits, FAQ, eMobility tools) • Program enrollment and Program/rebate registration • Campaign material • Brochure • Mail inserts/flyers) • User guides, • Drip Campaign (2 emails), enrollment tracking) • Video Creation (instructional/Outline Tutorial Video • Social media posts
	M1.15	**Data Migration Strategy**	Detailed in the vendor contract
	M1.16	**Environment Strategy**	Detailed in the vendor contract
	M1.17	**Branching Strategy**	Detailed in the vendor contract
	M1.18	**Solution Architecture Design Document**	Detailed in the vendor contract
	M1.19	**Functional Design Document**	Detailed in the vendor contract
	M1.20	**Payment integration**	Payments properly captured by SEW through integration with RBC (bank) and remitted to Alectra
	M1.21	**Customer and rate plan integration**	Integration with CC&B for customer information, account information and rate plan information is working as expected, acting reasonably.

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	M1.22	**Technical Specification documents including integrations**	Technical documents to be provided by SEW
	M1.23	**Data mapping**	Detailed in the vendor contract
	M1.24	**Release Schedule for testing environments specifying when integration and Provider code will be deployed to each environment for testing purposes**	For testing environments specifying when integration and Provider code will be deployed to each environment for testing purposes;
	M1.25	**Cutover Plan**	Outlining the schedule and procedures for the final deployment of code and updates to the production environment
	M1.26	**TOOL: Rate comparison tool (TOU, Tiered, ULO) showing impact of L1 vs L2 charging**	Tools developed and customized to Ontario
	M1.27	**TOOL: Rate comparison tool (TOU, Tiered, ULO) showing impact of adding an EV**	Tools developed and customized to Ontario
	M1.28	**TOOL: Public charging locator (Charge Locator (explore))**	Tools developed and customized to Ontario
	M1.29	**TOOL: GHG savings calculator**	Tools developed and customized to Ontario
	M1.30	**Online program enrollment and charger store implementation plan:**	The online module to Client's criteria (including reflecting Alectra's pricing, obtaining customer payments, establishing policy for what happens to the module once the pilot is fully subscribed)
	M1.31	**Customer enrollment form/ online portal**	Featuring capture of all customer information required to manage participants into the portal for participant management
	M1.32	**Customer enrollment baseline survey**	Baseline survey capturing participant information, behaviour, attitudes and expectations from participation
	M1.33	**Test Plan & provision of the software to be tested**	Production support activities for websites and mobile app
	M1.34	**Performance testing report**	provide Performance testing results report and remediate any critical and high findings before go-live.
	M1.35	**Penetration testing**	provide Penetration testing results report and remediate any critical and high findings before go-live.

	M1.36	**Successful User Acceptance Testing**	
	M1.38	**Successful test reports (post testing completion)**	
	M1.39	**Verification Report**	* Production Verification Testing * Verification of full completion of the design, configure and setup of the Software * Verification of software receiving data properly from networked EVSEs * Software operating in accordance with requirements
	M1.40	**Branded customer web portal and mobile app with all functionalities (pre - public Go-live) - Submissions to app stores of mobile application on Alectra's behalf**	Deployment of branded customer web portal and mobile app with all functionalities (pre - public Go-live)
	M1.41	**EVSE test:** **· Provide 2 of each type of hardware to be used in the project, shipped to Alectra for testing, including installation and commissioning instructions and all technical specifications**	Commissioning of test EVSE into SEW platform and full functionality achieved (communications, utilization, error logging and remote support, demand response) Alectra to test hardware at its facilities and with its staff; a period of 2-3 months should be allowed for testing. Provide portal access for Alectra to manage installed hardware.
	M1.42	**Milestone 1 Report**	Progress report and summary of Deliverables achieved to date and confirmation of acceptance by Client. List of all risks identified and corresponding mitigation strategy for each risk.
	M1.43	**Project checkpoint /milestone meeting**	Meeting to discuss the Milestone report and any issues.
	[redacted]		
	M2.1	**Program announcement (eMobility module & charger store)**	enrollment period initiation, execution of marketing and customer outreach campaigns. Customer recruitment efforts launched

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	M2.2	**Go-Live: Deployment of Smart eMobility platform (tools) and Charger Store**	Store front - open for customer enrolment into Group A Updates to marketing materials (up to 3 rounds of changes) made over the period of the campaign to address customer feedback, minimize calls to call-center, and improve customer acquisition.
	M2.3	**90-day period post go live support plan (Post Go live stabilization)**	Increased levels of support, monitoring, response, and resolution of production issues for a 90-day period post go live
	M2.4	**Log of total # of installed charging stations are successfully commissioned.**	Confirmation charging stations delivered & installed and working as intended at customers' residences complying with SLAs.
	M2.5	**Customer Survey & feedback report 1:**	Administer onboarding survey (survey #2) Document metrics surrounding coordination and installation of the equipment, customer application processing and eligibility verification process, and participant engagement (e.g. number of enrollments, approved applications, how long did it take, usability of the marketplace feature, influence the tools had, level of support experienced by the customer, etc.) Data to come from operational reports and customer feedback
	M2.6	**Report on Phase 1 and 2 KPIs as identified with the Client:**	· Phase 1 KPIs (e.g. expressed interest of tools usage instances, web traffic compared to before tools were offered) · Phase 2 KPIs (e.g. Log of number of approved applications, etc.)
	M2.7	**Milestone 2 Report:**	Progress report and summary of deliverables achieved to date and confirmation of acceptance by Client. List of all risks identified and corresponding mitigation strategy for each risk.
	M2.8	**Project checkpoint meeting**	Meeting to discuss the Milestone report and any issues.
	[redacted]		
	M3.1	**Close storefront to group A and open to group B**	

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	M3.2	**Load Management Activation confirmation**	When load management is first started. Load management must run for at least 1 year.
	M3.3	**Load management Report - Hardware**	Report on EVSE hardware response to demand response events initiated by Client.
	M3.4	**Load management Report - software**	Report on EVSE software response to demand response events initiated by Client.
	M3.5	**Charging station usage analysis report 1:**	Analyze charging station usage data to date (pilot midpoint) to understand customer charging behavior and load management impact.
	M3.6	**Deploy Customer Survey (midpoint evaluation survey)**	Conduct pilot midpoint customer surveys
	M3.7	**Customer satisfaction analysis report 2:**	Conduct pilot midpoint customer surveys and provide an analysis of the survey responses. Assess customer satisfaction with the program and eMobility module. Provide 2 rounds of updates to website materials to address customer feedback.
	M3.8	**Program performance analysis report 1:**	Report on phase 1, Phase 2 and Phase 3 KPIs to date (pilot midpoint). Detail to what extent the program and eMobility module performed as intended.
	M3.9	**Milestone 3 Report:**	Progress report and summary of Deliverables achieved to date and confirmation of acceptance by Client. List of all risks identified and corresponding mitigation strategy for each risk. Preliminary roadmap for scale up /integration with Alectra SCM portal.
	M3.10	**Project checkpoint meeting**	Meeting to discuss the Milestone report and any issues.
	[redacted]		
	M4.1	**Deploy Customer Survey (post pilot evaluation survey)**	Conduct final survey (survey #3) to capture customer satisfaction with the program and desires for post-project support
	M4.2	**Charging station usage analysis report 2:**	Update the 1st report capturing data from the latter half of the pilot. Analyze charging station usage data to understand customer charging behavior and load management impact. Report on KPIs

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	M4.3	**Customer satisfaction analysis report 3:**	Update the 1st report capturing data from the latter half of the pilot. Analyze customer feedback to evaluate satisfaction with the program and eMobility module. Report on KPIs
	M4.4	**Charging program trends and preferences report 2:**	Determine the program's impact on customer charging habits. Detail to what extent the eMobility module performed as intended.
	M4.5	**Lessons learned documentation:**	Document best practices and areas for improvement for future implementations.
	M4.6	**Findings and recommendations presentation:**	Share findings and recommendations with Client. Include evaluation of benefit to customers.
	M4.7	**Scale up plan for wider implementation:**	Scaling plan to expand the program to a larger customer base. Develop recommendations for program enhancements based on evaluation results. Detail what integration into Alectra's CX platform.
	M4.8	**Milestone 4 Report & Project Close out:**	Progress report and summary of Deliverables achieved to date and confirmation of acceptance by Client. List of all outstanding risks identified and corresponding mitigation strategy for each risk. Final roadmap for scale up /integration with Alectra SCM portal.
	M4.9	**Project checkpoint meeting & close out**	Meeting to discuss the Milestone report and any issues and close out activities.
Dependencies	This project will leverage the systems that are in place for the CX project (My Alectra) by the same vendor (SEW, also referred to as AiE).		
Major Assumptions and Constraints	The project's ability to be capitalized will be a key factor in Alectra having the funds to complete the project. We are reliant on the vendor to complete the project to specification and timelines. Milestones and project timelines are bound by time the OEB (funder) timelines Sticking to SEWs out of the box solution with the exception of where development needs to be completed to meet the scope of the OEB proposal.		
Major Risks	• There is a base platform that this SEW module sits on. As long as Alectra continues its relationship with the vendor on the base platforms, this module will function. Reliant on the vendor to keep up with interoperability with interoperability standards and vendor roaming agreements to support customer EV chargers.		

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	• Post pilot customer experience with the app and service may be impacted by pilot conclusion. Customers risk their Smart level 2 chargers becoming dumb chargers. Alectra to continue negotiations to clearly communicate to customers post pilot options. • Rate rebasing year requires team to be agile and support business priorities as needed with resources shared across both initiatives. Project timelines may be severely impacted by effort of DSP activities.

6.0 HIGH-LEVEL SCHEDULE – PROJECT MILESTONES

Key Activity/Milestone	Target Completion Date	Completion Criteria
Contract with Vendor (SEW/AiE)		Completed
Contract with OEB		Completed
Contract with 3rd Party Evaluator		Completed
Phase 1a (pre-login experience): Go live website launch	February 2025	Completed
Phase 1b (post-login experience): Go live Go live website launch	April 2025	Completed – bug fixes scheduled
EV charger hardware and software testing	May 2025	In progress (some delays)
PM Documents completed & approved by internal stakeholders	July 2025	In progress
OEB Milestone Report #1	July 2025	In progress
Phase 2 (marketplace for EVSE deployment) Go live	July 2025	In progress
EVSE installation with customers	September 2025	Not yet started
Phase 3 (grid optimization - DR activation): Go live	October 2025	Not yet started
OEB Milestone Report #2	January 2026	Not yet started
OEB Milestone Report #3	July 2026	Not yet started
Final Evaluation Report	October 2026	Not yet started
OEB Milestone Report #4	December 2026	Not yet started

7.0 PROJECT MANAGEMENT INFORMATION

This project will require a combination of both professional and skilled personnel. The following tables list both internal Alectra employees that will play a core role, as well as external personnel/companies that will play a role in the project t, and their associated responsibilities for the project.

Key Stakeholders

Company	Key Project Role	Title	Stakeholder name
SEW	Executive Sponsor	CEO	[redacted]

SEW	NA Delivery Executive - Overall NA Delivery Leader, help with delivery escalations	VP, Product Delivery	[redacted]
SEW	Sales Head	VP, Sales	[redacted]
SEW	Sales Manager - Help with sales management	Associate VP, Sales	[redacted]
SEW	Delivery Sponsor - Overall account delivery manager	Director, Product Engineering	[redacted]
SEW	Delivery Lead - Project Manager	Lead, Product Delivery	[redacted]
SEW	Delivery Lead - Project Manager	Director, Technical Delivery	[redacted]
SEW	Chief Product Officer - SEW eMobility	CPO, Smart eMobility	[redacted]
SEW	Chief product officer-SCM	CPO, SCM	[redacted]
SEW	Chief Marketing Officer	VP, Strategic Initiatives	[redacted]
SEW	Marketing Delivery Lead	EVP, Corporate Marketing	[redacted]
SEW	Integration Architect	VP, Product Engineering, Enterprise Integrations	[redacted]
SEW	APAC Delivery Lead - SEW eMobility	Program Manager	[redacted]
SEW	APAC Delivery Lead - SEW eMobility	Project Manager	[redacted]
SEW	Product Analyst - SEW eMobility	Sr. Product Analyst	[redacted]
SEW	Product Analyst - SEW eMobility	Sr. Product Analyst	[redacted]
SEW	Solution Architect - SEW eMobility	Solution Architect	[redacted]
SEW	QA Lead - SEW eMobility	Sr. Quality Engineer	[redacted]
SEW	Delivery Escalation - SmartCX	VP, Product Delivery	[redacted]
SEW	Delivery Lead - SmartCX	Delivery Manager	[redacted]
SEW	Product Analyst - SmartCX	Sr. Analyst, Product & Solution Eng.	[redacted]
Alectra	Executive Project Sponsor – Provide funding for the project and ultimate approvals. Execute contracts with 3rd party.	EVP, Customer Experience	[redacted]
Alectra	Project Manager – Accountable for the project management and coordination of Alectra functions impacting the project.	Head, Smart Cities	[redacted]
Alectra	Project Lead – Manage schedule, scope and budget. Coordinate with vendors and core project team to ensure requirements are delivered and on track. Also coordinates with the customer. Provides a supporting role to the project.	Project lead, Smart Cities	[redacted]

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Alectra	Product Manager (Technical lead)- responsible for designing and coordinating solutions from multiple vendors into a single deliverable. Provide technical Knowledge with deep business understanding, and are a significant contributor to requirements gathering, implementation planning, and solution development	Strategic Platform Advisor	[redacted]
Alectra	Project Coordinator– Assists with project coordination activities and managing pilot participants	Specialist	
Alectra	Technical Specialist - EVSE SME lead EVSE and demand response testing Demand response and grid exchange SME to inform the payment process and load management parts of the pilot	Specialist	
Alectra	Data analytics specialist	Growth and Operations Strategist	
Alectra	Marketing lead – to review all customer communications and ensure brand compliance.	Project lead, Smart Cities	
Alectra	Marketing assistant and UX lead – to provide Gulnar with communications support and SME for UX and design.	Inter, Communications & Design Thinking	
Alectra	SEW CX project advisor. Brings the customer perspective to project planning and design and alignment with CX future goals.	Director, Customer Operations, Customer Service	
Alectra	SEW CX project advisor. Brings the customer perspective to project planning and design and alignment with CX future goals.	Manager, Revenue Assurance	
Alectra	Customer Insights specialist - to inform the customer experience and data driven approaches	Manager, Customer Insights	
Alectra	Budget Coordinator – communicates where the project budget stands	Financial Planning & Analysis Specialist	

Alectra	Finance structure lead – communicates where the project budget stands and guides the group on how to structure the budget for capitalization	Manager, D&I Administration	[redacted]
Alectra	Procurement Support - Setting up POs	Specialist, D&I Planning and Governance	
Alectra	Financial reporting advisor - approval needed for project capitalization	Director, Financial Reporting	
Alectra	Financial reporting and Customer billing advisor	VP, Finance	
Alectra	Financial reporting and Customer billing advisor	Director, Treasury	
Alectra	EVP guidance on making resources available and overall input into the final product	EVP and Chief Digital & Innovation Officer	
Alectra	Guidance on making resources available and overall input into the final product. Approval may be needed at several stage.	VP, GRE&T Centre	
Alectra	Day-to-day project support. Guidance on making resources available and overall input into the final product. Approval may be needed at several stage.	VP, Customer Service	
Alectra	Legal lead - provides oversight for all legal documentation.	Executive Vice President, Legal, Strategy and Corporate Secretary	
Alectra	Drafting of legal agreement (e.g. participant agreement, vendor agreement, etc.).	Legal Counsel	
Alectra	Testing coordinator - will manage and oversee the testers	Specialist, CC&B and Emerging Technologies	
Alectra	Testers - integrated testing	Specialist, CC&B and Emerging Technologies (Customer Service)	
Alectra	Testers - integrated testing	Supervisor, CIS Support & Emerging Technologies (Customer Service)	
Alectra	User testing support	Business Analyst	
Alectra	IT lead and customer systems SME	Team Lead, Customer Systems	

Alectra	Test lead	Operation Readiness Consultant	[redacted]
Alectra	EV driver or user advisor	Technical Manager, Advanced Planning	
Alectra	Rates integration lead	Manager, Customer Systems, Information Technology	
Alectra	Technical advisor	Director, Customer Portfolio Lead & Technical Advisor Product Management	
Alectra	Training lead	Change and Transformation Specialist Business Transformation	
Alectra	Evaluator coordination support and vendor oversight support. Installer contracting support.	Manager, Smart Cities	
Alectra	IT security advisor	Director, IT Security and Risk	
Alectra	Brand compliance and alignment with Alectra practices. Corporate communications advisor	External Communications advisor	
Skylar	Brand compliance and alignment with Alectra practices. Corporate communications advisor		
OEB	OEB rep	Lead | OEB Innovation Sandbox	
OEB	OEB rep	Innovation Analyst	
OEB	OEB rep	Lead | OEB Innovation Sandbox	
OEB	OEB rep	Lead | OEB Innovation Sandbox	
Dunsky	3rd party project evaluator	Managing Consultant	

Project Team Resources

Business Unit	Resource Name	Project Role	Time/Effort Required	When Required
GRE&T Centre	[redacted]	Project Lead	2700 hrs.	2025 - 2026
GRE&T Centre		Director, Smart Cities	500 hrs.	2025 - 2026
GRE&T Centre		Specialist, Smart Cities	2600 hrs.	2025 - 2026
GRE&T Centre		Lead, Communications	800 hrs.	2025 - 2026
GRE&T Centre		Manager, Smart Cities	650 hrs.	2025 - 2026
GRE&T Centre		Specialist, Smart Cities	750 hrs.	2025 - 2026
GRE&T Centre		Current Student Support	600 hrs.	2025
GRE&T Centre		Analytics	90 hrs.	2025
GRE&T Centre		Technical Product Lead	Half an FTE	2025
GRE&T Centre		Lead tester	¼ an FTE	2025
GRE&T Centre		UX	300 hrs.	2025
Customer Service		Customer Service Support	130 hrs.	2025 – 2026
Customer Service		Customer Service Support	150 hrs.	2025
Customer Service		Testing Coordinator	280 hrs.	2025
Customer Service		Tester Integration	230 hrs.	2025
Customer Service		Customer Service Support	350 hrs.	2025 – 2026
Customer Service		CC&B Specialist	300 hrs.	2025
Information Technology		Security Lead	200 hrs.	2025 – 2026
Information Technology		Customer Systems Lead	100 hrs.	2025
Information Technology		Customer Portfolio Lead	50 hrs.	2025

Business Unit	Resource Name	Project Role	Time/Effort Required	When Required
Information Technology	[redacted]	Customer Systems	50 hrs.	2025
Grid Modernization	[redacted]	Analyst	75 hrs.	2026
Finance	[redacted]	Finance	150 hrs.	2025
Regulatory Affairs	[redacted]	Analyst	200 hrs.	2025 – 2026
Corp Comms	[redacted]	Comms Specialist	25 hrs.	2025 – 2026
Corp Comms	[redacted]	Comms Specialist	25 hrs.	2025 – 2026
OCM	[redacted]	Change Specialist	50 hrs.	2025

8.0 CHANGE MANAGEMENT AND COMMUNICATION PLAN

Stakeholder Impact Assessment

Stakeholder	Key Changes and Concerns	Implications of Not Addressing Concerns	Activities to Mitigate Changes and Concerns
External Customers	Introduction of new website navigation and online self-service tools; potential confusion with updated interfaces and support channels.	Decreased customer satisfaction, increased contact center volume, and possible reputational risk if customers cannot easily adapt.	Clear external communications, FAQ updates, intuitive website design, and proactive support via CSRs during transition period.
CSRs	Need to learn new website navigation and support processes; possible uncertainty about roles/responsibilities and handling increased inquiries from external customers.	Reduced employee confidence and efficiency, increased errors, and staff frustration, leading to lower service quality.	Phased training sessions, job aids, Q&A forums, and ongoing feedback mechanisms to ensure CSRs are comfortable and competent with new tools.
Corp Comms Team	Development and delivery of key messages about changes; alignment of communications across channels and audiences.	Inconsistent or unclear messaging may result in stakeholder confusion and resistance to change.	Early engagement, message testing, and coordinated rollout of communications across internal and external platforms.
OCM/Change Specialists	Oversight of change management activities, stakeholder impact monitoring, and ongoing adjustment of strategies.	Potential misalignment in change approach, missed concerns, and delayed project benefits if not actively managed.	Regular impact assessments, feedback loops, and adaptive change strategies informed by stakeholder input and data.

Effective governance serves as the cornerstone of a resilient and effective project. This governance model outlines the framework through which strategic decisions are made, risks are managed, and responsibilities are distributed. By establishing clear roles, processes, and accountability structures, the model aims to promote integrity, responsiveness, and informed oversight.
Whether considering regulatory compliance or stakeholder engagement, this governance framework is structured to support decision-making that aligns with the goals of the OEB Sandbox project and Alectra's core brand and long-term objectives. It provides a consistent approach informed by established practices and collective priorities.

Governance Structure

This section outlines the roles and responsibilities within the governance model. For example:

- **Core Team**: Responsible for strategic oversight, risk management, and regulatory compliance.
- **Executive Management**: Responsible for operational leadership, decision-making, and execution of strategy.
- **Committees**: Outline the various committees (e.g., audit committee, risk committee, etc.) and their specific responsibilities.
- **Other key roles**: Include any other key roles within the governance structure and their responsibilities.

Team	Roles	Responsibilities
Alectra	Executive Management	Responsible for setting the company's overall strategic direction, risk management, regulatory compliance, operational leadership, and ultimate decision-making.
	Steering Committee	Made up of representatives across functions at Alectra to provide input to inform product development, and provide insights into business processes. Communicate strategic updates, decisions required and escalate key issues.
	Core Team	Responsible for managing the day-to-day project management activities and decision-making
	Work Stream Members	Groups that are to provide SME and are responsible for the delivery of deliverables
	Other key roles	Responsible for individual tasks specific to their function at Alectra.
SEW	Executive Management	Responsible for setting the company's overall strategic direction, operational leadership, making resources available, and ultimate decision-making.
	Core Team	Responsible for managing the day-to-day project management activities and decision-making
	Other key roles	Responsible for individual tasks specific to their function

A stakeholder communication plan is a strategy document that outlines how we will communicate with stakeholders. It defines who the stakeholders are, what information they need, when and how often they need the information, and who will deliver this information.

PROJECT BRIEF

Stakeholder group	Individuals (stakeholder register to inform)	Information Needs & Key messages	Communication Methods or channels	Frequency of Communication	Communication Protocol	Feedback Mechanisms
Core Project Team	Alectra	Detailed project updates, tasks, deadlines, and challenges. Launch project; confirm scope, roles, timelines; generate excitement and alignment.	Teams, Workshop meetings, email	Weekly workshop calls and daily scrum calls as needed. Focused meetings as needed.	Alectra – full core team to be cc'd	Email, weekly workshop.
	SEW	Detailed project updates, tasks, deadlines, and challenges.	Emails, Teams meetings	Daily or as needed	SEW – Core team and other required stakeholders to be copied as required during various phases	Emails, regular meetings
	Joint core team (SEW & Alectra)	Detailed project updates, tasks, deadlines, and challenges. RAID log items.	Regular team meetings, Emails, Project management tools.	Full core team → Weekly (Tuesdays) or as needed Project leads scrum meeting → Monday,	Record meetings and store on SharePoint. All documents must be saved on SharePoint or Confluence,	Email, Teams calls, Confluence/SharePoint documents.

Stakeholder group	Individuals (stakeholder register to inform)	Information Needs & Key messages	Communication Methods or channels	Frequency of Communication	Communication Protocol	Feedback Mechanisms
				Thursday, Friday or as needed.	where it can be accessed by the team.	
Executive Management	Alectra	High-level project status, budget reports, major roadblocks and escalation support	In-person/teams meeting, Status report deck	Bi-weekly status meeting	Deck shared ahead of time, followed up with Action items email and RAID log update.	Teams calls
	Alectra & SEW Executives	High-level project status, and escalation discussion	In-person/teams meeting, Status report deck	Bi-weekly status meeting	SEW presents a status update slide. Group openly discusses status.	Teams calls
Legal	Counsel – external as needed.	Contractual terms, agreements, risk/legal concerns.	Email, meetings, summary briefs	As needed	CC core team on legal threads	Redlined documents, legal memos.
Testers	Alectra	Testing schedules, platform access, feedback loops	Email, testing platform, Teams	15min touchpoints every other day and longer meetings as needed. Demo prior to each sprint	Provide feedback through tracking tickets on Jira and during demo calls.	UAT forms (Excel test cases and Jira), feedback sessions, and defect triage meetings.
Customer Service	Alectra	Customer journey, issue escalation, and onboarding details.	Email and training documents and sessions.	Weekly or bi-weekly	Provide updated info before customer interactions	Ticket system, surveys

Stakeholder group	Individuals (stakeholder register to inform)	Information Needs & Key messages	Communication Methods or channels	Frequency of Communication	Communication Protocol	Feedback Mechanisms
Marketing & Communications	Alectra SEW	Program branding, key messages, timelines, public announcements. Web analytics	Email, meetings, SharePoint	weekly and go-live launch based.	Messaging to align with program goals and Alectra brand (including engagement practices)	Draft reviews, approvals
IT & Technical integration	Alectra	Integration requirements, cybersecurity, technical support	Teams, service desk tickets	As needed	Follow internal change request processes	Ticketing system
Payments, Processing & commercialization	Alectra	Payment process, reconciliation procedure,	Meetings, emails	As needed		Meeting notes and reports
Evaluation	Dunsky Marketing and analytics – Alectra	Access to data, project structure, pilot design, evaluation questions	Email, meetings, SharePoint	Bi-weekly or as needed	Follow project governance structure	Evaluation plans, reports, and deliverable document comments
Customers	EV Drivers – Phase 1	Pilot goals, expectations, timelines, customer support info. Program updates, onboarding, new features	Email, onboarding material, help desk	As scheduled/pilot-based	Use plain language, track responses. Follow campaign rollout plan	Surveys, support line, App feedback, support channels

Stakeholder group	Individuals (stakeholder register to inform)	Information Needs & Key messages	Communication Methods or channels	Frequency of Communication	Communication Protocol	Feedback Mechanisms
	Non-EV Drivers	Incentive info, recruitment materials, eligibility. Recruitment updates, awareness of benefits	Email, social media, website. Marketing campaigns, targeted outreach	During recruitment window	Standard comms approval process. Follow campaign rollout plan	Sign-up forms, interest tracking
	SmartCharge Participants (Group A & B)	Program performance, any transitions or new pilots	Email, help desk, app notifications	As needed	Leverage CRM/email systems	Exit surveys, app engagement
Suppliers	TBD – Grizzl-E	Order updates, changes in resource needs	Email, procurement system	Weekly or as needed	Follow procurement protocol	Delivery confirmation, check-in meetings
Installers	Installers – Bracer EV and JML Electric	Site info, install schedule, technical guidance, health & safety info	Email, site visits, Teams	Weekly	Provide checklists and support docs	Post-install feedback forms
Regulators (OEB)	OEB	Progress updates, major milestones, potential delays or changes in scope	Email, formal reports, meetings	Monthly or milestone-based	Adhere to regulatory format	Meeting minutes, formal letters
Other Utilities	Synergy North and others	Lessons learned, collaboration opportunities, tech findings	Email, webinars, shared reports	Quarterly or milestone-based	External knowledge-sharing protocol	Knowledge exchange sessions

Communication Plan

Detail the processes for decision-making, including approvals, escalation procedures, and conflict resolution. To ensure clear communications and to keep the project deliverables on track, the project teams involved agree to communicate concerns, issues and discuss possible changes through the reporting structure between the Project Manager and the Vendor (SEW).

