Chris Sandve
Chief Regulatory Officer
Phone: 604-623-3726
Fax: 604-623-4407
bchydroregulatorygroup@bchydro.com

February 27, 2023

Sara Hardgrave
Acting Commission Secretary and Manager
Regulatory Services
British Columbia Utilities Commission
Suite 410, 900 Howe Street
Vancouver, BC V6Z 2N3

Dear Sara Hardgrave:

RE: British Columbia Utilities Commission (BCUC or Commission)
British Columbia Hydro and Power Authority (BC Hydro)
Optional Residential Time-of-Use Rate Application (Application)

BC Hydro writes to file its Application pursuant to sections 58 to 60 of the *Utilities Commission Act* for approval of an optional Residential service time-of-use rate for all electricity consumption at a Residential service account, including electric vehicle charging (Rate Schedule 2101 Residential Service – Time-of-Use, also referred to as the **Optional Residential TOU Rate**).

The Optional Residential TOU Rate is an “add on” rate that applies year round and every day of the year (i.e., weekdays, weekends, and holidays). Participating customers will still be billed for their total electricity usage during a billing period at their existing Residential rate. They will then receive a 5-cent credit for each kWh of electricity consumed during the Overnight period (11 p.m. to 7 a.m.) and a 5-cent additional charge for each kWh of electricity consumed during the On-Peak period (4 p.m. to 9 p.m.). No credit or additional charge will be applied to consumption during the Off-Peak period (9 p.m. to 11 p.m. and 7 a.m. to 4 p.m.).

BC Hydro respectfully requests approval of the Optional Residential TOU Rate effective the later of April 1, 2024 or the first day of the fourth calendar month following the Commission order approving the rate schedule.

For further information, please contact Shiau-Ching Chou at 604-623-3699 or by email at bchydroregulatorygroup@bchydro.com.

Yours sincerely,

Chris Sandve
Chief Regulatory Officer

cc/ll

Summary Table of Contents

List of Figures

List of Tables

List of Appendices

BC Hydro Power smart

BC Hydro Optional Residential

Time-of-Use Rate Application

Chapter 1

Introduction

Table of Contents

List of Tables

1.1 Introduction

BC Hydro files this application (**Application**) to seek British Columbia Utilities Commission (**BCUC** or **Commission**) approval of a new optional Residential service time-of-use rate (Rate Schedule 2101 – Residential Service, also referred to as the **Optional Residential TOU Rate**).

The Optional Residential TOU Rate is for all electricity consumption at a Residential service account, including electric vehicle charging. Customers with a separate meter for electric vehicle charging under the same Residential service account may choose to apply the Optional Residential TOU Rate to their electric vehicle charging consumption only. It is an “add-on” rate that applies year-round and every day of the year (i.e., weekdays, weekends, and holidays). Participating customers will still be billed for their total electricity usage during a billing period at their existing Residential rate.[1] They will then receive a 5-cent credit for each kWh of electricity consumed during the Overnight period (11 p.m. to 7 a.m.) and a 5-cent additional charge for each kWh of electricity consumed during the On-Peak period (4 p.m. to 9 p.m.). No credit or additional charge will be applied to consumption during the Off-Peak period (9 p.m. to 11 p.m. and 7 a.m. to 4 p.m.).

This chapter introduces this Application and Chapter 2 provides the legal, regulatory, policy, and business context.

Chapter 3 provides further information on our consultation process and findings. We undertook extensive research and analyses to better understand our Residential customers, their individual situations and their views on rates and electricity consumption habits to inform this Application. We also conducted a 24-month long

[1] Most BC Hydro Residential customers living in the integrated service area take service under Rate Schedule 1101 Residential Inclining Block Rate and a small number of farm customers take service under RS 1151 Exempt Residential Service rate.

consultation process, engaging over 35,000 customers and stakeholders to review rate designs.

Chapter 4 sets out our proposal to offer the Optional Residential TOU Rate. As explained in that chapter, the Optional Residential TOU Rate:

- Uses “add-on” credits and charges to encourage customers to shift their electricity use to times when BC Hydro’s system capacity is more available. This “add-on” design enables a wide-range of customers to save by participating and helps to protect customers who do not participate;
- Will contribute to meeting customers’ future electricity needs. Consistent with the capacity savings targets set out in BC Hydro’s 2021 Integrated Resource Plan (**2021 IRP**), which relies on customer-based solutions over new infrastructure, it will help meet an expected increase in peak demand driven, in part, by electric vehicle adoption;
- Provides bill savings to encourage customers to shift their electricity consumption from BC Hydro’s system peak period to other hours of the day;
- Sends price signals that reflect the cost of service and is expected to provide benefits to all customers across a range of potential outcomes;
- Incorporates customers’ feedback, which demonstrates strong support for optional time-of-use rates, and is designed to achieve customer understanding and acceptance;
- Aligns with Bonbright rate design criteria and our rate design objectives and performs better against these considerations compared to alternatives; and,
- Includes Availability and Special Conditions to help protect customers and will be accompanied by an implementation plan so that customers receive the

support they need to achieve bill savings and an evaluation plan to verify if the expected benefits are being achieved to inform adjustments.

BC Hydro retained Dr. Sanem Sergici and Mr. Ryan Hledik of The Brattle Group to inform the development of the Optional Residential TOU Rate. Appendix F provides Dr. Sergici and Mr. Hledik's Review of BC Hydro's Optional Residential TOU Rate. It states:

> "We concluded that BC Hydro's proposed TOU design is consistent with successful industry rate design practices and effectively balances key ratemaking criteria. In particular, the company's proposed credit- and charge-based approach to implementing the TOU is an innovative approach to increase the appeal of a TOU rate for customers currently enrolled in an inclining block rate. Further, our review indicates that BC Hydro's assumptions about potential participation in and load impacts of TOU rates are reasonable and consistent with the available empirical evidence on the subject."[2]

1.2 Background

As discussed further in section 3.2 of Chapter 3, the current Residential Inclining Block (**RIB**) Rate applies on a default basis to all Residential service customers in our integrated service area, with limited exceptions.[3] Except for service under Rate Schedule (**RS**) 1151 or RS 1105, BC Hydro does not currently offer Residential customers in the integrated area an optional alternative to the RIB Rate.

The Optional Residential TOU Rate will provide customers with choice. Customers who feel they can achieve bill savings under the Optional Residential TOU Rate by shifting their electricity consumption from BC Hydro's system peak period to other

2 Refer to Appendix F (A Review of BC Hydro's Optional Residential TOU Rate, The Brattle Group), page 12.

3 Other than Residential farm customers, who may take service under RS 1151 – Exempt Residential Service, and customers who may take service under RS 1105 – Residential Service – Dual Fuel (Closed). In both cases, customers may only take service under these rate schedules if they qualify. There are also a small number of customers, such as common use areas of residential multi-occupancy buildings, who have options to select an applicable General Service rate.

hours of the day can choose to “add” the rate to their existing Residential rate. In the coming months, BC Hydro plans to consult on additional optional rates that could provide Residential customers with more choices to meet their electricity needs.

This Application fulfills the following Near-Term Action of BC Hydro’s 2021 IRP:[4]

> BC Hydro will file a rate design application with the Commission in 2022 seeking approval for two new services and associated rates:
>
> 1. A voluntary residential time-of-use rate that will apply to the residential account. This new service will implement the residential voluntary time-of-use rate element of the Base Resource Plan; and
>
> 2. A voluntary time-of-use rate for home charging of electric vehicles. This new service will support the electric vehicle peak reduction element of the Base Resource Plan.
>
> BC Hydro will be submitting the rate design application to the Commission in calendar year 2022 for the new services, with a requested implementation date of April 1, 2023, for both.

While BC Hydro initially expected to file this Application in 2022 and offer two separate time-of-use rates, one for the whole home and one for separately metered electric vehicle charging, our approach evolved as we conducted customer engagement. With the benefit of additional time, BC Hydro developed the “add-on” concept that underpins the Optional Residential TOU Rate. We expect the Optional Residential TOU Rate will achieve better outcomes compared to alternatives explored. In addition, customers with a separate meter for electric vehicle charging under the same Residential service account may choose to apply the Optional Residential TOU Rate to their electric vehicle charging consumption only, which means there is no need for BC Hydro to offer two separate rates.

[4] Refer to pages 7-29 and 7-30 (www.bcuc.com/Documents/Proceedings/2021/DOC_65194_B-1-BCH-IntegratedResourcePlan-Public.pdf).

1.3 Orders Sought

BC Hydro seeks Commission orders approving our proposed Optional Residential TOU Rate, effective the later of April 1, 2024, or the first day of the fourth calendar month following the Commission order approving the rate schedule.[5]

BC Hydro also proposes that the Commission direct BC Hydro to file an evaluation report on the Optional Residential TOU Rate in fiscal 2029. In addition, BC Hydro requests a Commission order to rescind various reporting requirements from Directive No. 2 of BCUC Order No. G-92-19 on BC Hydro's amendments to its Electric Tariff to facilitate Residential customers charging of zero-emission vehicles at their dwelling and incorporate any reporting requirements that may still be helpful into this proposed evaluation report. This request is discussed further in Appendix I of the Application.

Draft orders are included in Appendix A to the Application. A draft rate schedule is included as Appendix B to the Application.

1.4 Proposed Regulatory Process

Table 1–1 below sets out a proposed regulatory process and schedule for the review of the Application.

BC Hydro notes that nine weeks is required to provide notification to all Residential customers, as notification occurs as part of the billing cycle and most Residential customers are billed every second month. This is reflected in the proposed schedule below.

5 Refer to section 4.8 of Chapter 4 where we discuss the requirement for a later timeline for the effective date of the Optional Residential TOU Rate due to the longer time required to implement the rate.

Table 1–1 Proposed Regulatory Schedule and Process

Action	Date (2023)
Application Submitted to the Commission	February 27
BC Hydro Provides Notice of Application to Identified Parties; Customer Notification Underway	March 10
BC Hydro Provides Confirmation of Notice to Residential Customers	May 17
BCUC Information Request No. 1 to BC Hydro	June 2
Intervener Information Requests No. 1 to BC Hydro	June 9
BC Hydro Responses to BCUC and Intervener IR No. 1	July 20
Further Process	To be determined

1.5 Structure of Application

The Application is structured as follows:

- Chapter 1 provides a summary of the purpose and scope of the Application, as well as some background information and a proposed regulatory review process;
- Chapter 2 provides the legal, regulatory, policy and business context for the Application;
- Chapter 3 provides information on the characteristics of our Residential customers and summarizes the customer and stakeholder consultation process and results. As discussed further in Chapter 3, BC Hydro undertook extensive consultation to inform the development of this Application;
- Chapter 4 outlines the proposed Optional Residential TOU Rate;
- Appendix A provides the draft orders that BC Hydro is seeking in the Application;
- Appendix B provides a draft version of our tariff sheet for the Optional Residential TOU Rate;

- Appendix C provides BC Hydro's 2021 IRP, as filed with the Commission in December 2021;
- Appendix D provides our customer stakeholder engagement materials and results that informed the Application;
- Appendix E provides The Brattle Group's report, "Capacity Savings Estimates in BC Hydro's 2021 IRP: An Independent Review";
- Appendix F provides The Brattle Group's report, "A Review of BC Hydro's Optional Residential TOU Rate";
- Appendix G provides a cost of service analysis of the Optional Residential TOU Rate;
- Appendix H provides the calculations and inputs for the Optional Residential TOU Rate as well as an economic assessment; and,
- Appendix I explains BC Hydro's request to rescind various reporting requirements from Directive No. 2 of BCUC Order No. G-92-19 on BC Hydro's amendments to its Electric Tariff to facilitate Residential customers charging their zero-emission vehicles at their dwelling and to incorporate any requirements the Commission still considers helpful into BC Hydro's proposed evaluation report on the Optional Residential TOU Rate.

1.6 Matters Not Addressed in this Application

BC Hydro is considering various rate design matters that are not included in this Application but will be addressed through future filings with the Commission. A summary of these initiatives is listed below:

- In the coming months, BC Hydro plans to consult on additional optional rates that could provide Residential customers with more choices to meet their electricity needs;

- This Application does not include proposals related to Rate Schedule 1289 – Net Metering Service (**RS 1289**). RS 1289 has been the subject of recent Commission Orders, a number of evaluation reports, and a range of customer and stakeholder engagement activities.[6] BC Hydro plans to file an application regarding RS 1289 in fiscal 2024. The process to develop this application will include further consultation on issues considered in BC Hydro's October 2020 Net Metering Evaluation Report No. 5, including virtual net metering, treatment of hydropower generation, and marginal cost pricing with a system access charge;[7]
- This Application does not include proposals related to amendments to BC Hydro's Electric Tariff Terms and Conditions. BC Hydro has commenced work on engagement to inform an application regarding Electric Tariff Terms and Conditions, which we expect to file in fiscal 2024;
- This Application does not include proposals related to BC Hydro's non-integrated areas. BC Hydro plans to advance an application regarding non-integrated area rates as part of our upcoming consultation on additional optional rates that could provide Residential customers with more choices to meet their electricity needs;
- This Application does not include proposals related to General Service or Transmission Service rate schedules. BC Hydro expects to file a Transmission Service rate design application shortly after this Application. BC Hydro has been undertaking customer research into potential optional rates for General

---

6 Refer to Commission Order No G-168-20 (www.ordersdecisions.bcuc.com/bcuc/decisions/en/481549/1/document.do) and Net Metering Evaluation Report No. 5 (www.bchydro.com/content/dam/BCHydro/customer-portal/documents/corporate/regulatory-planning-documents/integrated-resource-plans/current-plan/2020_10_30_COMPL_G_168_20_RS_1289_NM_EVAL_RPT.pdf), October 30, 2020, in response to Order G-168-20, Directive 5. In Net Metering Evaluation Report No. 5 see section 3 of for earlier evaluation reports and section 7 on stakeholder engagement.

7 Net Metering Evaluation Report No. 5, section 10.

Service customers, and we will advance an application for such rates according to customer and stakeholder interest and resource availability; and,

- This Application does not include proposals related to our Public Electric Vehicle Fast Charging Service Rates. In accordance with Commission Order No. G-391-22, BC Hydro will file an application for permanent Electric Vehicle Fast Charging rates by June 30, 2023.[8]

In this Application, BC Hydro is not applying to set rates for the purpose of changing the revenue-cost ratio for a class of customers. Section 58.1(7) of the *Utilities Commission Act* states that the Commission must not set rates for a public utility for the purpose of changing the revenue-cost ratio for a class of customers, except on application by the public utility.

BC Hydro has received feedback from some stakeholders interested in regionally differentiated rates, such as a unique rate schedule for customers in specific regions or communities in BC Hydro's Zone I integrated service area. Consistent with long-standing policy, BC Hydro proposes to continue with "postage stamp" rates that apply across all BC Hydro's Zone I integrated service area.[9] For electric utilities, like BC Hydro with diverse service territories and customer characteristics, postage stamp rates can provide customers with relatively low cost electricity across a wide-range of circumstances, with minimum controversy.

---

8 Refer to Commission Order No. G-391-22 (www.ordersdecisions.bcuc.com/bcuc/orders/en/521461/1/document.do), Directive 1.

9 Refer to Appendix C-1C (BC Hydro's 2015 Rate Design Application) (www.bcuc.com/Documents/Proceedings/2015/DOC_44664_B-1-BCH-2015-Rate-Design-Appl.pdf) where the Government of B.C.'s letter regarding postage stamp rates can be found, see section 2.2.2.1.

BC Hydro
Power smart

BC Hydro Optional Residential Time-of-Use Rate Application

Chapter 2

Context for the Application

Table of Contents

List of Tables

2.1 Introduction

In this chapter, BC Hydro sets out the legal, regulatory, policy and business context for the Application.

Sections 58 to 60 of the *Utilities Commission Act* set out the Commission's rate-setting function and the legal test for rates to be fair, just and not unduly discriminatory.

BC Hydro's Optional Residential TOU Rate proposal in this Application is guided by:

- The eight Bonbright rate design criteria, which the Commission has previously determined form an appropriate foundation for rate structures; and,
- Our rate design objectives of affordability, economic efficiency, decarbonization, and flexibility.

BC Hydro's proposal in this Application also aligns with the Government of B.C.'s CleanBC plan (**CleanBC**) to "increase our use of cleaner energy, especially electricity, in our lives and in key sectors of our economy – shifting away from our reliance on fossil fuels for transportation, industry, and housing".[10] Specifically, B.C.'s *Zero-Emission Vehicles Act*[11] mandates an increase in electric vehicle adoption and this is forecast to be a significant driver of increased peak demand going forward. This Application corresponds to a Near-term Action of BC Hydro's 2021 Integrated Resource Plan (**2021 IRP**) to help manage this expected increase in peak demand.

[10] Refer to the Government of B.C.'s CleanBC plan, page 11, at: https://www2.gov.bc.ca/assets/gov/environment/climate-change/action/cleanbc/cleanbc_2018-bc-climate-strategy.pdf.

[11] https://www.bclaws.gov.bc.ca/civix/document/id/complete/statreg/19029.

Time-of-use rates are common across North America. Our jurisdictional review of North American utilities offering time-of-use rates showed that both whole home and end-use rates are available to customers.

This chapter is structured as follows:

- Section 2.2 provides the legal and regulatory context for this Application;
- Section 2.3 provides the provincial policy context for this Application;
- Section 2.4 summarizes BC Hydro's business context; and,
- Section 2.5 summarizes BC Hydro's jurisdictional review findings.

2.2 Legal and Regulatory Context for our Proposed Rate

In this Application, BC Hydro is applying to offer the Optional Residential TOU Rate to Residential customers.

Sections 58 to 60 of the *Utilities Commission Act* set out the Commission's rate-setting function and the legal test for rates to be fair, just and not unduly discriminatory. BC Hydro's proposal in this Application is guided by the eight Bonbright rate design criteria, which the Commission has previously determined form an appropriate foundation for rate structures, as well as our rate design objectives of affordability, economic efficiency, decarbonization, and flexibility. Further information is provided in the sub-sections below.