The SEW team will have direct communication with the Project Manager and Project Lead. All concerns or changes after the Project Sponsor signs off will involve conversations between SEW and the Project Manager. The Project Manager will communicate changes with the Project Sponsor. These changes can only take place through a formal change order, after all relevant documentation is completed.

Risks are identified and managed by the **Core team**, with reports provided to the Executive Management team. Risk will be tracked in the RAID log throughout the course of the project and are summarized in the status reports.

Transparent and regular communication is maintained through meetings, reports, and updates. This includes the following meetings:

Role	Frequency of meetings
Core teams	Minimum once a week to discuss project management status and other meetings (e.g. DOU, next phase planning, etc.) scheduled as need and in accordance with the project plan. Core teams also meet internally weekly to discuss next steps, RAID log items and program design. Project lead escalates issues and decisions to project manager and executives on an as needed basis.
Alectra's core team + Alectra's steering committee	Meetings to occur as we explore new ways and processes. The steering committee is a cross functional team that is invited to all demo sessions to comment on the development activities.
Core team + executive team	Weekly status for core team Bi-weekly status reporting with executives

Training Plan

Topic Area/ Content	Employees Requiring Training	Estimated Duration (Hrs.)	Estimated Delivery Date	Proposed Trainer/ Provider
Website navigation	CSRs	1.5	Feb 20th	FAQ
Website navigation and Bx training Phase 1a	CSRs, Marketing Team and testing team	1.5	Feb 20th	SEW (Platform Walkthrough)

RESPONSES TO DISTRIBUTED RESOURCE COALITION INTERROGATORIES

INTERROGATORY 1-DRC-7

Reference: • Exhibit 1, Tab 7, Schedule 1

Preamble: Alectra indicates that its Alectra Drive for Fleets (ADF) project leverages connected EV charging infrastructure and intelligent software to optimize fleet charging while managing local grid capacity constraints.

a) Please provide any and all working papers, reports, and analysis conducted on or in support of the ADF project.

b) Please identify the EV charging vendors or categories of vendors involved in the ADF project and explain how Alectra ensured technology-neutral and non-discriminatory testing across solutions.

c) Please explain how Alectra Utilities defines and measures avoided or deferred utility upgrades in the context of the ADF project.

d) Please explain how results will be scaled to inform system-wide planning assumptions, including any adjustments applied to account for differences between participants and Alectra's broader fleet customers.

e) Has Alectra considered whether it intends to develop a permanent fleet managed charging program based on the ADF project?

f) Please confirm whether Alectra Utilities will file the final evaluation results of the ADF project with the OEB.

RESPONSE:

a) Alectra respectfully notes that this interrogatory is overly broad and would require the disclosure of internal working documents that are not relevant to the determination of this proceeding. The key material and relevant information regarding the ADF Project has been provided in the attached project charter in 1-DRC-7_Attachment 1_Charter AlectraDrive for Fleets.

b) The Alectra Drive for Fleets project involves the procurement of EV charging equipment and fleet charging management software and related services. As contracting discussions with these vendors are ongoing at the time of filing, the selection of vendors has not been finalized.

Evaluation criteria focused on objective, vendor-agnostic requirements, including interoperability, scalability, and the ability to integrate hardware and software solutions. For example, solutions were required to comply with the Open Charge Point Protocol (OCPP) standard to reduce technology lock-in and mitigate future integration risk. Additional criteria included demonstrated capability to deliver and support the proposed solution and prior experience providing similar services.

Testing protocols are being developed based on program requirements informed by Alectra Utilities' objectives and applicable IESO requirements.

c) The Alectra Drive for Fleets project, does not establish a formal definition or quantitative metric for “avoided” or “deferred” customer service upgrades. Customers requiring immediate distribution system upgrades to accommodate EV chargers are excluded from the Alectra Drive for Fleets project through eligibility screening.

As part of the pilot's evaluation objectives, Alectra Utilities intends to assess whether managed charging mitigates incremental peak demand relative to unmanaged charging. Measurement will be based on observed impacts to peak load and load profiles using standard evaluation practices. As data collection has not yet commenced, no measurement has been undertaken to date.

d) The Alectra Drive for Fleets project is intended to support program evaluation and modelling to inform potential system-wide planning insights. As data collection has not yet commenced and participants have not yet been contracted, no results are currently available to be scaled.

If sufficient data is generated, Alectra Utilities would use modelling informed by observed charging behavior to assess how pilot results may translate to broader fleet customer segments. Any scaling would consider differences in fleet size, charging patterns, operating profiles, and service locations, and would be assessed using standard distribution planning practices. The application of pilot results to system-wide planning assumptions would be subject to further analysis and validation.

e) The Alectra Drive for Fleets pilot is intended to generate information to assess whether fleet managed charging can provide grid services, and under what conditions and at what cost. At this time, Alectra Utilities has not made any decisions regarding the development of a permanent fleet managed charging program.

f) Alectra Utilities would be prepared to share those results with the OEB, subject to their relevance and through an appropriate regulatory proceeding.

1-DRC-7

Attachment 1
Charter AlectraDrive for Fleets

PROJECT CHARTER

alectra
Discover the possibilities

AlectraDrive for Fleets

1.0 PROJECT IDENTIFICATION

Project Lead/Manager	[redacted]	**Project Sponsor**	[redacted]
Project Start Date	2/1/2025	**Project End Date**	3/31/2028
Workstream Name	AlectraDrive for Fleets	**Document Version**	1.0

2.0 EXECUTIVE SUMMARY

Project Description

The AlectraDrive for Fleets project accelerates fleet electrification in Alectra's service territory, supporting operators with advisory services, EVSE deployment, and managed charging solutions. The project leverages partnerships with leading vendors (e.g., Panasonic, Siemens) and is jointly funded by IESO's Grid Innovation Fund and NRCan's On-Road Decarbonization Fund. Through collaborative efforts and a clear RACI structure, the project ensures responsibilities are well-defined and deliverables are met. Testing and validation at Alectra sites will ensure robust integration before customer rollout.

Benefits

- **Customer Benefits:**
    - **Reduced Operational Costs**: Fleet operators can significantly reduce costs associated with deploying and operating plug-in electric vehicles through optimized charging and shifting charging behaviour to overnight when rates are lowest.
    - **Enhanced Customer Satisfaction:** Comprehensive advisory services and educational support will help fleet operators navigate their electrification journey, leading to higher satisfaction rates.
    - **Capital Assistance:** Customers will reduce capital costs by receiving EV chargers installed for a low monthly "as-a-service" cost, allowing fleets to electrify more quickly than if they had to pay for all EVES up front.

- **Grid Benefits:**
    - **Reduced Grid Impact:** Managed charging solutions will help in reducing the impact on the grid by optimizing load distribution and supporting peak demand management.
    - **Cost-Effectiveness:** By learning from fleet behaviors and managed charging events, Alectra can optimize charging to reduce costs and avoid costly investments in utility infrastructure
    - **Infrastructure Cost Reduction:** Managed charging strategies will help in reducing infrastructure costs and traditional poles and wires upgrades by shifting charging behavior to off-peak times

- **Enhanced Grid Resilience:** Managed charging technology integration minimizes grid impact and enhances resilience by actively managing charging patterns and utilizing demand response capabilities.

Financial Summary

The AlectraDrive for Fleets project is supported by significant external funding and internal resources, enabling a multi-year pilot focused on fleet electrification and grid optimization.

Funding Sources & Amounts:

- The project is jointly funded by the Independent Electricity System Operator (IESO) Grid Innovation Fund and Natural Resources Canada (NRCan) On-Road Decarbonization Fund.
- As of March 2025, IESO has committed approximately $1,100,000 to support managed charging software development, grid integration, and reporting activities.
- NRCan has allocated $ $1,044,695 for EVSE procurement, installation, and customer advisory services.
- Funding agreements are scheduled to be finalized by Q2 2025, with disbursements aligned to project milestones through March 2028.

Budget Overview:

- The total project budget covers capital expenditures (EVSE hardware, software licenses, installation costs) and operating expenditures (project management, consulting, ongoing support).
- Major cost drivers include vendor contracts, internal labor, and technology deployment.
- Vendor partners may provide additional in-kind contributions, such as discounted hardware or advisory support.

Financial Timeline:

- Initial funding and project setup occur in Year 1 (2025), with major capital investments and customer onboarding in Years 2–3 (2026–2027).
- Ongoing operational costs and benefits (e.g., reduced grid infrastructure upgrades, customer operational savings) are realized throughout the project, with final reporting and closeout in Year 4 (2028).

Assumptions & Risks:

- Budget estimates are based on anticipated fleet participation, average EVSE installation costs, and projected managed charging software expenses.
- Risks include potential delays in vendor contracting, changes in funding disbursement schedules, and variability in customer recruitment rates.

3.0 PROJECT DEFINITION

Project Scope

IN SCOPE - Scope Inclusions & High-Level Requirements

• Customer education and advisory services (funded by both NRCan and IESO), including website updates, tailored fleet reports, and assessments. • Capital investment through EVSE purchase and installation for selected fleet customers (NRCan-funded, tracked as an IESO KPI). • EV load forecasting (IESO-funded), culminating in a final report at project closure detailing projected fleet load growth and mitigation strategies (e.g., managed charging). • Deployment of software-controlled managed charging for customer fleets to reduce grid impact and customer costs. • Testing of hardware and software on Alectra assets prior to customer recruitment and project delivery. • General project management activities: financial reporting, PMO reporting, procurement, legal contracting, and stakeholder communications. • Capture and transfer of learnings for future eDSM programming and Smart Cities initiatives.
OUT OF SCOPE - Scope Exclusions
• Full Alectra-territory wide implementation (this is a 3-year pilot). • Electrical infrastructure upgrades at customer sites. • Vehicle purchase and procurement for customer fleets.

Project Deliverables

IESO Deliverables			
Milestone	**Deliverable (ID)**	**Due Date**	**Explanation**
M1	GIF 2024 Demonstration Framework – 3.1 collaborate with IESO to finalize 12–20 wholesale-level test cases	Nov 30, 2025	Confirm scope of wholesale-level tests and finalize with IESO GIF team.
M1	GIF 2024 Demonstration Framework – 3.2 complete IESO template	Nov 30, 2025	Populate the prescribed framework template aligned to finalized test cases.
M1	Program Design Report – 4.1 project management documentation (charter, RACI, plan, budget)	Nov 30, 2025	Submit core PM artifacts package per IESO Part A/B expectations.
M1	Program Design Report – 4.2 customer recruitment plan	Nov 30, 2025	Final plan covering channels, tools, qualification, and funnel KPIs.
M1	Program Design Report – 4.3 evaluation vendor procurement & contract execution	Nov 30, 2025	Award and execute evaluator agreement (e.g., Guidehouse) to enable M&V.
M1	Program Design Report – 4.4 evaluation/M&V plan (outline)	Nov 30, 2025	Outline logic model, data sources, and measurement methods.

M1	Program Design Report – 4.5 T-D coordination protocols	Nov 30, 2025	Define coordination and data exchange practices across T&D interfaces.
M1	Program Design Report – 4.6 program design	Nov 30, 2025	Document offer rules, eligibility, settlement, and operations concept.
M1	Program Design Report – 4.7 EV load forecasting report outline and plan	Nov 30, 2025	Objectives, use cases, data sources, and approach for fleet load study.
M1	Program Design Report – 4.8 marketing & customer education plan	Nov 30, 2025	Web/content roadmap, campaigns, and stakeholder outreach plan.
M1	Program Design Report – 4.9 fleet advisory services outline	Nov 30, 2025	Services catalog (rightsizing, EVSE siting, charging strategies, etc.).
M1	Program Design Report – 4.10 plan distribution-level test cases	Nov 30, 2025	Define D-level (local grid) test scenarios to complement wholesale tests.
M1	Alectra Internal Hardware Plan – 5.1 complete hardware procurement (Alectra sites)	Nov 30, 2025	Purchase internal EVSE and controllers for lab/site validation.
M1	Alectra Internal Hardware Plan – 5.2 complete hardware installation (Alectra sites)	Nov 30, 2025	Install/commission internal EVSE for testing plan execution.
M1	Milestone Report 1 – 6.1 IESO milestone report (Part A & B)	Nov 30, 2025	Submit IESO-prescribed report set.
M1	Milestone Report 1 – 6.2 invoices ≥$50k	Nov 30, 2025	Provide all >$50k invoices as required.
M2	Measurement & Verification – 4.1 develop and draft M&V plan	Aug 1, 2026	Draft detailed M&V plan for managed charging/DR performance.
M2	UAT Plan – 5.1 complete hardware procurement (Alectra & customers)	Aug 1, 2026	Procure EVSE for pilot sites to support UAT/SIT.

M2	UAT Plan – 5.2 complete installation & commissioning (Alectra & customers)	Aug 1, 2026	Install/commission EVSE at pilot sites to readiness.
M2	UAT Plan – 5.3 develop UAT report incl. testing plan for EVSE, managed charging, fleet SW	Aug 1, 2026	Produce UAT plan/report covering customer success validation.
M2	UAT Plan – 5.4 complete Site Integration Testing (SIT) report	Aug 1, 2026	Produce SIT report on end-to-end integrations.
M2	Fleet Engagement – 6.1 vendor contracts executed	Aug 1, 2026	Execute outstanding vendor SOWs/POs required for delivery.
M2	Fleet Engagement – 6.2 develop customer participation agreements	Aug 1, 2026	Draft program agreements and schedules.
M2	Fleet Engagement – 6.3 execute customer participation agreements	Aug 1, 2026	Sign 2–3 customers as per plan.
M2	Fleet Engagement – 6.4 website updates & customer education documents	Aug 1, 2026	Launch/update program pages & materials.
M2	Fleet Engagement – 6.5 interim customer survey & interviews #1	Aug 1, 2026	Conduct and summarize first wave.
M2	Fleets Plan – 7.1 finalize EV load forecasting approach	Aug 1, 2026	Confirm methodology/scopes for forecasting deliverable.
M2	Fleets Plan – 7.2 align with DER Market Platform	Aug 1, 2026	Define alignment with Alectra DER market platform.
M2	Milestone Report 2 – 8.1–8.3 reports, invoices ≥$50k, permits/certificates (as appl.)	Aug 1, 2026	Submit M2 reporting package and supporting docs.
M3	M&V Report – 4.1 develop M&V report (data collection, validation, analysis)	Jul 1, 2027	Analyze 12-month dataset and present results.
M3	M&V Report – 4.2–4.4 conduct 8–15 D-level tests (Managed Charging, DR, system asset protection)	Jul 1, 2027	Execute distribution-level field tests across three themes.
M3	GIF Framework – 5.1–5.2 conduct 12–20 IESO-prescribed test cases & update template	Jul 1, 2027	Run wholesale test set and update framework file.

M3	Fleet Advisory Services – 6.1–6.2 services report & interim survey #2	Jul 1, 2027	Summarize advisory services and second wave insights.
M3	Software Commissioning – 7.1 complete commissioning & optimization	Jul 1, 2027	Commission CMS, tuning schedules/caps.
M3	Milestone Report 3 – 8.8–8.3 KPI report; deploy incentives; customer hardware installation completion; reports/invoices/permits	Jul 1, 2027	Submit KPI report; document incentives & installations; file M3 package.
M4	Final Report (AODA template) – 3.1–3.6 (analysis/use cases; survey results; AODA compliance & accessibility report; load impact & DER MP integration; commercialization/scalability; results & next steps)	Jan 1, 2028	Final comprehensive public-facing report set per IESO template and AODA.
M4	KPI Report – 4.1 evaluate against proposal KPIs	Jan 1, 2028	Final KPI read-out against proposal targets.
M4	Milestone Report 4 – 5.1–5.6 reports/invoices; customer incentives deployed; closeout & IESO presentation; customer closeout activities	Jan 1, 2028	Final reporting & program closeout package.

NRCan Deliverables			
Phase	**Deliverable**	**Due Date**	**Explanation**
Phase 1	Project Management documentation	Nov 30, 2025	Charter, RACI, plan, budget.
Phase 1	Vendor contracting (evaluator + other vendors as required)	Nov 30, 2025	Execute evaluator and priority vendors.
Phase 1	Fleet customer journey mapping (stakeholder interview summary; journey map; website recommendations; recruitment plan)	Nov 30, 2025	Discovery & plan set for recruitment/UX.

Phase 1	Customer identification & recruitment strategy development	Nov 30, 2025	Criteria, long-list, marketing & education outlines.
Phase 1	Fleet Advisory Services outline (service overview, education kit, guides/FAQs, support framework)	Nov 30, 2025	Define advisory artifacts & processes.
Phase 1	Program development/design & vendor identification	Nov 30, 2025	Scope, detailed project plan, vendor requirements/selection.
Phase 1	Site identification (Alectra sites) & internal testing plan	Nov 30, 2025	Site criteria/approved list; internal testing plan & report-outs.
Phase 1	Managed charging testing (Alectra sites) – viability, roles, gaps, deployment ideas	Nov 30, 2025	Validate tools on Alectra assets pre-customer.
Phase 1	Evaluation plan development (outline)	Nov 30, 2025	Outline methods & metrics.
Phase 1	Technology integration testing, initial analysis & research	Nov 30, 2025	Documented findings per location as needed.
Phase 1	Phase 1 Report	Nov 30, 2025	Summarize Phase 1 results.
Phase 2	Fleet vendor contracts executed (final)	May 1, 2026	Signed partner/vendor agreements.
Phase 2	Fleet customer contracts executed (2–3)	May 1, 2026	Execute participation agreements.
Phase 2	Fleet advisory service deployment & fleet assessment	May 1, 2026	EVSE needs; install scope; rightsizing & route optimization; data sources.
Phase 2	Website material development & updates	May 1, 2026	Education hub and content live.
Phase 2	Identification of utility data sources	May 1, 2026	Parent-child equipment mapping, constraints, future standards options.
Phase 2	Development/refinement of use cases	May 1, 2026	Document objectives/requirements & scenarios.
Phase 2	Education & awareness building (incl. staff training needs, curriculum)	May 1, 2026	Campaigns and training planning.

Phase 2	Site identification (customer) & approvals	May 1, 2026	Identify/evaluate/approve pilot sites.
Phase 2	Final Evaluation Plan	May 1, 2026	Finalize evaluation approach.
Phase 2	Baseline data collection (fleet/routes)	May 1, 2026	Collect required baseline data.
Phase 2	Managed charging testing (Alectra sites) – update	May 1, 2026	Progressed findings and implementation concepts.
Phase 2	Interim customer survey & interviews #1	May 1, 2026	First customer insight wave.
Phase 2	EVSE installation & materials (customer sites) – initial	May 1, 2026	Needs assessment, procurement, install summary, testing feedback.
Phase 2	Fleet managed charging & optimization program delivery – development	May 1, 2026	Managed charging parameters (customer/grid) & data support.
Phase 2	Software integration (telematics/CMS)	May 1, 2026	Integrate managed charging software with fleet systems.
Phase 2	Phase 2 Report	Nov 1, 2026	Phase 2 progress/results.
Phase 3	Operations & customer support (ongoing)	Nov 1, 2026	Procedures, site visits, support.
Phase 3	Mid-project assessment & business model revision (as needed)	Nov 1, 2026	Assessment memo & change outline.
Phase 3	Baseline collection (continued)	Nov 1, 2026	Update baseline data as needed.
Phase 3	EVSE installation & materials (customer sites) – completion	Nov 1, 2026	Final readiness & completion report.
Phase 3	Managed charging & optimization – development	Nov 1, 2026	Ongoing schedule/parameter optimization.
Phase 3	Software integration – integrated	Nov 1, 2026	CMS integrated into fleet software.
Phase 3	Deployment of customer incentives (participation)	Nov 1, 2026	Deliver customer incentives; collect inputs for evaluation.
Phase 3	Stakeholder review meetings	Nov 1, 2026	Schedules, agendas, summaries, actions.
Phase 3	Phase 3 Report	Nov 1, 2026	Phase 3 results.

Phase 4	Operations & customer support (ongoing)	Jun 1, 2027	Continued ops & support.
Phase 4	Interim customer survey & interviews #2	Jun 1, 2027	Second insight wave.
Phase 4	Managed charging & optimization – development	Jun 1, 2027	Continued operations and optimization.
Phase 4	Deployment of customer incentives	Jun 1, 2027	Continued incentive delivery.
Phase 4	Phase 4 Report	Jun 1, 2027	Phase 4 results.
Phase 5	Operations & customer support (wrap-up)	Apr 1, 2028	Final support & decommissioning steps.
Phase 5	Project closeout & handoff (ownership transfer, survey, data download, financials)	Apr 1, 2028	Closeout checklist completed.
Phase 5	Final customer interviews & survey #3	Apr 1, 2028	Final insights; experience analysis.
Phase 5	Final Evaluation	Apr 1, 2028	Final third-party evaluation report.
Phase 5	Managed charging & optimization (final period)	Apr 1, 2028	Final program delivery cycle.
Phase 5	Deployment of customer incentives (final period)	Apr 1, 2028	Final incentive cycle and inputs for reporting.
Phase 5	Final report & recommendations + research paper / best practices	Apr 1, 2028	Capstone report incl. best practices.

Consolidated (NRCan & IESO)				
Theme	**IESO Item**	**NRCan Item**	**Due Date**	**Alignment/Consolidation Approach**
Program design & PM docs	M1 4.1–4.6/4.8–4.10	Phase 1 Project Mgmt; Program Development/Design; Recruitment/Education artifacts	Nov 30, 2025	Single PM/design pack + annexes (marketing, advisory, test plan). Apply IESO template for Part A/B; provide NRCan summary in Phase 1 report.
Evaluation planning	M1 4.4 (outline), M2 4.1 (M&V plan)	Phase 1 Evaluation Outline; Final Evaluation Plan (Phase 2)	Nov 30, 2025 / May 1, 2026	Maintain one Evaluation/M&V plan; publish excerpts to each funder's structure.

Internal testing	M1 5.1–5.2 (Alectra HW procure/install)	Phase 1 Internal Testing Plan & findings	Nov 30, 2025	One internal testing dossier (plan + results) used in both submissions.
UAT/SIT & integration	M2 5.3–5.4	Phase 2 Software Integration; EVSE Install (customers)	Aug 1, 2026 / May–Nov 2026	One UAT/SIT pack: customer readiness + integration results; include NRCan site narratives.
Customer surveys & interviews	M2 6.5 (Interim #1); M3 6.2 (Interim #2)	Phase 2 Interim #1; Phase 4 Interim #2; Phase 5 Final #3	Aug 1, 2026 / Jul–Jun 2027 / Apr 1, 2028	Single survey instruments; staged reports tailored per funder schedule.
Incentives	M3 8.9; M4 5.4	Phase 3/4/5 "Deployment of Incentives"	Jul 1, 2027 / Jan 1, 2028 / Apr 1, 2028	One incentive ledger/schedule; attach to both IESO and NRCan reports.
Final reporting	M4 AODA Final Report set + KPI Report + Closeout	Phase 5 Final Evaluation; Final Report & Recommendations	Jan 1, 2028 / Apr 1, 2028	Develop one master final report, generate IESO AODA version + NRCan final with recommendations.

Critical Success Factors and Metrics

KPI / Metric	Funder	Target / Threshold	Description / Measurement Approach
Unidirectional Chargers Installed	NRCan	Min 8, Max 15	Number of Level 2 chargers installed at pilot sites
Fleet Electrification Partners Contracted	NRCan	Min 2, Max 5	Number of fleet customers onboarded
Managed Charging Success Rate	IESO/NRCan	≥ 85% (IESO: 85–90%)	% of scheduled managed charging events completed
Charger Uptime	IESO/NRCan	≥ 90%	% of time chargers are operational
Software Uptime	IESO/NRCan	≥ 90%	% of time managed charging platform is available
Peak Load Reduction (Depot Level)	IESO/NRCan	≥ 13%	% reduction in depot-level peak kW demand
Off-Peak Load Shift (Managed Charging)	NRCan	10–20%	% of charging load shifted to off-peak hours
Communication Signal Success	IESO	≥ 90%	% of successful responses to grid signals (TOU/DR)
Customer Satisfaction (Advisory/Education)	IESO/NRCan	≥ 75%	% of pilot and general customers satisfied (survey)
Customer Satisfaction (Managed Charging Events)	IESO	≥ 75%	% of pilot customers satisfied with managed charging

Baseline Data Collection	IESO/NRCan	12 months	Months of telematics and charging data collected
Evaluation Plan Completion	IESO/NRCan	1 (complete)	Approved evaluation/M&V plan delivered
EV Load Forecasting Report Completion	IESO/NRCan	1 (complete)	Final load forecasting report delivered
Incentives Delivered and Tracked	IESO/NRCan	100% of eligible	All incentives delivered and tracked for reporting
Education/Advisory Effectiveness	IESO/NRCan	Qualitative/Survey	Effectiveness of education and advisory services
Regulatory Compliance (AODA, Safety, etc.)	IESO/NRCan	100% compliant	All public deliverables meet accessibility and safety

Delivery & Compliance
- All IESO milestone and NRCan phase deliverables are submitted on time, complete, and in the required format.
- Shared deliverables are produced once and versioned appropriately for each funder, ensuring consistency and efficiency.

Testing & Integration
- Internal testing of hardware and software at Alectra sites is completed and documented before any customer deployment.
- User Acceptance Testing (UAT) and Site Integration Testing (SIT) are successfully conducted at pilot customer sites, with all pass/fail criteria met and any issues remediated.
- Wholesale-level and distribution-level test cases are executed as prescribed, with results documented and lessons learned incorporated into program improvements.

Performance & Experience
- Managed charging sessions achieve a success rate of at least 85%, adhering to scheduled caps and windows.
- Charger uptime and managed charging software uptime are maintained at or above 90% during the active pilot period.
- Peak demand (kW) at participating fleet depots is reduced by at least 13% compared to baseline.
- Customer satisfaction with advisory services and program participation is at least 75%, as measured by survey responses.
- All final public-facing deliverables meet AODA accessibility requirements.

Forecasting & Insights
- The EV Load Forecasting Report is delivered as scheduled, with actionable insights integrated into planning and DER market platform alignment.

Customer Outcomes
- Pilot Customer Advisory Services:
  - Selected fleet customers receive tailored advisory services, including fleet rightsizing, EVSE siting, charging strategy development, and ongoing support throughout the pilot. Each pilot customer's journey is mapped and documented, with feedback collected at multiple stages.
- Education for Pilot Customers:
  - Pilot participants are provided with educational materials, training sessions, and direct support to ensure successful electrification and managed charging adoption. This includes onboarding guides, FAQs, and access to technical experts

- General Education and Outreach:
    - Educational resources, communications, and outreach campaigns are developed and delivered to the broader Alectra customer base and the general public. This includes website updates, informational webinars, marketing materials, and awareness-building initiatives to promote fleet electrification and managed charging best practices.
- Customer Satisfaction and Engagement:
    - Customer satisfaction is measured through surveys and interviews at key project milestones. Insights from pilot and general customers are used to refine program offerings and support continuous improvement.
- Successful Onboarding and Participation:
    - At least 2–3 fleet customers are onboarded under executed participation agreements by the end of Phase 2. All pilot customers actively participate in managed charging and advisory services, with their experiences informing future program scale-up.
- Incentives Delivery and Tracking:
    - Financial incentives are delivered to participating customers for managed charging participation, with all incentive delivery and customer performance tracked and reported for evaluation.

High-Level Schedule – Project Milestones

Date	IESO Milestone	NRCan Phase	Description
Nov 30, 2025	Milestone 1	Phase 1	Project setup: management documentation, recruitment plan, evaluation outline, internal testing, advisory services, initial reporting.
May 1, 2026	—	Phase 2	Vendor and customer contracts executed, fleet assessment, website updates, baseline data collection, managed charging setup, interim survey #1.
Aug 1, 2026	Milestone 2	—	UAT/SIT reports, hardware/software commissioning, customer agreements, website updates, interim survey #1.
Nov 1, 2026	—	Phase 3	Operations support, mid-project assessment, EVSE installation completion, managed charging,

			incentives, stakeholder meetings.
Jul 1, 2027	Milestone 3	—	Measurement & verification report, distribution-level tests, advisory services report, software commissioning, KPI report, incentives, interim survey #2.
Jun 1, 2027	—	Phase 4	Continued operations, managed charging, incentives, interim survey #2, phase report.
Jan 1, 2028	Milestone 4	—	Final AODA-compliant report, KPI report, closeout, customer incentives, ownership transfer.
Apr 1, 2028	—	Phase 5	Project closeout, final evaluation, customer incentives, final survey/interviews, best practices report.

Dependencies

Requirement	Description
Vendor Contracts	Timely execution of contracts and statements of work with hardware, software, and advisory vendors is required for project delivery.
Customer Site Readiness	Fleet customer sites must be prepared and approved for EVSE installation and managed charging integration.
Technology Availability	Managed charging software and hardware must be available and compatible with customer fleets and Alectra systems.
Funding Disbursement	Ongoing funding from NRCan and IESO must be received according to milestone schedules.
Regulatory Approvals	All installations and operations must comply with relevant utility, municipal, and safety regulations.
Data Access	Access to fleet telematics and charging data is necessary for evaluation, reporting, and optimization.

Internal Resources	Sufficient project management, technical, and support staff must be available throughout the project lifecycle.

Major Assumptions and Constraints

Assumption	Description
Customer Participation	Assumes sufficient interest and commitment from fleet customers to participate in the pilot.
Technology Compatibility	Assumes EVSE hardware and managed charging software are compatible with customer vehicles and site infrastructure.
Funding Continuity	Assumes NRCan and IESO funding agreements remain in force through project completion.
Staff Capacity	Project team capacity and expertise are maintained; facilities can accommodate required staff and equipment.
Timeline Adherence	Project milestones and phases are completed according to the proposed schedule.
Data Quality	Assumes reliable and timely access to fleet and charging data for evaluation and reporting.
Regulatory Stability	Assumes no major changes in utility, municipal, or federal regulations that would impact project scope or delivery.

Major Risks

Risk	Description	Mitigation
Vendor Delays	Delays in legal review or contract execution with vendors could impact project timelines.	Early engagement, clear requirements, and contingency planning for alternate vendors.
Customer Recruitment Challenges	Difficulty in recruiting and onboarding fleet customers may limit pilot scope.	Proactive outreach, flexible participation criteria, and incentives for early adopters.
Technical Integration Issues	Challenges with managed charging software or hardware integration could affect pilot success.	Thorough internal testing, phased rollout, and dedicated technical support.
Funding Disbursement Delays	Delays or changes in NRCan or IESO funding schedules could impact project activities.	Maintain regular communication with funders, align deliverables to milestone payments, and prepare contingency budgets.
Regulatory or Compliance Changes	Changes in regulations or compliance requirements could	Monitor regulatory landscape, engage with compliance

	affect project scope or operations.	experts, and adapt project plans as needed.
Data Access or Quality Issues	Incomplete or unreliable data could hinder evaluation and reporting.	Establish robust data collection protocols, validate data sources, and maintain backup systems.
Resource Constraints	Limited staff or expertise could impact project delivery.	Plan for cross-training, maintain a resource pool, and engage external support if needed.

4.0 PROJECT ORGANIZATION

Project Governance

The AlectraDrive for Fleets project is governed by a structure that ensures clear accountability, effective decision-making, and streamlined issue escalation. The governance model centers on the Project Manager/Lead, supported by a core project team, functional contributors, vendor partners, and key stakeholders.

Governance Structure:

- Project Sponsor: Provides strategic direction, secures funding, approves major deliverables, and resolves escalated issues.
- Project Manager/Lead: Oversees day-to-day project delivery, manages scope, schedule, budget, quality, team coordination, and communications.
- Core Project Team: Includes technical leads, advisory specialists, data analysts, and support staff responsible for executing project tasks.
- Vendor Partners: Hardware, software, and advisory vendors (e.g., Panasonic, Siemens) engaged for technical integration, installation, and managed charging solutions.
- Stakeholder Committee: Includes representatives from Alectra, participating fleet customers, and external advisors for oversight and feedback.
- Escalation Path: Issues unresolved at the project team level are escalated to the Project Sponsor and, if needed, to the Executive Committee.

Key Stakeholders

Stakeholder	Reason for Involvement	Department	Title/Role
[redacted]	Strategic direction, funding, approvals	Smart Cities	Project Sponsor
[redacted]	Project delivery, coordination	Smart Cities	Project Manager/Lead
[redacted]	Technical oversight, integration	Smart Cities	Technical Lead
[redacted]	Data analysis, reporting	Smart Cities	Data Analyst
[redacted]	Customer engagement, education	Smart Cities	Advisory Specialist
Vendor Partners	Hardware/software/advisory delivery	External	Vendor Representatives
Fleet Customers	Pilot participation, feedback	External	Fleet Managers

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Stakeholder Committee	Oversight, feedback, escalation	Cross-functional	Committee Members

Project Team Resources

Business Unit	Resource Name	Project Role	Time/Effort Required	When Required
Smart Cities	[redacted]	Project Manager/Lead	60%	Throughout
Smart Cities	[redacted]	Technical Lead	20%	Throughout
Smart Cities	[redacted]	Data Analyst	70%	Throughout
Smart Cities	[redacted]	Advisory Specialist	80%	Throughout
External Vendors	Panasonic, Siemens	Vendor Partners	As needed	Per milestone
External Fleet	Pilot Customers	Fleet Managers	As needed	Per phase/milestone

Project Roles Responsibilities

Role Name	Description of Responsibility
Project Sponsor	Strategic alignment, funding, approvals, benefit realization, issue resolution, and project success evaluation.
Project Manager/Lead	End-to-end delivery, scope, schedule, budget, team management, communications, risk/issues, and reporting.
Technical Lead	Hardware/software integration, technical troubleshooting, vendor coordination, and testing oversight.
Data Analyst	Data collection, analysis, KPI tracking, and reporting for evaluation and optimization.
Advisory Specialist	Customer engagement, education, advisory services, and outreach coordination.
Vendor Partners	Delivery of hardware, software, and advisory services; technical support and integration.
Fleet Managers	Participation in pilot, feedback, and collaboration on site readiness and managed charging adoption.
Stakeholder Committee	Oversight, feedback, escalation, and support for project governance and decision-making.

5.0 PROJECT MANAGEMENT APPROACH

Managing Finances

- The Project Manager is responsible for overseeing and reporting on both IT and overall project budgets, including updates into ERP systems.
- All contractor, supplier, and vendor invoices and expenses are submitted and approved through established workflows, with milestone-based funding tracked for NRCan and IESO.
- Financial reporting is aligned with funder requirements, with monthly and milestone-based updates provided to internal finance and external stakeholders.

Managing Organizational Change Management and Communications

- Communications are managed according to the project's Change Management and Communication Plan.
- The Project Manager coordinates all major communication events, including stakeholder updates, customer outreach, and internal team briefings.
- Communications frequency is tailored to project phase and audience, with regular updates via email, SharePoint, and scheduled meetings.

Project Tracking

- Project activities are tracked using Asana, with schedules updated and published weekly by the Project Manager.
- Status reports are issued monthly for Tier 3 projects.

Managing Change Requests

- Any changes to project scope, timeline, budget, or resources are assessed by the Project Manager and either approved or escalated to the Project Sponsor or Steering Committee.
- Change Request forms are prepared for significant changes (e.g., >30 days delay, >10% budget impact) and must be approved before implementation.

Risks/Issues/Changes Tracking

- Risks, issues, and key decisions are tracked in Asana and RAID log.
- All new risks and issues identified during a reporting period are documented in the project status reports.
- The PMO reviews and reassigns risks and issues as needed to ensure accountability.

Validating and Approving Deliverables

- The Project Manager has five working days after delivery to obtain sign-off for each deliverable.
- If sign-off is not obtained within five days, the issue is escalated to the Project Sponsor.
- Deliverable acceptance is documented in writing or via verbal confirmation, with the Project Sponsor providing final approval.

Sign-off and Acceptance of Deliverables

- At key project junctures, the team recommends acceptance of deliverables to the Project Sponsor.
- The Project Sponsor signs off on all major project deliverables, ensuring alignment with strategic objectives and funder requirements.

RESPONSES TO DISTRIBUTED RESOURCE COALITION INTERROGATORIES

INTERROGATORY 1-DRC-8

Reference: • Exhibit 1, Tab 7, Schedule 1

Preamble: Alectra states that the Grid Enablement - Alectra V2X Pilot (V2X Pilot) is intended to evaluate the grid impact of bidirectional EV charging for light- and medium-duty vehicles, including school buses, and to assess the potential for V2G services such as peak demand reduction and demand response.

a) Please provide any and all working papers, reports, and analysis conducted on or in support of the V2X Pilot. b) Please explain the degree of control exercised by Alectra over V2X dispatch, including how control is coordinated among the utility, aggregators, fleet operators, and charging vendors.

b) Please identify the grid services that will be evaluated (e.g., peak demand reduction, contingency support, voltage support, N-1 support), and specify what level these services will be assessed at (customer, transformer or feeder, station, etc.).

c) Please provide the performance metrics used to evaluate V2X resources.

d) Please explain and discuss whether Alectra considers V2X-enabled EVs to be a viable NWS for distribution system needs.

e) Please identify the potential value streams that will be evaluated in the pilot and explain how Alectra intends to prioritize or coordinate these value streams where multiple services compete for the same V2X resource.

f) Please identify any known or anticipated procedural barriers to V2X deployment (e.g., interconnection rules, protection settings, telemetry, settlement, customer agreements).

g) Please confirm whether any grid modernization investments proposed in the Application explicitly support bidirectional power flows and V2X dispatch, including telemetry aggregation, protection coordination, and real-time visibility.

h) Has Alectra considered establishing a permanent V2X-enabled program or procurement mechanism based on the V2X Pilot?

i) Please confirm whether Alectra will file a final V2X Pilot evaluation report and/or dataset with the OEB.

RESPONSE:

a) Alectra respectfully notes that this interrogatory is overly broad and would require the disclosure of internal working documents that are not relevant to the determination of this proceeding. The key material and relevant information regarding the V2X Project has been provided in the attached project plan in 1-DRC- 8_Attachment 1_Charter V2X Project Management Plan.

b) Alectra's degree of control over V2X dispatch is supervisory and pre-planned. Dispatch is coordinated among Alectra Utilities, the fleet operator, and the charging vendor through an energy management software platform to ensure operational and technical requirements are met. Alectra Utilities will define dispatch windows and testing parameters, while the fleet operator retains control over vehicle availability and minimum state-of-charge requirements. The fleet operator may override dispatch signals and opt out of participation at any time.

c) The V2X Pilot is intended to evaluate the technical feasibility of several potential grid services under simulated conditions. The pilot is not intended to provide live contingency support, voltage support, or N-1 support. Rather, these conditions will be simulated to assess whether V2X-enabled electric school buses could technically respond to such system needs in potential future applications. Simulated grid services will be measured at the customer site level.

d) The performance of V2X resources will be assessed using technical, operational, and coordination-related metrics. These include:

   a. the ability of the resource to dispatch the forecasted capacity;
   b. the ability to sustain dispatch for the required duration;
   c. compliance with minimum state-of-charge constraints; and
   d. the effectiveness of coordination among the utility, fleet operator, charging vendor, and software provider.

e) Alectra Utilities considers V2X-enabled electric vehicles to be one of several emerging technologies that could potentially contribute to non-wires solutions. Alectra Utilities' approach to non-wires solutions remains technology-neutral and service-led through an active market. Distribution system needs will be evaluated first, and solutions will be assessed based on their ability to cost-effectively and reliably meet those needs. V2X capabilities may contribute where appropriate, subject to demonstrated feasibility. For more information about performance characteristics and their relation to Alectra's planned procurement of NWS, please see DRC-10.

f) The pilot will evaluate several potential value streams, including peak demand reduction at the customer site, load shifting and load management, operational flexibility, and greenhouse gas emissions reduction. Testing will include assessing whether minimum state-of-charge requirements are maintained, the ability to shift load profiles, and the ability to transition between different simulated grid service scenarios. Where multiple services compete for the same V2X resource, fleet and customer operational requirements will be prioritized over grid services. Dispatch events will only occur when fleet operator requirements are satisfied. As the pilot operates in a simulated environment, Alectra Utilities will control the timing and sequencing of test events.

g) At this time, Alectra Utilities has not identified any definitive procedural barriers that would prevent implementation of the V2X Pilot. However, the pilot is expected to inform Alectra Utilities' understanding of potential procedural, technical, or regulatory considerations associated with broader V2X deployment. These findings will be summarized in a final evaluation report.

h) The V2X Pilot itself does not rely on incremental grid modernization investments beyond those already proposed in the Application. Alectra's investments in Grid Modernization are outlined in Appendix B14.

i) Alectra Utilities is still evaluating the long-term potential for a V2X-enabled program or procurement approaches. The V2X Pilot is intended to inform Alectra Utilities' understanding of the technical feasibility, operational considerations, and potential role of V2X resources within a technology-neutral non-wires solutions framework. For more information about Alectra's planned procurement of NWS, please see DRC-10.

j) Yes. Alectra Utilities will share the final pilot evaluation report with the OEB.

1-DRC-8

Attachment 1
Charter V2X
Project Management Plan

2025 | By: Alectra GRE&T Centre

Alectra V2X Pilot: Project Management Plan

Last Updated: Nov 28/2025

Project Management Plan

Table of Contents

Project Purpose/Background

The Government of Canada aims for 35% of medium- and heavy-duty vehicle sales to be zero-emission by 2030, reaching 100% by 2040. Electric school buses (ESBs) are a key focus due to their unique market position, representing a low-hanging fruit in the transition to zero-emission vehicles. ESBs, ideal for V2X technology, can reduce greenhouse gas emissions by 9 million metric tons annually, equivalent to removing 2 million cars from the roads by 2030.

The Alectra V2X Pilot will accelerate the adoption of bidirectional charging for light- and medium-duty vehicles, including electric school buses and Ford F-150s, within Ontario's power grid. The project will test V2X technology to evaluate performance, efficiency, and grid impact, supporting large-scale deployment and enabling strategic fleet dispatch to reduce peak demand and enhance grid resiliency.

This project adopts a customer-centric and data-driven approach, ensuring early adopters are well-informed about V2X advantages through feedback and input. Key initiatives include installing V2X chargers at transportation hubs, conducting a detailed Technology Assessment and Evaluation Report, and completing a Commercialization and Scalability Study for V2X business models and market readiness.

Challenges and solutions will be examined in collaboration with the protections and control team, addressing V2X connections and distribution generation rules. Additionally, the project will explore the revenue potential of ESBs providing power to the grid or buildings, creating a win-win scenario for schools and utility entities.

This initiative is partially funded by Natural Resources Canada (NRCan) and the Independent Electricity System Operator (IESO).

Project Objectives:

The V2X Pilot aims to:

1. Deploy and commission 3–5 bidirectional chargers, with at least three supporting electric school buses.
2. Evaluate technical performance of V2X systems, including:
    - Bidirectional charger efficiency
    - Charging/discharging performance
    - Impacts on vehicle battery performance
    - Grid integration and operational constraints
3. Demonstrate grid services use cases such as:
    - Peak demand reduction
    - Net export to the grid

  - Demand response participation
  - Building-level energy support
4. Develop commercialization pathways and scalable business models for broader V2X adoption.
5. Inform policy, regulatory, and standards development to enable future deployment at scale.
6. Develop educational and training materials to support V2X and Non-Wires Solutions (NWS) awareness.

Project Scope:

In Scope:

- Installation and commissioning of 3–5 bidirectional chargers at selected pilot sites (with focus on electric school bus depots).
- Integration with utility systems and validation of export limits in coordination with System Planning and Operations.
- Technology Assessment and Evaluation Report covering:
  - Charger capabilities and interoperability
  - System efficiency
  - Vehicle impacts
  - Grid performance and operational findings
- Commercialization and Scalability Study including:
  - Business model development
  - Market readiness assessment
  - Policy and regulatory recommendations
  - Codes, standards, and best practices for V2X implementation
- Customer engagement and education activities.
- Data collection and analysis to support pilot evaluation.

Out of Scope:

- Manufacturing of buses or charging equipment.
- Major upgrades to the utility's broader grid infrastructure.
- Long-term maintenance contracts beyond initial warranty periods.
- Expansion to other medium or large sized vehicle types (e.g., transit buses).

Outcome

- Install 3–5 bidirectional chargers, with at least three dedicated to electric school buses

- Assess vehicle performance, charging times, bidirectional charger efficiency, and evaluate how vehicle batteries can support the grid through net injection, peak shaving, and other use cases such as demand response (DR) events
- Assess codes, standards, best practices, policy and regulatory recommendations for larger scale V2X implementation
- Develop training materials to support V2X and Non-Wires Solutions (NWS) education

Impact

- Improve grid resiliency by using v2X enabled school buses to discharge back to the grid during peak periods and help balance load
- Support fleet electrification and create viable business cases for V2X adoption including educating and informing customers on the benefits and uses of bidirectional charging, and their role in supporting the energy transition
- Improve public health and reduce emissions from diesel school buses
- Lower fleet operating and energy costs while enhancing local energy security
- Drive economic growth and job creation through large-scale school bus electrification

Benefits

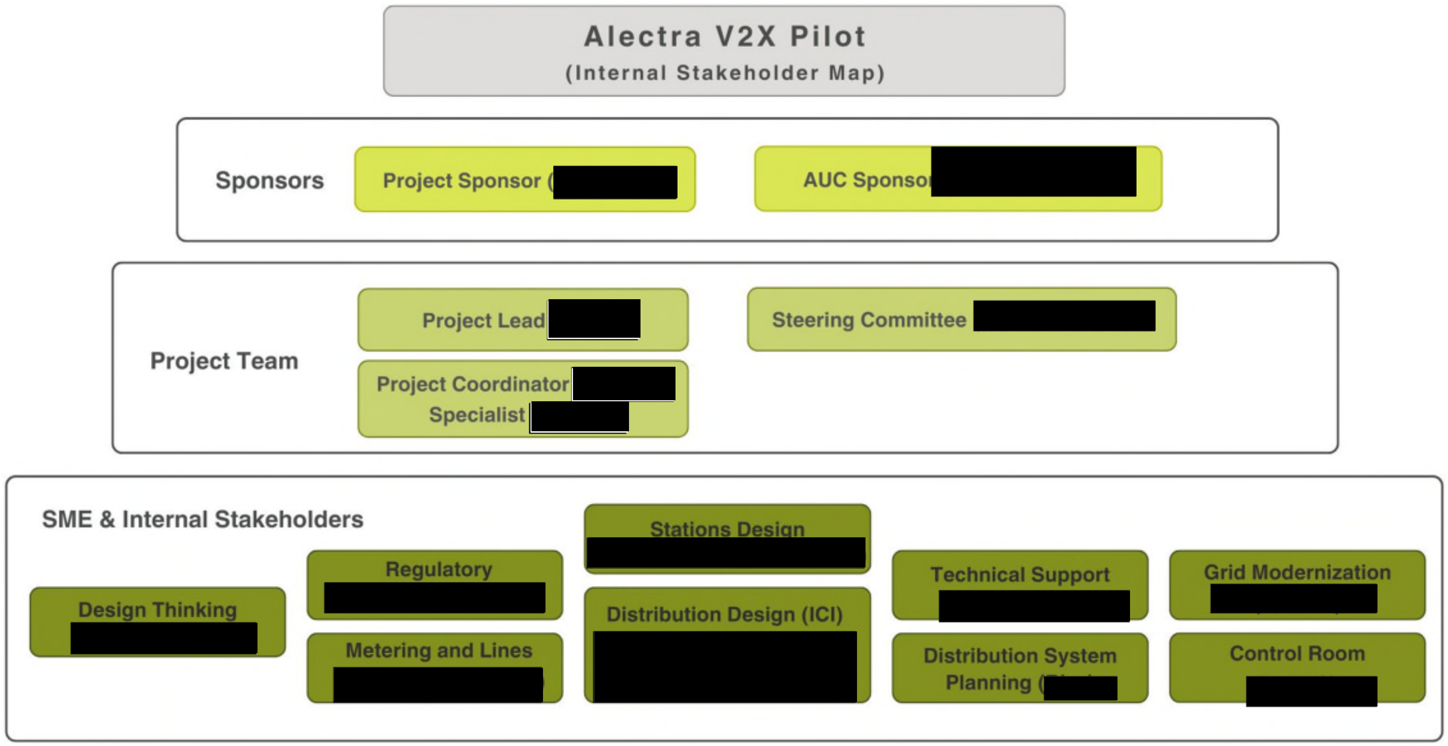
The Alectra V2X Pilot is expected to deliver benefits to the distribution system, customers, and the broader electricity sector by demonstrating how bidirectional electric vehicles can function as a flexible distributed energy resource. From a system perspective, the pilot will assess the ability of V2X-enabled vehicles—particularly electric school buses—to provide grid services (in simulated environments). This includes peak demand reduction, load balancing, and net energy injection. The project will generate real-world operational data on the impacts of bidirectional charging on feeders, transformers, and control room operations, informing distribution planning, protection practices, and non-wires alternatives assessments. These insights will help Alectra evaluate whether V2X resources can defer or complement traditional infrastructure investments while maintaining power quality and system performance.

In addition, the pilot will support customer electrification and broader policy objectives by reducing adoption risks for fleet operators and testing potential customer value propositions. Participating customers will gain experience with advanced V2X infrastructure and explore opportunities to reduce energy costs, improve site-level resilience, and participate in emerging grid services. The pilot will also contribute to environmental and public health benefits by accelerating the transition from diesel to electric school buses and supporting transportation decarbonization. Finally, the findings from the pilot will inform future regulatory, policy, and market design considerations by identifying technical, procedural, and commercial barriers to broader V2X deployment, thereby reducing uncertainty and risk associated with any future permanent V2X programs or procurements.

Stakeholder Communication Plan

Vendor	Name of Stakeholder(s)	Contact Info	Brief Deliverable Description	Frequency	Alectra Rep	Priority	Delivery Method
Norda Stelo	[redacted]	[redacted]	Scalability Support: Roadmap for ICI	Quarterly	[redacted]	Medium	Email + Working Sessions + Deliverable Reviews
Volta Research (Hero Energy as Subcontractor)	[redacted]	[redacted]	UAT Testing Support	Bi-weekly	[redacted]	High	UAT Sessions + Technical Meetings
Smart Grid Innovation Network	[redacted]	[redacted]	Training & Education Material; Knowledge Dissemination	Bi-weekly	[redacted]	Medium	Webinars + Document Packages
Green Communities Support	[redacted]	[redacted]	Consultation on ESBs (Electric School Busses)	Bi-weekly	[redacted]	Low	Email + Coordination Calls
Attridge Transportation/Enerstrat	[redacted]	[redacted]	ESB Site 1	Weekly	[redacted]	High	Working Sessions + Site Meetings + Emails
Highland Fleets	[redacted]	[redacted]	ESB Site Support to acquire ESBs	Tri-weekly	[redacted]	Medium	Virtual Meetings + Email
Software Provider - Synop	[redacted]	[redacted]	Control of EVSE; Execution of UAT	Bi-weekly	[redacted]	High	Working Sessions + Site Meetings + Emails
Installer – Smith and Long	[redacted]	[redacted]	Guidance on installation; installation for ESB Site 1	Weekly	[redacted]	High	Site Meetings + Email + Phone
Evaluator - Dunsky	[redacted]	[redacted]	Evaluator for codes, standards, policy recommendations	Bi-weekly	[redacted]	High	Email + Working Sessions + Deliverable Reviews
Evaluator - Guidehouse	[redacted]	[redacted]	Evaluator for UAT	Bi-weekly	[redacted]	High	Email + Working Sessions + Deliverable Reviews

Internal Stakeholder Map



Internal RACI

Legend

- **Responsible (R):** Person(s) completing the task.
- **Accountable (A):** Person ultimately answerable for the task's success.
- **Consulted (C):** Person(s) providing input and expertise.
- **Informed (I):** Person(s) who need to know progress or outcomes.

Please note the below RACI is **only for internal staff** (with the exception of funders). A separate RACI will be drafted for vendors.