2.2.1 Utilities Commission Act

The rate-setting function of the BCUC is set out by sections 58 to 60 of the *Utilities Commission Act*: [12]

- Section 58 sets out the process by which the BCUC is engaged to set rates. This process may be initiated by the BCUC, a public utility, or an interested

[12] www.bclaws.gov.bc.ca/civix/document/id/complete/statreg/96473_01.

person. After a hearing, the BCUC must "determine the just, reasonable and sufficient rates to be observed and in force" and then, by order, set the rates;

- Section 58.1 addresses rate rebalancing. Rate rebalancing refers to a process to change revenue-cost ratios for a public utility's customer classes (i.e., the ratio of revenues a utility earns from a class of customers to the fully allocated cost of service costs incurred by the utility in serving that class of customers). Subsection 58.1(7) states that the BCUC "may not set rates for a public utility for the purpose of changing the revenue-cost ratio for a class of customers except on application by the public utility". BC Hydro is not applying to change the revenue-cost ratio for any of its customer classes in this Application. Accordingly, section 58.1 is not applicable to this Application;
- Section 59 addresses discrimination in rates. For example, it states that a public utility must not make a rate that is unjust, unreasonable, unduly discriminatory or unduly preferential, or a rate that otherwise contravenes the *Utilities Commission Act*, an order of the BCUC or any other law;
- Subsection 59(5) specifies that a rate is "unjust" or "unreasonable" if, among other things, "the rate is more than a fair and reasonable charge for service of the nature and quality provided by the utility", or if it is "insufficient to yield a fair and reasonable compensation for the service provided by the utility"; and,
- Section 60 specifies the criteria the BCUC is to consider in setting rates. For example, the BCUC must have due regard to the setting of a rate that:
  - ▶ Is not unjust or unreasonable;
  - ▶ Provides the public utility a fair and reasonable return on any expenditure made by it to reduce energy demands; and,
  - ▶ Encourages public utilities to increase efficiency, reduce costs and enhance performance.

The sections above are often summarized as the legal test of whether proposed rates are "fair, just, and not unduly discriminatory*".*

Section 44.1 of the *Utilities Commission Act* empowers the Commission to require BC Hydro to periodically file integrated resource plans and sets out certain requirements for what those plans must include. For example, an integrated resource plan must include a description of what BC Hydro plans to do to respond to British Columbia's energy objectives, including plans respecting the implementation of "demand-side measures". A demand-side measure is defined in the *Clean Energy Act* as, among other things, a rate undertaken "to shift the use of energy to periods of lower demand".[13]

The Optional Residential TOU Rate proposed in this Application is a demand-side measure because it is intended to shift the use of electricity to periods of lower demand. The proposed Optional Residential TOU Rate is being advanced in accordance with BC Hydro's 2021 IRP. Further information on the proposed Optional Residential TOU Rate and its alignment with the 2021 IRP is provided in section 2.4 below and in section 4.3.1 of Chapter 4.

2.2.2 Bonbright's Rate Design Criteria

In its Decision on BC Hydro's 2008 Residential Inclining Block Application, the BCUC found that the eight rate design criteria identified by Dr. James Bonbright in his influential work, Principles of Public Utility Rates, are consistent with the *Utilities Commission Act* test of "fair, just and not unduly discriminatory" and that these criteria form an appropriate foundation for rate structures.[14,15]

---

13 *Clean Energy Act* (https://www.bclaws.gov.bc.ca/civix/document/id/complete/statreg/10022_01), section 1(1).

14 Columbia University Press, 1961. A second edition of this seminal work has not gained as much currency as the original 1961 edition.

15 Refer to the BCUC's Reasons for Decision to Order G-124-08 (https://www.ordersdecisions.bcuc.com/bcuc/orders/en/116943/1/document.do) regarding BC Hydro's Residential Inclining Block Rate Application, dated September 24, 2008, page 51.

The eight rate design criteria identified by Dr. Bonbright are summarized as follows, in no particular order:

- Recovery of the revenue requirement;
- Fair apportionment of costs among customers;
- Price signals that encourage efficient use and discourage inefficient use;
- Customer understanding and acceptance; practical and cost-effective to implement;
- Freedom from controversies as to proper interpretation;
- Rate stability;
- Revenue stability; and,
- Avoidance of undue discrimination.

BC Hydro's proposed Optional Residential TOU Rate is guided by the eight Bonbright rate design criteria. We assess the Optional Residential TOU Rate against these eight criteria in section 4.7.1 of Chapter 4.

2.2.3 Our Rate Design Objectives

BC Hydro has established four rate design objectives, each of which is advanced by the proposals in this Application. The four objectives are:

- **Economic efficiency**: the rate design should reflect BC Hydro's marginal costs and send price signals that encourage efficient use of electricity and efficient investment decisions by customers;
- **Decarbonization**: the rate design should support greenhouse gas reductions through electrification where economically efficient;

- **Flexibility**: the rate design should incorporate flexibility to respond to changes in the economic and policy environment and anticipate the need for greater product and service differentiation in rate design; and,
- **Affordability**: avoiding or mitigating bill impacts to customers.

We assess our proposed Optional Residential TOU Rate against our rate design objectives in section 4.7.2 of Chapter 4.

2.3 The Current Provincial Policy Context

As a provincial Crown corporation, BC Hydro reports to the Government of B.C. through the Ministry of Energy, Mines and Low Carbon Innovation. The Government of B.C.'s expectations and policy objectives are expressed through legislation, regulations, policy statements, and mandate letters to BC Hydro.

2.3.1 Government of B.C.'s CleanBC Plan Sets Goal to Increase Adoption of Electric Vehicles

On December 5, 2018, the Government of B.C. released its CleanBC plan. CleanBC is intended to put British Columbia on a path to reduce climate pollution, build a low-carbon economy, and make life more affordable.

Among other things, CleanBC sets out a goal to "increase our use of cleaner energy, especially electricity, in our lives and in key sectors of our economy – shifting away from our reliance on fossil fuels for transportation, industry, and housing".[16]

The Government of B.C. subsequently passed the *Zero-Emission Vehicles Act* on May 30, 2019. The *Zero-Emission Vehicles Act* requires automakers to meet an escalating annual percentage of new light-duty zero-emission vehicle sales and leases in British Columbia, as follows:

[16] Refer to the Government of B.C.'s CleanBC plan, page 11 at: https://www2.gov.bc.ca/assets/gov/environment/climate-change/action/cleanbc/cleanbc_2018-bc-climate-strategy.pdf.

- 10% of sales by 2025;
- 30% by 2030; and,
- 100% by 2040.[17]

To help achieve these targets, the Government of B.C. is providing the CleanBC Go Electric light-duty vehicle rebate program, which is intended to make zero-emission vehicles more affordable for British Columbians. The program provides point-of-purchase rebates on eligible passenger vehicles of up to $3,000. In addition, the Government of Canada launched the Incentives for Zero-Emission Vehicles Program in May 2019, with point-of-sale incentives of up to $5,000 for consumers who buy or lease an electric vehicle.

The CleanBC Roadmap to 2030, released October 25, 2021, is an elaboration and continuation of CleanBC.[18] It sets out future actions including accelerated targets for zero-emission vehicles and new standards for medium and heavy-duty vehicles aligned with leading jurisdictions. Specifically, the CleanBC Roadmap to 2030 sets the following interim targets for zero-emission vehicle sales and leases in British Columbia:[19]

- 26% by 2026;
- 90% by 2030; and,
- 100% by 2035.

---

17 *Zero-Emission Vehicles Act* https://www2.gov.bc.ca/gov/content/industry/electricity-alternative-energy/transportation-energies/clean-transportation-policies-programs/zero-emission-vehicles-act.

18 CleanBC Roadmap to 2030: https://www2.gov.bc.ca/assets/gov/environment/climate-change/action/cleanbc/cleanbc_roadmap_2030.pdf.

19 Ibid, page 35.

In addition, the federal government has also set a target for light-duty zero-emission vehicle sales of 100% by 2035.[20]

The Optional Residential TOU Rate aligns with provincial policy because it will help to reduce the costs associated with electric vehicle adoption for customers who decide to purchase an electric vehicle and enrol in the rate. It will also reduce costs for all ratepayers over the long-term by helping to manage an expected increase in peak demand which is driven, in part, by increased electric vehicle adoption.

Further information on the bill savings opportunities for customers with an electric vehicle who enrol in the Optional Residential TOU Rate is provided in section 4.4 of Chapter 4.

Further information on how the Optional Residential TOU Rate will help manage an expected increase in peak demand driven, in part, by increased electric vehicle adoption is provided in section 2.4 below and in section 4.3.1 of Chapter 4.

2.3.2 Government of B.C.'s Mandate Letters

The Government of B.C.'s mandate letter to BC Hydro was issued on June 15, 2021, and includes the following specific priorities:[21]

- Provide leadership in advancing CleanBC's climate and economic development objectives, including electrification, fuel switching, and energy efficiency initiatives in the built environment, transportation, mining, oil and gas, and other sectors; and,

[20] In June 2021, the Government of Canada set a mandatory target for all new light-duty cars and passenger trucks sales to be zero-emission by 2035, accelerating Canada's previous goal of 100% sales by 2040: https://www.canada.ca/en/transport-canada/news/2021/06/building-a-green-economy-government-of-canada-to-require-100-of-car-and-passenger-truck-sales-be-zero-emission-by-2035-in-canada.html.

[21] Refer to the Government of B.C.'s Mandate Letter to BC Hydro at: https://www.bchydro.com/content/dam/BCHydro/customer-portal/documents/corporate/accountability-reports/openness-accountability/bch-mandate-letter-2021-2022.pdf.

- Working with customers, develop efficient and flexible rate proposals for BC Utilities Commission review that will incent greenhouse gas emission reductions and keep rates affordable.

The Application is consistent with these priorities. Chapter 4 sets out our proposed Optional Residential TOU Rate which will reduce the costs associated with electric vehicle adoption and will help to reduce greenhouse gas emissions.

The Government of B.C.'s mandate letter to BC Hydro also includes a foundational principle that all Crown corporations, including BC Hydro, adopt a Gender-Based Analysis Plus (**GBA+**) lens so that equity is reflected in operations and programs. As discussed further in section 3.2.2 of Chapter 3, BC Hydro implemented GBA+ to develop the proposals in this Application with broad engagement and feedback from customers, stakeholders, and First Nations.

The Premier of B.C.'s most recent mandate letter to the Honourable Josie Osborne, Minister, Energy, Mines and Low Carbon Innovation, on December 7, 2022,[22] prioritized a number of areas for further progress, while continuing to make progress on areas identified in the mandate letter to BC Hydro. Some of these priorities include:

- Drive delivery of your ministry's CleanBC Roadmap to 2030 policies and programs on time and on target to help ensure we meet our legislated greenhouse gas (**GHG**) goals;
- Work with BC Hydro to implement its Electrification Plan and to ensure the province is well positioned to electrify B.C.'s economy and industry, including options for Indigenous ownership and/or equity interest in BC Hydro infrastructure and Indigenous partnership in clean energy projects; and,

[22] Refer to the Government of B.C.'s Mandate Letter to Minister Osborne at: https://www2.gov.bc.ca/assets/gov/government/ministries-organizations/premier-cabinet-mlas/minister-letter/emli_-_osborne.pdf.

- In collaboration with the Minister of Transportation and Infrastructure, complete the Clean Transportation Action Plan to support shifts to sustainable modes of travel, advance modern transportation systems, and help meet our ambitious GHG targets for the transportation sector.

The Optional Residential TOU Rate supports these priorities as well. As discussed above, it will help to reduce the costs of electric vehicle adoption for both customers who decide to purchase an electric vehicle as well as all ratepayers, by managing the associated increase in peak demand. This supports the CleanBC Roadmap to 2030 policies, BC Hydro's Electrification Plan and the overall policy goal to shift to sustainable modes of travel.

2.4 BC Hydro's Business Context for Our Proposed Rate

As noted above, BC Hydro's peak demand is expected to increase, in part because of the anticipated increase in electric vehicle adoption. BC Hydro's Optional Residential TOU Rate will help to manage this increased peak demand, consistent with our 2021 IRP, which relies on customer-based solutions over building new infrastructure.

2.4.1 BC Hydro's Load Forecasts Recognizes the Peak Demand Impacts of Electric Vehicle Adoption

On December 21, 2021, BC Hydro filed its December 2020 Load Forecast (**Load Forecast**) as Appendix C to our 2021 IRP Application. Section 7 of the Load Forecast provides the electric vehicle forecast and section 9.3.2 provides the electric vehicle peak demand forecast. The Load Forecast defines BC Hydro's peak demand as:

> "the maximum expected amount of electricity consumed in a single hour under an average cold temperature assumption referred to as the design temperature. BC Hydro is a winter peaking utility, as its demand is more sensitive to colder temperatures than warmer temperatures. The total BC Hydro

system typically reaches its annual peak on a cold winter day between 5:00 pm and 6:00 pm."[23]

At the time BC Hydro's December 2020 Load Forecast was completed, BC Hydro's all-time total domestic system peak was 10,577 MW which occurred on January 14, 2020.[24] The magnitude of the peak demand directly impacts BC Hydro's cost of service, with higher peak demand resulting in more demand-related costs.

Electric vehicles are forecast to be a significant source of peak demand, if not managed. BC Hydro's reference electric vehicle peak demand forecast is provided in Table 2-1 below.[25] This is an unconstrained peak demand forecast which assumes electric vehicle drivers start charging their vehicle upon arriving at home and are not subject to any modelling constraint on when they charge.

Table 2-1 BC Hydro's December 2020 Load Forecast - Electric Vehicles and Their Impact on BC Hydro's Peak Demand

Fiscal Year	Reference Case Number of Electric Vehicles (Vehicles)	Peak Demand Forecast, Assuming Reference Case Number of Electric Vehicles with Unconstrained Charging (MW)
F2024	155,517	188
F2030	543,548	677
F2040	1,757,812	2,196

2.4.2 BC Hydro's 2021 Integrated Resource Plan Calls for Time-Varying Rates to Manage Peak Demand

BC Hydro's 2021 IRP looks at a 20-year time frame and guides decisions on our integrated system to meet the future electricity needs of our customers. Our 2021 IRP is included as Appendix C to this Application.

23 December 2020 Load Forecast, page 108 of 256, Appendix C of BC Hydro's 2021 IRP: https://docs.bcuc.com/Documents/Proceedings/2021/DOC_65194_B-1-BCH-IntegratedResourcePlan-Public.pdf.

24 Subsequently, BC Hydro broke its all-time record peak demand with a peak demand of 10,762 MW on December 27, 2021, 10,800 MW on December 20, 2022, and 10,900 MW on December 22, 2022.

25 The estimated peak demand forecast is cumulative from the base year of fiscal 2022.

BC Hydro's planning objectives for the 2021 IRP are: keeping costs down for customers, reducing greenhouse gas emissions through clean electricity, limiting land and water impacts, and supporting the growth of British Columbia's economy. In alignment with those objectives, a defining feature of the 2021 IRP is that it:

> "relies more on customer-based solutions through demand-side measures, including new voluntary rate structures, to encourage customers to use less electricity and use it more efficiently, and less on adding new physical assets with their land and water impacts, and financial commitment."[26]

This Application is a Near-term Action of the 2021 IRP, and the proposed rate in this Application delivers the capacity savings called for in the 2021 IRP. BC Hydro conducted extensive customer and stakeholder consultation to develop the 2021 IRP. This consultation indicates strong support for time-varying rates, as described in Chapter 4 of our 2021 IRP Application:

> "BC Hydro asked public and Customer participants in this consultation how the Base Resource Plan element to pursue voluntary time-varying rates and supporting demand response programs aligned with their values and interests and to state their reasons.
>
> …
>
> Overall, 77% of public survey respondents expressed positive alignment with this element, while 15% indicated little or no support. Customer survey results were similar, with 72% positive alignment and 9% little or no alignment.
>
> Reasons why participants were aligned with this element included: because it's easy to implement, has worked elsewhere, is cost effective by deferring new infrastructure and provides customers with the opportunity to lower their electricity bills.

26 Refer to page 4 of BC Hydro's Appendix B to the 2021 IRP, included in this Application as Appendix C.

> Participants expressed support for the voluntary opt-in nature of this element. Participants also recognized this element could support them in managing their electricity use.
>
> Those not aligned cited the concern that some customers would be penalized if they cannot shift their electricity use." [27]
>
> "BC Hydro asked participants how the draft Base Resource Plan element to pursue voluntary time-varying rates and demand response programs targeting electric vehicle drivers aligned with their values and interests, and to state their reasons.
>
> …
>
> Overall, 78% of public survey respondents expressed positive alignment with this element, while 12% indicated little or no support. Respondents thought this element was an effective, easy way to shift more demand to off-peak times.
>
> Participants who were not aligned stated that Electric Vehicle owners may not be able to shift their charging hours, or that they, personally, did not own an Electric Vehicle."[28]

2.4.3 BC Hydro's Demand-Side Management Plan Includes Demand Response Programs[29] to Work in Combination with Rates

BC Hydro's 2021 IRP explains how demand response programs can be coordinated with time-of-use rates to give customers different options to reduce their peak demand.[30] Empirical research has demonstrated how time-of-use rates can achieve greater peak demand reduction if implemented with enabling technologies such as timers.[31]

---

27 BC Hydro's 2021 IRP Application, https://docs.bcuc.com/Documents/Proceedings/2021/DOC_65194_B-1-BCH-IntegratedResourcePlan-Public.pdf, Chapter 4, section 4.5.3.

28 Ibid., Chapter 4, section 4.5.4.

29 Demand response programs are incentive programs that encourage customers to reduce their peak demand.

30 Refer to Page 17 of BC Hydro's Appendix B to the 2021 IRP, included in this Application as Appendix C.

31 Arcturus 2.0: A meta-analysis of time-varying rates for electricity, The Electricity Journal 30 (2017) (https://www.sciencedirect.com/science/article/pii/S1040619017302750), A. Faruqui et al.

In December 2021, BC Hydro filed its Fiscal 2023 to Fiscal 2025 Demand-Side Measures Expenditure Schedule in the proceeding to review our Fiscal 2023 to Fiscal 2025 Revenue Requirements Application. In that filing, we describe how BC Hydro's Demand-Side Management Plan has been developed in the context of the 2021 IRP to move forward along the energy and capacity savings path set by the Base Resource Plan, which selected portfolios of energy efficiency and capacity focused demand-side measures (i.e., time-varying rates and demand response programs). As described on page 48 of Attachment 1 of our Fiscal 2023 to Fiscal 2025 Demand-Side Measures Expenditure Schedule:[32]

> "Starting in fiscal 2023 BC Hydro will introduce the Electric Vehicle Connected Charger Rebate offer, which will top up the CleanBC charger incentive for networked (i.e. connected) chargers. This initiative will jumpstart the market and incent chargers that can be later utilized to support and deliver the Electric Vehicle Demand Response offer launching in fiscal 2024.
>
> The Residential Peak Saver offer will also launch in fiscal 2024, whereby participating customers will be called upon on peak event days to make changes to their load themselves, e.g. by using the delayed start settings on their dishwasher and dryer or simply turning things off.
>
> The Connected Charger Rebate offer, Electric Vehicle Demand Response offer and Residential Peak Saver offer are all designed to work in conjunction with and support the adoption of voluntary time varying rates and will encourage our customers to shift electricity use to off-peak periods. These rate options and offers together will enable participating customers to save money on their bills while contributing to a reduction of the system peak, leading to long term savings."

[32] BC Hydro F23-25 DSM Expenditure-Schedules (bcuc.com) (https://docs.bcuc.com/Documents/Proceedings/2021/DOC_65190_B-10-BCH-F23-25-DSM-Expenditure-Schedules.pdf), page 48 of Attachment 1.

As explained on page 50 of Attachment 1 of our Fiscal 2023 to Fiscal 2025 Demand-Side Measures Expenditure Schedule:

> "the Electric Vehicle Demand Response incentive program will also encourage the installation of networked chargers to facilitate customer participation in time-of-use rates."[33]

BC Hydro's Demand Side Management expenditures also include funding for marketing, awareness and customer support for our proposed Optional Residential TOU Rate. This is discussed further in section 4.8.4.1 of Chapter 4.

2.5 Time-of-Use Rates Are Common Across North America

BC Hydro conducted a jurisdictional review of North American utilities offering time-of-use rates. This review is provided below and shows that both whole home and end-use time-of-use rates are available to customers. Whole home rates are more common and have been around for the last two decades. More recently, some utilities have begun introducing end-use rates particularly for electric vehicles. However, where they are offered, it is usually necessary for a customer to have a separate utility revenue meter at their premises to separately measure their electric vehicle charging consumption.[34]

Table 2-2 identifies some utilities in Canada and the U.S. that offer optional whole home rates to residential customers. Some of these rates are designed to encourage electric vehicle drivers to charge their electric vehicles during overnight periods when demand is lower and system capacity is more available. In several cases, utilities offer more than one time-of-use rate designed to suit different customer needs and preferences. Where utilities offer three energy pricing periods,

[33] Ibid., page 50 of Attachment 1.

[34] Refer to page 29 of *Residential Electric Vehicle Rates That Work*. Smart Electric Power Alliance. (https://sepapower.org/resource/residential-electric-vehicle-time-varying-rates-that-work-attributes-that-increase-enrollment/).

the off-peak or super off-peak (lowest energy charge) to on-peak ratio is generally between 2:1 and 3:1. As shown in Figure 4-7 of Chapter 4, this is in line with the price ratio of the Optional Residential TOU Rate.

Table 2-2 Jurisdictional Scan of Utilities in Canada and the U.S. Offering Time-of-Use Rates

Utility	Deployment & Rate Structure	Rate Name	Rate Pricing	
Canada				
Hydro One[35]	Default Seasonal with three energy pricing periods on weekdays. Weekends are Off-Peak.	Time-of-Use	**Winter** Off-Peak: 7.40 cents per kWh Mid-Peak: 10.20 cents per kWh On-Peak: 15.10 cents per kWh	
Nova Scotia Power[36]	Opt-in Weekdays: Winter time-of-use with three energy pricing periods, all other months, weekend and holidays: two energy pricing periods.	Domestic Service Time of Use Tariff	**Winter (Dec to Feb)** Off-Peak: 9.29 cents per kWh On-Peak: 20.57 cents per kWh Standard Rate: 16.22 cents per kWh	
U.S.				
Consumer's Energy*[37]	Opt-in Year-round with two energy pricing periods.	Smart Hours Rate - RT10 10	**Summer (Jun to Sep)** Off-Peak: 16.20 cents per kWh On-Peak: 21.20 cents per kWh	**Winter (Oct to May)** Off-Peak: 15.90 cents per kWh On-Peak: 16.90 cents per kWh

35 https://www.hydroone.com/rates-and-billing/rates-and-charges/electricity-pricing-and-costs

36 https://www.nspower.ca/about-us/producing/rates-tariffs/domestic-tod

37 https://www.consumersenergy.com/residential/rates/electric-rates-and-programs/rate-plan-options/smart-hours#:~:text=June%20%2D%20September%3A%20Weekdays%2C%20from,compared%20to%20off%2Dpeak%20times.

Utility	Deployment & Rate Structure	Rate Name	Rate Pricing	
Georgia Power*[38]	Opt-in Year-round time-of-use with two energy pricing periods.	Time-of-Use - TOU-REO-13	Off-Peak: 5.16 cents per kWh (all other months and hours outside of On-Peak periods) On-Peak: 20.32 cents per kWh (Jun to Sep, weekdays)	
Green Mountain Power*[39]	Opt-in Year-round rate with two energy pricing periods.	Rate 11	Off-Peak: 12.21 cents per kWh On-Peak: 28.64 cents per kWh	
Pacific Gas & Electric*[40]	Default Year-round rate with two energy pricing periods.	E-TOU-C (4 to 9 pm)	**Summer (Jun to Sep)** Off-Peak: 41.0 cents per kWh On-Peak: 49.0 cents per kWh	**Winter (Oct to May)** Off-Peak: 31.0 cents per kWh On-Peak: 39.0 cents per kWh
Portland General Electric[41]	Opt-in Year-round with three energy pricing periods. Hours for the three periods differ between season.	Time-of-Use (whole home or electric vehicle) Schedule 7	**Summer (May to Oct)** **Winter (Nov to Apr)** Off-Peak: 7.43 cents per kWh Mid-Peak: 11.92 cents per kWh On-Peak: 32.28 cents per kWh	
Salt River Project*[42]	Opt-in Year-round with two energy pricing periods every day.	TOU E-26	**Summer (May/Jun/Sep/ Oct)** Off-Peak: 8.03 cents per kWh On-Peak: 21.70 cents per kWh	**Summer Peak (Jul-Aug)** Off-Peak: 8.06 cents per kWh On-Peak: 24.85 cents per kWh

38 www.georgiapower.com/content/dam/georgia-power/pdfs/electric-service-tariff-pdfs/TOU-REO-13.pdf

39 https://greenmountainpower.com/wp-content/uploads/2016/09/Rate-11.pdf

40 https://www.pge.com/en_US/residential/rate-plans/rate-plan-options/time-of-use-base-plan/time-of-use-plan.page

41 www.srpnet.com/assets/srpnet/pdf/price-plans/residential-electric/tou-e-26.pdf

42 www.srpnet.com/assets/srpnet/pdf/price-plans/residential-electric/tou-e-26.pdf

Utility	Deployment & Rate Structure	Rate Name	Rate Pricing	
			Winter (Nov to Apr) Off-Peak: 7.85 cents per kWh On-Peak: 10.45 cents per kWh	
San Diego Gas & Electric*[43]	Default Year-round time-of-use with three energy pricing periods. Weekdays and weekends have different time periods for each pricing period.	TOU-DR1	**Year-round** Off-Peak: 43.50 cents per kWh Super Off-Peak: 41.00 cents per kWh On-Peak: 51.90 cents per kWh	
Sacramento Municipal Utilities District (SMUD)44	Default Year-round with two and three energy pricing periods.	Time-of-Day (5-8 pm)	Summer (June to Sept) Off-Peak: 13.50 cents per kWh Mid-Peak: 18.64 cents per kWh On-Peak: 32.79 cents per kWh	Winter (Oct to May) Off-Peak: 11.20 cents per kWh On-Peak: 15.47 cents per kWh
Southern California Edison*45	Default Year-round with two and three energy pricing periods.	TOU-D-4-9 PM	Summer (June to Sept) Off-Peak: weekdays 34.00 cents per kWh and 34.00 cents per kWh weekends. On-Peak: 54.00 cents per kWh and 44.0 cents per kWh weekends.	Winter (Oct to May) Off-Peak: weekdays and weekends, 36.0 cents per kWh Super Off-Peak: weekdays and weekends, 33.0 cents per kWh On-Peak: weekdays and weekends, 47.0 cents per kWh

*This utility offers more than one time-of-use rate.

43 www.sdge.com/residential/pricing-plans/about-our-pricing-plans/whenmatters
44 www.smud.org/en/Rate-Information/Time-of-Day-rates/Time-of-Day-5-8pm-Rate/Rate-details
45 www.sce.com/residential/rates/Time-Of-Use-Residential-Rate-Plans

BC Hydro Optional Residential Time-of-Use Rate Application

Chapter 3

BC Hydro's Residential Service Customers and Rate Design Consultation

Table of Contents

List of Figures

List of Tables

3.1 Introduction

In this chapter, we describe what we learned about our Residential service customers preferences regarding optional rates.

We undertook various research and consultation activities to inform this Application. Our goal was to better understand our Residential service customers and learn more about their individual situations and energy consumption habits as well as their views on optional rates. We conducted a 24-month long consultation process, engaging over 35,000 customers and stakeholders to review and explore various Residential rate design options to better meet their needs.

This chapter is structured as follows:

- Section 3.2 provides an overview of our Residential service customers;
- Section 3.3 describes the customer consultation undertaken to inform this Application and a summary of feedback received; and,
- Section 3.4 describes the consultation with stakeholders that represent various customer groups and a summary of feedback received.

In addition, Appendix D provides our customer stakeholder engagement materials and results that informed the Application and in section 4.6 of Chapter 4 we discuss the specific customer and stakeholder feedback we received on the Optional Residential TOU Rate.

3.2 BC Hydro's Residential Services

3.2.1 BC Hydro's Residential Service Rates

Residential service customers account for about 89% of BC Hydro's customers, 38% of domestic energy sales, and 45% of revenue.[46] The Residential service rate class

[46] Based on fiscal 2022 customer data.

is BC Hydro's largest rate class on all three of these measures. It has diverse characteristics and needs.

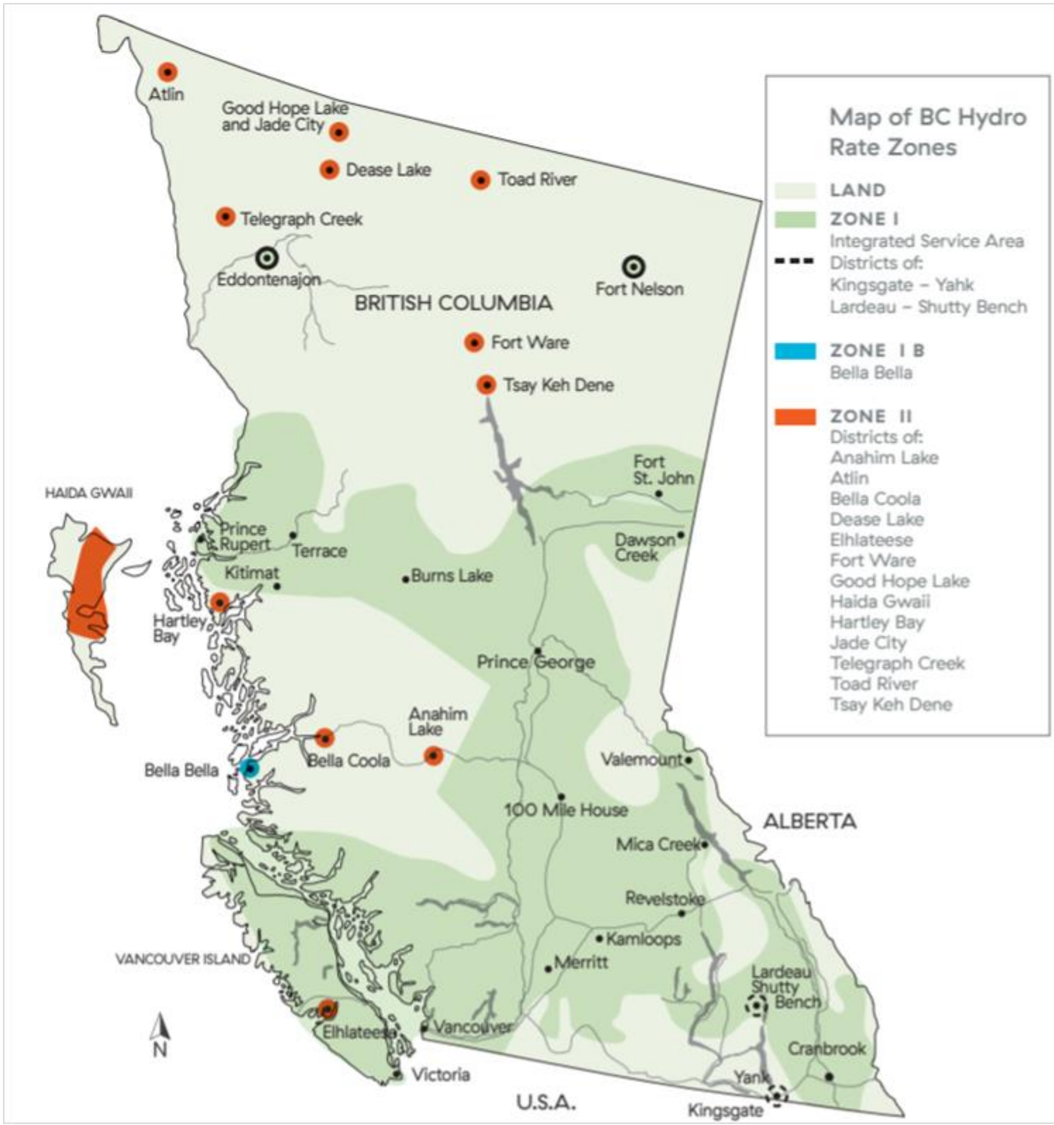
There are approximately 1.9 million BC Hydro Residential customers. About 99.7% are in the integrated service area and connected to BC Hydro's integrated grid (Rate Zone I), and 0.3% are in the non-integrated area (Rate Zone IB and II) and served by local generation resources.

Table 3-1 below summarizes BC Hydro's Residential customers by rate schedule, and Figure 3-1 below shows BC Hydro's service territory by rate zone.

Table 3-1 BC Hydro's Residential Service Offerings

Rate Schedule (RS)	Applies to	Number of Customers	% of Customers	Revenue ($ million)
RS 1101, 1121 – Residential Service	Zone I	1,892,412	98.7%	2,236
RS 1105 - E-Plus Service (closed)	Zone I	5,348	0.3%	5
RS 1107, 1127 - Residential Service – Zone II	Zone II	5,025	0.3%	8
RS 1148 - Residential Service – Zone II (closed)	Zone II	2	0.0%	0.00315
RS 1151, 1161 - Exempt Residential Service	Zone I, IB	14,681	0.8%	54
Total		1,917,468	100.00%	2,303

Figure 3-1 BC Hydro's Rate Zones



As shown in Table 3-1 above, the vast majority of BC Hydro's Residential customers take service under Rate Schedules (**RS**) 1101 and 1121, commonly referred to as the Residential Inclining Block Rate (**RIB Rate**). RS 1101 is for premises with separately metered dwellings, and RS 1121 Multiple Residential Service is for premises with more than two dwellings under one meter.[47] The same charges apply to service under both RS 1101 and 1121.

Currently, the RIB Rate applies on a default basis to all Residential customers in our integrated service area (i.e., Zone I). There are limited options available to some qualifying customers under other rate schedules. Qualifying Residential farms may take service under RS 1151, 1161 (**Flat Rate**) which has a flat energy charge instead of inclining block energy charges like the RIB Rate, and qualifying customers may receive service under RS 1105.[48] There are also a small number of customers, such as common areas of Residential multi-occupancy buildings, who have options to select the applicable General Service or Residential service rate. Qualifying Residential customers may also participate in RS 1289 - Net Metering Service.

The RIB Rate has a fixed daily basic charge and per kWh inclining block energy charges. The lower step 1 energy charge applies to consumption below a threshold of 1,350 kWh per two-month billing period (675 kWh per one-month billing period). The higher step 2 energy charge applies to consumption above that threshold. The 675 kWh threshold was set at approximately 90% of the median consumption of BC Hydro's Zone I Residential customers. The charges applicable to the RIB Rate are provided in Table 3-2 below.

Table 3-2 RIB Rate Summary

RIB Rate	Rates Effective April 1, 2022
Basic Charge	20.90¢ per day
Step 1 Energy Charge	9.50¢ per kWh
Step 2 Energy Charge	14.08¢ per kWh
Step 1 / Step 2 Threshold	1,350 kWh per two-month billing period (675 kWh per one-month billing period)

47 A dwelling is defined on page 1-3 and premises is defined on page 1-6 of BC Hydro's Electric Tariff: https://www.bchydro.com/content/dam/BCHydro/customer-portal/documents/corporate/tariff-filings/electric-tariff/bchydro-electric-tariff.pdf

48 Rate Schedule 1105 – Residential Service – Dual Fuel is a closed service that will be phased out by March 31, 2028 per Commission Order G-194-17. Rate Schedule 1105 is commonly referred to as the "E-Plus" rate.

3.2.2 Understanding Our Customers from a Gender-Based Analysis Plus (GBA+) View

BC Hydro also used a GBA+ approach to understand our customers' characteristics. GBA+ is a methodology used to increase equity by assessing how individuals may experience policies, programs, and initiatives based on characteristics such as gender, income, ethnicity, age, or ability.[49,50]

Assessing customer characteristics using a GBA+ approach allowed for greater understanding of the types of customers that may be interested in or impacted by our proposal. In addition, the analysis also helped to better understand the perspectives of specific customer groups as expressed in customer consultation, and to address questions raised during stakeholder consultation.

The analyses focused on customer characteristics such as primary heating fuel type, housing type, and household size as these characteristics are correlated to customers' electricity consumption. The analyses also highlighted additional differences in consumption based on characteristics such as region, home ownership, and income.

The sub-sections below discuss the key customer characteristics that emerged from the GBA+ analysis.[51]

3.2.3 Characteristics of BC Hydro's RIB Rate Customers

BC Hydro's Residential service customers are diverse, residing in different climate regions in the province, with various housing and heating types. This section summarizes electricity consumption of RIB Rate customers based on region,

49 https://www2.gov.bc.ca/assets/gov/british-columbians-our-governments/services-policies-for-government/gender-equity/factsheet-gba.pdf

50 The Government of B.C.'s Mandate Letter issued June 15, 2021 identifies that BC Hydro is expected to "adopt a GBA+ lens" when assessing its operations and programs.