Task	[redacted] (Project Lead)	Project Support Team	AUC Sponsor [redacted]	Project Sponsor [redacted]	Technical Support [redacted])	Steering Committee [redacted]	[redacted]	Network Operations ([redacted]	Connections Team	Lines and Metering	Grid Mod	Regulatory	Funders (NRCan, IESO)
Overall													
Strategic Project Planning	R/A	I		C		I							I
Development of PM material	R/A	R		I									I
Strategic Program Design development	R/A	I	I	C		C					C		C
Develop T-D coordination protocols	R/A	I		C		C					C		C
Budget management	R/A	I		I									I
Complete funder reports	R/A	R		I		I							I
NRCan reporting sign-off	A			R									I
IESO reporting sign-off	A			R		I							I
Consultation with Fleets Team on IESO Reports													
Internal Stakeholder Engagement	R/A	R		C		I							
External Stakeholder Engagement	R/A	R		I		I							
Phase 1: Planning (Aug 2025)													
Pilot Site Selection	R/A	I	I	I		I		C	C	C			I
Execute Vendor Agreements	R/A	I		I		I							I

Connections Application	R/A	R		I		I			C	C			I
Phase 2: Deployment (Apr 2026)													
Installation and Deployment	R/A	R		I	C	I		C	C	C			I
Regulatory Approvals and Compliance	R/A	I		C		I						C	I
Finalize UAT Plan	R/A	R		I	C	I					C		I
Participant Surveys	R/A	R		C		I	C						I
Phase 3: Testing (Aug 2027)													
V2X Technology Assessment	R/A	R		I	C	I		I			C		I
Wholesale/distribution level tests	R/A	R		I	C	I		C			C		C
DER platform integration	R/A	R	I	I	C	C		I			R		I
Integration with Microgrid Room	R/A	R	I	I	C	I							I
Participant Surveys	R/A	R		C		I	C						I
Data Collection and Analysis	R/A	R	I	I	C	I					I		I
Phase 4: Wrap-Up (Mar 2028)													
Eval Report	R/A	R	I	C		C					I		
Commercialization and Scalability Study	R/A	R	I	C		C					I	C	I
Complete Training Module	R/A	R		C		C							I
Knowledge Dissemination	R/A	R		C		C	C						C
V2X Customer Closeout Activities (equipment transfer, etc)	R/A	R		I		I							I

Active Major Issues

Name	Health Status	Category	Priority	Mitigation	Due

Ford Home Integration Kit not available in Canada (required to enable V2B at Cityview)	**At Risk**	**Scope**	**Normal**	- Escalated challenge with NRCan to determine if an exemption can be made through Measurement Canada - Exploring alternatives to Home Integration Kit. Met with Roulez Electrique to consider Sigenergy charger. ESA will need to validate and confirm certification - Exploring other chargers capable of V2B - Exploring other vehicles capable of V2B. Including through Charge@Work program	**2/27/2026**

Active Major Risks

Name	**Impact**	**Priority**	**Probability (%)**	**Mitigation**

Software integration challenges	Low	Normal	50%	• Chose a provider with an integrated stack and existing integration with hardware and bus OEM • Months long conversations with Synop to ensure outcomes/deliverables will be met
Ongoing trade negotiations; tariffs impacting prices and causing delays in receiving quotes for bus OEMs	Medium	Normal	60%	• Actively engage bus OEMs on prices • Procure a bus that is already deployed
Dependencies at Dundas location causing delays in receiving buses Attridge/Highland negotiations ZETF reliance	Medium	Normal	70%	• Have a back-up site: Guelph • Have a back-up bus to ensure no delays in unlocking funding: Microbird G5
Delays with legal agreements	Medium	Medium	40%	• Maintain communication with Alectra legal team to ensure project timelines can be met to the best of everyone's ability • Maintain communication with vendor (legal team or general contact)

				- Due diligence with internal supplier set-up to ensure process is as smooth as can be

Inactive Major Risks

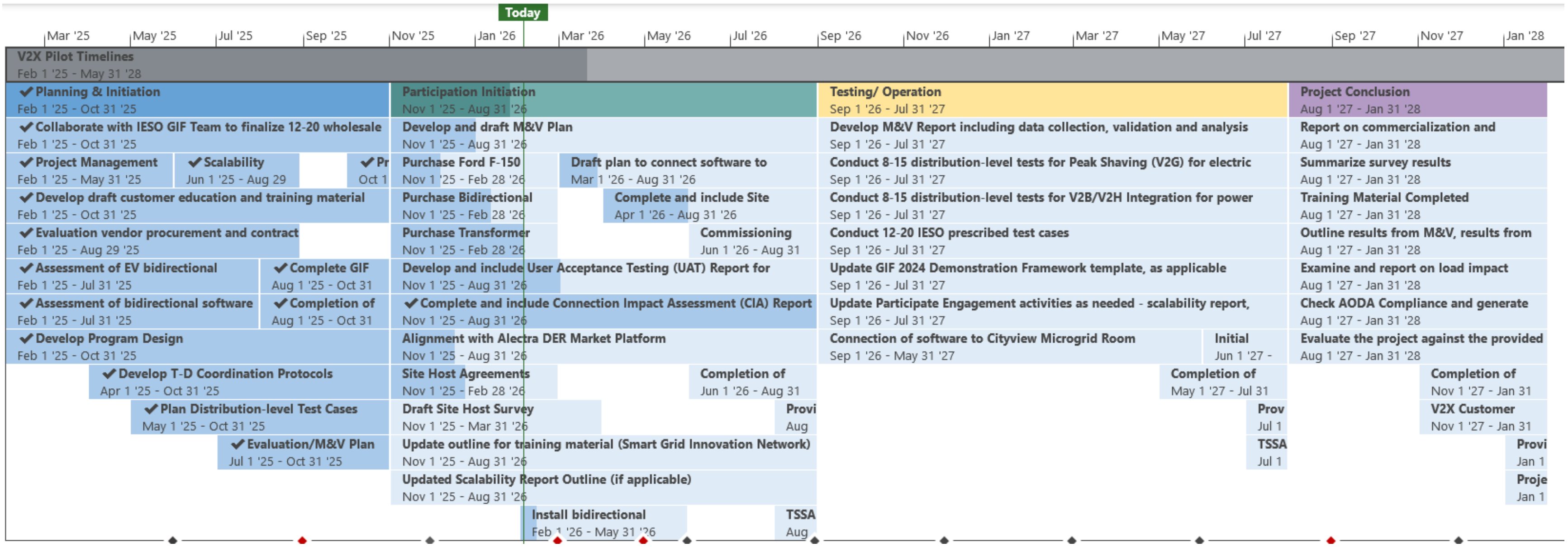
Name	Impact	Priority	Probability (%)	Mitigation
The team was notified by the ESA that the Tellus Power Green chargers may have misrepresented their certification from Intertek.	Medium	Normal	50%	**Risk Closed: We were able to mitigate this risk** - The team is engaging Tellus, ESA and Intertek to determine the gaps and explore a resolution. We are also exploring backup chargers if TPG can't get certified
Lion Electric/partner dropping out	Medium	Normal	100%	**Risk Closed: This risk has occurred and we have successfully mitigated** - Proactively engage other electric school bus OEMs with bidirectional capabilities (e.g., Blue Bird, Thomas Built Buses, GreenPower, etc.) to maintain flexibility and ensure supply chain resilience.

				• Identify and build relationships with third-party fleet operators who may have access to eligible vehicles. • Review procurement timelines to ensure enough lead time for potential supplier shifts without delaying project milestones
Software provider/Fermata furloughing employees	Medium	Normal	100%	**Risk Closed: This risk has occurred and we have successfully mitigated** • Develop a comprehensive software requirements document to clearly outline functional and technical needs for V2X management, including data reporting, dispatch logic, and DERMS integration. • Actively assess and engage alternate V2G software vendors (e.g., Nuvve, The Mobility House, Synop) with proven utility and OEM experience.
Borgwarner/charger OEM of choice closing charging division	Medium	Normal	100%	**Risk Closed: This risk has occurred and we have successfully mitigated** • Develop a charger requirements specification document to ensure interoperability, protocol compliance (e.g., ISO 15118-20), and vehicle compatibility.

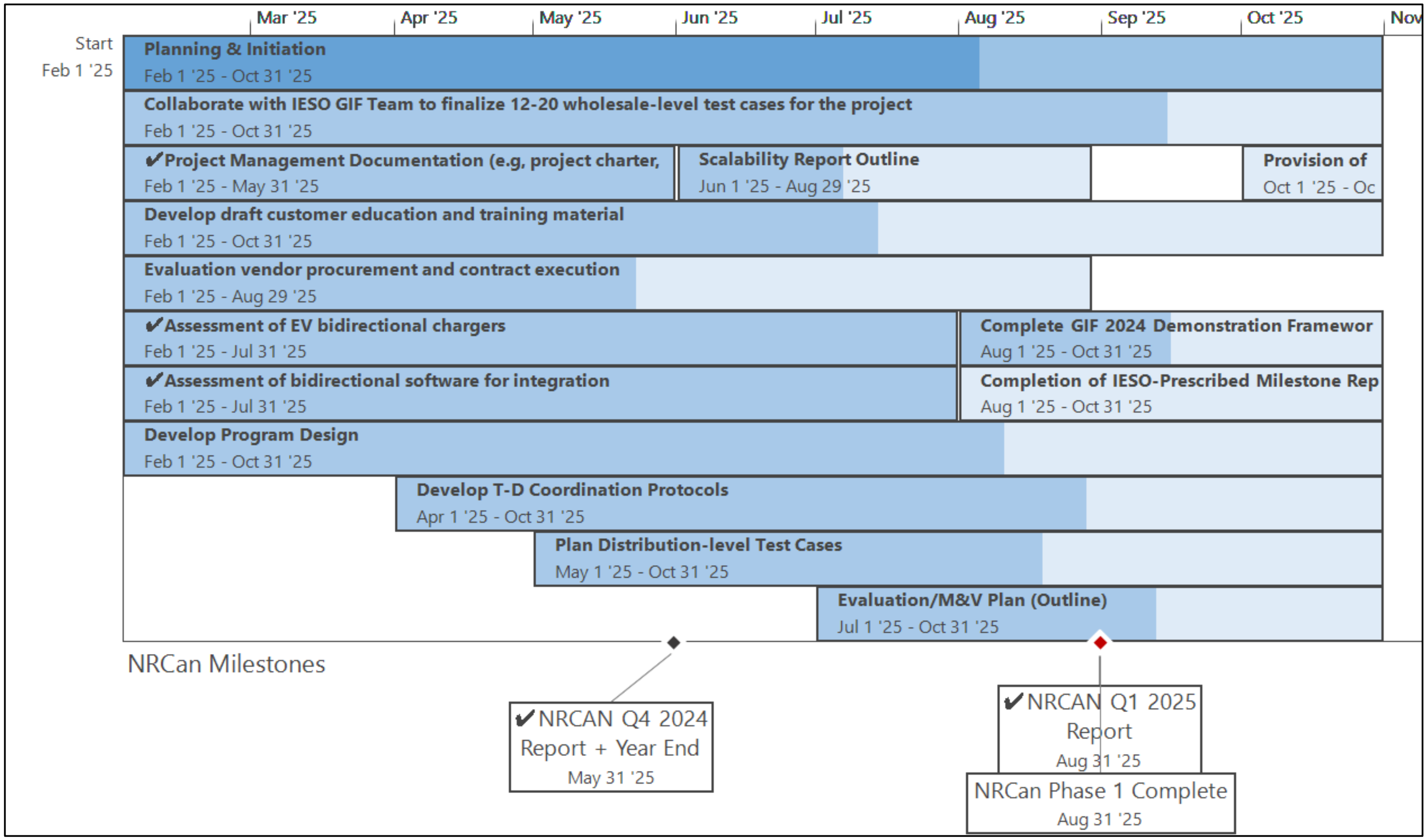
				- Engage other charger OEMs (e.g., Heliox, ChargePoint, ABB, Rhombus) to assess readiness for bidirectional use cases and ensure UL certification progress
Massive upgrades required at Hamilton site causing risks with	Medium	Normal	40%	**Risk Closed: We were able to mitigate this risk** - Work closely with Alectra's DER Connections and ICI teams to proactively identify infrastructure constraints, service upgrade requirements, and connection timelines - Conduct an early technical site assessment (load capacity, transformer sizing, feeder availability) to scope the full extent of electrical upgrade
Uncertainty in availability of Microbird G5 at Dundas	Medium	Normal	50%	**Risk Closed: We were able to mitigate this risk** - Combine Highland – Attridge to procure more buses - Potential backup site
Supply chain delays impacting arrival of transformer	Low	Normal	40%	**Risk Closed: We were able to mitigate this risk**

				Working very closely with DER Connections and ICI Design to escalate connections process Engaged supply chain to determine if we might have a transformer in stock
Control room rejecting net injection back to grid	Low	Normal	45%	**Risk Closed: We were able to mitigate this risk** Engage Hisham to build a relationship with the control room Ensure kW injected back to grid is limited
Potential legal issues for Attridge	Low	Normal	50%	**Risk Closed: We were able to mitigate this risk** Remain updated as things progress to see if there will be significant impact to timelines or Attridge's finances Will continue pushing for project timelines to be met irrespective of other priorities they may have Have Switzer site as a backup *Also keeping Alectra' legal updated*

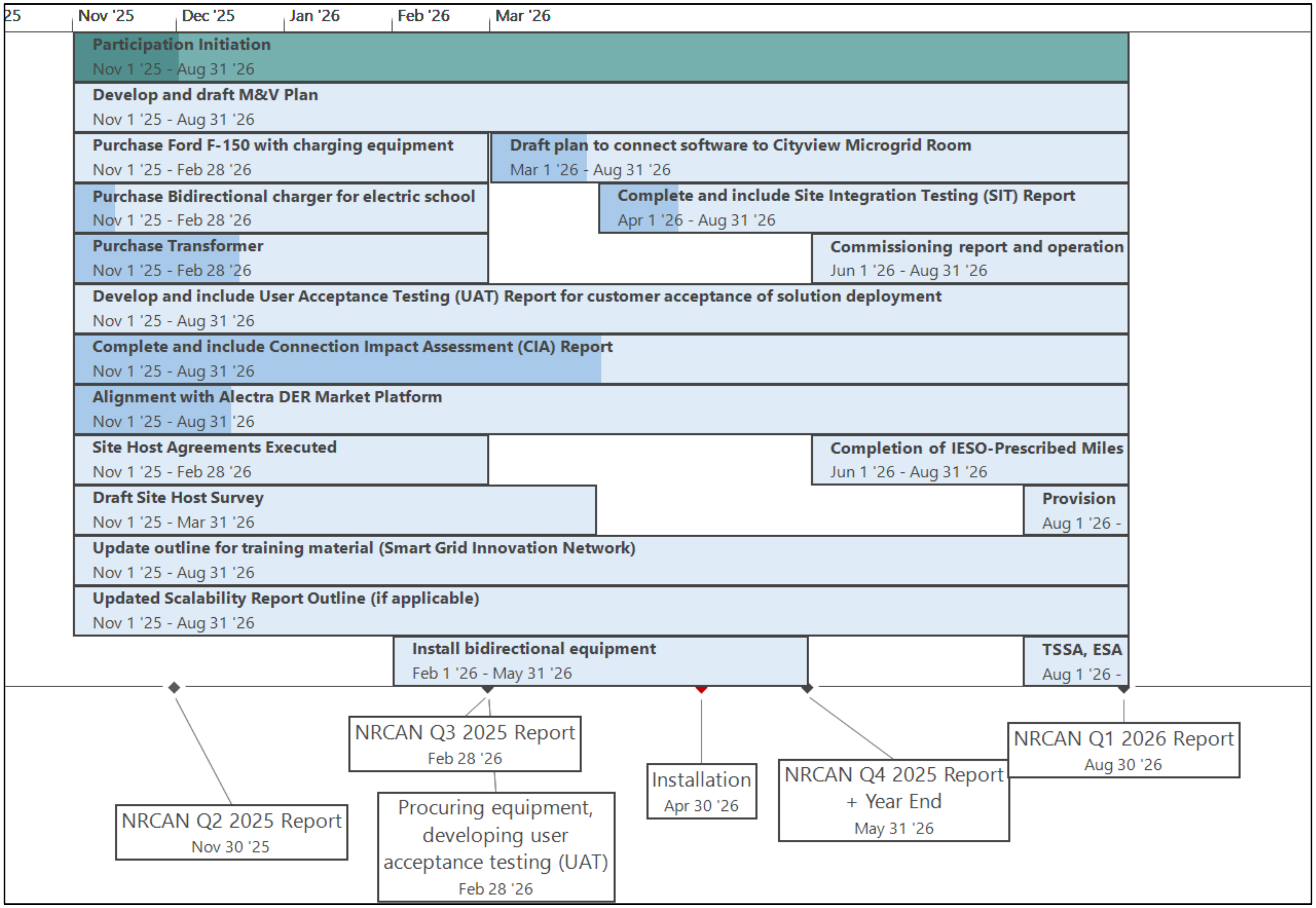
Project Timeline



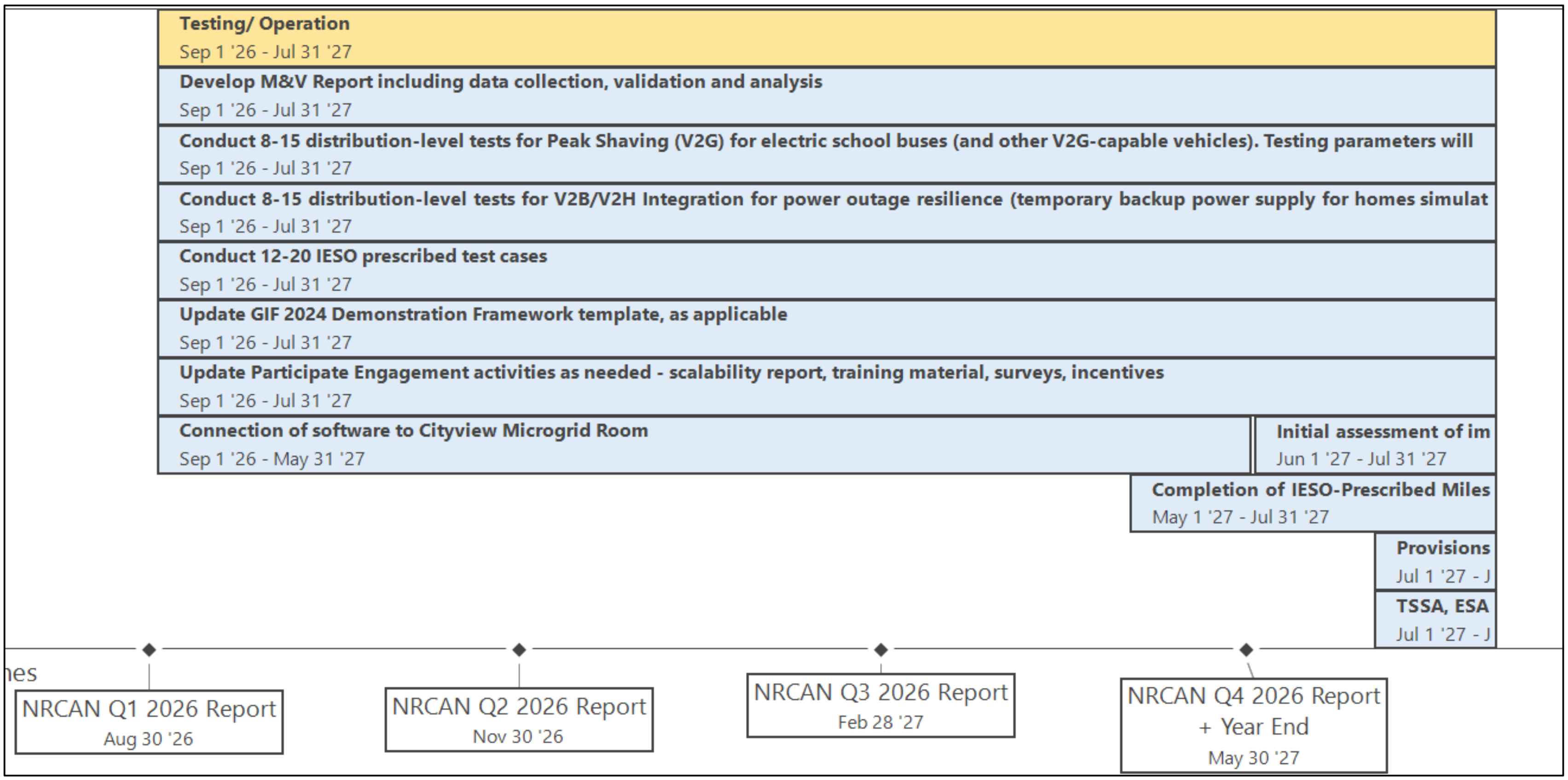
Phase 1 – Planning & Initiation



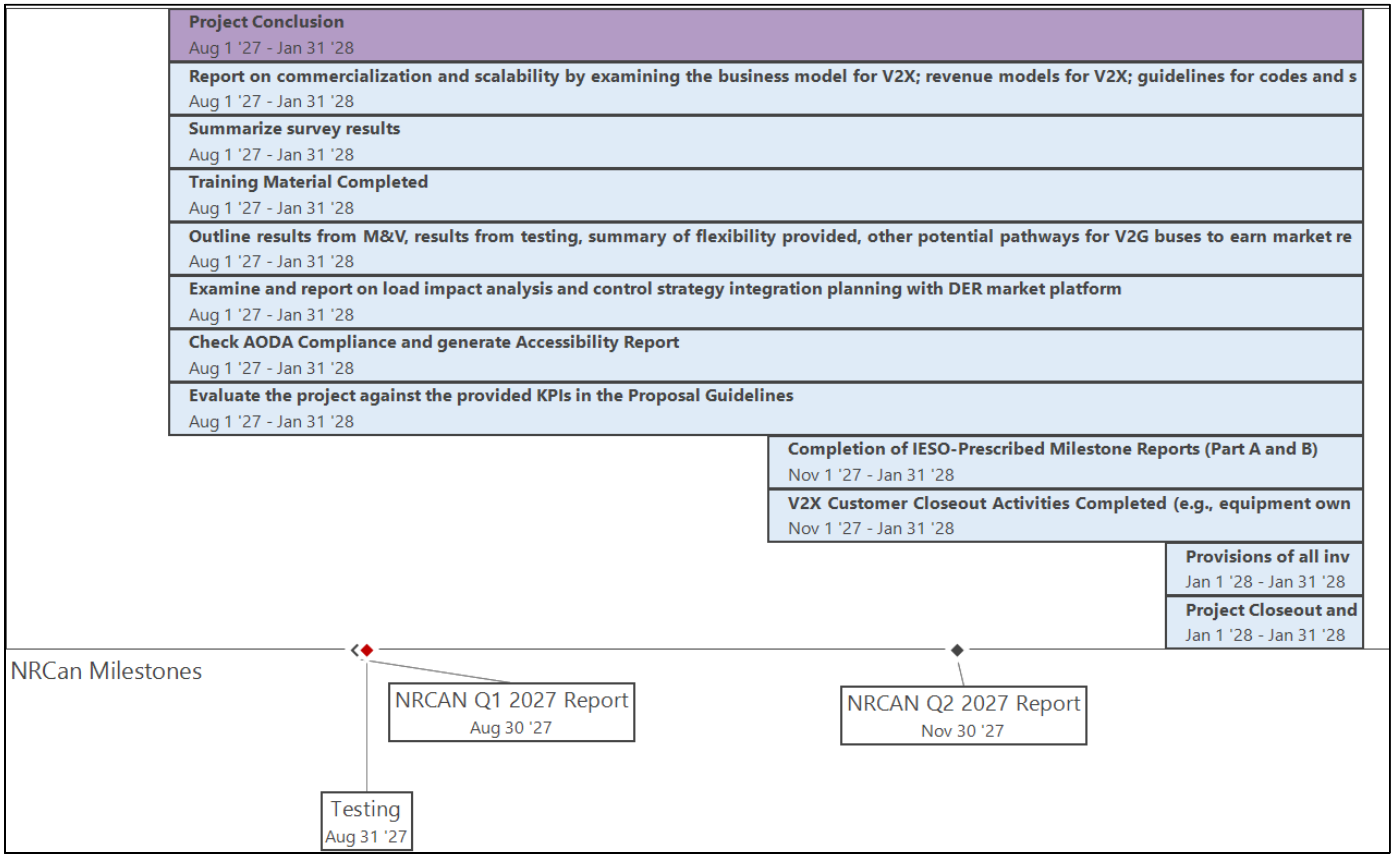
Phase 2 – Participation Initiation

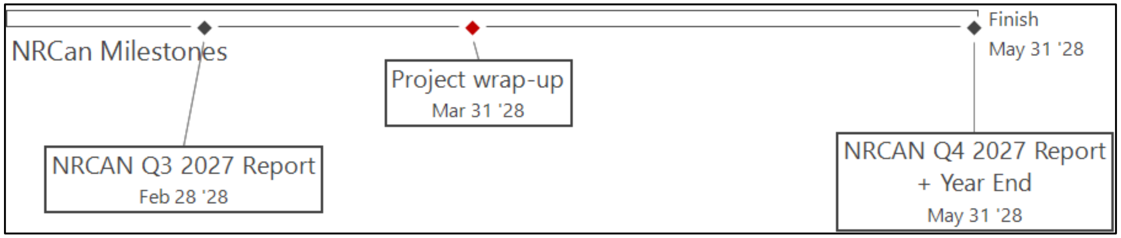


Phase 3 – Testing/ Operation



<u>**Phase 4 – Project Conclusion**</u>




NRCan Milestones
Finish
May 31 '28
Project wrap-up
Mar 31 '28
NRCAN Q3 2027 Report
Feb 28 '28
NRCAN Q4 2027 Report
+ Year End
May 31 '28

RESPONSES TO DISTRIBUTED RESOURCE COALITION INTERROGATORIES

INTERROGATORY 2-DRC-9

Reference:
- Exhibit 2A, Tab 1, Schedule 1, pp. 14 and 19.
- Exhibit 2A, Appendix J, pp. 31-49
- EB-2019-0018, Interrogatory responses to DRC, 1 DRC-2
- EB-2022-0013, Interrogatory responses to DRC, DRC-3

Preamble Alectra notes that it has experienced a significant number of DER connections in recent years, with 6,340 DER connections with a total installed capacity of 343MW on its grid at the end of 2023. Alectra projects that by 2031, the number of DER connections would increase to 9,161 with a total installed capacity of approximately 480MW, reflecting an increase of 40% in total generation capacity compared to 2023. Alectra also projects more than 500,000 EVs in its service area by 2031 resulting in an additional 524MW. In an interrogatory response to DRC in EB-2022-0013, Alectra provided an update to its EV adoption and actual and forecasted load demand for the period 2020-2024 since the 2019 distribution rates application (EB-2019-0018), as follows:

Table 1 – EV Forecast 2020-2024

		2020	2021	2022	2023	2024
EB-2019-0018	EVs (#)	5,600	9,328	13,242	17,351	21,666
	EV (kW - on peak)	7,800	13,100	18,500	24,300	30,300
EB-2022-0013	EVs (#)	11,071	14,123	17,613	23,388	31,349
	EV (kW - on peak)	14,614	18,642	23,249	30,872	41,381

a) Pease update the above table and analysis based on any and all new information reasonably available to Alectra, including the recently announced allowance of up to 49,000 Chinese EVs into the Canadian market, with the most-favoured-nation tariff rate of 6.1%,[1] and provide the most recent estimate of the number of EVs within the Alectra's service territory. If an update is available, please indicate whether it alters the forecast of the number of EVs in Alectra's service territory and the share of light vehicles that are expected to be EVs.

b) Please confirm that Alectra's current EV adoption forecast explicitly incorporates the federal ZEV sales mandate and its interim targets.

c) Please provide Alectra's forecasted annual EV sales as a percentage of new vehicle sales in its service area in 2026, 2030, and 2035. Please compare those projected shares to the federal ZEV sales targets and comment on any differences.

d) Please confirm whether Alectra considered multiple EV adoption scenarios (e.g., high/medium/low cases) in preparing its forecast. If yes, please provide a summary of each scenario, the adoption levels assumed, and the associated system impacts. If not, please explain why scenario analysis was not considered appropriate or necessary.

e) Has Alectra undertaken any benchmarking or comparative analysis of its EV adoption and load forecasts against those of other Ontario LDCs? If not, please explain why Alectra did not undertake such benchmarking. If yes, please provide a summary of the results of any such benchmarking, including a comparison of:
   (i) Projected EV penetration rates (as a % of customers or vehicles),
   (ii) Projected EV-related annual load (kWh),
   (iii) Load growth attributable to EVs over the 2026 and beyond period.

f) Please indicate how many (and where applicable the number of MW) of each of the following types of customer connections Alectra facilitated in its service territory over the rate period:

[1] See Prime Minister of Canada, "Prime Minister Carney forges new strategic partnership with the People's Republic of China focused on energy, agri-food, and trade", (16 January 2026).