51 BC Hydro has limited data on some customer characteristics typically considered in GBA+ analysis. Accordingly, these analyses do not provide a full understanding of the impacts of our rate design proposals on all Residential service customers.

housing type, and primary home heating fuel type. The information is derived from our billing data and from our most recent Residential End-Use Study.[52]

3.2.3.1 All RIB Rate Customers

As mentioned above, the RIB Rate is the default rate for Residential service customers in our integrated service area. Almost 99% – about 1.9 million – of BC Hydro's Residential service customers take service under the RIB Rate.[53]

The average monthly consumption of all RIB Rate customers in fiscal 2022 was 830 kWh, which is about 10,000 kWh a year, with an average monthly bill of approximately $100.

As shown in Figure 3-2 below, most RIB Rate customers consume less than 20,000 kWh a year and most live in single-detached homes and duplexes (55%) or apartments (31%).[54]

[52] BC Hydro's 2020 Residential End-Use Study included results from approximately 8,000 survey respondents.

[53] Customer analysis in Chapter 3 does not consider Rate Schedule 1121 customers, all of whom have a single meter that measures electricity consumption at premises containing multiple dwellings, and Rate Schedule 1101 customers who have meters that measure electricity consumption in common areas of residential multi-occupancy premises. These customers have been excluded from the analysis because there are few of them relative to the total number of RIB customers, and because their consumption patterns differ from those of typical individual Residential customers.

[54] In this Application, BC Hydro uses the term "apartments" to refer to separately metered, individual dwellings in multi-occupancy buildings, and may include either owned or rented dwellings.

Figure 3-2 Annual Electricity Consumption by Housing Type

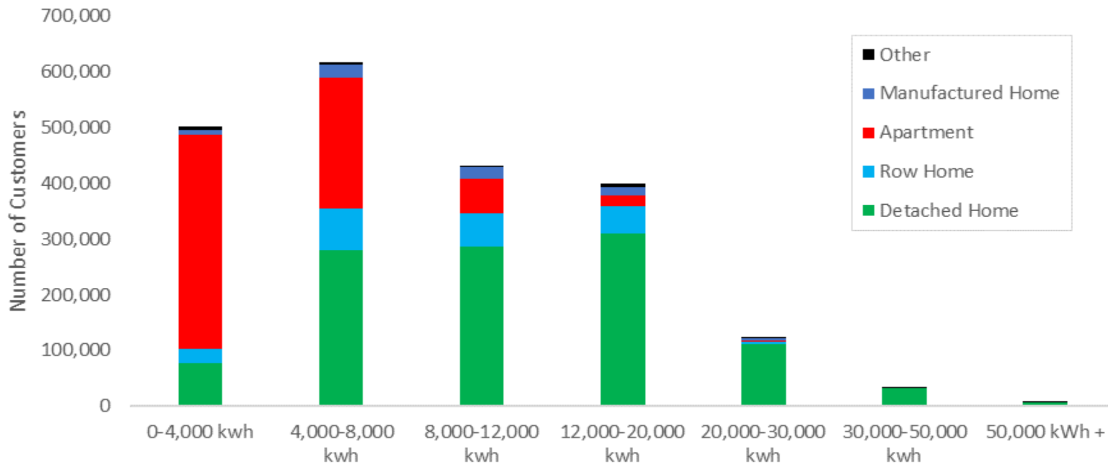


Figure 3-3 below is a map of BC Hydro's four service regions and Figure 3-4 below shows the regional distribution of RIB Rate customers.

Figure 3-3 BC Hydro Service Regions

Figure 3-4 Distribution of RIB Customers by Region

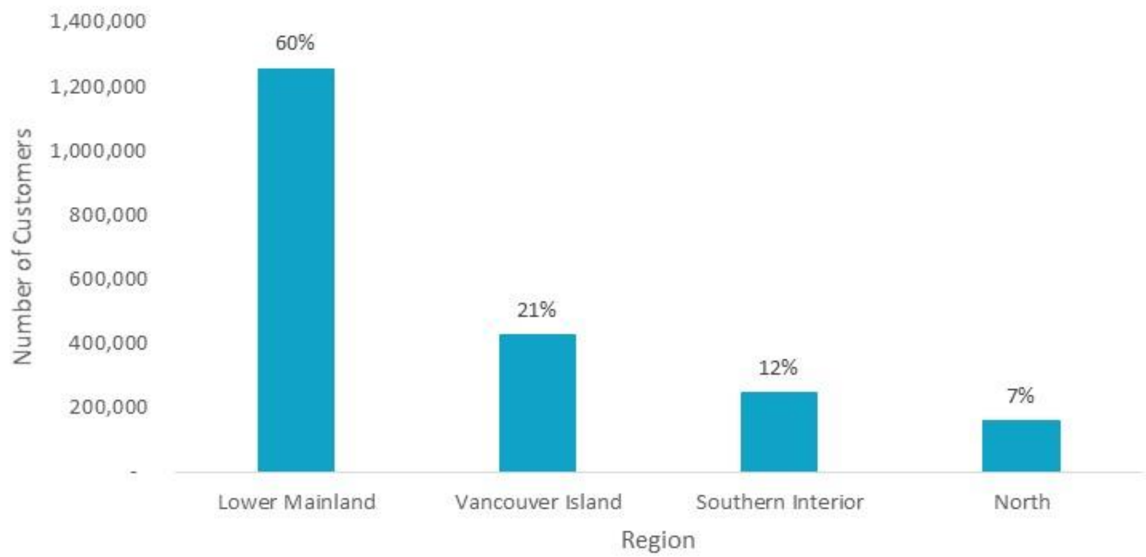


Table 3-3 below shows the housing type distribution across the four regions shown in Figure 3-3 above. Just over half of all single-detached homes and nearly 80% of all row homes and apartments are located in the Lower Mainland. Manufactured homes show a more even distribution across the four regions, a pattern significantly different from the other housing types.

Table 3-3 Distribution of Housing Type by Region

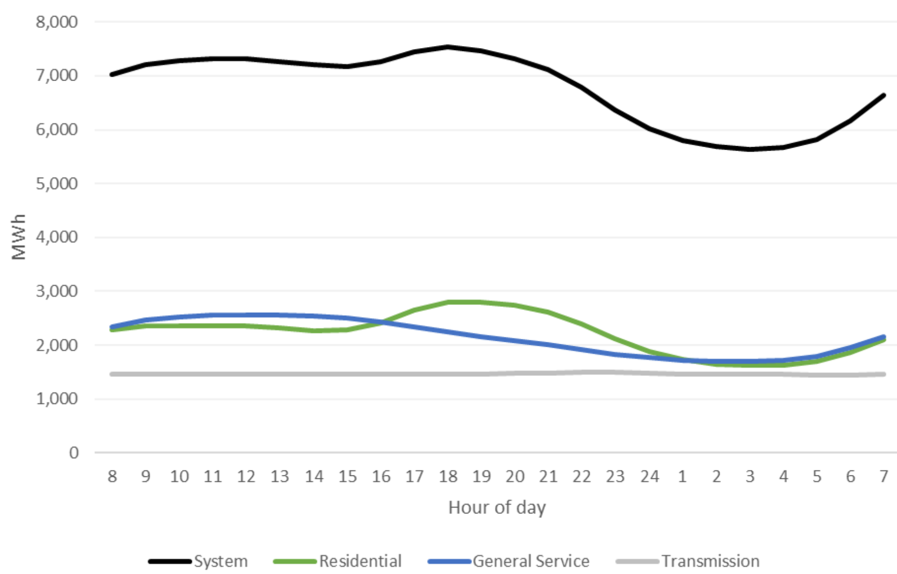
Region:	Single-Detached Homes	Row Homes	Apartments	Manufactured Homes
Lower Mainland	51.0%	77.1%	76.8%	17.4%
Vancouver Island	24.4%	15.4%	13.0%	24.6%
Southern Interior	15.3%	4.8%	7.2%	34.7%
North	9.3%	2.7%	3.0%	23.3%

3.2.3.2 BC Hydro System Load Profile is Heavily Influenced by the Residential Customer Consumption Trends

As noted in section 3.2.1 above, Residential customers represent BC Hydro's largest rate class in terms of number of customers, energy sales, and revenue.

Figure 3-5 below compares the fiscal 2022 average hourly consumption patterns for BC Hydro's three main rate classes (Residential, General Service, and Transmission) to the overall system load profile. As shown, BC Hydro's overall system load profile mirrors that of the Residential rate class, highlighting that BC Hydro's system load profile is highly influenced by the Residential customers' consumption trends. Residential customers' consumption patterns shows that energy usage starts to increase in late afternoon hours when many customers arrive home after work and then decreases in late evening hours when they go to bed.

Figure 3-5 BC Hydro Fiscal 2022 Load Profiles for Main Rate Classes and System as a Whole.



3.2.3.3 Customers' Consumption by Housing Type

Customers' overall consumption is influenced by the type of home they live in.

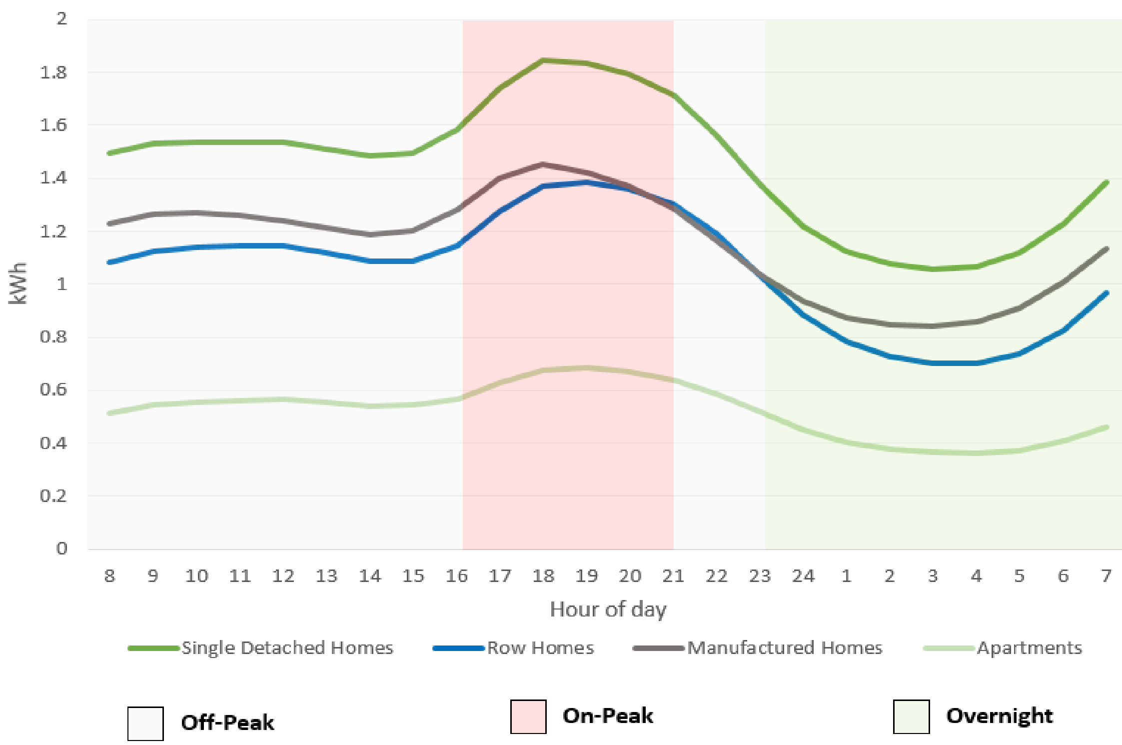
Figure 3-6 below shows that customers living in single detached homes have highest overall average consumption. This is mostly due to the larger living spaces, larger household sizes and higher rate of electric vehicle adoption with at-home charging.

Customers living in row homes tend to consume less electricity than those living in single-detached homes. This is due to typically smaller living spaces associated with this housing type and fewer exterior surfaces.

Manufactured homes often represent the smallest physical living space relative to other housing types, despite this, these homes are typically poorly insulated leading to higher average consumption than row homes and apartments.

Apartments have the lowest overall average consumption due to smaller living spaces, smaller household sizes, and fewer exterior surfaces. Many apartment buildings also rely on central hot water, and some have central heating systems. In addition, some electricity consumption of apartments occurs in the common areas such as elevators, lobby and hallway lighting and heating, and shared electric vehicle charging.

Figure 3-6 Average Annual Residential Consumption Profile by Housing Type



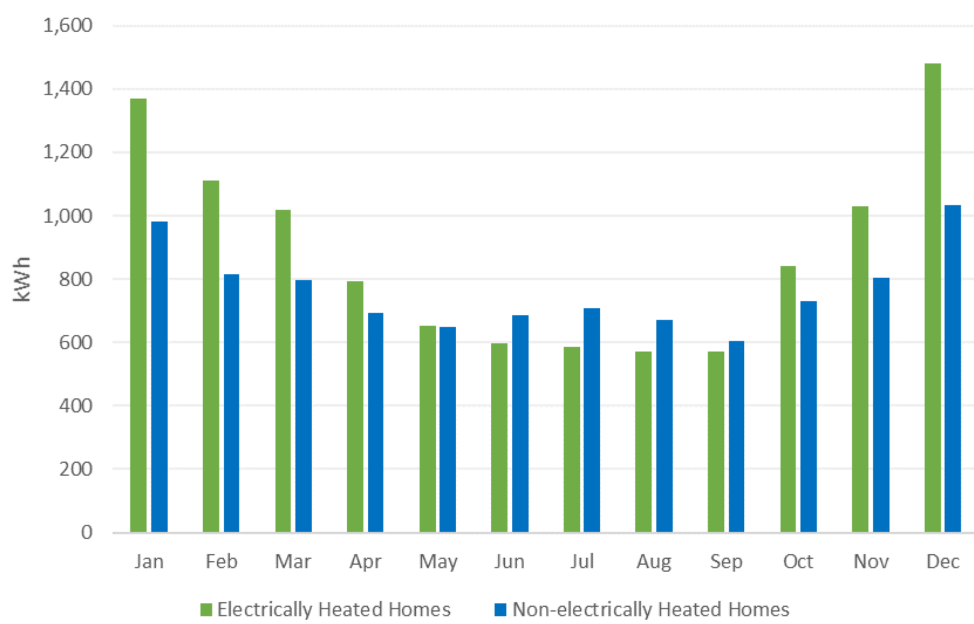
Despite the significant differences in their overall consumption levels, customers living in all housing types demonstrate similar consumption patterns in terms of overall load profile shape and usage distribution. Customers living in row homes have slightly less overnight consumption; however, this difference is relatively minor in terms of the proportion of their overall consumption. This comparison is shown in section 4.2.2 of Chapter 4.

3.2.3.4 Customers' Consumption by Heating Type

Space heating fuel plays a significant role in a customer's consumption.

Figure 3-7 below shows the average monthly consumption for electrically and non-electrically heated homes. As expected, homes that rely on electricity as a space heating fuel use significantly more electricity during the winter months (November to February), on average about 37% more than homes that are non-electrically heated.

Figure 3-7 Average Monthly Consumption by Space Heating Type



Although the overall level of electricity usage is higher for electrically-heated dwellings, the load profiles of the two groups follow the same general trend.

Figure 3-8 below shows the average hourly consumption of the winter and non-winter months for the two types of space heating. It shows that the Residential consumption trend follows the same general pattern regardless of heating type and season. However, there are significant seasonal differences between electrically and non-electrically heated dwellings. While non-electrically heated homes see an average increase in consumption of 35% during the winter months, this increase is much more significant for electrically heated homes (83%) when compared to non-winter months.

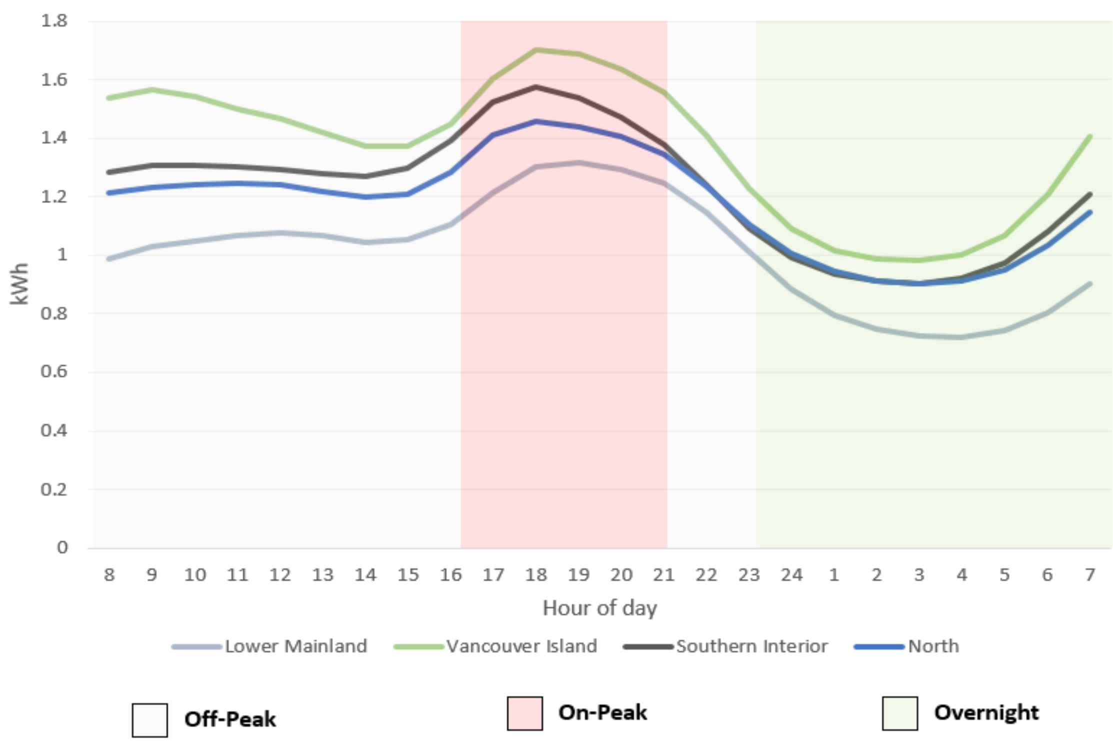
Figure 3-8 Seasonal Average Residential Consumption Distribution by Space Heating Type

3.2.3.5 Customers' Consumption by Region

In addition to housing type and heating type, customers' overall consumption also varies by their physical location. As seen in Figure 3-9 below, customers living on Vancouver Island have higher average consumption, mainly due to their more limited access to natural gas heating. Customers living in the Lower Mainland on the other hand, have noticeably lower average consumption compared to the other three regions. As shown in Figure 3-9 below, this is largely due to the milder temperatures and higher concentration of smaller living spaces such as apartments.

Similar to housing and heating types, even though customers' overall consumption levels are different by their geographic location, their consumption patterns maintain the typical Residential load shape shown in Figure 3-5 above.

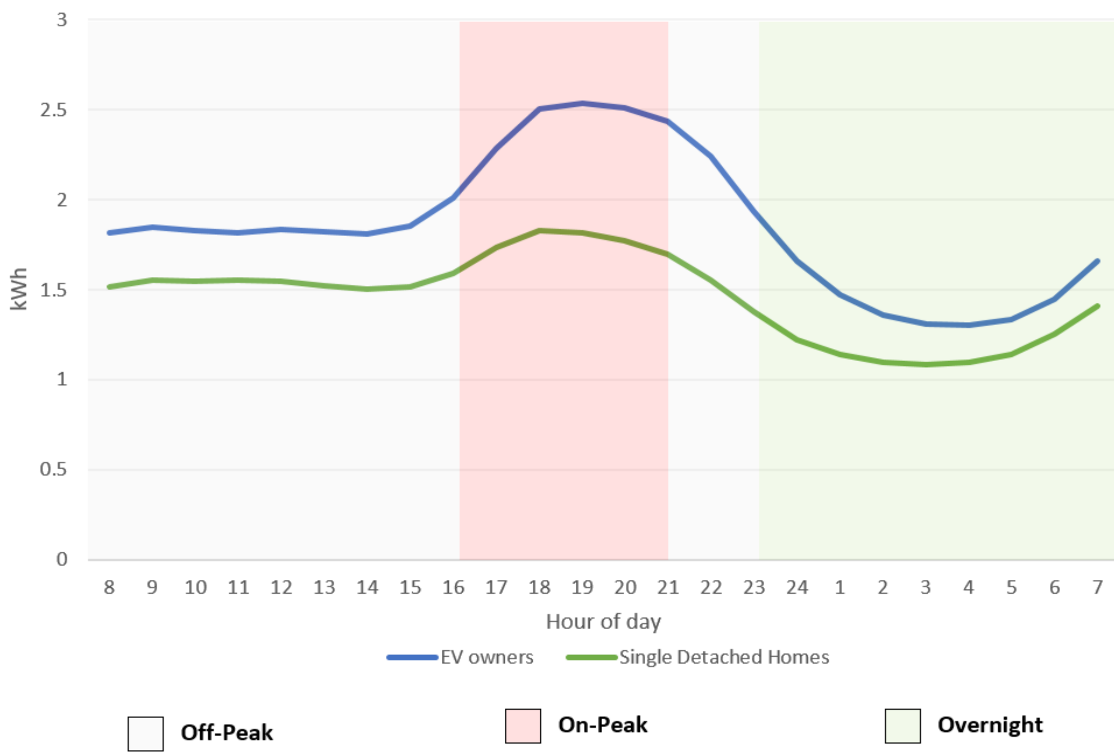
Figure 3-9 Average Annual Residential Consumption Distribution for by Region



3.2.3.6 Consumption of Customers with an Electric Vehicle

As explained in section 4.3.5 of Chapter 4, customers with an electric vehicle consume approximately 2,800 kWh more energy on average per year. Figure 3-10 below compares the average load profile for customers who own electric vehicles against all single-detached homes. Based on the consumption differences between these two groups, it is apparent that although electric vehicle owners exhibit the same overall electricity usage behaviours as the rest of the Residential rate class customers (see Figure 3-5), they appear to have increased electricity usage during the On-Peak period compared to all single-detached homes.

Figure 3-10 Average Annual Residential Consumption Distribution for Electric Vehicle Owners versus All Single Detached Homes



3.3 Summary of Customer Consultation

To inform this Application, BC Hydro conducted a 24-month long consultation process, engaging over 35,000 customers and stakeholders.[55]

3.3.1 Overview

Most customers think about their electricity bill first, and not the rate under which they are charged. Along with desire for service that's low cost, affordable and reliable, customers want rates that offer choices to meet a variety of needs and circumstances, and also encourage clean electrification.

Some customers, especially electric vehicle owners, expressed an interest in time-of-use rates. However, there was a strong view against default time-of-use rates on the basis that it would be difficult for many customers to change when they use electricity.

The analysis of survey responses and other customer engagement feedback pointed to three key themes:

- Keeping bills low and reliability of service are the top priorities for our customers;
- Familiarity with current rates and interest in new rate concepts varies based on the unique circumstances of each customer; and,
- Of the potential optional rate concepts presented, time-of-use rates were most favoured.

3.3.2 Customer Consultation Objectives and Process

BC Hydro used a broad and multi-faceted consultation approach to effectively reach customers and stakeholders.

[55] Appendix D provides our customer stakeholder engagement materials and results that informed the Application.

3.3.2.1 Objectives and Methods

The following objectives guided our approach to customer consultation:

- **Build awareness** – Bring attention to the process by reaching out to customers through various communication channels;
- **Be accessible** – Using various methods, present concepts in terms that are easy to understand, and provide a variety of feedback channels;
- **Ensure inclusion** – Understand that people have different needs, abilities, and interests. Create opportunities to gather diverse perspectives; and,
- **Be transparent** – Demonstrate to customers and stakeholders that we listened by sharing what we heard.

BC Hydro launched the consultation process that informed this Application in December 2020. Customer and stakeholder consultation activities occurred through the following phases:

- **Rate perceptions and concepts:** December 2020 to July 2021; and,
- **Rate options and bill impacts:** August 2021 to December 2022.

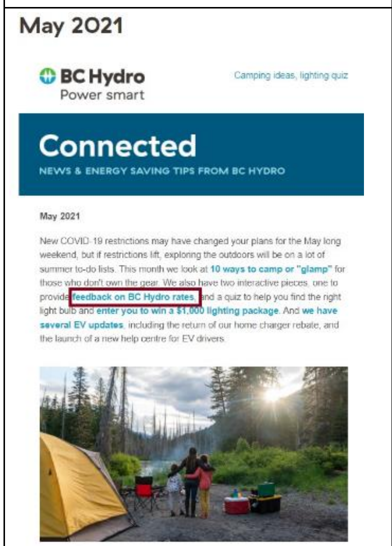
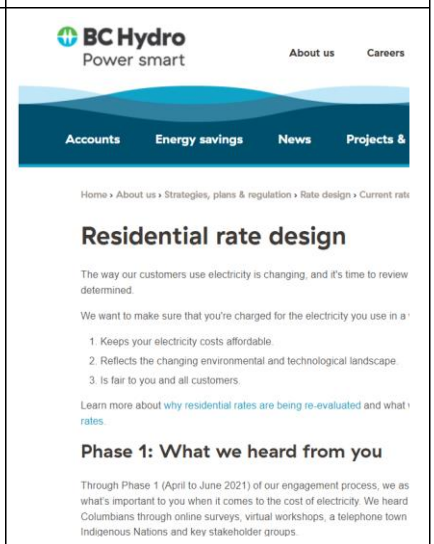
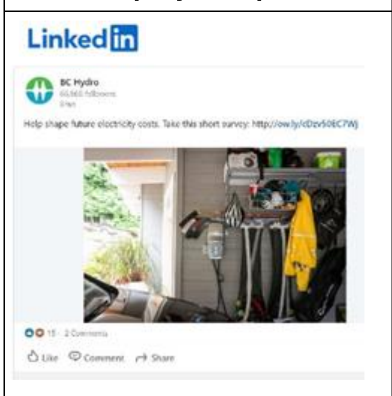
Consultation activities collected both quantitative and qualitative feedback:

- **Quantitative** activities included conducting customer surveys, in which BC Hydro selected and reached out to a random sample of customers from our database, and conducted public polls, which surveyed the opinions of those who chose to participate. These methods produced results that can be measured and projected onto a larger population; and,
- **Qualitative** activities included conducting interviews, meetings, and workshops to provide an opportunity for in-depth discussion and learning. Combined with quantitative results, these activities allowed for a deeper understanding of customer responses.

3.3.2.2 Customer Channels and Promotion

A variety of customer communication channels were used to promote the consultation. Interested individuals were directed to bchydro.com/yourrates, which outlined the consultation process and was updated with key findings following each phase of engagement. Table 3-4 below shows examples of channels used.

Table 3-4 Examples of Engagement Promotions

Connected e-Newsletter (May 2021)	Bill Promo (May/June 2021)	bchydro.com
		
LinkedIn (May 2021)	**Twitter (May 2021)**	**Facebook (May 2021)**
		

Some customers are not as comfortable with digital communications or engaging online, and others may have limited or no access to the internet. To reach those customers, BC Hydro included messaging on customers' BC Hydro paper bills and provided alternative consultation options, such as phone surveys and telephone town halls.

3.3.2.3 Summary of Customer Consultation

Table 3-5 below provides a summary of BC Hydro's various consultation efforts. Overall, more than 35,000 individuals participated in the consultation activities.

Table 3-5 Summary of Customer Consultation

Customer Engagement Efforts	Timing	Number of Participants[56]	Purpose
Consultation Efforts with Quantitative Results			
Perception Survey by Sentis (Refer to Appendix D-7A)	December 2020	978	Understanding the needs of customers and perceptions about rates.
Your Power Poll by BC Hydro (Refer to Appendix D-7B)	April 2021	1,931	Testing survey questions for understanding with registrants of an ongoing panel.
Public Survey No. 1 by BC Hydro (Refer to Appendix D-7C)	April to June 2021	22,680	Exploring rate concepts with customers and the public.
Concepts Survey by Sentis (Refer to Appendix D-7D)	May 2021	821	Learning about rate preferences, energy use, values and priorities as well as bill perceptions.

56 The total includes individuals who may have participated in multiple consultation sessions.

Customer Engagement Efforts	Timing	Number of Participants[56]	Purpose
Time-of-Use Survey by Leger (Refer to Appendix D-7E)	October 2021	1,009	Exploring voluntary time-of-use rate concepts with electric vehicle and non-electric vehicle owners.
Public Survey No. 2 by BC Hydro (Refer to Appendix D-7F)	November 2021	5,935	Exploring rate options with customers and the public.
Options Survey by Sentis (Refer to Appendix D-7G)	November to December 2021	1,346	Learning more about electricity rate priorities, comparing a flat rate vs. a stepped rate, rate perceptions, and exploring whether customers intend to fuel switch to electricity.
Time-of-Use Concept and Pricing Survey by Sentis (Refer to Appendix D-7H)	December 2022	838	Exploring additional time-of-use rate concepts and pricing options with customers.
Consultation Efforts with Qualitative Results			
Telephone Interviews by BC Hydro	April 2021	15	Individual calls to learn about customer perceptions and values related to rates, including those from Indigenous Nations.
Telephone Town Halls by Stratcom	May 2021	395	Two sessions to explore rate concepts.
Digital Dialogue by UPWORDS (Refer to Appendix D-7I)	August 2021	35	In-depth discussion about bill impacts.
Focus Groups by Leger (Refer to Appendix D-7J)	January 2022	32	Four sessions to explore time-of-day concepts with electric vehicle and non-electric vehicle owners.

Customer Engagement Efforts	Timing	Number of Participants[56]	Purpose
Online qualitative follow-up to Time-of-Use Concept and Pricing Survey by Sentis (Refer to Appendix D-7H)	December 2022	76	Assess understanding of Time-of-Use concept and reasons for or against opting into the Time-of-Use rate.
	Total	**35,200+**	

3.3.3 Feedback Themes from Our Customers

This section summarizes key themes in the feedback received from customers including verbatim quotes from participants in the engagement efforts listed in Table 3-5 above.

3.3.3.1 Customers Think About Their Electricity Bill First, Not the Rate They are Charged

One important theme from our consultation is that customers tend not to think about electricity rates. Instead, they think about their bills and affordability.

When asked to rank what is most important to them regarding electricity service, the top three choices in both the Sentis survey and Public Survey No. 1 were:

- My bills are as low as possible;
- It is affordable to me; and,
- Every customer has access to reliable service.

Overall, the rate design a customer prefers is primarily a function of how that rate will impact their bill and what they will pay. This priority was apparent across our engagement efforts including the most recent Time-of-Use Concepts and Pricing Survey conducted by Sentis in December 2022. When participants were asked what they would want to know more about the time-of-use rate design presented, the most common response was how the time-of-use will impact their bill.[57] Consistent with this, saving money was among the most common reasons why one rate is preferred over the other.[58] Although customers are much more concerned with their bill amount, 75% of respondents in the December 2021 Options Survey by Sentis also recognized their personal role in combating climate change as important.

3.3.3.2 Customer Want Options That Reflect Their Personal Circumstances

When asked to think about rates, most customers seem to consider how any change might impact them and ask, in effect, "Will I be better off or worse off?" Depending on their circumstances and attitudes, they may also think about others who may be negatively impacted.

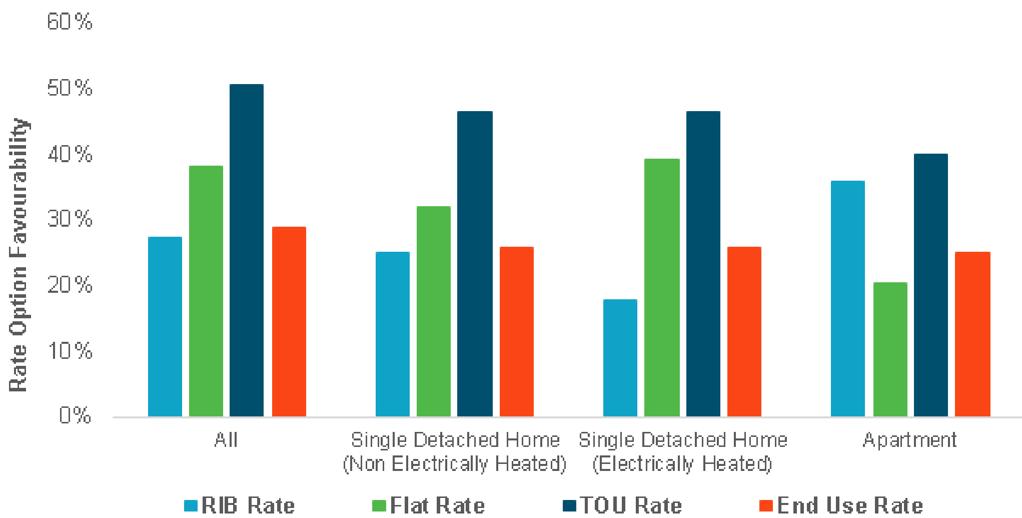
Generally, customers who often experience higher bills on the current RIB Rate tend to seek rate options that will help them reduce their electricity bills, and those with lower bills tend to prefer the status quo. Often, an individual customer's ideal rate is one that reflects their individual circumstances. For example, a rate for those with no access to alternative heating fuels, a rate for those who live in colder winter regions, or a rate for those who feel they have already done everything they can to conserve to reduce their electricity cost.[59]

Results from the largest customer consultation conducted as part of our rate design effort, the BC Hydro's Public Survey No. 1, suggest that a customer's personal circumstances that affect their level of electricity consumption, such as their dwelling type and heating source, impact their interest in a particular rate design. Figure 3-11 below shows that those who live in electrically-heated detached homes, which typically exhibit higher consumption, generally prefer rate options that offer savings opportunities, while customers in apartments generally prefer rate options that do

57 Refer to Appendix D-7H (Time-of-Use Concept and Pricing Survey by Sentis).
58 Refer to Appendix D-7G (Options Survey by Sentis).
59 Refer to Appendix D-7D (Concepts Survey by Sentis and Public Survey No. 1 – Attitudes towards energy management).

not increase their current bills. Across all customers groups, time-of-use rates were most preferred by customers.

Figure 3-11 Preferred Rate Concept by Housing Type (BC Hydro Public Survey No. 1)



Examples of feedback received from customers regarding their personal circumstances and rate design include:

> "I think it's beneficial for those of us that are really concerned about climate change and the consumption of electricity that we can actually do something on our part."[60]

> "Yes, [EV TOU] is more interesting to me. I would definitely charge my car at different times to save money on my electrical vehicle."[61]

> "I get home at 5 pm and need to completed my evening tasks before going to bed. Life is hard enough without worrying about being penalized for using a service we already pay for when we need it."[62]

---

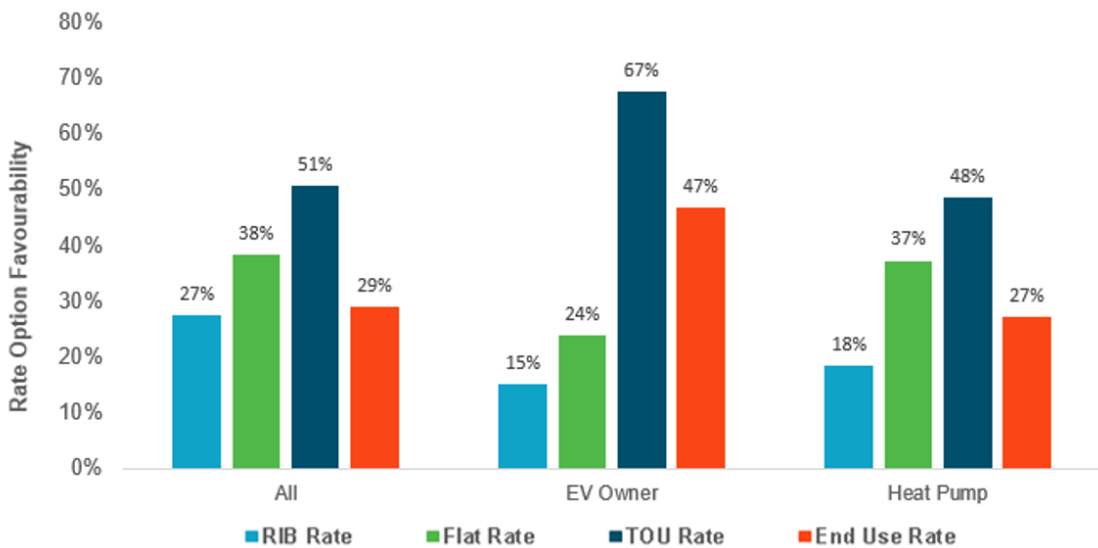
60 Refer to slide 9 of Appendix D-7J (Focus Groups by Leger), January 2022.