(i) single residential unit EV charger connections;
(ii) commercial facility EV charger connections;
(iii) condo EV charger connections; and
(iv) renewable energy and back up generation, including the type of facility (solar roof top,solar thermal, wind, energy storage) and the customer breakdown for such facilities (residential, general service, commercial/industrial, and/or large industrial).

g) Please indicate how many of each of the following types of customer connections Alectra anticipates in its service territory over the 2026-2031 period:
(i) single residential unit EV charger connections;
(ii) commercial facility EV charger connections
(iii) condo EV charger connections; and
(iv) renewable energy and back up generation, including the type of facility (solar roof top, solar thermal, wind, energy storage) and the customer breakdown for such facilities (residential, general service, commercial/industrial, and/or large industrial).

h) Have any Alectra customers been prevented from or delayed in installing EV charges as a result of capacity constrains in Alectra's distribution system? If so, how many customers have been prevented or delayed and for how long?

i) Please provide details as to the areas in Alectra's service territory experience the highest reliability and safety risks associated with EV adoption and DER connections (such as neighbourhood, number of DERs connected, overview of risks and reliability issues, customer concerns, etc.). If Alectra is unable to provide further details, please explain why not and whether such information may be obtained in this proceeding or subsequent proceedings.

j) Please discuss the disadvantages and downside risks to Alectra's distribution system, customers, investments in EVs and DERs, infrastructure, and/or workforce of underinvesting in EV infrastructure and DER connection and adoption infrastructure if a higher electrification scenario materializes compared to the one relied upon in the

Application. Please also discuss the implications of underinvestment over the rate period (2027-2031), mid-term (2031-2041), and long-term (2041 onwards).

k) Similarly, please discuss any disadvantages where a lower electrification scenario materializes.

l) Please comment on known barriers to EV adoption in Alectra's service territory, including for multi-unit rental residential, and how the Application seeks to address these barriers and ensure equitable access to charging infrastructure for all customers.

m) Does Alectra have any programs to support the upgrading of supply infrastructure to enable EV charging infrastructure when Alectra is planning expansion or upgrades? If yes, please provide details. If no, please discuss what types of programs could be developed to support proactive and future infrastructure upgrades to enable equitable access to EV charging infrastructure for all customers.

n) Please provide Alectra's views on any barriers to EV adoption for residents of multi-unit complexes in Alectra's service area. Among any other views, please provide specific comment on whether multi-unit residential complexes represent one of the more challenging venues for EV adoption, and whether Alectra agrees that addressing those challenges should be prioritized. Please explain Alectra's position on each of these points.

o) Please describe any ongoing activities or initiatives proposed by Alectra that can help to address challenges specific to EV transition in multi-unit residences by way of proactive infrastructure upgrades or future upgrades. Please include any planned or anticipated initiatives at the system-wide level in addition to any more localized initiatives.

RESPONSE:

a) Alectra Utilities provides the updated EV forecast in Table 1 below.

Table 1 - EV Forecast 2026-2031

	2026	2027	2028	2029	2030	2031
EV (#)	105,527	157,200	226,969	318,869	433,511	534,349
EV (MW - on peak)	124	180	256	354	476	586

Alectra Utilities provided a detailed updated analysis of EV uptake in Exhibit 2A, Appendix J Load Forecast & System Adequacy Assessment Report.

Please see the response to 2-Staff-58 related to recent Government of Canada announcements related to EV policies.

b) Alectra Utilities confirms that its EV forecast incorporates federal ZEV mandates. Please see Exhibit 2A, Tab 1 Schedule 1 Appendix J Page 32 and 33 for all considerations incorporated into Alectra Utilities EV forecast.

c) Alectra Utilities provides in Table 2 the forecasted annual EV sales as percentage of EV sales in its service area as a % of new vehicle sales and federal ZEV mandate announced as published on December 20th, 2023. Alectra Utilities notes that on February, 5th 2026, the Government of Canada announced changes to the ZEV mandate. Alectra Utilities is awaiting details from Transport Canada on updated projections for ZEV uptake and, at this time, does not have any further updates.

Table 2 - EV Sales Forecast Comparison for 2026, 2030, 2035

	2026	2030	2035
Federal ZEV Annual Sales Target	20%	60%	100%
Alectra's ZEV Annual Sales Forecast	18%	58%	100%

d) Alectra Utilities developed its EV update forecast responsive to Government of Canada policies and mandates. As of 2025, Alectra Utilities had 78,158 EV vehicles registered in its service area which exceeded the projection 70,908 vehicles by 10%. Alectra Utilities considered that actual EV uptake in its service area tracked projections accurately and determined that alternative uptake scenarios were unnecessary. Alectra Utilities will continue to monitor and adjust projections as new information becomes available.

e) As provided to response in part d) above, Alectra Utilities EV uptake actuals were accurately tracking to projections hence Alectra Utilities did not determine it necessary to compare against other LDCs.

f) For parts (i), (ii) and (iii) please refer to response to 1-DRC-02 part (c).

For part (iv), the number of actual DER Facility Connections and MW Connected over the 2024 – 2025 period are given in Tables 3 and 4 below.

Table 3 - Number and Type of DER Facility Connections

DER Technology	2024	2025	Customer Type
Solar	374	378	Residential 93% Commercial 7%
Energy Storage	3	3	ICI
Other(1)	17	7	ICI
Totals	**394**	**388**	

(1) includes Natural Gas, CHP, Diesel generation

Table 4 - MW DER additions for 2024 and 2025

DER Technology	2024	2025
Solar	6.37	6.45
Energy Storage	1.75	2.38
Other(1)	18.86	8.28
Totals	**26.98**	**17.11**

(1) includes Natural Gas, CHP, Diesel generation

g) For parts (i), (ii) and (iii), please refer to response to 1-DRC-02 part (d).

Fort part (iv), Total forecast DER facility connections, customer breakdown and MW connected for the 2026-2031 period are given in Tables 5 and 6 below.

Table 5 - Forecast Number and Type of DER Facility Connections for 2026 - 2031

DER Technology	2026	2027	2028	2029	2030	2031	Total	Customer Type
Solar	383	388	392	397	402	407	2369	Residential 93% Commercial 7%
Energy Storage	3	3	3	4	4	4	21	ICI
Other[(1)]	7	7	7	7	7	7	42	ICI
Totals	**393**	**398**	**402**	**408**	**413**	**419**	**2433**	
[(1)] includes Natural Gas, CHP, Diesel generation								

Table 6 - Forecast MW DER Additions for 2026 - 2031

DER Technology	2026	2027	2028	2029	2030	2031	Total
Solar	6.52	6.60	6.68	6.76	6.84	6.92	40.34
Energy Storage	2.46	2.56	2.65	2.75	2.86	2.96	16.25
Other[(1)]	8.36	8.45	8.53	8.62	8.70	8.79	51.46
Totals	**17.35**	**17.61**	**17.87**	**18.13**	**18.40**	**18.68**	**108.04**

[(1)] includes Natural Gas, CHP, Diesel generation

h) Alectra Utilities is not aware of any customers who have been formally prevented or delayed in installing EV chargers due to capacity constraints. However, capacity related constraints are discussed with customers at an early stage in the process, these are captured through an already established EVCCP process in accordance with OEB guidelines. Further details are provided in 1-DRC-02 (b). In some cases, customers may elect not to proceed where system upgrades are required; however, Alectra does not maintain records of customer decisions not to apply or proceed.

i) Alectra Utilities provides a response to EV adoption first, followed by details related to DER connections.

As provided in Exhibit 2A, Appendix J page 36, incremental EV demand projection is not concentrated in a single municipality or sub-region. Alectra Utilities has determined that EV connections and corresponding demand are projected to be distributed across the entire service territory which reflects the dispersed nature of EV adoptions which Alectra has experienced. To date, Alectra Utilities has not experienced any material risks related to safety and reliability associated with EV adoption. Alectra Utilities will continue to closely monitor EV adoption as uptake increases consistent with its ongoing system planning practice of monitoring and tracking loading across its stations, feeders and transformers. Alectra Utilities has appropriately incorporated EV update projections into its system peak demand forecast to ensure system capacity is available to provide safe, reliable and efficient service to its customers.

With respect to DER connections, Alectra Utilities confirms that there are areas where DER interconnections are constrained. However, the constraints are at the station level. Alectra Utilities understands that the existing DER connection constraints are driven by short-circuit limitations (refer to Response to Interrogatory 2-ED-12-a). Alectra Utilities has also provided evidence that it has not encountered consistent, systematic feeder-level constraints preventing the connection of REG facilities, and that constraints are more appropriately described through station-level limitations and identified technical drivers (e.g., short-circuit, thermal, and voltage considerations), as set out in Exhibit 2A, Tab 1, Schedule 1, Appendix A - System Capability Assessment for Renewable Energy Generation.

Alectra Utilities actively participates and provides appropriate information into the OEB's Centralized Capacity Information Map (CCIM) Centralized Capacity Information Map | Ontario Energy Board[1]. Alectra Utilities customers can access the maps to better understand available capacity and DER hosting capacity constraints.

j) Alectra Utilities provides a response to capacity risk related to EV adoption first, followed by details related to preparing the grid to facilitate DER connections.

In the DSP, Alectra Utilities has detailed the risks which would result from inadequate capacity in stations, lines and overloading distribution transformers. Please refer to Stations capacity risk in Table B13-5 in Exhibit 2A Tab 1 Schedule 1, Appendix B13. Please refer to feeder capacity risk in Table B12-3 in Exhibit 2A Tab 1 Schedule 1. Please refer to transformer overloading risk in Table 5.3.2-9 in Exhibit 2A Tab1 Schedule 1 Ch 5.3.2.

Alectra Utilities continuously monitors station, feeder and transformer loading and updates system peak demand forecasts. Alectra will provide corresponding station, feeder and distribution transformer investments in future distribution system plans. Accordingly, Alectra Utilities is unable to provide outlooks beyond 2031.

In the event Alectra Utilities experiences a higher than anticipated number of DER connections, Alectra Utilities will abide by the Distribution System Code and its obligations.

k) As provided in response to part i) above, Alectra Utilities anticipates that the incremental EV system demand to be distributed across its service territory. As such, Alectra Utilities does not anticipate any significant disadvantage if the electrification materialize at slower pace. Alectra Utilities will continue to monitor and track station, feeder and transformer loading and adjust future plans beyond 2031 accordingly.

l) For known barriers to EV adoption in Alectra's service territory, refer to 1-DRC-02 (b). Also refer to n) below

m) Alectra Utilities has incorporated EV charging infrastructure enablement into its existing customer connection and upgrade process as required in the Distribution System Code. As such, Alectra Utilities does not provide separate programs for upgrading supply infrastructure to accommodate EV charging installations.

Alectra Utilities has incorporated EV uptake projections and corresponding system capacity requirement plans distributed across its entire service area so as to provide equitable access to all Alectra Utilities' customers.

n) Alectra Utilities recognizes that the adoption of electric vehicles (EVs) in multi-unit residential complexes presents distinct challenges relative to single-family dwellings, and that these challenges can act as barriers to broader EV adoption.

From Alectra Utilities perspective, common barriers associated with EV adoption in multi-unit residential complexes include:

- limitations related to existing electrical infrastructure capacity within older buildings,
- complexity related to the coordination of upgrades across multiple unit owners or tenants,
- physical and spatial constraints within parking structures,
- uncertainty relating to cost allocation for electrical upgrades and charging infrastructure, and
- governance and decision-making processes within condominium corporations or property management organizations.

As a result, Alectra Utilities agrees that multi-unit residential complexes can represent one of the more challenging environments for EV adoption when compared to low-density residential settings.

At the same time, Alectra Utilities notes that the challenges associated with EV adoption in multi-unit residential complexes are influenced by factors that extend beyond the electricity distributor's direct control, including building design, ownership structures, municipal requirements, and provincial building codes. Addressing these challenges typically requires coordination among multiple stakeholders, including building owners, residents, municipalities, charging service providers, and policymakers.

Alectra Utilities continues to support EV adoption broadly through planning activities, connection processes, and engagement with customers and stakeholders, while recognizing that targeted approaches for multi-unit residential complexes may evolve over time as part of broader policy, regulatory, and market developments.

o) Alectra Utilities recognizes that enabling electric vehicle (EV) charging in multi-unit residential buildings can be complex. Challenges often relate to building-specific electrical limitations, shared ownership and decision-making structures, and the need to coordinate upgrades within existing infrastructure.

Alectra Utilities approach to supporting EV adoption in these settings is focused on ensuring the distribution system is planned and operated to accommodate electrification growth, and on working with customers and municipalities to identify appropriate connection solutions on a case-by-case basis.

From a system planning perspective, Alectra Utilities considers EV adoption and broader electrification trends in its load forecasting and distribution system planning processes. These efforts help identify where capacity upgrades or reinforcements may be required over time to support increased EV charging while maintaining system reliability.

Alectra Utilities also coordinates with municipalities and other stakeholders as part of ongoing growth and energy transition discussions. This includes providing technical input on municipal requirements, such as EV-ready parking provisions, to ensure they are feasible from a distribution system perspective and to help inform localized planning for future load growth.

At the building level, solutions for EV charging in multi-unit residential buildings are typically specific to the individual property. Alectra works with customers through its standard connection processes to assess requirements and determine any necessary distribution system upgrades or servicing arrangements.

Overall, Alectra Utilities view is that addressing EV charging challenges in multi-unit residential buildings requires a combination of system-wide readiness and building-specific solutions. Many of the factors influencing EV deployment in these settings are outside the electricity distributor’s direct control and depend on coordination among multiple parties.

RESPONSES TO DISTRIBUTED RESOURCE COALITION INTERROGATORIES

INTERROGATORY 2-DRC-10

Reference: • Exhibit 2A, Tab 1, Schedule 1, p. 326
• Appendices B13 and B14

Preamble: Alectra indicates that it will develop the detailed catalogue of NWS option as part of the DER Supporting Technologies capital project and in Planning Tools and Automation project.

Alectra notes that is ability to deploy NWS proposed in the Application and future NWS is contingent on funding and technical implementation of enabling technologies proposed in the Application, including Advanced Distribution Management System, Integrated Network Management, Planning Tools and Automation, and DER Wholesale Market Preparedness.

a) Please explain how Alectra will ensure the program is “technology-neutral”, including:

 (i) any minimum technical eligibility requirements that functionally exclude certain technologies (e.g., telemetry, metering, interconnection, protection requirements); and
 (ii) how Alectra will treat portfolios (aggregations) versus single-resource bids.

b) Please describe how Alectra intends to implement the competitive sourcing processes identified in the Application (i.e., RFI/RFP/RFQ and/or local auctions).

c) For each of the five station areas (Newton TS, Nebo TS, Barrie MS, Melbourne MS, Alliston MS), please identify:

(i) the specific wires investment(s) deferred and the deferral duration assumed;

(ii) the minimum NWS subscribed capacity and performance needed to maintain the applicable planning standard; and

(iii) the decision triggers (e.g., timing and thresholds) that would cause Alectra to proceed with the wires alternative.

d) Please describe any planned backstop to ensure reliability if subscribed capacity is not obtained or is not deliverable when needed, including interim operational measures and the lead times required to re-initiate the deferred wires work.

RESPONSE:

a) Alectra Utilities notes that the detailed NWS Program design (including market rules, eligibility criteria, and procurement documentation) will be finalized following OEB approval of the proposed NWS Program and the establishment of the Non-Wires Solution Deferral Account.

Alectra Utilities confirms that the proposed NWS Program is intended to be technology-neutral and competitively sourced, meaning solutions will be assessed on their ability to meet the identified system to meet defined system needs at a specified location, time, and duration, rather than by prescribing eligible technologies. Alectra will publish the identified system need and allow customers and third parties to compete through market-based mechanisms to meet that need, regardless of the underlying technology or asset type (Exhibit 2A Tab1 Schedule 1 Appendix B14, Section IV.1 and IV.2).

(i) Alectra Utilities expects to apply functional, performance-based eligibility requirements that are necessary to ensure safe and reliable operation and to demonstrate that subscribed capacity is deliverable when required. These requirements are not intended to exclude particular technologies. Rather, they will apply equally to any resource (or portfolio) proposing to provide the required service. As the NWS program design is finalized, eligibility requirements are expected to address:

- Deliverability and performance: ability to provide the required magnitude, duration, and duty cycle of capacity/energy relief for the specific station pocket and required hours/conditions.
- Measurement and verification: revenue-grade or otherwise verifiable metering and data necessary to validate delivery and settle performance.
- Communications / telemetry: communications capability commensurate with the operational need (e.g., monitoring and/or dispatch/curtailment signals where required).
- Interconnection and protection: compliance with applicable interconnection, protection coordination, and safety requirements to ensure system integrity.
- Operational coordination: ability to operate within required constraints (e.g., locational requirements, dispatch windows, and any required operating envelopes).

(ii) Alectra Utilities intends to treat aggregated portfolios comparably to single-resource bids, provided that the portfolio can meet the same aggregate capacity, reliability, and locational requirements for the applicable station pocket. For portfolio bids, Alectra Utilities expects to require, at minimum:

- a single point of accountability (e.g., the aggregator) for performance, communications, and settlement;
- demonstration that the portfolio is locationally deliverable for the relevant station pocket; and
- performance measurement and verification consistent with the program requirements.

Please refer to Exhibit 2A Tab1 Appendix B14, Section IV.1 and IV.3.4.

b) Alectra will implement competitive sourcing for Non-Wires Solutions through a market-based procurement mechanism. Alectra will identify and publish location-specific system needs, defined by required MW and/or MVAR capability, timing, and duration, associated with distribution network constraints (Appendix B14, Section IV.1).

Customers and third parties will be able to register individual resources or aggregated portfolios to participate. Services will be procured through competitive auctions or solicitations using service-specific contract structures aligned to the nature of the system need, including longer-term availability and shorter-term operational services. Successful bids will be awarded contracts, with services scheduled, dispatched, and settled based on verified delivery. All of these activities will be enabled through the Distribution Wholesale Market Preparedness (DWMP) toolsets (Appendix B14, Sections IV.1 and IV.2).

c)

(i) Please refer to *Interrogatory Response 2-Staff-47, Attachment 2-Staff-47_Attach1_NWS BCA Template*, Tab "Station_Lines_CAPEX_OPEX", rows 24–121, which identifies, for each of Newton TS, Nebo TS, Barrie MS, Melbourne MS, and Alliston MS, the wires investments proposed to be deferred and the associated deferral duration assumptions.

(ii) Please refer to *Interrogatory Response 2-Staff-47, Attachment 2-Staff-47_Attach1_NWS BCA Template*, Tab "Capacity_Energy_Needs", which sets out the expected subscribed capacity and associated performance characteristics required to maintain the applicable planning standard for each station area.

(iii) Alectra Utilities notes that the specific decision triggers for proceeding with a wires alternative will be established as part of the detailed NWS Program design following OEB approval. Notwithstanding, Alectra Utilities expects that the decision to advance a wires alternative (and/or other prudent mitigation measures) would be informed by two primary outcomes from market engagement and procurement:

1. Market availability: where procurement does not secure sufficient subscribed capacity and/or deliverability assurances to maintain the applicable planning standard for the station area; and/or
2. Market pricing / economic feasibility: where procurement indicates that adequate capacity is available but at a materially higher cost such that the NWS portfolio does not pass the benefit-cost assessment under the NWS gate-based screening framework.

In such circumstances, Alectra Utilities would apply the contingency approach described in *Interrogatory Response 2-Staff-48*, including re-assessing the conventional alternative and, where feasible, advancing the conventional alternative and/or other prudent mitigation measures to maintain service and reliability.

d) Please refer to Interrogatory Response 2-Staff-48.

RESPONSES TO DISTRIBUTED RESOURCE COALITION INTERROGATORIES

INTERROGATORY 2-DRC-11

Reference: • Exhibit 2A, Tab 1, Schedule 1, Appendix B09

Preamble: Alectra notes that its proposed Information Technology Systems project includes investments in tools for DER performance analysis, system modelling, and supporting IT infrastructure required for integration, implementation planning, and customer engagement; supporting the evaluation and deployment of NWS leveraging DERs

Alectra notes that it will collect a list of DERs that could be used to provide grid services and that DER technologies will be assessed based on a review of performance literature and validated through interviews with those familiar with the in-field performance of the technology. The resulting performance characteristics will create a consolidated database which can be used to inform the selection of optimal DER solutions.

a) Please describe, in detail, the process and criteria Alectra will use to compile the initial list of DER technologies that could be used to provide grid services, including:
   (i) the scope of DER technologies considered (e.g., generation, storage, DR, EV-related technologies, control technologies);
   (ii) any inclusion or exclusion criteria applied at the outset; and
   (iii) whether the list is limited to commercially deployed technologies or includes emerging or pilot-stage technologies.

b) Please describe the literature review referenced by Alectra, including:
   (i) the types of sources to be reviewed (e.g., peer-reviewed studies, utility pilot evaluations, vendor data, standards-based testing);

(ii) any preference or weighting of such sources based on credibility, jurisdictional relevance, or recency etc.; and

(iii) how conflicting or inconsistent performance findings across sources will be considered and addressed.

c) Please describe the interview-based validation process, including:

(i) the categories of interviewees (e.g., utilities, aggregators, vendors, system operators);

(ii) the criteria for determining whether an interviewee is “familiar with in-field performance”; and

(iii) how qualitative interview inputs will be translated into quantitative or decision-useful performance characteristics.

d) Please identify the specific performance characteristics that Alectra expects to include in the consolidated DER database, such as:

(i) capacity, availability, response time, duration, reliability, and locational constraints; and

(ii) customer-side constraints or dependencies (e.g., participation rates, behavioural assumptions).

e) Please explain how the consolidated DER performance database will be used in practice to inform DER selection, including:

(i) whether DERs will be ranked, screened, or optimized using defined thresholds or scoring methodologies;

(ii) how performance characteristics will be linked to specific system needs or constraints; and

(iii) whether selection outcomes are expected to be deterministic or scenario-dependent.

f) Please identify the specific performance characteristics that will be captured in the consolidated DER database, including, where applicable:

:

(i) capacity, response time, duration, and availability;
(ii) reliability and degradation over time;
(iii) locational or network constrains; and
(iv) interoperability and control requirements.

g) Please explain how the modelling results will be used to create the stated "list of tools that are available for use, and under what conditions," and how this list will be used in future NWS identification and planning decisions.

RESPONSE:

a) Alectra's approach to non-wires solutions (NWS) is technology-neutral and services-led. Alectra will first define distribution service programs that are explicitly mapped to underlying distribution system needs.

Service programs are defined by Alectra's System Planning and Grid Modernization teams and specify the technical, temporal, and locational requirements required to address those needs, as well as the comparable requirements and economic cost of a traditional infrastructure solution. These service definitions form the foundation for valuation, procurement, contracting, and operational integration.

Technical assessments and system modelling are then used to confirm which classes of assets are capable of delivering each service program.

Only after services are fully defined does Alectra proceed with program recruitment design, engaging customers and third parties through its technology-neutral, market-based procurement framework.

All non-wires solutions service programs will be implemented through this framework, as described in IR response 2-DRC-10(b), with contracts allocating performance risk to counterparties to support reliable service delivery.

(i) Scope of DER technologies considered

:

Alectra will apply a services-first, technology-neutral approach. Any resource class capable of delivering the defined service may be considered, including but not limited to generation, energy storage, flexible load, EV-related resources, control technologies, and aggregated portfolios thereof.

(ii) Inclusion and exclusion criteria

Eligibility will be determined for each service program based on the ability to meet the defined service requirements.

(iii) Commercial versus emerging technologies

Eligibility will not be limited to commercially deployed technologies. Both commercial and emerging resource classes may be considered where they can demonstrate the ability to meet the defined service requirements.

b) On literature review, please see below:

(i) Types of sources reviewed

Alectra Utilities expects that the literature review will include peer-reviewed studies, utility and system operator program evaluations, regulatory decisions and guidance, standards-based testing, and empirical evidence from jurisdictions with established non-wires or flexibility programs.

(ii) Preference or weighting of sources

Preference will be given to regulatory-led and utility-led evidence supported by measured outcomes, where the results are representative of their customer classes, have a clear end-to-end approach articulated, and are scalable. For sources that capture data points that cannot be mapped to representative customer classes or that don't relate to an end-to-end service, the data will be reviewed but only viewed as indicative.

(iii) Treatment of conflicting or inconsistent findings

:

Where findings differ, Alectra will apply professional judgement to assess the source and relevance of those differences and their implications for service program design.

c) Interviews will be used to refine defined distribution service programs with the objective of ensuring that service programs are practical, scalable, and implementable.

(i) Categories of interviewees

Interviewees will include electric utilities, researchers, vendors and aggregators, and customers with direct experience or prospective participation, to inform service program design, contract structures, and procurement mechanisms.

(ii) Familiarity with in-field performance

An interviewee will generally be considered familiar with in-field performance of DERs where they have direct experience with live operations or with pilot implementation with measured performance outcomes.

(iii) Translation of interview inputs into decision-useful information

Interview inputs will generally be used to refine service program definitions, implementation considerations, and procurement structures, as well as to validate contract terms and participation conditions and support scalable service programs.

d) Below are specific performance characteristics that Alectra expects to include in the consolidated DER database:

(i) Technical performance characteristics

The consolidated DER performance database will be a technical reference used to record whether classes of assets are technically capable of meeting defined distribution service requirements based on a system modelling and power flow analysis.

(ii) Customer-side constraints and dependencies

:

The database will not include any customer-side constraints and dependencies.

e) In respect of how the consolidated DER performance database will be used in practice to inform DER selection, including:

(i) Use of ranking, screening, or optimization methods

The consolidated DER performance database will be an internal reference used to confirm whether classes of assets can meet defined distribution service requirements. Selection will be determined through market-based procurement and managed against defined service requirements.

(ii) Linkage to system needs and constraints

System needs and service requirements will be defined independently of DER performance characteristics through planning analysis.

(iii) Deterministic versus scenario-dependent outcomes

Outcomes of the analytical process using the database are expected to be market- and scenario-dependent rather than deterministic.

f) The consolidated DER performance database will describe the technical capability of classes of assets to meet defined distribution service requirements. It will not capture locational attributes, network constraints, or control requirements, which will be defined within service specifications and addressed through market-based procurement processes.

(i) Capacity, response time, duration, and availability

The database will record, on a technical capability basis, whether a class of assets can meet defined service requirements

(ii) Reliability and degradation over time

:

Reliability and degradation considerations will be captured to the extent necessary to confirm the ability of a class of assets to meet the defined service requirement over the applicable service horizon.

(iii) Locational or network constraints

Locational attributes and network constraints will not be captured in the database. These elements will be defined as part of the service specifications that reflect underlying system needs.

(iv) Interoperability and control requirements

Interoperability and control requirements will not be captured in the database and will be addressed through service specifications and contractual requirements established through procurement.

g) System modelling results will be used to identify distribution system needs and define associated service requirements.
For modelling purposes, participating technologies will be represented as electrical assets, consistent with standard distribution planning practice.

:

RESPONSES TO DISTRIBUTED RESOURCE COALITION INTERROGATORIES

INTERROGATORY 2-DRC-12

Reference: • Exhibit 2A, Tab 1, Schedule 1, p. 326
• Appendix B13

Preamble: Alectra notes that its proposed Station Capacity project and NWS investments are expected to reduce execution risk and enable broader application of NWS across the grid.

e) Please explain how the Station Capacity project set out in Appendix B13 will (i) reduce execution risk and (ii) enable broader application of NWS across Alectra's grid.

RESPONSE:

e) Alectra Utilities does not agree with the premise that the phrase "these investments" in *Exhibit 2A, Tab 1, Schedule 1, Appendix B13 – Stations Capacity, p. 567* refers to the Station Capacity project in Appendix B13. In that passage, "these investments" is intended to refer to the enabling investments in *Appendix B14 – Enabling Resiliency and Modernization* (e.g., Advanced Distribution Management System, Integrated Network Model, Planning Tools and Automation, and DER Wholesale Market Preparedness), which are described as reducing NWS execution risk and enabling NWS application at scale.

Please refer to *Appendix B14 – Enabling Resiliency and Modernization* for the description of how enabling capabilities (e.g. planning/screening at scale, operationalization and control-room execution, telemetry/dispatch readiness, and integrated delivery) reduce NWS execution risk and support broader NWS application.