61 Ibid., slide 19.

62 Refer to slide 9 of Appendix D-7H.

Figure 3-12 below also supports the idea that a customer's circumstance affects their preference for rates. In this instance, electric vehicle owners who are well-suited to schedule their electric vehicle charging at lower priced periods, such as overnight, show strong preference for time-of-use rates over other rate concepts by a significant margin. Similarly, heat pump owners whose heating consumption isn't well-suited to be scheduled at lower cost periods but contributes to higher bills under the current RIB Rate also prefer time-of-use rates over other rate concepts.

Figure 3-12 Preferred Rate Concept by Customer Segments (BC Hydro Public Survey No. 1)



Examples of feedback received from customers regarding rate design and electrification include:

> "I am happy to see that BC Hydro is considering an improved rate structure to account for the implementation of electric vehicles, heat pumps and electric furnaces, all of which we are going to need to transition to very soon to fight climate change."[63]

[63] Refer to Appendix D-7F (Summary Report – Public Survey No. 2 by BC Hydro, November 2021).

> "I would definitely subscribe to a time-of-use charge from my EV. Such a rate structure would encourage me to sell my wife's car and buy another EV. It would certainly encourage further purchases of EV's."[64]

The diversity of circumstances and individual interests reflected in the customer feedback and rate preferences all support the need and desire for rate choices.

3.3.3.3 Customers are Interested in Time-of-Use Rates, with Caveats

Of all the potential optional rate options we explored, time-of-use rates drew the most interest from participants. The January 2022 Focus Group study participants appeared to understand the concept of electricity capacity and BC Hydro's rationale for proposing time-of-use rates.[65] Many customers are familiar with the concept of time-of-use rates, either because they once lived in jurisdictions where time-of-use rates are an option, or through family and friends who have personal experience with these rates.

Those who support time-of-use rates see such rates as supporting clean electrification while providing options to reduce electricity costs by offering lower cost periods that can help them save. Electric vehicle owners are especially supportive of a rate that would allow them to charge their vehicles overnight at a lower rate. Nearly two-thirds of EV owners who participated in the October 2021 Time-of-Use Survey by Leger and the December 2022 Time-of-Use Concept and Pricing Survey by Sentis indicated that they would be interested in signing up for an optional time-of-use rate.[66]

However, participants had mixed reactions as to the fairness and success of such rates. Those who are critical of a time-of-use rate seem to view these rates as unfair to those who have limited or no ability to change when they use electricity to take advantage of lower rates during Off-Peak hours. This includes customers whose

[64] Ibid.
[65] Refer to Appendix D-7J.
[66] Refer to Appendix D-7E and Appendix D-7H.

primary heating fuel source is electricity, who work from home or do shift work, and customers who live in apartments that prohibit the use of major appliances overnight due to the associated noise.

Overall, customers showed preference to specific design elements of time-of-use rates:

- Most prefer that time-of-use rates be optional, leaving the decision whether to enroll or not up to the customer;[67]
- When asked about seasonal time-of-use rates, the general sentiment among participants was they would prefer having time-of-use rates available all year-round in order to minimize the need to change and adopt new habits seasonally;[68]
- Every day time-of-use rates are preferred over weekday only to help establish and maintain routines and habits;[69]
- Many felt that time-of-use peak period energy pricing should not exceed $0.25 per kWh to avoid penalizing those who will need to use electricity during this time period;[70] and,
- The potential requirement for a separate meter to participate in an electric vehicle specific time-of-use rate was seen as a deterrent to participation in the rate.[71]

Examples of feedback received from customers regarding time-of-use rates include:

> "I like the idea of having a lower rate at certain times. As a senior it would help me keep my hydro costs lower."[72]

[67] Refer to Appendix D-7J.
[68] Ibid.
[69] Refer to Appendix D-7E.
[70] Ibid.
[71] Refer to Appendix D-7J.
[72] Refer to Appendix D-7F.

> "I definitely think that it would be counter intuitive to have it only for winter because a lot of people will just fall off the wagon."[73]

> "Using appliances at night in multi-unit buildings is not an option as washers and dryers cannot be operated in quiet times."[74]

> "We are a family of four with young kids. We have to run clothes and dishwashers often and cannot really time shift those activities."[75]

> "No one size fits all but it would be good to find the one method which would help meet the needs of keeping hydro as a clean energy fuel while maintaining a reasonable cost to homeowners. Giving homeowners a choice as to when they could access electricity at a lower rate by choices they personally make as to how and when they use electricity is a good model."[76]

3.3.3.4 December 2022 Time-of-Use Concept and Pricing Survey by Sentis

In the December 2022 Time-of-Use Concept and Pricing survey by Sentis, BC Hydro conducted more detailed research on customers' energy usage behaviours and their understanding and preferences toward the proposed Optional Residential TOU Rate.

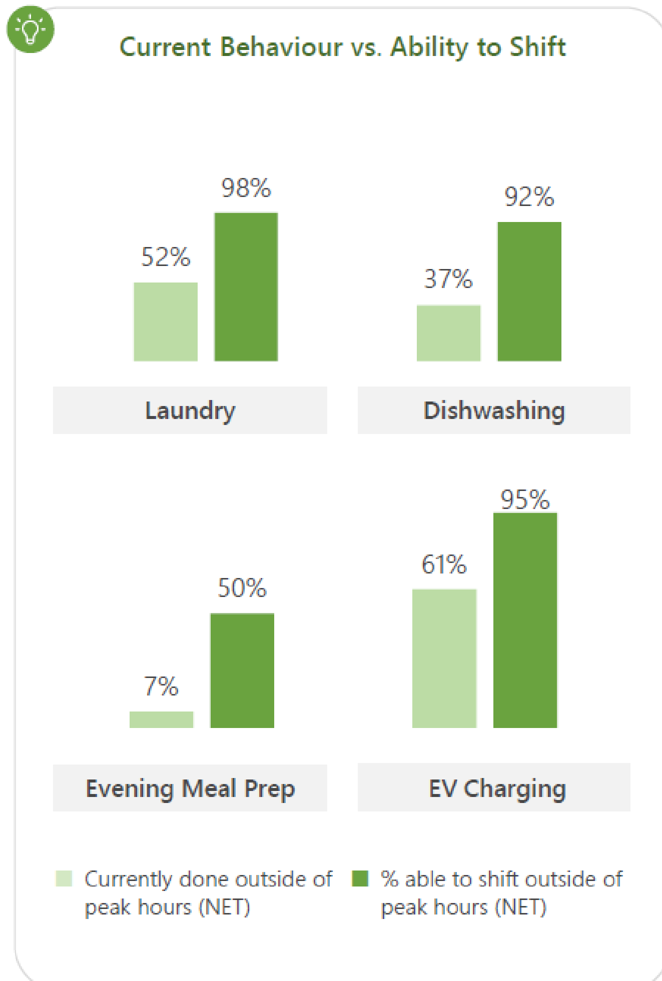
Overall, 39% of all respondents indicated that they would consider enrolling in the new time-of-use rate and 32% indicated they would not. Those who are likely to consider the time-of-use rate are primarily electric vehicle owners (59%) and those who can shift their laundry and dishwashing (56%) away from the On-Peak period. [77]

Among those who said they definitely will choose to add the Optional Residential TOU Rate (13%), 39% have an electric vehicle or have ordered one, and 91% said they can shift laundry and dishwashing out of On-Peak Hours. Figure 3-13 below shows these customers' current energy usage behaviours and their reported ability

[73] Refer to Appendix D-7J, page 18.
[74] Refer to Appendix D-7F, page 7.
[75] Ibid., page 6.
[76] Ibid., page 7.
[77] Refer to Appendix D-7H.

to shift their electricity consumption in response to the Optional Residential TOU Rate.

Figure 3-13 Current Behaviour vs. Ability to Shift of Customers Who Definitely Will Choose the Optional Residential TOU Rate



Of the survey respondents who said they definitely will not choose to enrol in the Optional Residential TOU Rate, the top three reasons provided were:

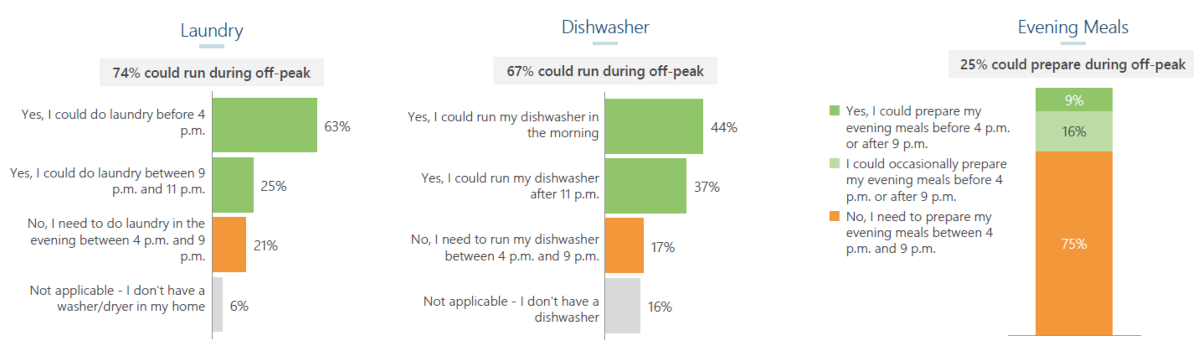
- Circumstances / routine dictate our power use / can't avoid peak time use;
- Don't like this concept / not fair / not practical for people to shift use; and,
- Negative / cynical comments about BC Hydro.

About a third (35%) of these customers have a household of more than four people, 59% live in a single-detached home, and over 80% are in a moderate or high income household.

As shown in Figure 3-14 below, customers generally demonstrate flexibility when it comes to how they could shift their dishwashing and laundry routines. Four-in-ten customers currently wash dishes during the On-Peak period but only 17% indicated that they need to run their dishwasher during this period. A notable percentage (37%) say they could run their dishwasher during the Overnight period. In addition, while just under half of customers indicated that they currently do their laundry during the Off-Peak period, three-quarters of customers indicated that they could do their laundry during this period.

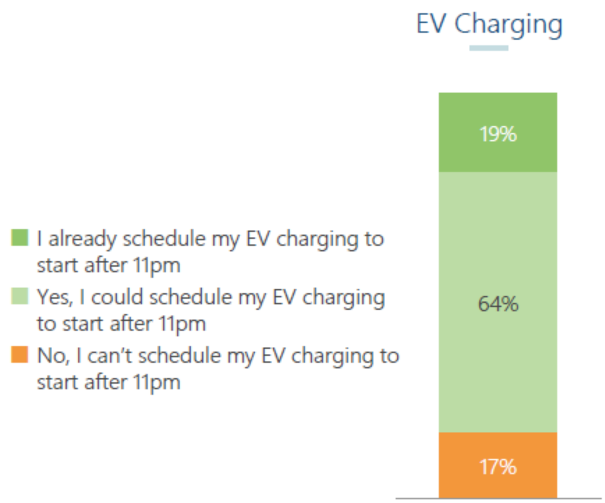
Customers demonstrate the least flexibility when it comes to shifting the preparation of their evening meals. A large majority of customers currently prepare evening meals during the On-Peak period, and three-quarters indicated that they are not able to shift this activity to other periods.

Figure 3-14 Customers' Ability Shift their Laundry, Dishwashing and Evening Meal Preparation



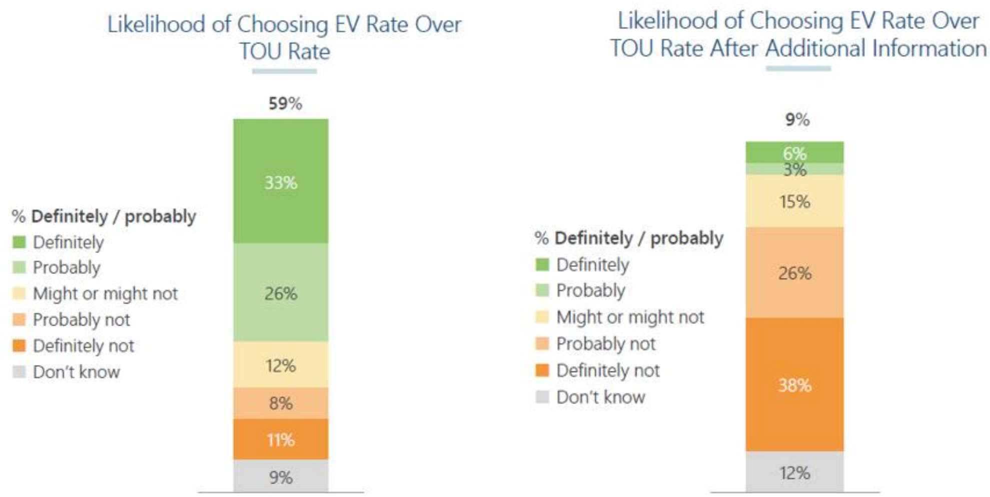
As shown in Figure 3-15 below, when asked about their electric vehicle charging habits, most electric vehicle owners (83%) indicated that they either already charge their electric vehicle during the Overnight period or could schedule the charging to start after 11 p.m.

Figure 3-15 Customers' Ability to Shift Electric Vehicle Charging



As shown in Figure 3-16 below, close to two-thirds of the electric vehicle owners indicated they would choose to apply the Optional Residential TOU Rate to their electric vehicle charging load only instead of their whole home. However, when asked about the likelihood of taking this approach if a separate BC Hydro meter had to be installed for their electric vehicle charging load, the interest in this option dropped to just under 10%.

Figure 3-16 Customer Interest in an Electric-Vehicle Only Time-of-Use Rate



As shown in Figure 3-17 and Figure 3-18 below approximately three-quarters of all respondents (73%) indicated they understood the Optional Residential TOU Rate design and over half (56%) are interested in finding out more about it. Among electric vehicle owners, the understanding and interest was even higher with 88% indicating that they understand it and 74% interested in learning more.[78]

[78] Refer to Appendix D-7H.

Figure 3-17 I Understand How This Proposed Optional Time-of-Use Rate Works

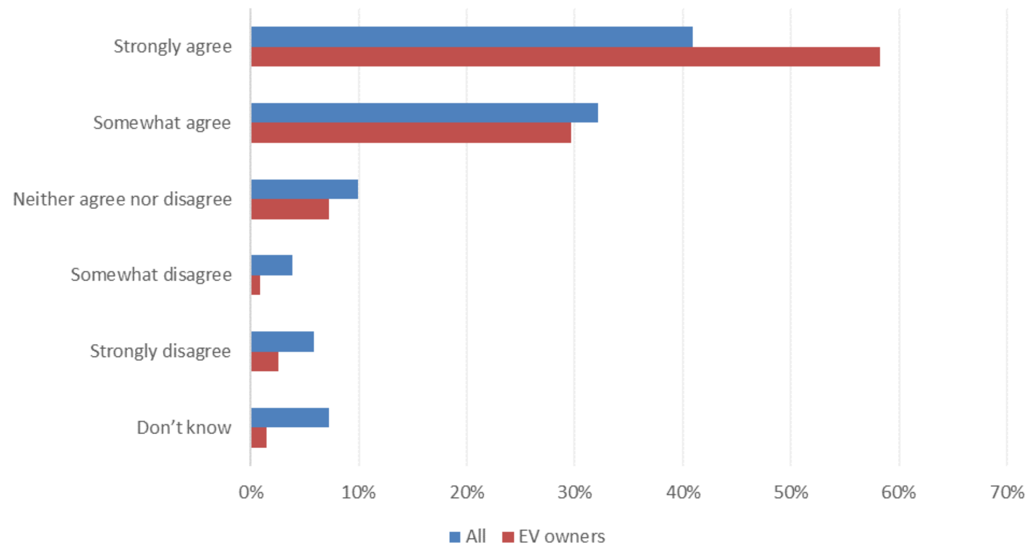
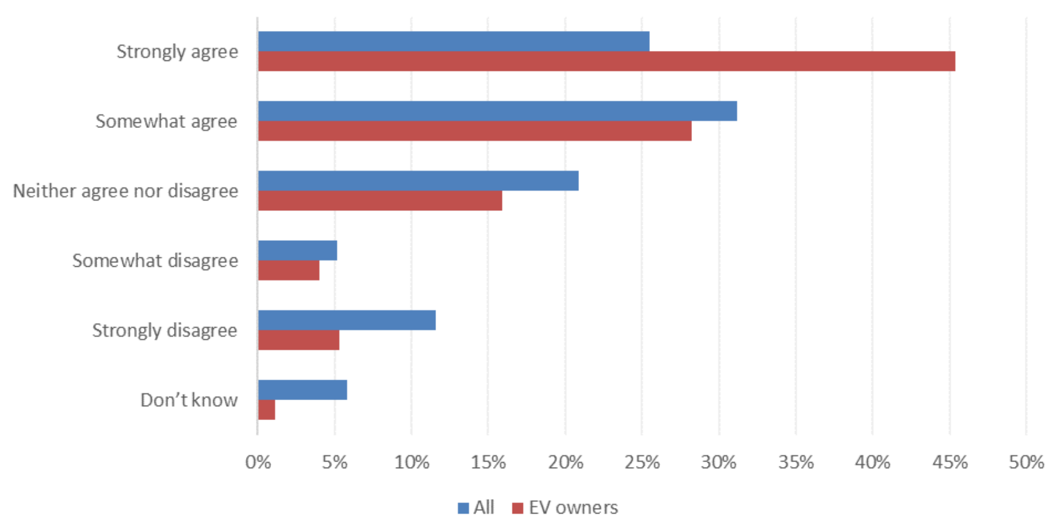


Figure 3-18 I Am Interested in Finding Out More About This Potential New Optional Rate



Notably, customers who indicated that they didn't understand the Optional Residential TOU Rate design presented in the survey tended to object to the time-of-use rate concept altogether rather than indicating a specific aspect of the design that they found confusing.[79]

3.4 Summary of Stakeholder Consultation

In addition to engaging with customers and the public, BC Hydro also invited stakeholders and interveners representing various customer groups and local governments to participate in our consultation process. These activities are summarized below.