RESPONSES TO DISTRIBUTED RESOURCE COALITION INTERROGATORIES

INTERROGATORY 2-DRC-13

Reference: • Exhibit 2A, Tab 1, Schedule 1, p. 405
• Appendix B14

Preamble: Alectra identifies the following programs as part of its grid modernization investments:

- Advanced Distribution Management System (**ADMS**);
- Integrated Network Management (**INM**) platform; and
- Planning Tools and Automation (**PTA**) initiative;
- DER Wholesale Market Preparedness (**DWMP**).

Alectra estimates that 120-130 MW of new participating DERs could materialize on its system during the 2027-2031 period and states that investments are required to manage bi-directional flows, time-varying constraints, and DER dispatch safely.

a) Please provide Alectra's target timelines for DER and EV charging interconnection decisions once PTA initiative is operational, compared to current average timelines.

b) Please explain how Alectra will ensure that automated interconnection assessments are applied consistently and non-discriminatorily across DER technologies (including EV charging, storage, managed load, and aggregation).

c) Please describe how dispatch instructions or curtailments issued through DWMP or ADMS will be prioritized where multiple DERs or EV assets are affected, including whether priority will be based on contract type, market participation, or system need.

d) Please explain how Alectra will determine and communicate locational constraints for DERs and EV charging assets, including how:
   (i) frequently they will be updated; and
   (ii) they will be communicated to DER owners or aggregators.

e) Please confirm whether Alectra intends to publish feeder-level or station-level capacity maps suitable for DER and EV project siting decisions, and provide the expected timing.

f) Please identify which DER and EV-enabling capabilities will be fully functional by the start of each year of the DSP period (2027-2031).

g) Please explain the risks to DER and EV owners and aggregators if the timing of INM, PTA, ADMS, or DWMP is delayed, including whether such delays would limit participation in NWS or result in additional costs or requirements for DER proponents.

RESPONSE:

a) Assuming a complete application is received (i.e., all required information is provided in the required format), the current maximum timelines under the DER Connection Procedures (DERCP)[1] are defined in calendar days:
   (i) Small DER CIA timelines are 60 days (no reinforcement) or 90 days (with reinforcement).
   (ii) Mid-sized and Large DER CIA timelines are 60 days and 90 days, respectively, and increase to 75 days and 105 days where an upstream host distributor/transmitter CIA is required.
   (iii) DER Offer to Connect timelines are 15/30/60 days depending on whether a site assessment is required and whether the connection is at an existing customer connection; and
   (iv) a Simplified CIA is recommended within 30 days.

[1] https://engagewithus.oeb.ca/derandevchargingconnections/news_feed/oeb-issues-amendments-to-dsc-and-dercp-2025

Assuming all applicable service conditions are satisfied, the current maximum timelines under the EV Charging Connection Procedures (EVCCP)[2] are defined in business days:

(i) EV charging connection completion is:
   a. 5 business days (low voltage); or
   b. 10 business days (high voltage).

PTA is intended to reduce manual effort and improve throughput so Alectra can manage increasing request volumes within these timelines and, where feasible, better, while maintaining the required engineering/designer review.

b) Alectra will apply automated interconnection assessments consistently and non-discriminatorily by using a single, unified INM network model and PTA-enabled standardized workflows that automate technical preparation steps while retaining engineering/designer review for all applications.

PTA is intended to support repeatable, traceable, and auditable assessments aligned with applicable OEB requirements and timelines (including the DER Connection Procedures[3] and EV Charging Connection Procedures[4]), with automation triggered only when all required information is submitted in the required format.

Consistency is reinforced through standardized application templates and completeness checks under the DERCP and EVCCP, so decisions are driven by application type, operating characteristics (e.g., export/load behavior), and project size, not by DER technology. Where information is incomplete or deficient, Alectra will follow the DERCP/EVCCP completeness and deficiency processes and the streamlined automated pathway will apply once required information is provided.

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[2] https://engagewithus.oeb.ca/ev-integration/news_feed/notice-of-amendments-to-the-distribution-system-code
[3] Supra Note 1
[4] Supra Note 2

c) Where multiple DERs and EV assets are affected, the DWMP's and ADMS' optimization capabilities will dispatch the DER based on concurrent evaluation of contract type (market obligations) and system needs.

d) Please refer to response 2-DRC-10-b.

e) The OEB has opted to develop a centralized, province-wide tool, the Centralized Capacity Information Map (CCIM), to ensure that data from all LDCs in Ontario is available and in a standardized format, enhancing transparency and accessibility for stakeholders.[5]

The OEB outlined the relevant information required for the CCIM, laid out in the OEB Letters from June 26th, 2025[6], and September 19th, 2025[7], and October 17th, 2025[8].

As a member of the Working Group, Alectra will continue to provide relevant information in the data format and timeline (on a quarterly basis) prescribed by the OEB[9].

f) For DER Wholesale Market Preparedness, the following capabilities will be available by the start of each year in the DSP period:
   (i) 2027: Integration and Basic Market Co-ordination
   (ii) 2028: Further Integration with Wholesale markets and enhanced market co-ordination

   For Integrated Network Management initiative, the following capabilities will be available by the start of each DSP year:

[5] https://engagewithus.oeb.ca/35235/widgets/202511/documents/150964
[6] https://engagewithus.oeb.ca/derandevchargingconnections-wg/news_feed/distribution-system-data-to-enable-a-centralized-capacity-information-map
[7] https://engagewithus.oeb.ca/derandevchargingconnections-wg/news_feed/distributed-energy-resource-hosting-capacity-data-for-the-centralized-capacity-information-map
[8] https://engagewithus.oeb.ca/derandevchargingconnections-wg/news_feed/oeb-guidance-letter-on-distribution-system-capacity-information-map-phase-1-2
[9] Supra Note 5

(i) 2027: Initial Data Ingestion, Business Rules (Automated QA/QC), Conversion to IEC CIM, IEC CIM Network Model exchange interface for DWMP

(ii) 2028-2029: Additional Data Sets related to system modeling and planning

(iii) 2030: IEC CIM Network Model, Loading, and system planning data sets exchange interface for PTA

For the Planning Tools and Automation initiative, the following capabilities will be available by the start of each DSP year:

(i) 2030: unbalanced three-phase time-series analysis flexible hosting capacity, automated interconnection assessment and consideration for non-wires solutions.

Please refer to Appendix B14, Section IV, Sub-section 4.2 for additional information.

g) Please refer to Appendix B14, Section IV, Sub-Section 4.4.2, specifically the Status Quo sections for each initiative, to understand the risks to DER and EV owners and aggregators if the timing of INM, PTA, ADMS, or DWMP is delayed, including whether such delays would limit participation in NWS or result in additional costs or requirements for DER proponents.

RESPONSES TO DISTRIBUTED RESOURCE COALITION INTERROGATORIES

INTERROGATORY 2-DRC-14

Reference: • Exhibit 2A, Tab 1, Schedule 1
• Exhibit 2, Tab 1, Schedule 2, Appendix B08

Preamble: Alectra notes that its Fleet Renewal investments will support its long-term goal to environmental sustainability by transitioning to electric and hybrid vehicles, which help reduce overall greenhouse gas emissions.

a) Please complete the following chart indicating the breakdown of vehicle type in Alectra's current vehicle fleet:

Vehicle Type	Fully Electric	Plug-in Hybrid	Hybrid	Non-EV/Hybrid	Total
Heavy Duty Vehicles					
Medium Duty Vehicles					
Light Duty Vehicles					

b) What proportion of Alectra's planned fleet renewal investment will involve fully electric and/or hybrid vehicles? Please complete the following chart indicating Alectra's anticipated breakdown of vehicle type in Alectra's planned fleet renewal investment (2027 to 2031):

Vehicle Type	Fully Electric	Plug-in Hybrid	Hybrid	Non-EV/Hybrid	2027-2031 Total
Heavy Duty Vehicles					
Medium Duty Vehicles					
Light Duty Vehicles					

c) Please indicate the estimated quantum of efficiency savings (including fuel cost savings) that Alectra anticipates it will achieve by utilizing hybrid vehicles and EVs rather than traditional internal combustion engine vehicles.

RESPONSE:

a) Please see the table below.

Table 1- Alectra Utilities Fleet Asset Breakdown by Vehicle Type

Vehicle Type	Fully Electric	Plug-In Hybrid	Hybrid	Non-EV/Hybrid	Total
Heavy Duty Vehicles	1	0	1	174	**176**
Medium Duty Vehicles	0	0	0	22	**22**
Light Duty Vehicles	20	18	0	299	**337**
Total	**21**	**18**	**1**	**495**	**535**

b) As stated in Ex. 2-1-1, Appendix B08, line 3, “Alectra Utilities’ approach to fleet electrification involved evaluating the suitability of electric vehicles at the time of scheduled replacement.” Accordingly, the utility cannot provide a specific number of electric or hybrid vehicles over the 2027-2031 period.

c) For the reasons set out in response to part b), Alectra Utilities cannot specific a quantum of efficiency savings that it may achieve over the forecast period through the deployment of electric and hybrid vehicles.

RESPONSES TO DISTRIBUTED RESOURCE COALITION INTERROGATORIES

INTERROGATORY 3-DRC-15

Reference: • Exhibit 3, Tab 1, Schedule 1, Attachment 3-2

Preamble: Alectra engaged Itron to complete a 2026-2031 Sales and Customer Forecast. The revenue load forecast includes total energy and demand sales and considers factors such as the adoption of EVs, as well as the electrification of commercial transportation.

a) Please discuss how Itron and Alectra's load forecast considers the impact and integration of EVs and EV charging infrastructure and provide any and all related analysis, working papers, and/or reports.

b) What are the consequences if EV growth rates exceed Alectra's forecasts? Please include in your response a discussion on what challenges this will present in terms of Alectra's ability to meet the higher demand and any consequences it may have on Alectra's ability to meet demand past 2031 if demand continues to accelerate more quickly than anticipated.

c) Please provide, in the chart format below, an assessment of the impacts on loads and demands — including the load forecast — of Alectra's estimate of EVs and distributed generation in each year and any supporting references.

	2025	2026	2027	2028	2029	2030	2031
EVs (number, kW or kWh)							
EV charging infrastructure (number, kW or kWh)							
Distributed Generation (number, type, kW or kWh)							
etc.							

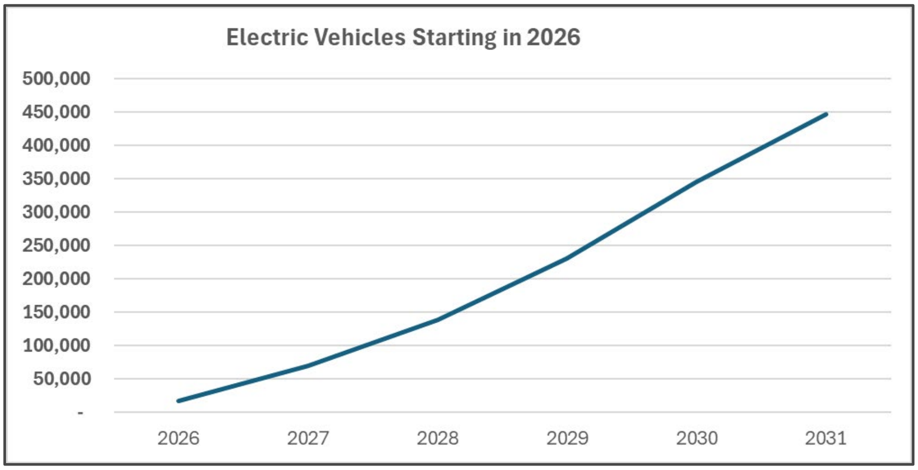
RESPONSE:

a) **Response prepared by Itron**

The baseline revenue forecast has been adjusted for expected electric vehicle (EV) charging sales. The underlying EV forecast assumptions are those developed by Alectra Utilities' System Planning and are based on the annual EV population projections by vehicle type for the 2020–2040 period. These include light-duty battery electric vehicles (LDV-BEV), light-duty plug-in hybrid electric vehicles (LDV-PHEV), medium-duty battery electric vehicles (MDV-BEV), medium-duty plug-in hybrid electric vehicles (MDV-PHEV), and heavy-duty vehicles (HDV).

The EV charging forecast starts with a system-wide annual EV population projection by vehicle type. The EV units used to calculate incremental EV-related energy sales represent the net increase in units relative to 2025. The 2025 and 2026 EV additions are adjusted as described in 3-SEC-72(c). The cumulative incremental EV unit additions from 2026 onward are illustrated in Figure 1.

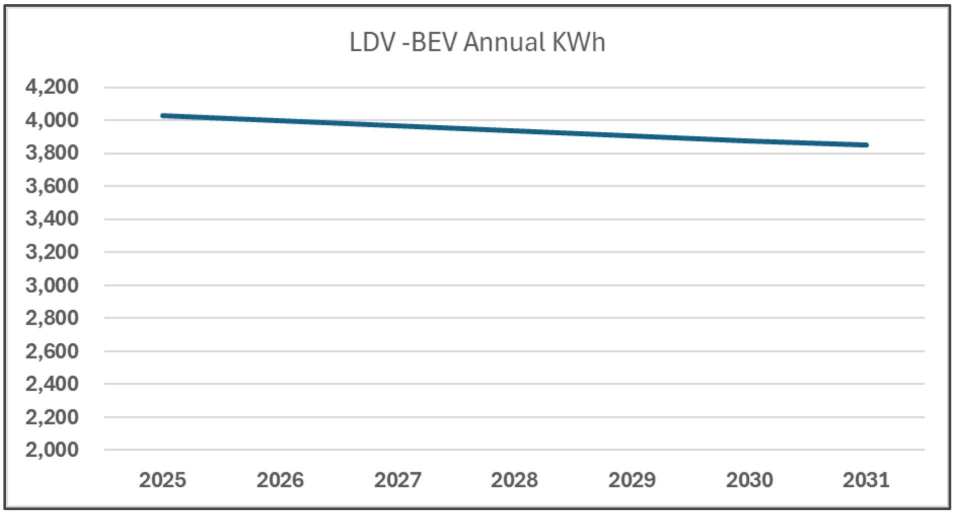
Figure 1 – Incremental EV Unit Forecast



Charging consumption from EVs adopted prior to 2026 is already embedded in historical actual sales data and is therefore not double counted. The revenue forecast reflects incremental EV-driven sales beginning in 2026.

The forecast assumes the starting average annual EV charging for LDV is 4,376 kWh, MDV kWh is 26,398 kWh, and HDV is 132,230 kWh. The starting annual charging loads are from the ISO New England 2023 Electric Transportation Electrification Forecast. It has been assumed that plug-in hybrid EVs (PHEV and PMDV) charge half as much as all-electric vehicles. In addition, it has been assumed that EV vehicle efficiency improves over time. The efficiency index is based on the Vermont Efficiency Investment Corp (VEIC) 2023 EV forecast. Vehicle efficiency improves roughly 0.8% per year. The resulting BEV annual kWh per vehicle is depicted in Figure 2.

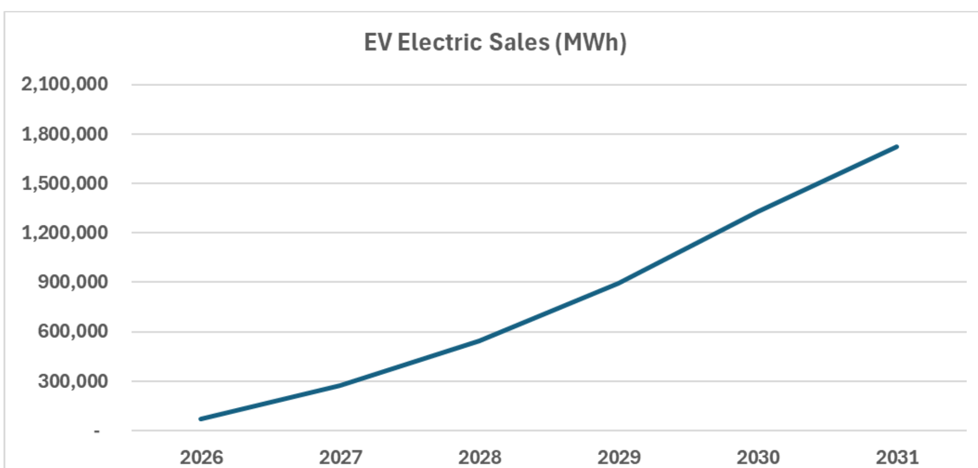
Figure 2 - LDV-BEV Annual Per Vehicle Energy Use (kWh)



Annual EV use for the other EV vehicle types is also adjusted for efficiency improvements.

The sales forecast is the product of the number of incremental vehicles and vehicle average use. Figure 3 below shows total EV charging sales starting in 2026.

Figure 3 - EV Charging Electric Sales (MWh)



The EV forecast is allocated to rate zones based on 2024 EV registration numbers within each rate zone. Table 1 below shows the rate zone allocations.

Table 1 - EV by Rate Zone

Pricing Zone Allocation Factors						
	BRZ	**ERZ**	**GRZ**	**HRZ**	**PRZ**	**Total**
Registered EVs	7,731	9,927	3,083	8,493	26,415	55,649
Share	**13.9%**	**17.8%**	**5.5%**	**15.3%**	**47.5%**	1.00

Within each rate zone, sales are mapped to the rate classes. 80% of LDV charging is allocated to the Residential class. It is assumed that 20% of LDV charging is away from the home and is allocated to the GS<50 kW class. Table 2 summarizes the rate class allocations.

Table 2 - Rate Class Allocations

Rate Class Allocation						
Type	**Res**	**GSL50**	**GSP50**	**GSP500/700/1000**	**LU**	**Total**
LDV	80%	20%	0%	0%	0%	100%
MDV	0%	50%	25%	25%	0%	100%
HDV	0%	0%	0%	70%	30%	100%

MDV and HDV rate class allocations are based on discussions with Alectra Utilities.

Annual sales are allocated to months based on a typical monthly charging pattern from the New England ISO transportation report.

For the EV sales forecast file, please see Tab “1.EV” of 3-EP-11_Attach 1_Electrification Assumptions.xlxs. The NEISO electrification presentation (*3-DRC-15_Attach 1_NEISOPresentation.pdf*) and the Vermont efficiency trend source file (*3-DRC-15_Attach 2_VEIC EV Efficiency (Source).xlsx*) are included as part of this data request.

b) If EV adoption exceeds forecast levels, Alectra may experience incremental technical, operational, and financial impacts.

Higher-than-forecast EV charging load could result in accelerated loading on distribution feeders and transformers, increasing the likelihood of thermal constraints and localized voltage performance issues. This may require earlier reinforcement or replacement of distribution assets, as well as potential upgrades to supply transformer stations and upstream transmission facilities.

From a financial perspective, accelerated infrastructure requirements would increase capital expenditure. Where reinforcements are required on an expedited basis, project costs may be higher.

Alectra mitigates these risks through its established system planning and operational practices. These include ongoing monitoring of feeder and transformer station loading, assessment of anticipated load connections, and periodic regional planning studies undertaken in coordination with the IESO, Hydro One, and neighbouring utilities. Load forecasts are reviewed and updated through these processes, and system reinforcements are identified and implemented, as required, to maintain system reliability.

c) **Response prepared by Itron**

EV unit forecasts and associated sales and billed demand are summarized in Table 3 below. Please refer to *Tab "1.EV"* of *3-EP-11_Attach 1_Electrification Assumptions* file for supporting information.

Table 3 – Total EV Count and Corresponding Energy Sales and Billed Demand

	2026	2027	2028	2029	2030	2031
Vehicles (Units)	105,527	157,200	226,969	318,869	433,510	534,349
Sales (MWh)	69,979	272,376	541,505	892,293	1,325,720	1,724,180
Billed Demand (MW)	11	47	86	131	182	240

In regard to distributed generation impact on load, please see 8-ED-41.

3-DRC-15

Attachment 1
NEISO Tranpt Presentation

Draft 2023 Transportation Electrification Forecast

Load Forecast Committee

Victoria Rojo
LEAD DATA SCIENTIST | LOAD FORECASTING

Introduction

- The ISO's transportation electrification forecast seeks to forecast the energy and demand impacts associated with the uptake of electric vehicles (EVs) within selected categories of vehicles:
  - Light-duty personal vehicles
  - Light-duty fleet vehicles
  - Medium-duty delivery vehicles
  - School buses
  - Transit buses

Methodology Updates for CELT 2023

- Developed a more consistent approach to generate state-level EV adoption forecasts
  - This effort includes canvasing of all federal, state, and local goals regarding EV adoption
  - Details on state-level adoption forecasting were discussed in the December 9, 2022 transportation electrification adoption forecast presentation
- Enhanced weather sensitivity of the energy and demand impacts of the personal light-duty vehicle portion of the forecast
  - Aligns methodology across all vehicle types
  - Moves from static monthly profiles to dynamic modeling of daily energy consumption based on weather
  - For more information see slides 4-9 of the November 7, 2022 update on the transportation electrification forecast

EV ADOPTION FORECAST

EV Adoption Forecast Overview

- For the CELT 2023 forecast, ISO has developed a more consistent approach for generating state-level EV adoption forecasts
- ISO has developed two adoption scenarios that reflect different assumptions about the pace and extent of transportation electrification within each state
  - **"Full Electrification" adoption scenario**
    - Intended to represent an upper bound on the pace and extent of EV adoption
    - Reflects comprehensive EV adoption estimates reflective of state emissions goals and associated EV adoption targets will be developed
    - Assumes state ZEV (Zero Emissions Vehicle) goals are met entirely by electric vehicles
    - Assumes all vehicles in each vehicle class are electrified by 2050
    - ***This scenario is informational only (not directly used in the forecast)***
  - **"Draft CELT 2023" adoption scenario**
    - Intended to reflect the likely pace and level of EV adoption over the next 10 years given the current understanding of individual state goals, policies, and programs
    - Reflects uncertainty in the timing of goal achievement and extent to which electric vehicles will be utilized to accomplish goals
    - ***This scenario was used to generate the energy and demand impacts for the Draft CELT 2023 forecast***

Federal EV Adoption Considerations

- Inflation Reduction Act
  - Enacts a tiered incentive for the purchase of new personal light-duty EVs meeting increasingly strict vehicle assembly and material sourcing requirements through 2032
  - Includes incentives for the purchase of used EVs through 2032
  - Includes incentives for the purchase of commercial light, medium, and heavy-duty EVs though 2032
  - Impact on regional EV adoption remains uncertain

- Environmental Protection Agency's (EPA) Clean School Bus Program
  - Funding from the Bipartisan Infrastructure Law provides $5 billion over the next five years (FY 2022-2026) to replace existing school buses with zero-emission and low-emission models
  - A number of New England cities have already been awarded funding during the 2022 selection process and have made clear their intent to apply for future funding

- 2021 White House announcement regarding 2030 goal for light-duty vehicle sales which was applied to the adoption of both personal and fleet light-duty vehicles and aims for:

  "…electric vehicles to make up 50% of all vehicles sold in the United States by 2030."

State-Specific EV Adoption Considerations

- Multi-State Zero-Emission Vehicle MOUs
  - 2013 Multi-State Zero-Emission Vehicle MOU (MA, CT, RI, VT) - goal of 5 million light-duty ZEVs on road by 2025 across the 9 signatory states
  - 2020 Multi-State Medium- and Heavy-Duty Zero Emission Vehicle MOU (MA, CT, RI, VT, ME) - commitment to phase out fossil fuel-burning medium- to heavy-duty truck and bus sales by one hundred percent by 2050, with a target for 30 percent of new truck and bus sales to be zero-emission by 2030 in all 15 signatory states

- Various individual state and local considerations including
  - State transportation electrification "Road Maps"
  - Local (usually individual cities) announcements/goals/programs for transitioning public transit and school bus fleets to ZEV
  - State transportation electrification "Action Plans"

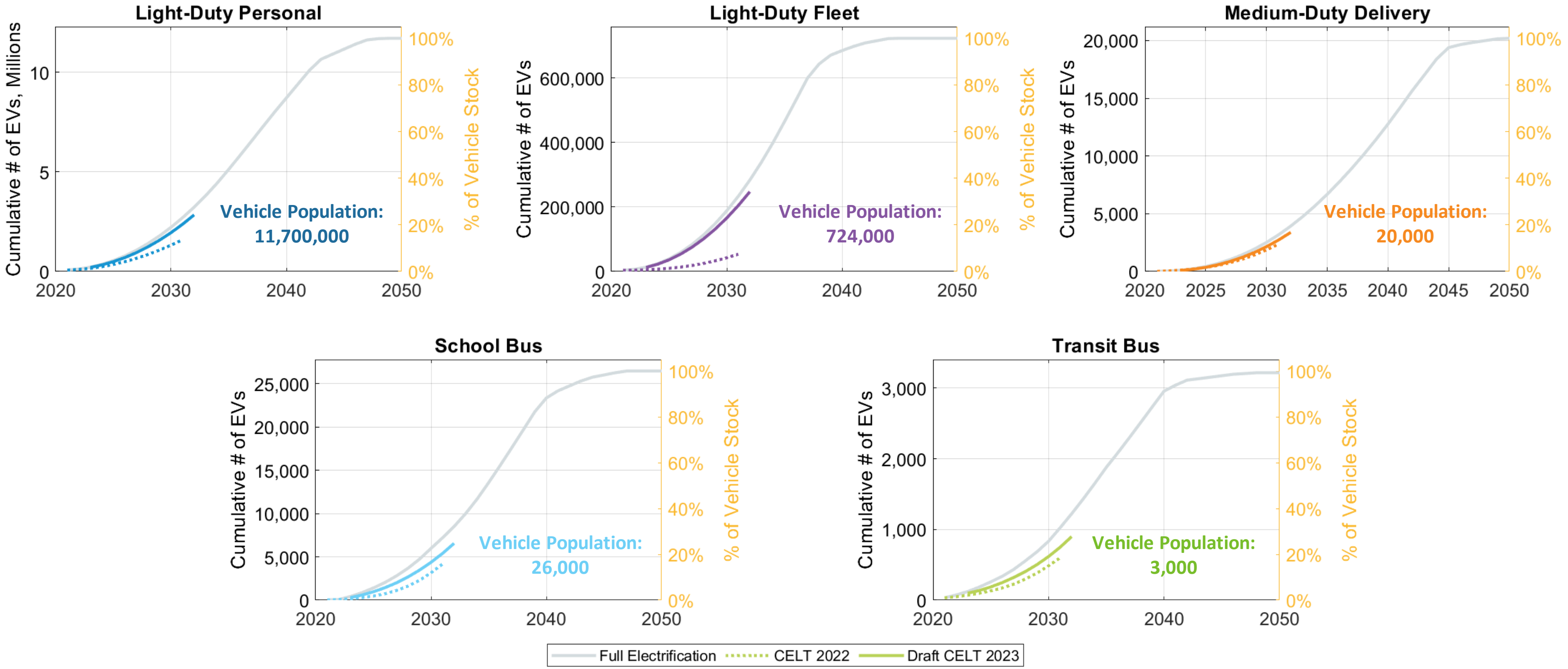
- Existing or anticipated adoption of California rules for ZEVs (MA and VT)
  - Advanced Clean Cars II (ACCII) requires by 2035 that 100% of light-duty vehicles sold will be ZEVs
  - Advanced Clean Trucks (ACT) requires by 2035 that:
    - 55% of Class 2b – 3 truck sales are zero emissions.
    - 75% of Class 4 – 8 straight truck sales are zero emissions.
    - 40% of truck tractor sales are zero-emissions

- State feedback
  - The ISO has shared all assumptions and references, along with preliminary adoption figures with each of the six New England states. Guidance was provided on:
    - Reasonableness of the "Full Electrification" scenario
    - Considerations for developing the "Draft CELT 2023" scenario

- The December 9, 2022 adoption forecast presentation lists considered drivers state by state
  - An updates version of state-level considerations will be included in the final 2023 transportation electrification forecast

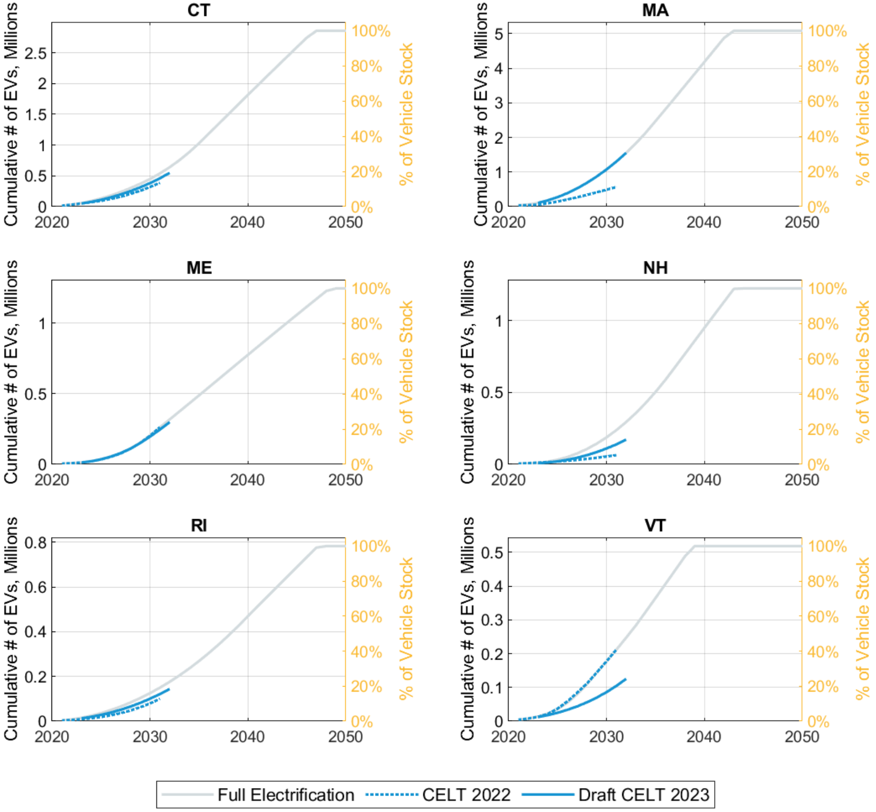
Draft 2023 EV Adoption Forecast

Cumulative EV Stock for New England



Personal Light-Duty EV Adoption

Cumulative EV Stock

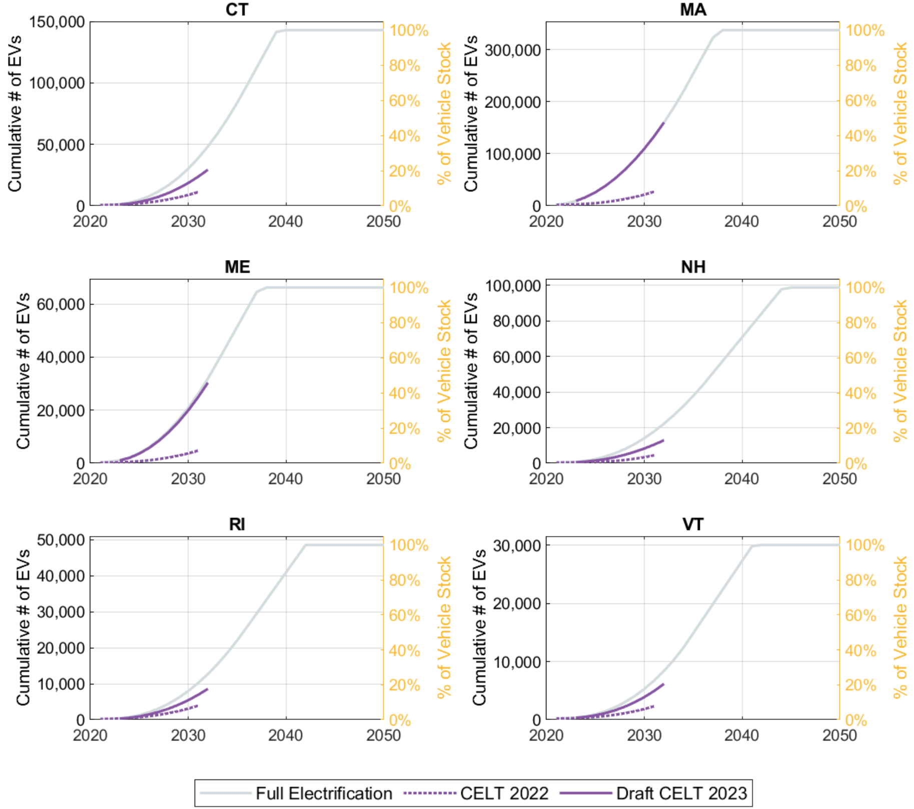


Annual Incremental Increase in EV Stock

Year	CT	MA	ME	NH	RI	VT	NE
2023	20,844	48,107	4,634	2,251	5,461	4,604	85,901
2024	27,146	72,081	9,218	4,801	7,165	5,748	126,159
2025	33,759	93,651	13,758	8,006	8,773	7,095	165,043
2026	40,468	116,072	19,036	11,115	10,414	8,601	205,706
2027	47,110	138,446	25,066	14,385	12,403	10,267	247,676
2028	53,768	160,595	32,035	17,830	14,418	12,097	290,742
2029	61,258	182,196	39,262	21,371	16,470	14,082	334,639
2030	68,898	203,904	45,314	24,946	18,577	16,089	377,727
2031	77,764	227,216	49,894	28,655	20,756	18,366	422,651
2032	87,919	251,736	52,854	32,593	22,643	20,935	468,679
10-year total (2023-2032)	518,934	1,494,004	291,071	165,953	137,080	117,884	2,724,923
Previous 10- year total (2022-2031)	369,920	530,755	258,273	58,524	96,652	207,673	1,521,796
Change	**+149,014**	**+963,249**	**+32,798**	**+107,429**	**+40,428**	**-89,789**	**+1,203,127**

Fleet Light-Duty EV Adoption

Cumulative EV Stock

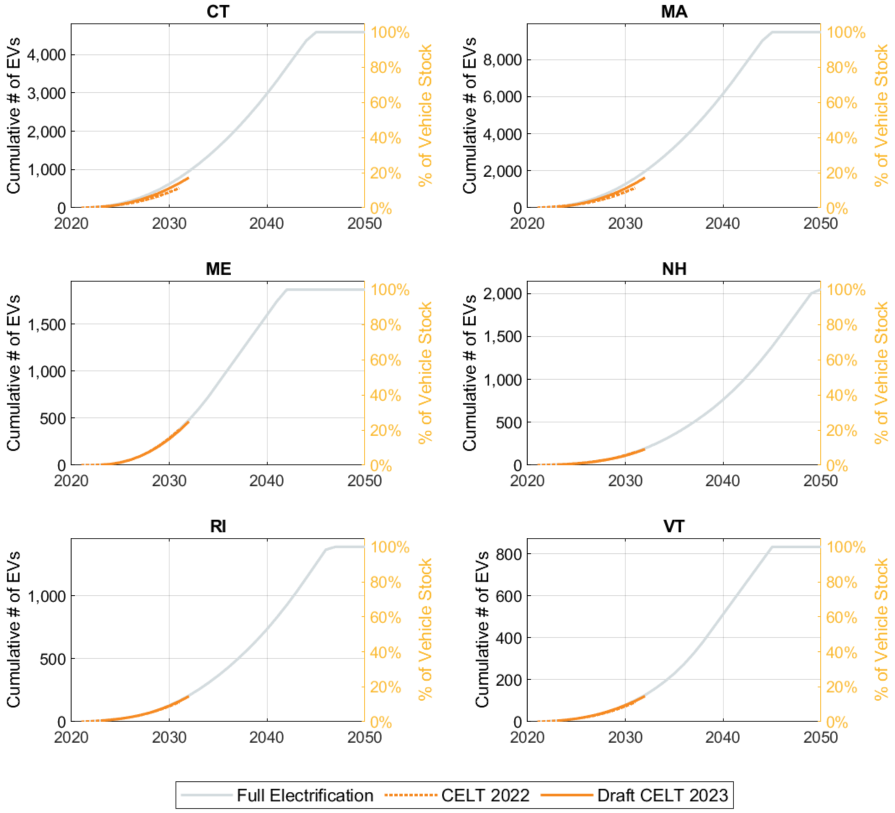


Annual Incremental Increase in EV Stock

Year	CT	MA	ME	NH	RI	VT	NE
2023	348	4,784	494	153	101	95	5,975
2024	782	7,175	1,002	345	228	166	9,698
2025	1,338	9,567	1,577	590	390	265	13,728
2026	1,877	11,959	2,130	828	547	369	17,710
2027	2,450	14,351	2,693	1,081	714	487	21,777
2028	3,059	16,743	3,257	1,349	891	620	25,919
2029	3,702	19,135	3,821	1,625	1,079	757	30,117
2030	4,362	21,526	4,385	1,900	1,271	899	34,344
2031	5,040	23,918	4,948	2,181	1,469	1,050	38,607
2032	5,735	26,310	5,437	2,473	1,671	1,211	42,838
10-year total (2023-2032)	28,693	155,468	29,744	12,525	8,361	5,919	240,713
Previous 10- year total (2022-2031)	10,588	25,222	4,525	4,060	3,705	2,106	50,206
Change	**+18,105**	**+130,246**	**+25,219**	**+8,465**	**+4,656**	**+3,813**	**+190,507**

Medium-Duty Delivery EV Adoption

Cumulative EV Stock

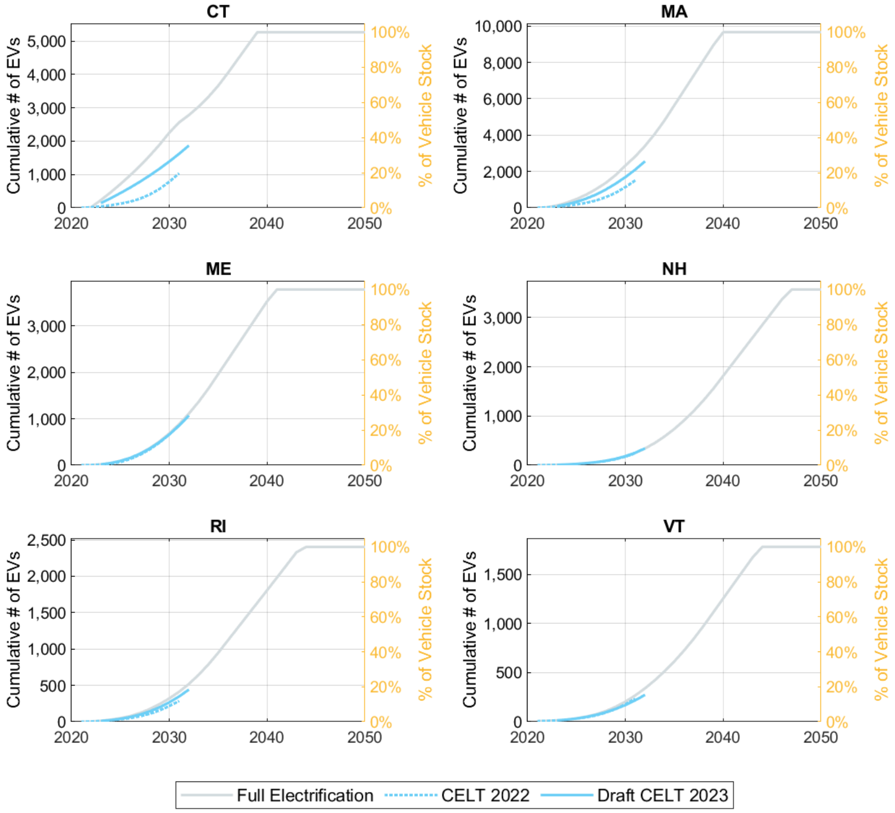


Annual Incremental Increase in EV Stock

Year	CT	MA	ME	NH	RI	VT	NE
2023	13	27	4	3	5	3	55
2024	26	52	7	5	7	4	101
2025	40	83	18	8	9	6	164
2026	54	112	27	10	12	8	223
2027	68	141	38	14	16	10	287
2028	83	171	50	18	20	13	354
2029	99	204	61	23	25	15	426
2030	115	238	74	28	30	18	502
2031	132	272	86	34	35	20	579
2032	148	311	99	41	40	23	661
10-year total (2023-2032)	778	1,611	464	184	199	120	3,352
Previous 10- year total (2022-2031)	514	1,064	378	152	155	93	2,356
Change	**+264**	**+547**	**+86**	**+32**	**+44**	**+27**	**+996**

School Bus EV Adoption

Cumulative EV Stock

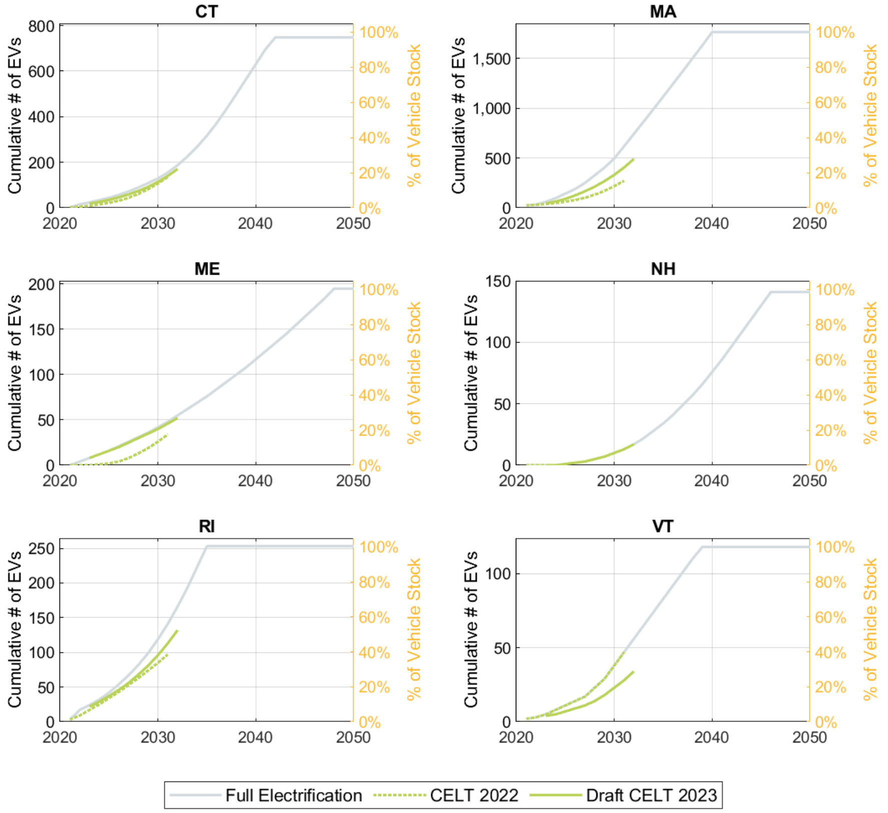


Annual Incremental Increase in EV Stock

Year	CT	MA	ME	NH	RI	VT	NE
2023	133	68	14	4	8	5	232
2024	144	103	27	7	11	8	300
2025	154	140	47	11	18	12	381
2026	165	179	66	15	25	16	467
2027	176	224	89	21	34	21	564
2028	188	277	112	29	44	27	678
2029	202	320	138	40	56	33	789
2030	217	362	164	53	68	40	904
2031	230	410	190	70	81	48	1029
2032	248	459	217	88	94	56	1161
10-year total (2023-2032)	1,857	2,542	1,064	338	439	266	6,505
Previous 10- year total (2022-2031)	1,032	1,502	857	244	286	228	4149
Change	**+825**	**+1,040**	**+207**	**+94**	**+153**	**+38**	**+2,356**

Transit Bus EV Adoption

Cumulative EV Stock



Annual Incremental Increase in EV Stock

Year	CT	MA	ME	NH	RI	VT	NE
2023	7	14	4	0	6	1	32
2024	7	19	4	0	7	1	38
2025	9	27	4	1	8	2	51
2026	11	35	4	1	9	2	62
2027	13	41	5	1	10	2	73
2028	15	47	5	2	12	3	83
2029	18	55	5	2	13	4	98
2030	22	64	5	3	15	5	114
2031	26	73	6	3	17	5	131
2032	30	86	6	4	19	6	151
10-year total (2023-2032)	158	461	48	17	116	31	833
Previous 10- year total (2022-2031)	134	247	34	13	94	45	567
Change	**+24**	**+214**	**+14**	**+4**	**+22**	**-14**	**+266**

METHODOLOGY

Methodology Overview

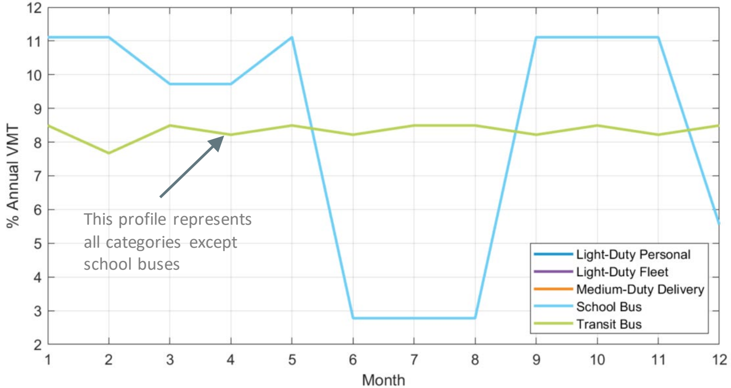
- Energy and demand impacts are based on analysis vehicle driving patterns and a samples of vehicle charging data
- Inputs developed specific to each vehicle category
  - Annual vehicle miles traveled (VMT)
  - Monthly allocation of VMT
    - Reflects seasonal driving patterns
    - Allocations for monthly VMT to weekdays/weekends
  - Hourly allocation of daily charging, by month
    - Shapes for Weekdays and weekends
  - Relationship between weather (daily average dry-bulb) and EV efficiency (kWh/mile)
- Monthly energy and demand impacts are developed for each vehicle category
  - Develop VMT assumptions for all days within a month
  - Apply temperature sensitive efficiency relationships to get daily energy
  - Apply daily charging shapes to allocate charging to hours
  - Monthly energy impacts stem from the same 30 year normal period used in the load forecast
  - Monthly demand impacts result from applying the weather distribution used in the load forecast
  - Scale to adoption forecast

Vehicle Miles Traveled (VMT)

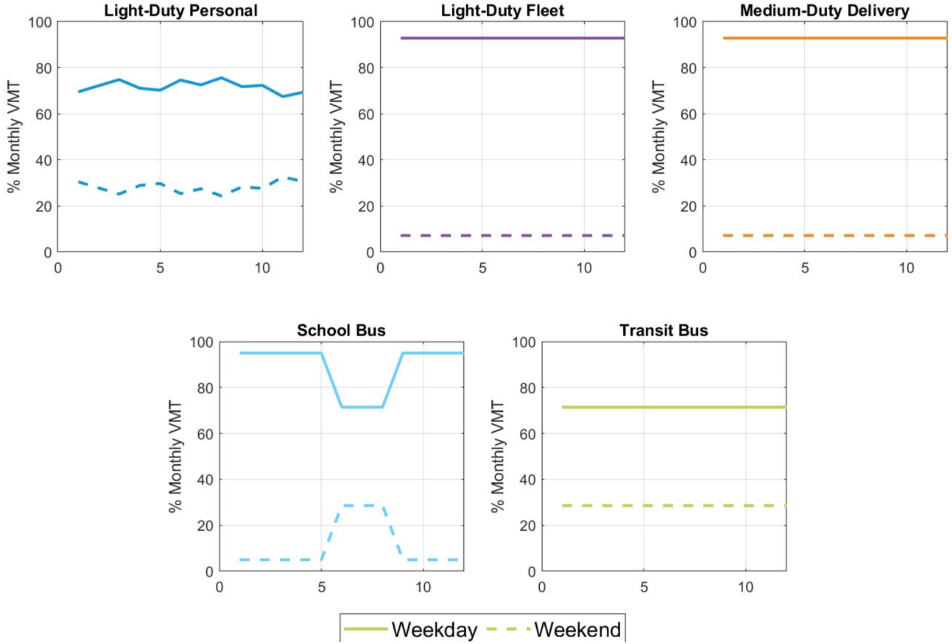
Annual VMT

Vehicle Category	Average Annual VMT
School bus	11,483
Transit bus	38,488
Medium-duty delivery	13,655
Light-duty fleet	21,258
Light-duty personal	11,505

Monthly VMT Allocation

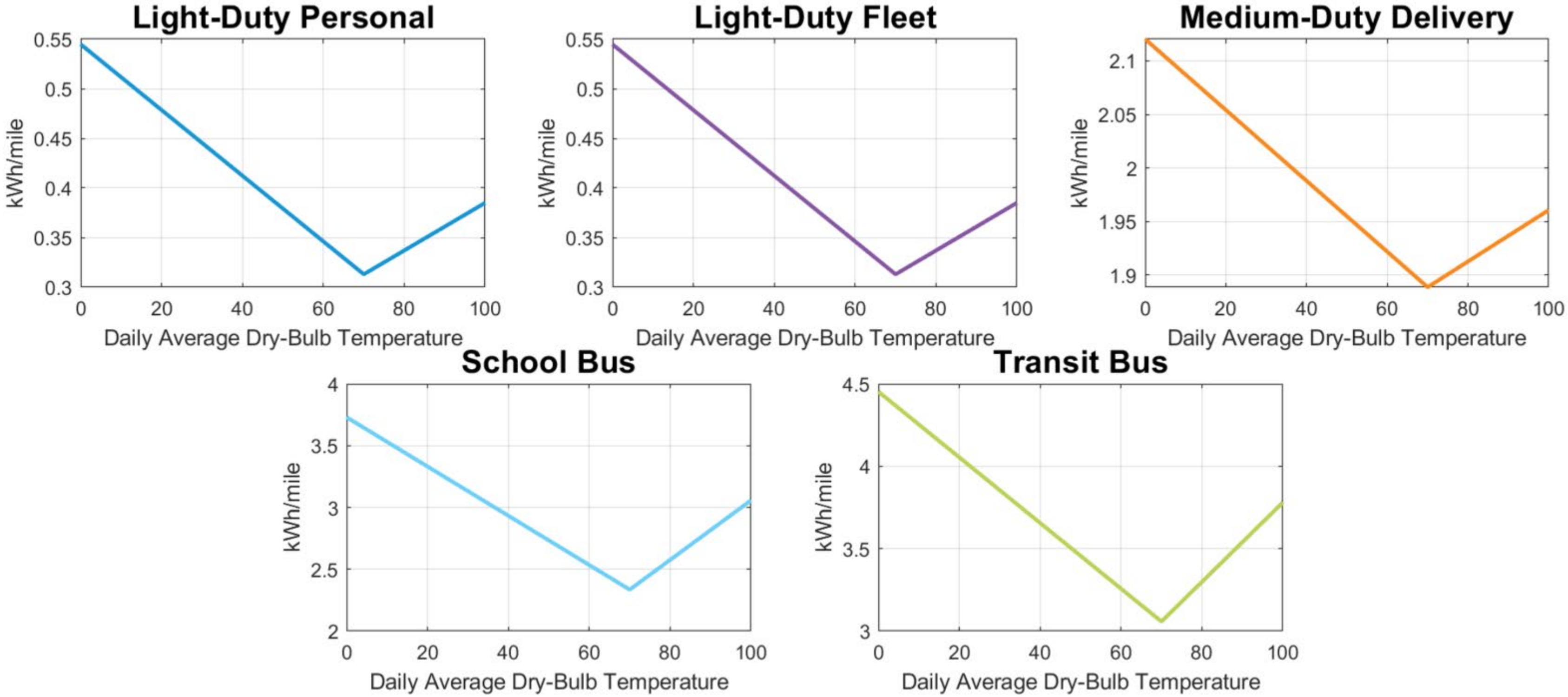


Day-type VMT Allocation



Electric Vehicle Efficiency

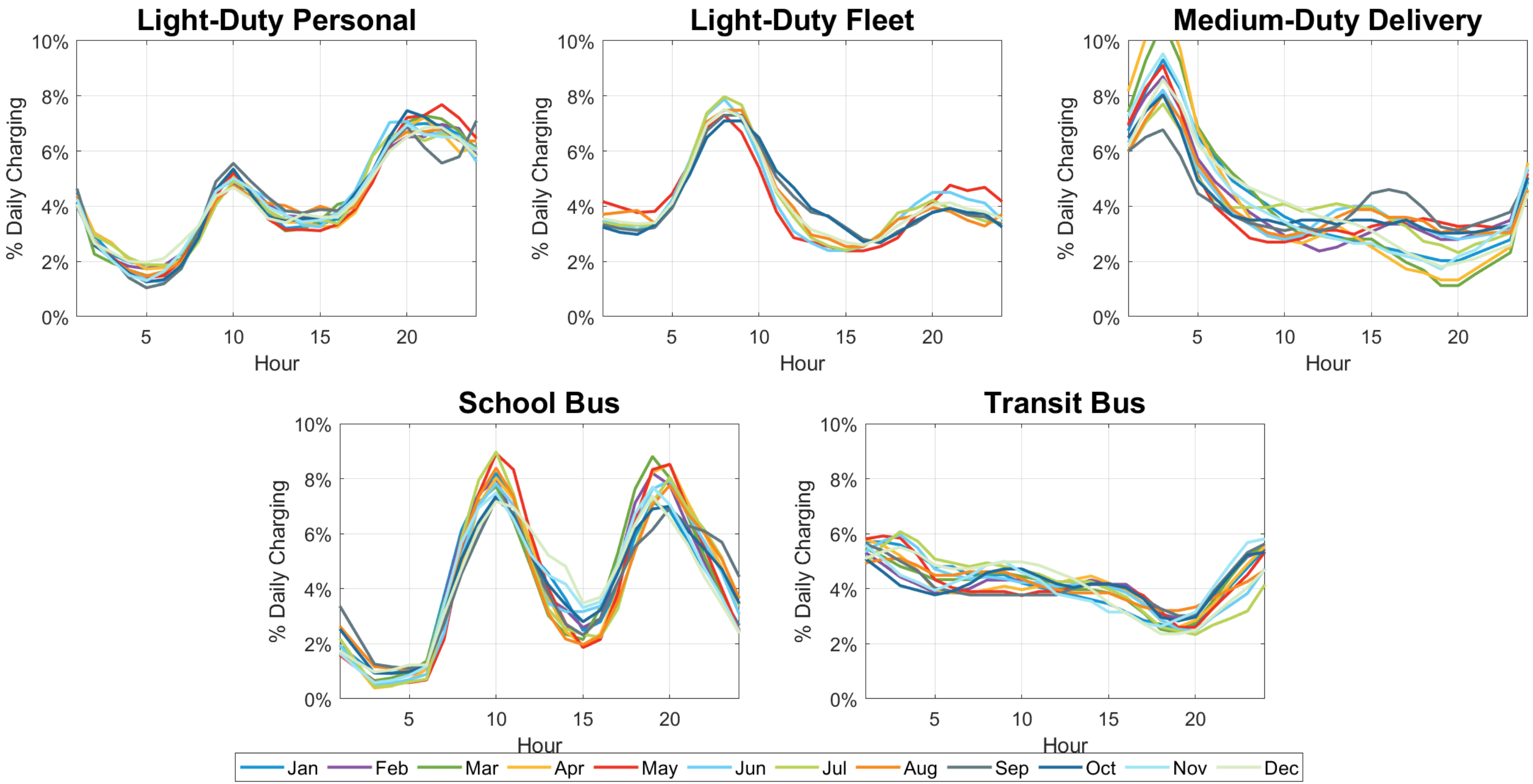
Energy Consumption as a Function of Daily Temperature