3.4.1 Stakeholder Consultation and Process

Stakeholders and interveners were invited to participate in public rate design workshops and submit feedback forms. Rate design workshops were held on:

- May 19, 2021 (Refer to Appendix D-1 for presentation materials and Appendix D-2 for feedback received);
- November 18, 2021 (Refer to Appendix D-3 for presentation materials and Appendix D-4 for feedback received); and,
- November 29, 2022 (Refer to Appendix D-5 for presentation materials and Appendix D-6 for feedback received).

Due to the COVID-19 pandemic, the first two workshops were held virtually. The November 2022 session was offered as a hybrid, allowing both in-person and virtual attendance. Invitations to the workshops were sent to:

- Stakeholder groups involved in previous rate design proceedings;
- Local government representatives;

[79] Refer to Appendix D-7H, page 17.

- Large commercial customers that expressed an interest in residential rates (i.e., those providing affordable housing or student housing, and groups with an interest in the development of residential housing); and,
- Commission staff.

BC Hydro also engaged with Indigenous communities through the First Nations Energy and Mining Council and BC Hydro staff who interact with Indigenous Nations were asked to help raise awareness of activities and encourage participation in the workshops from Indigenous customers.

Workshop participants were provided with information on the rate design options for the default rate and optional rate designs as well as a jurisdictional review. The workshops were led by and presented by BC Hydro staff. Participation was encouraged and resulted in many questions and comments which were addressed by the presenters during the workshops.

Participants in the workshops were asked to complete a feedback form that included questions on specific areas that required customer and stakeholder input. The feedback form also allowed participants to provide any additional comments they had on rate design concepts, options, and their particular interests.

A total of 227 participants attended the three workshops. Table 3-6 below outlines the interests represented by those who participated. Seventy-one of these participants submitted a feedback form to BC Hydro and provided input during the workshops.[80]

[80] BC Hydro notes that due to the small samples' stakeholder feedback from the two workshops should be viewed as directional and qualitative, rather than statistically significant or quantitative.

Table 3-6 Summary of Stakeholder Consultation

Stakeholder Engagement Efforts	Timing	Number of Participants	Representation
BC Hydro Workshops	• May 19, 2021 • November 18, 2021 • November 29, 2022	109 Virtual (May 2021) 74 Virtual (November 2021) 37 Virtual, 7 In-Person (November 2022)	• Residential customers • Aboriginal housing • Housing development • Electric vehicles • Environment & sustainability • Local government • Low income • Seniors • Union employees • Commercial customers
Four Meetings	May to December 2021	Three to 15 for each	• Builders • Indigenous Nations • Local Government • Low Income
	Total	**240+**	

3.4.2 Feedback Themes from Stakeholders

The sub-sections below provide a summary of the key themes from stakeholder feedback.

3.4.2.1 Stakeholders Demonstrate Strong Support for Rate Designs that Encourage Electrification and Decarbonization

Stakeholders' feedback received generally fell into the following key topics:

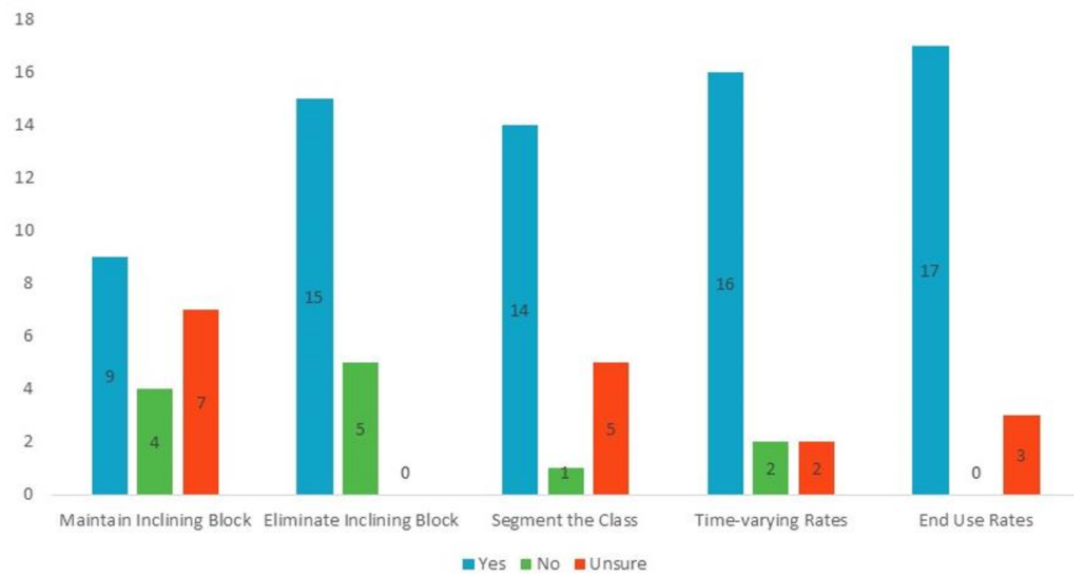
- Environment, particularly decarbonization, heat pumps, and electric vehicles;
- Affordability and fairness;
- Fuel switching; and,
- Time-of-Use rate designs.

In the first two workshops, many stakeholders emphasized the importance of removing barriers to electrification to achieve CleanBC's decarbonization objectives. One of the comments received stated:

> "Affordability and Decarbonization should be prioritized as this directly impacts the customers. Since Decarbonization is one of the National priorities and it is clear by now that electrification is clearly the solution in B.C., costing based on decarbonization and encouraging consumers to use electricity over gas would be ideal."[81]

Stakeholders generally support BC Hydro to explore all rate options. As shown in Figure 3-19 below, when asked about what rate design concepts BC Hydro should continue to explore, time-of-use and end-use rates received significant support among all rate concepts presented at the May 19, 2021 workshop.

Figure 3-19 Stakeholder Workshop No. 1 Participants – Summary of Feedback on Rate Concepts that BC Hydro Should Explore



[81] Refer to page 3 of Appendix D-2 (Residential Rates Stakeholder Workshop #1 Feedback Summary Report – May 19, 2021).

3.4.2.2 Stakeholders Support Time-of-Use Rate Designs that Minimize Bill Impacts for Non-Participants and Mitigate Impacts on Non-Participating Ratepayers

In general, stakeholders support the concept of incenting customers to shift usage from BC Hydro's system peak demand period to support electrification and make better use of existing electrical infrastructure. Examples of comments received include:

> "Time-of-use rates could further support electrification and minimize peak loads. We support seasonal, weekday/weekend, peak/off-peak and critical peak time varying options."[82]

> "Consider implementing time of day rate tiers to support lowering demand peaks and making better use of existing electrical infrastructure as electrification expands load. Also potentially an equity measure to support reduced rates for home heating using low cost thermal storage heating units."[83]

Optional time-of-use rates that could help electric vehicle drivers reduce their electric vehicle charging costs and reduce demand-related costs for all ratepayers were of particular interest. However, stakeholders also raised concerns that an electric vehicle charging rate that would require customers to separately meter their electric vehicle charging load would be impractical and too expensive and not practical.

3.4.2.3 Stakeholders Support BC Hydro's Proposed Optional Residential TOU Rate

The November 29, 2022 workshop presented stakeholders with the new "add-on" Optional Residential TOU Rate design that allows customer to remain on their current Residential service rate and add time-of-use energy pricing through a credit or an additional charge.

This design received overall support from stakeholders based on its ability to support multiple objectives including electrification and conservation while minimizing bill

82 Ibid., page 6.
83 Ibid.

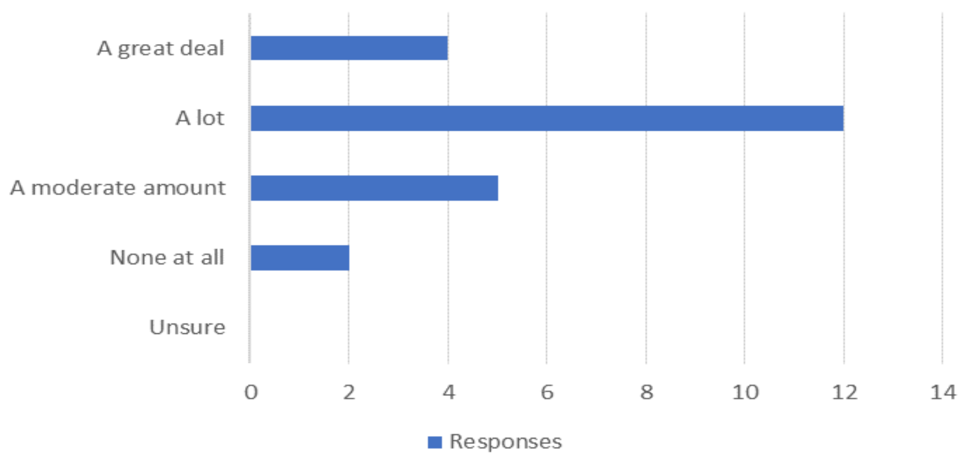
impacts to non-participants and mitigating revenue loss from those who would benefit under more traditional time-of-use rate designs without having to shift their energy usage. Examples of comments received include:

> "I think the proposed rate structure is very good - it supports/encourages electrification while still encouraging conservation behaviours with a tiered structure, is equitable in that small homes or low energy users still have an opportunity to save and is reasonably easy to understand with the +/- 5 cents idea. Since its optional it won't put anyone in the position of paying more or having a system they don't understand."[84]

Stakeholders also agreed that overall, the Optional Residential TOU Rate concept is relatively easy to understand.

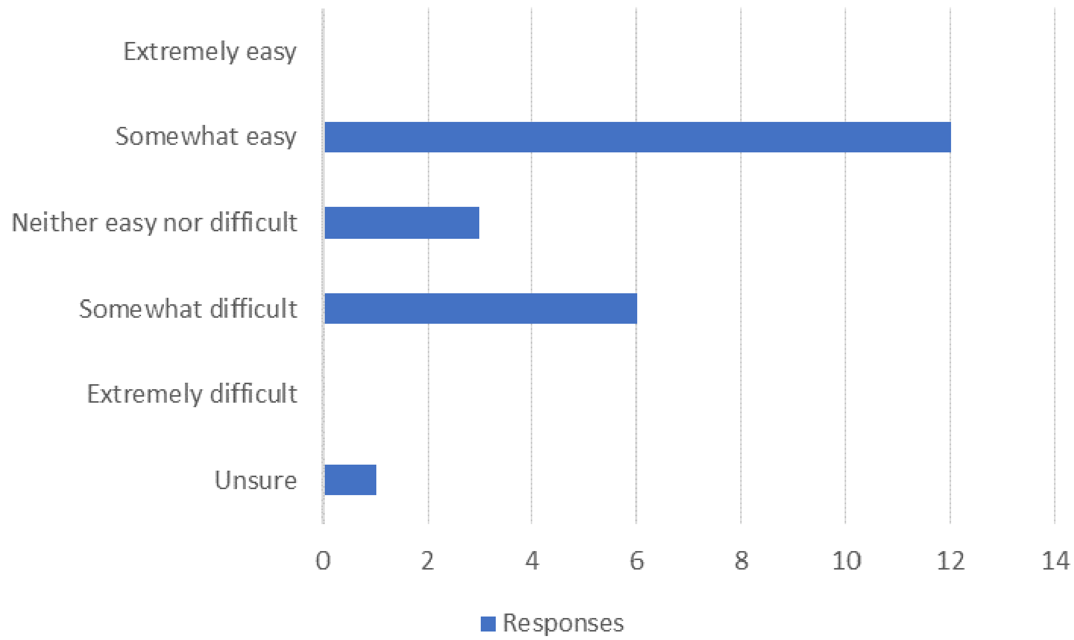
As shown in Figure 3-20 and Figure 3-21 below, when asked about customers' ability to understand the presented time-of-use rate and how it works, the majority of stakeholders responded favorably.

Figure 3-20 Stakeholder Workshop No. 3 Participants – To What Degree Do You Understand How the Optional Credit/Charge Time-of-Use Rate Concept Works?



[84] Refer to page 15 of Appendix D-6 (Residential Rates Stakeholder Workshop #3 Feedback Form Summary Report – Nov 29 2022).

Figure 3-21 Stakeholder Workshop No. 3 Participants – Do You Think This Rate Design is Easy for Customers to Understand?



Although most stakeholders felt that the Optional Residential TOU Rate offers an appropriate level of savings to encourage a shift of electric vehicle charging from the On-Peak period, some expressed concern that the level of savings from shifting of non-electric vehicle charging consumption alone may not be sufficient to encourage uptake and electricity usage behaviour changes.

Examples of comments received include:

> "EV owners would likely be enticed by this rate. For others, there is not enough schedulable load to result in significant savings under this rate…"[85]

> "As an apartment dweller with electric heating and only a dishwasher in suite (no washer/dryer), a savings of $25 per year for switching dishwasher use to after 11 pm isn't a big reduction,

[85] Ibid., page 8.

> personally. However, I think $240 savings per year for townhomes/single family homes that charge an EV in their garage could be enough incentive to switch to non-peak times."[86]

[86] Ibid., page 9.

BC Hydro Optional Residential Time-of-Use Rate Application

Chapter 4

Optional Residential Time-of-Use Rate Proposal

Table of Contents

List of Figures

List of Tables

4.1 Introduction

In this chapter, BC Hydro sets out our proposal to offer an optional Residential service time-of-use rate for all electricity consumption at a Residential service account, including electric vehicle charging (Rate Schedule 2101 – Residential Service, also referred to as the **Optional Residential TOU Rate**). Customers with a separate meter for electric vehicle charging under the same Residential service account may choose to apply the Optional Residential TOU Rate to their electric vehicle charging consumption only.

The Optional Residential TOU Rate is an "add-on" rate that applies year-round and every day of the year (i.e., weekdays, weekends, and holidays). Participating customers will still be billed for their total electricity usage during a billing period at their existing Residential rate.[87] They will then receive a 5-cent credit for each kWh of electricity consumed during the Overnight period (11 p.m. to 7 a.m.) and a 5-cent additional charge for each kWh of electricity consumed during the On-Peak period (4 p.m. to 9 p.m.). No credit or additional charge will be applied to consumption during the Off-Peak period (9 p.m. to 11 p.m. and 7 a.m. to 4 p.m.).

As explained in the sections below, the proposed Optional Residential TOU Rate:

- Uses "add-on" credits and charges to encourage customers to shift their electricity use to times when there is more available capacity on the BC Hydro system. This "add-on" design enables a wide-range of customers to save by participating and helps protect customers who do not participate. Further information on this point is provided in section 4.2 below;
- Will contribute to meeting customers' future electricity needs. Consistent with the capacity savings targets set out in BC Hydro's 2021 Integrated Resource Plan (**2021 IRP**), which relies more on customer-based solutions over new

[87] Most BC Hydro's Residential customers living in the integrated service area take service under Rate Schedule (RS) 1101 Residential Inclining Block Rate (**RIB Rate**) and a small number of farm customers take service under RS 1151 Exempt Residential Service Rate (**Flat Rate**).

infrastructure, it will help meet an expected increase in peak demand driven, in part, by electric vehicle adoption. Further information on this point is provided in section 4.3 below;

- Provides bill savings to encourage customers to shift their electricity consumption from BC Hydro’s system peak period to other hours of the day. For example, participating customers with an electric vehicle could save an average of $44 per year and up to $250 per year and customers in electrically heated single-detached homes could save approximately $40 per year on average. Further information on this point is provided in section 4.4 below;
- Sends price signals that reflect the cost of service and is expected to provide benefits to all customers across a range of potential outcomes. Further information on this point is provided in section 4.5 below;
- Incorporates customers’ feedback, which demonstrates strong support for optional time-of-use rates and is designed to achieve customer understanding and acceptance. Further information on this point is provided in section 4.6 below;
- Aligns with Bonbright rate design criteria and our rate design objectives and performs better against these considerations compared to alternatives. Further information on this point is provided in section 4.7 below; and,
- Includes availability and special conditions to protect customers and will be accompanied by an implementation plan so that customers receive the support they need to achieve bill savings and an evaluation plan to verify if the expected benefits are being achieved to inform adjustments, if needed. Further information on this point is provided in section 4.8 below.

BC Hydro retained Dr. Sanem Sergici and Mr. Ryan Hledik of The Brattle Group to inform the development of the Optional Residential TOU Rate. Appendix F provides

Dr. Sergici and Mr. Hledik's Review of BC Hydro's Optional Residential TOU Rate. It states:

> "We concluded that BC Hydro's proposed TOU design is consistent with successful industry rate design practices and effectively balances key ratemaking criteria. In particular, the company's proposed credit- and charge-based approach to implementing the TOU is an innovative approach to increase the appeal of a TOU rate for customers currently enrolled in an inclining block rate. Further, our review indicates that BC Hydro's assumptions about potential participation in and load impacts of TOU rates are reasonable and consistent with the available empirical evidence on the subject."[88]

4.2 "Add-on" Credits and Charges Enable Wide Range of Customers to Save and Help Protect Customers Who Do Not Participate

This section provides a description of the Optional Residential TOU Rate which uses "add-on" credits and charges to encourage participating customers to shift their electricity use to times when more capacity is available on the BC Hydro system. The credits and charges apply daily and year-round (i.e., weekdays, weekends, and holidays) and are applied after a customer is billed at their existing Residential rate. As explained in the sub-sections below, this design enables a wide range of customers to save by participating and helps protect customers who do not participate.

4.2.1 Credits and Charges Encourage Customers to Shift Electricity Consumption to Times When Capacity Is More Available

With a time-of-use rate, the amount participating customers pay for service is based on the time of day. This type of rate can benefit all customers by encouraging participating customers to shift their electricity use to times when more capacity is available on the BC Hydro system so that the increased costs associated with adding more system capacity can be avoided or reduced. This rate can further

[88] Refer to Appendix F (A Review of BC Hydro's Optional Residential TOU Rate, The Brattle Group), page 12.

benefit participating customers who can achieve bill savings if they are able to shift their electricity use from higher priced demand periods to lower priced periods.

The Optional Residential TOU Rate is for customers living in BC Hydro's integrated service area[89] for service to dwellings, covering all electricity consumption at the dwelling, including electric vehicle charging. Customers with a separate BC Hydro meter for electric vehicle charging under the same Residential service account may choose to apply the Optional Residential TOU Rate to their electric vehicle charging consumption only.