** School bus and transit bus efficiencies reflect an adjustment for the partial use of auxiliary cabin heating systems*

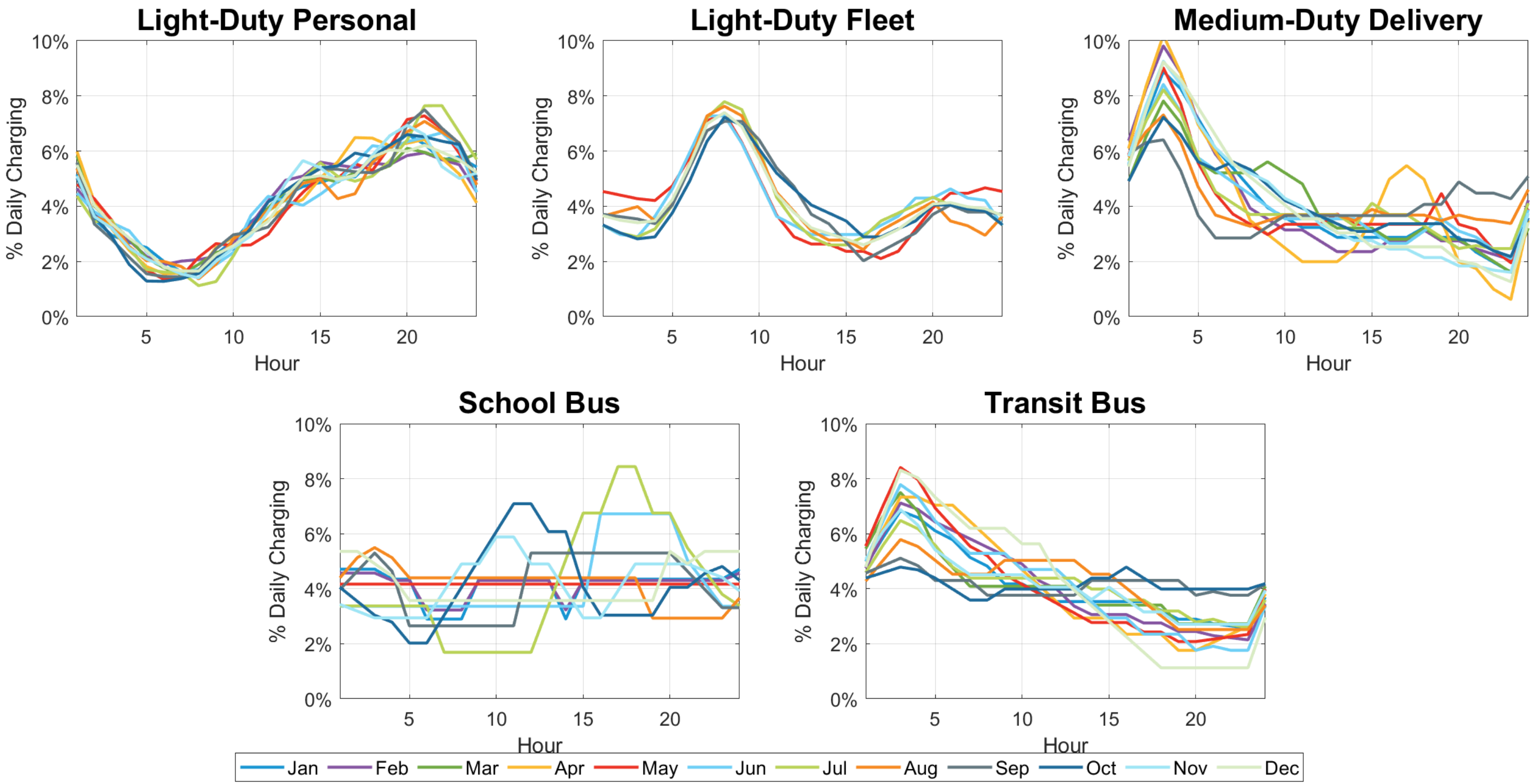
Allocation of Hourly Charging by Month

Non-Holidays & Weekdays



Allocation of Hourly Charging by Month

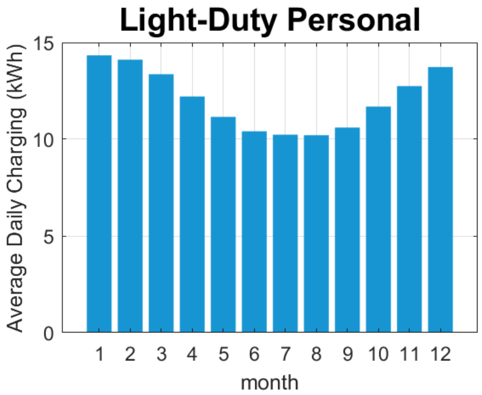
Holidays & Weekends

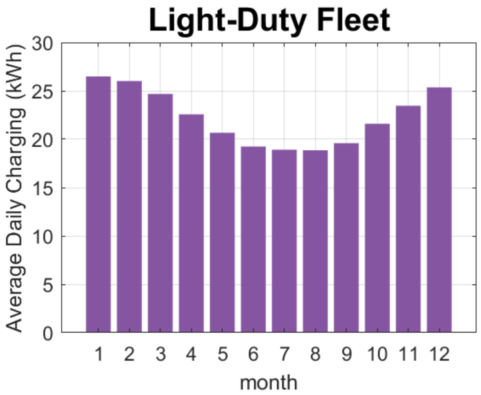


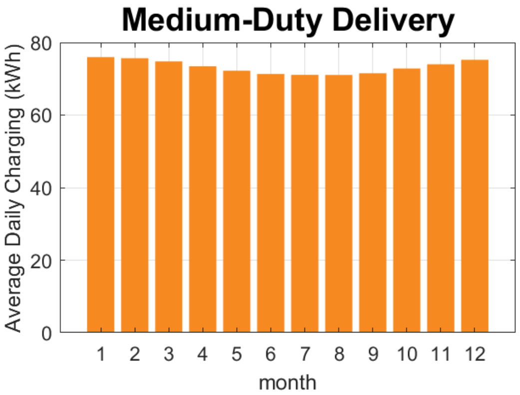
ENERGY FORECAST

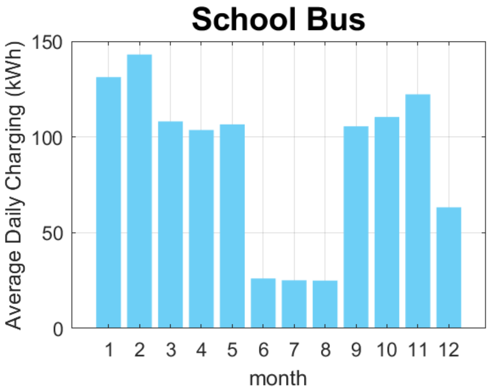
Estimating Energy Impacts of EV Adoption

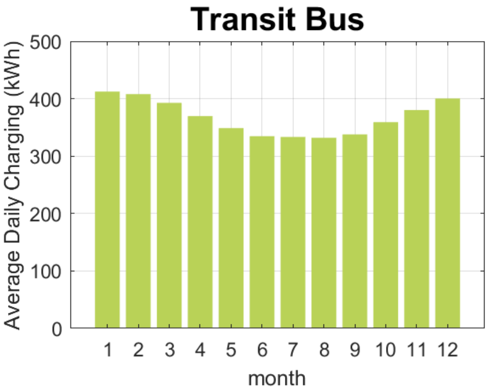
Average Daily Charging Energy – New England





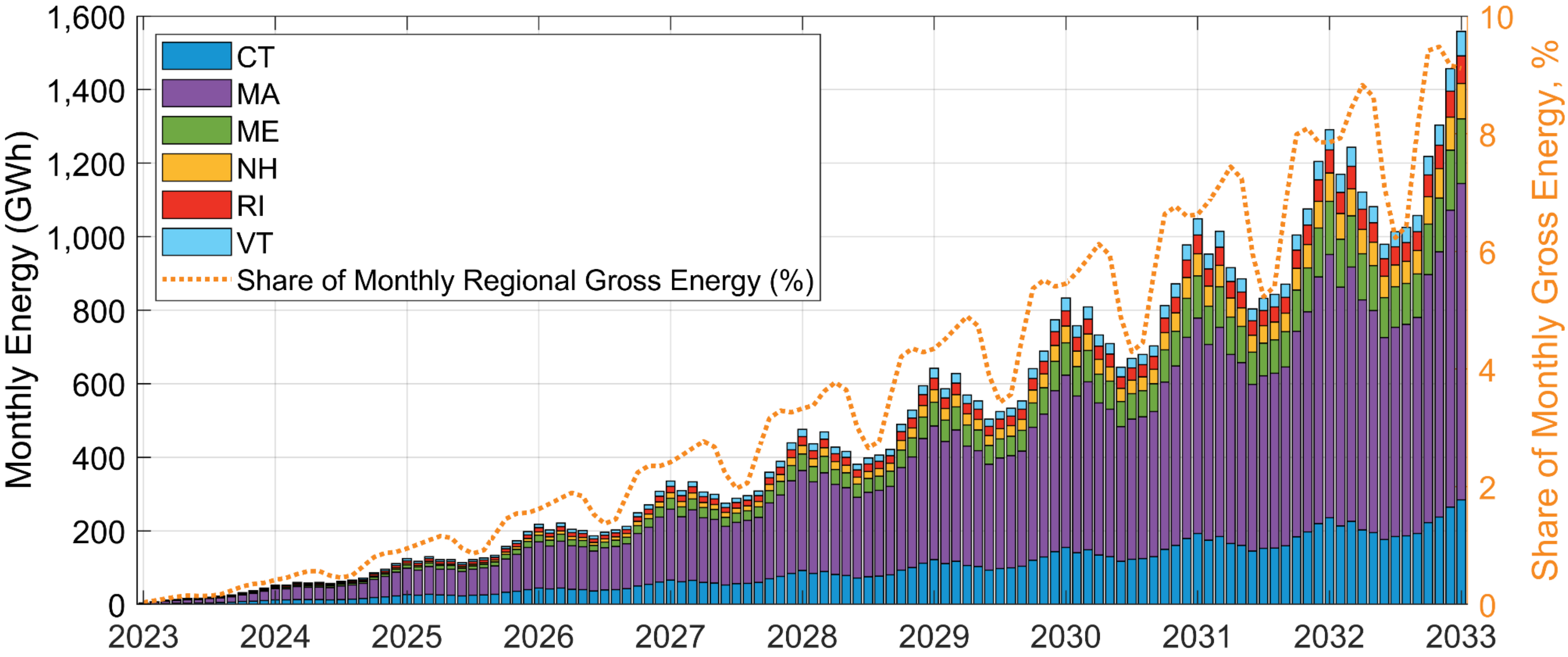






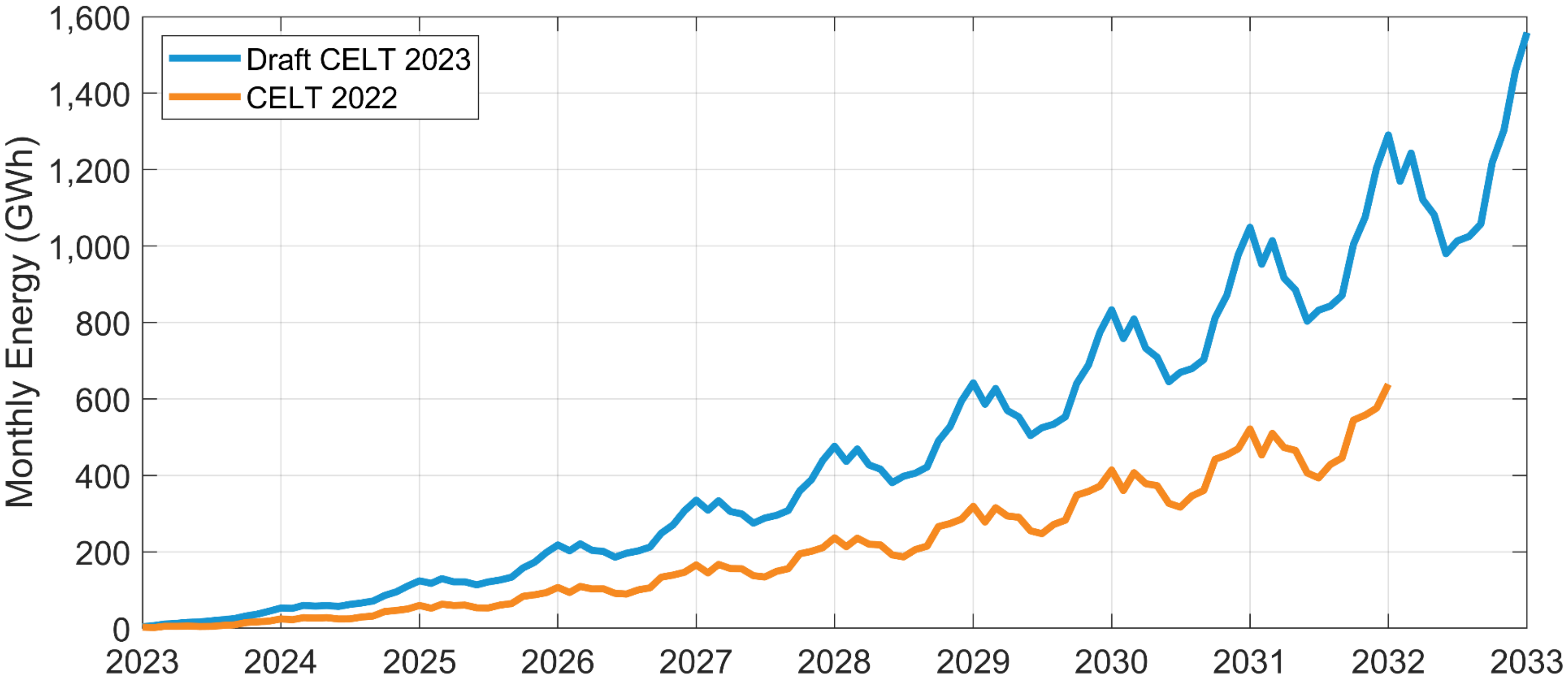
Draft 2022 Transportation Electrification Forecast

Monthly Energy



Transportation Electrification Energy Forecast

New England Comparison Between CELT 2022 and Draft CELT 2023



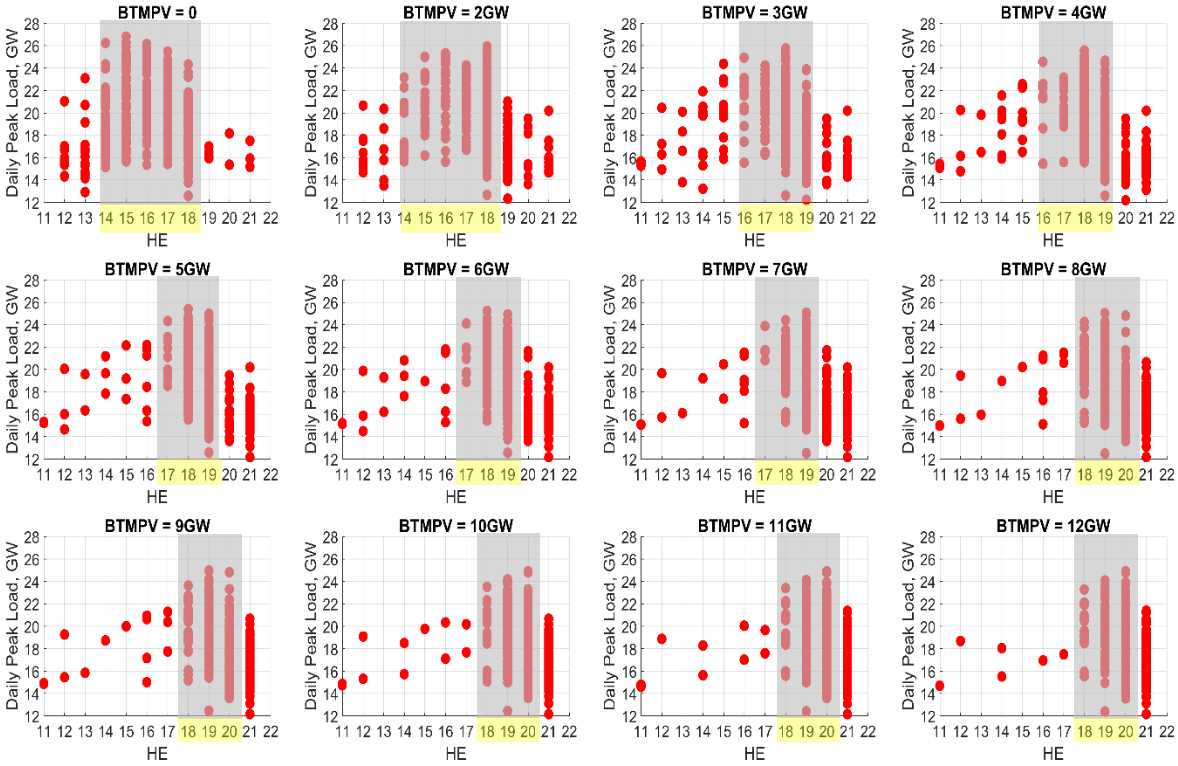
DEMAND FORECAST

Estimating Demand Impacts of EV Adoption

- For applications that include hourly analysis, EV demand will be modeled hourly
  - E.g., probabilistic ICR analysis
- Other forecast applications and reporting require a deterministic peak value (e.g., CELT report), and for which:
  - Winter peak demand:
    - Use the monthly average EV demand from HE 18-19
    - January-April, October-December
  - Summer demand impacts should reflect expectations of peak shifting due to increasing BTM PV penetrations (slides 26 and 27)
- Weather-sensitive demand impacts
  - Hourly weekday allocation of daily energy is used to estimate demand impacts
  - Daily energy is derived using VMT and temperature responsiveness of electric vehicle efficiency as outlined on slide 17

Summer Peak Net Load as BTM PV Increases

- Hourly net load and BTM PV data from the summers (July/August) of 2014-2021 were analyzed to simulate net loads with increasing penetrations of BTM PV
- Scatter plot shows the hour ending (HE) and magnitude (in GW) of net peak load as BTM PV increases
- Gray areas reflect estimated window of hours peak load may occur
  - Yellow areas highlight peak hours



Interaction of EV Summer Demand and BTM PV

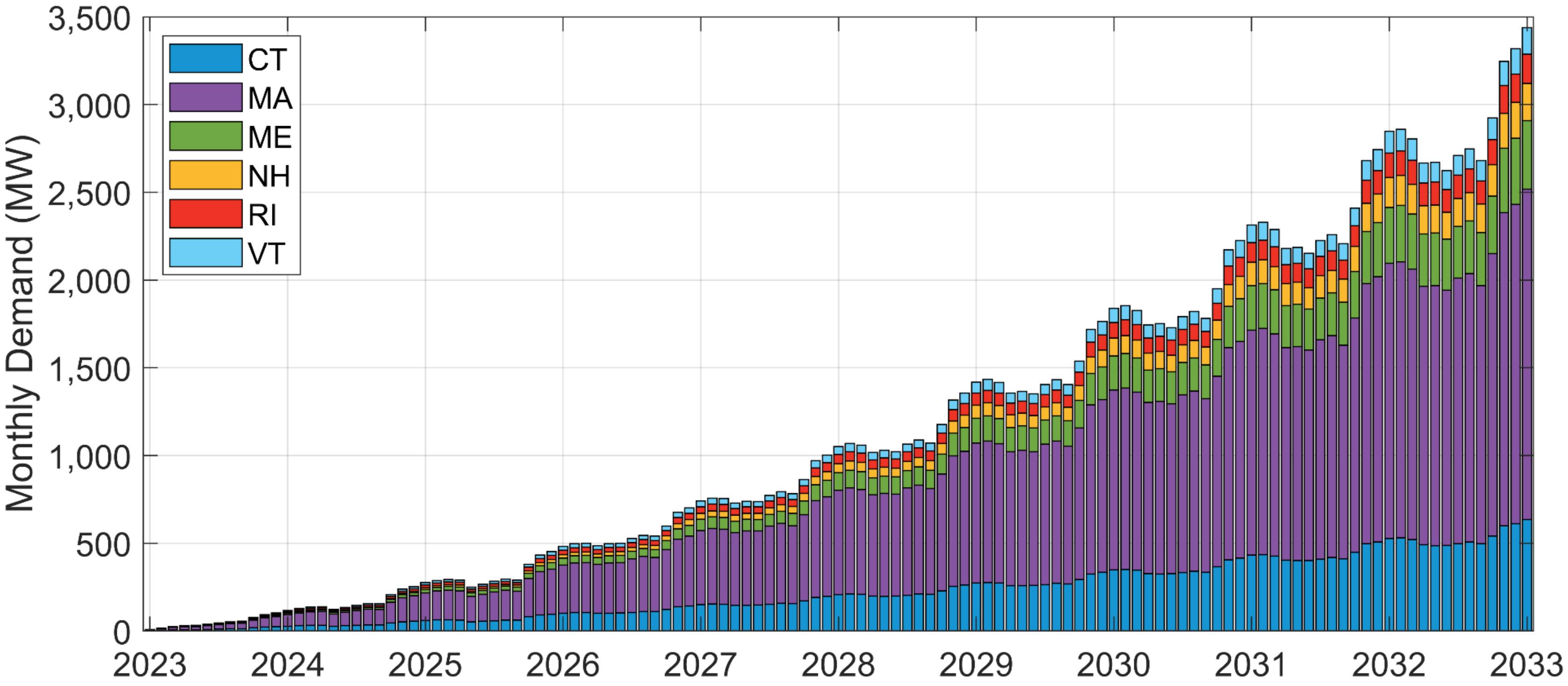
- For forecast applications and reporting that require a deterministic peak value, EV demand during the summer months is estimated as the average monthly EV demand during the summer peak hours tabulated to the right
  - May through September
  - Hours reflect effect of shifting peak demand due to BTM PV
- Used for forecasts of fleet vehicles and personal light-duty personal vehicles

Year	PV Nameplate Bin (GW)*	Summer Peak Hours
2023	6	[17,18,19]
2024	7	[17,18,19]
2025	8	[18,19,20]
2026	8	[18,19,20]
2027	9	[18,19,20]
2028	10	[18,19,20]
2029	10	[18,19,20]
2030	11	[18,19,20]
2031	11	[18,19,20]
2032	11	[18,19,20]

**Based on 2022 PV forecast values*

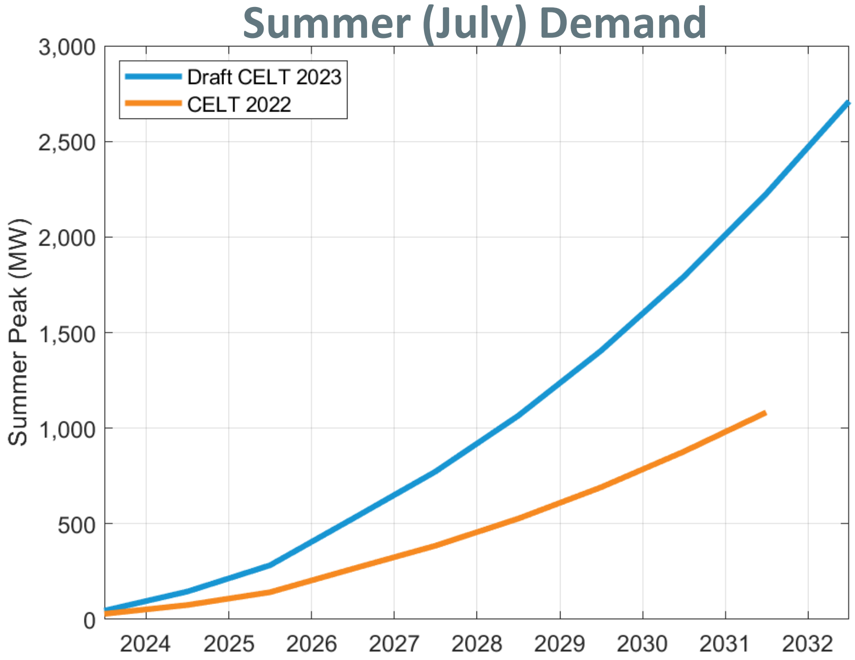
Draft 2022 Transportation Electrification Forecast

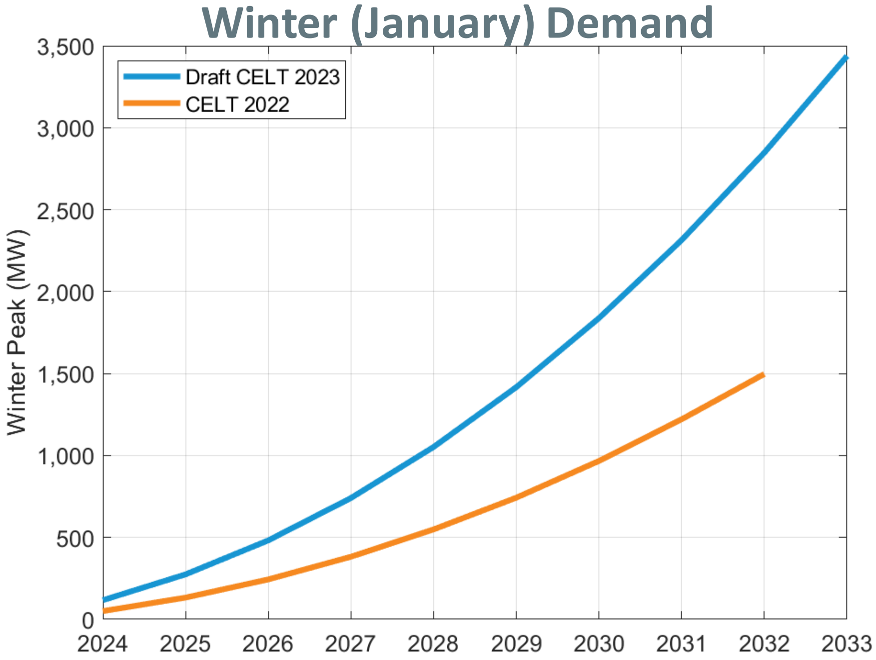
Monthly Demand by State



Transportation Electrification Demand Forecast

New England Comparison Between CELT 2022 and Draft CELT 2023*





* CELT 2022 values have been adjusted to begin accumulating 2023

NEXT STEPS

Next Steps

- ISO will continue to work with stakeholders to update adoption figures
- Final draft energy and demand impacts will be shared at the April 14, 2023 LFC meeting

Questions

3-DRC-15

Attachment 2
VEIC EV Efficiency Source

Please see live Excel