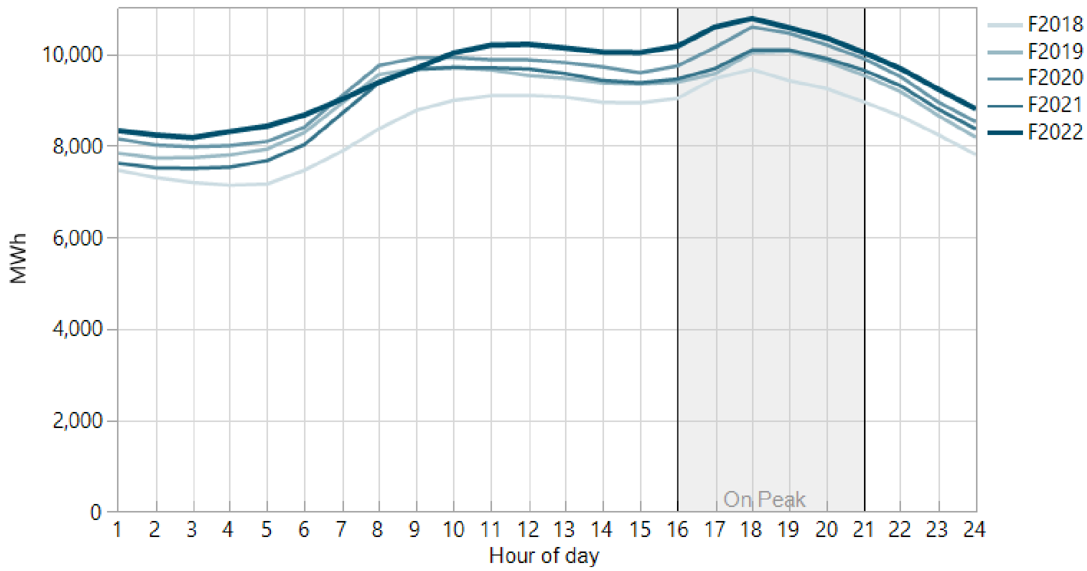
The Optional Residential TOU Rate is an "add-on" rate that applies year-round on weekdays, weekends, and on holidays. It consists of three different time-periods, as follows:

- On-Peak Period: 4 p.m. to 9 p.m.;
- Off-Peak Period: 7 a.m. to 4 p.m. and 9 p.m. to 11 p.m.; and,
- Overnight Period: 11 p.m. to 7 a.m.

As shown in Figure 4-1 below, which provides BC Hydro's system load shape by fiscal year from fiscal 2018 to fiscal 2022, the five-hour On-Peak period corresponds to BC Hydro's system peak hours, when system usage is highest. The eight-hour Overnight period corresponds to times when system usage is lowest.

[89] Refer to section 4.8.1 below for a discussion regarding why BC Hydro is not proposing to make the Optional Residential TOU Rate available to non-integrated service areas.

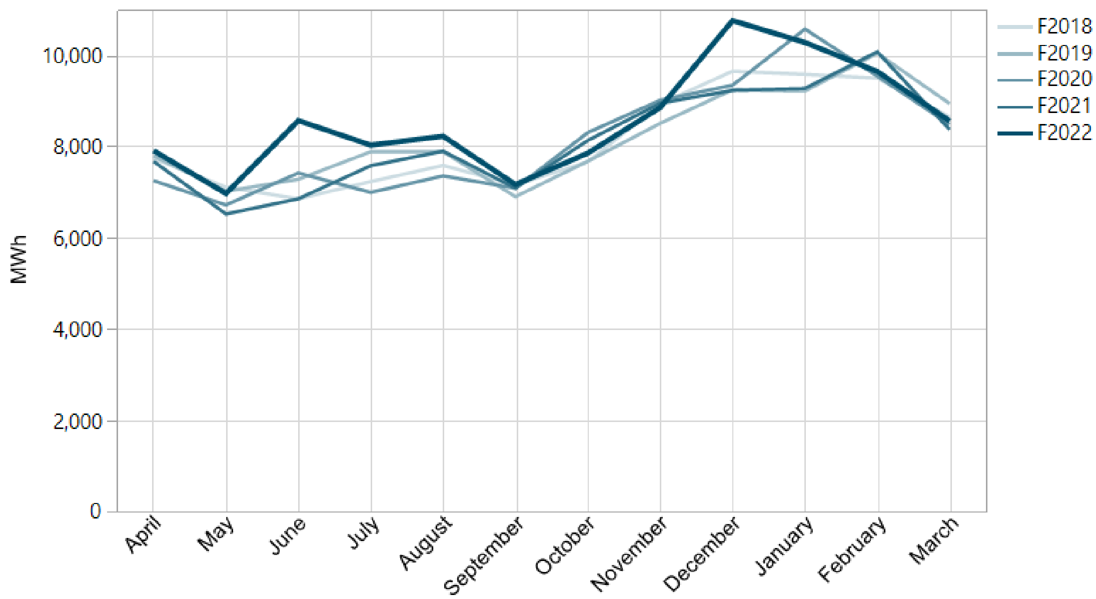
Figure 4-1 BC Hydro System Peak Days (Fiscal 2018 – Fiscal 2022)



BC Hydro is considered a winter-peaking utility. This means that, on a system-wide basis, BC Hydro's highest demand period each year is expected to occur in the winter. In some areas of the province, however, a particular feeder or substation may be summer peaking, which means that its peak demand is more sensitive to warmer temperatures and its highest demand period each year would be expected to occur in the summer.

Figure 4-2 below shows BC Hydro's annual system load shape by month for the past five fiscal years.

Figure 4-2 BC Hydro Annual System Load Shape by Month from Fiscal 2018 to Fiscal 2022



As mentioned above, the Optional Residential TOU Rate applies every day and year-round. The year-round applicability of the rate has three primary benefits:

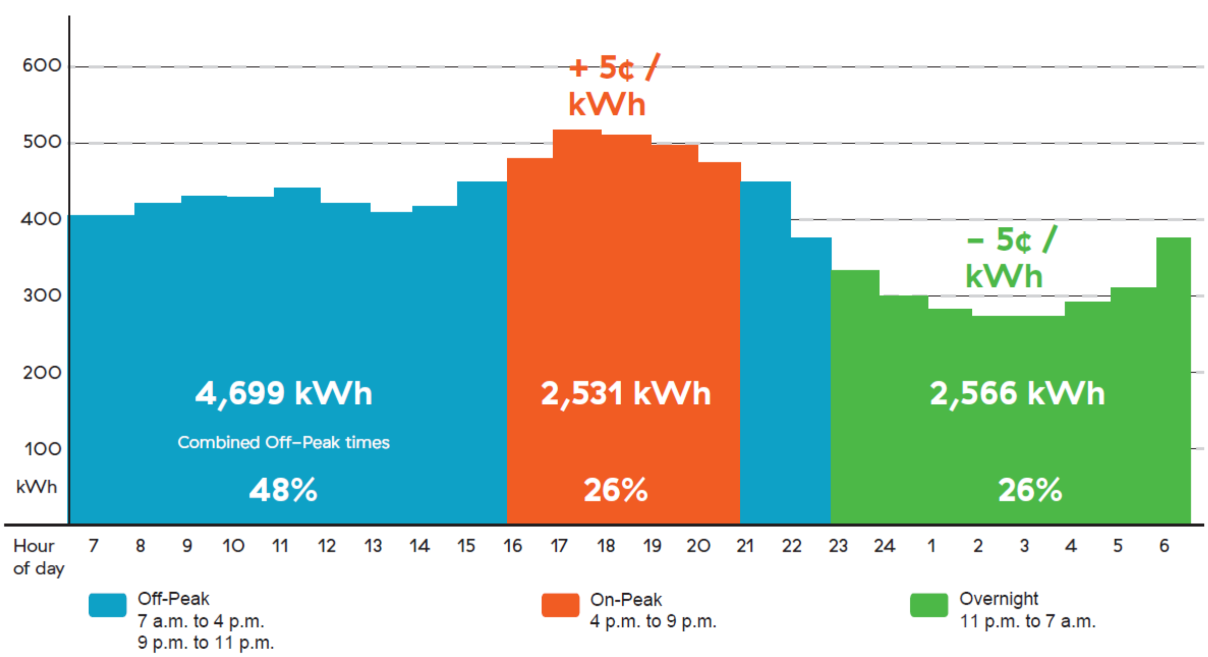
1. It provides increased savings opportunities for customers, as discussed further in section 4.4 below;
2. It responds to customer feedback which indicated a strong preference for year-round applicability for convenience and understanding, as discussed further in section 3.3.3.3 of Chapter 3 and section 4.6 below; and,
3. It will send a price signal to participating customers to encourage them to shift their electricity use to times when there more capacity is available on the BC Hydro system during both winter and summer months. This will help avoid or reduce the increased costs associated with adding more capacity at both a system level, with winter constraints, as well as at a more regional or local level where there may be constraints during the summer.

4.2.2 Optional Residential TOU Rate Enables Wide Range of Customers to Save by Participating

A wide range of BC Hydro customers will have the opportunity to save by participating in the Optional Residential TOU Rate. This is because, on average, Residential customers’ total electricity usage during the five-hour On-Peak period is almost identical to their total electricity usage during the eight-hour Overnight period. This means that if customers participating in the Optional Residential TOU Rate do not shift any of their electricity use out of the On-Peak period, then on average, they would pay the same as they would under their current rate.

Figure 4-3 below shows the average annual consumption distribution of Residential customers on the Residential Inclining Block Rate (**RIB Rate**). As shown, the average total electricity use during the Overnight period (when the 5-cents per kWh credit is applied) is approximately 26%. The average total electricity use during the On-Peak period (when the 5-cents per kWh additional charge is applied) is also approximately 26%.

Figure 4-3 Average Consumption Distribution of Residential Customer



Under the Optional Residential TOU Rate, participating customers will still be billed for their total electricity usage during a billing period at their existing Residential rate. As mentioned in section 3.2.1 of Chapter 3, most of BC Hydro's Residential customers living in the integrated service area take service under Rate Schedule (**RS**) 1101, the RIB Rate, which is the default rate for Residential customers. A small number of eligible farm customers take service under RS 1151, the Exempt Residential Service Rate (**Flat Rate**). The RIB Rate has a step 1 energy charge of 10.10 cents per kWh for consumption up to a set threshold and a step 2 energy charge of 14.08 cents per kWh for consumption over that threshold.[90]

After being billed at their existing Residential rate, customers will receive a 5-cent credit for each kWh of electricity consumed during the Overnight period (11 p.m. to 7 a.m.) and a 5-cent additional charge for each kWh of electricity consumed during the On-Peak period (4 p.m. to 9 p.m.). No credit or additional charge will be applied to consumption during the Off-Peak period (9 p.m. to 11 p.m. and 7 a.m. to 4 p.m.).

To support customer understanding, BC Hydro proposes that the 5-cent credit and additional charge stay consistent and not be escalated by the general rate increase each year. We recognize that over time the strength of the price signal provided by the 5-cent credit and additional charge may start to decrease. At this initial stage, we believe it is important to offer a rate design that is easy for customers to understand. As discussed in section 4.8.5 below, BC Hydro expects to complete an evaluation of the Optional Residential TOU Rate by fiscal 2029 and will include in that evaluation an assessment of whether general rate increases should be applied to the 5-cent credit and additional charge going forward.

Table 4-1 below summarizes the energy credit and additional charge for the Optional Residential TOU Rate.

90 In fiscal 2025 dollars, assuming BC Hydro's Fiscal 2023 to Fiscal 2025 Revenue Requirements Application is approved by the Commission and assuming the Fiscal 2023 Residential Pricing Principles are extended for fiscal 2024 and fiscal 2025.

Table 4-1 Optional Residential TOU Rate – Energy Credit and Additional Charge

Period	Time of Day (Every Day of the Year)	Energy Credit or Charge
Overnight	11 p.m. to 7 a.m.	5 cents per kWh energy credit
On-Peak	4 p.m. to 9 p.m.	5 cents per kWh additional energy charge
Off-Peak	9 p.m. to 11 p.m. and 7 a.m. to 4 p.m.	No credit or additional charge

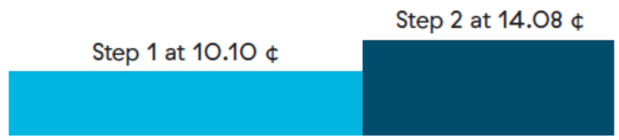
Figure 4-4 below illustrates the monthly energy charge for 1,000 kWh under the Optional Residential TOU Rate when added onto the RIB Rate if no electricity use is shifted out of the On-Peak period. As shown, the illustrative bill remains the same if no electricity use is shifted – the credits and additional charges offset. Accordingly, if this illustrative customer were to shift some of their electricity consumption out of the On-Peak period (where the additional charge is applied) and into either the Off-Peak period (with no credit or additional charge) or the Overnight period (where the credit is applied), they would be able to achieve bill savings.

Figure 4-4 Illustrative Monthly Energy Charge Calculation of the Proposed Optional TOU Rate

FIRST:

A customer's energy charges are calculated by the two-step rate. This example illustrates a typical residential customer who has used 1,000 kWh in an average month.

Two-step energy charges for an average month.



Fiscal 2025 Residential Inclining Block energy charges

Two-step energy charges

Step 1

675 kWh X $0.1010 = $68.18

Step 2

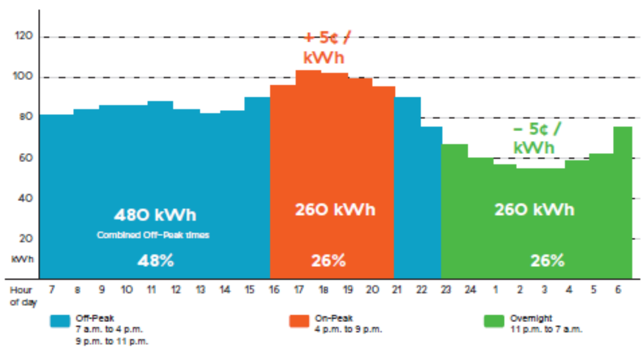
325 kWh X $0.1408 = $45.76

Total two-step energy charges: $113.94

SECOND:

This same customer's 1,000 kWh of usage is shown below in terms of energy use by time period. In this example, over a month period, they used as much energy (26%) between 4 p.m. and 9 p.m. as they did in the 11 p.m. to 7 a.m. period. Time-of-use energy charges are calculated by adding up electricity usage (kWh) during the Overnight (credit) and On-Peak (charges) periods.

Electricity for an average month, by each hour of the day. No shift in electricity use.



Time-of-use energy charges

Overnight Period Credit

260 kWh X ($0.05) = ($13.00)

On-Peak Period Charge

260 kWh X $0.05 = $13.00

Off-Peak: No credit or charge

480 kWh

Total time-of-use energy charges: $0.00

THIRD:

The customer's monthly bill includes the RIB rate + time-of-use energy charges **$113.94 + $0.00 = $113.94**

While Figure 4-1 and Figure 4-2 above demonstrate that the Optional Residential TOU Rate can provide customers with opportunities to save on average, every customer is different and whether the Optional Residential TOU Rate works for an individual customer depends on their own individual consumption patterns. For this reason, BC Hydro also analyzed the consumption patterns of customers with different characteristics to understand how the Optional Residential TOU Rate would work across a range of different customers. Our analysis showed that while a customers' housing type, heating type, and geographic location impact their overall consumption, customers' consumption patterns (i.e., the relative amount they consume at different times of the day) are actually very similar.[91]

Table 4-2 below shows how much higher or lower bills would be for different types of customers, on average, if they do not shift any of their electricity use out of the On-Peak period. As shown, these bill differences are relatively minor. This means that a wide range of customers will start from a position where they can save by participating in the Optional Residential TOU Rate.

Table 4-2 Consumption Distribution and Energy Charge Comparisons by Housing and Heating Type before Shifting

Customer Group	Number of Customers*	Average Annual Bill ($)	On-Peak Period Load %	Overnight Period Load %	Annual Bill Difference ($)
Electrically heated					
Apartment	293,182	$670	25.7%	25.8%	$0
Single-detached home	252,326	$2,236	24.2%	27.4%	$(28)
Rowhome	88,231	$1,384	25.6%	25.3%	$2
Manufactured home	13,218	$1,640	23.9%	27.7%	$(25)
Other	12,482	$2,378	23.0%	29.6%	$(60)
Non-electrically heated					
Apartment	141,258	$399	27.4%	24.3%	$5
Single-detached home	644,710	$1,360	26.3%	25.7%	$3
Rowhome	69,100	$810	27.4%	24.0%	$11
Manufactured home	46,326	$1,151	25.7%	25.7%	$0
Other	9,089	$1,230	22.7%	29.8%	$(33)

* Based on fiscal 2022 RIB customers with a full year consumption history.

4.2.3 "Add-On" Design of Optional Residential TOU Rate Is Intended to Address Challenge with Offering Time-of-Use Rates When the Default Rate is an Inclining Block Rate

As discussed in section 3.2.1 of Chapter 3, the RIB Rate is an inclining block energy charge rate where customers pay a higher energy charge for consumption above a

[91] The proportion of electricity different groups of customers consume during the On-Peak, Off-Peak, and Overnight periods vary very slightly. For further information on consumption patterns of different customer groups, refer to section 3.2 of Chapter 3.

set threshold. The "add-on" credit and additional charge design of the Optional Residential TOU Rate is intended to overcome a challenge that typically occurs when offering optional time-of-use rates to customers whose default rate has an inclining block rate design, like BC Hydro customers on the RIB Rate.

Under inclining block rates, the amount that a customer could save by opting into a time-of-use rate with energy charges that vary based on the time of day depends not only on when they consume electricity and their ability to shift that consumption from higher-priced periods to lower-priced periods but also on their overall consumption amount. This is because those customers with high overall consumption, who consume a large portion of their electricity at a higher energy charge may be able to save simply by opting-in to a time-of-use rate with lower time-based energy charges, without making any changes to shift when they use electricity. Conversely, customers with low overall consumption, who consume most of their electricity at a lower energy charge may be unable to achieve savings because the time-based energy charges are too high relative to what they currently pay. As Dr. Sergici and Mr. Hledik explain:

> "When the existing rate has an inclining block structure, a large number of smaller-than-average customers benefit from the discounted first tier of the rate. If the proposed TOU rate does not retain that usage-based discount, a majority of the population is unlikely to experience bills savings by switching to the TOU Rate."[92]

The Optional Residential TOU Rate largely overcomes these challenges by preserving customers' underlying lower or higher energy charges based on their overall consumption and offering time-of-use price signals as an "add-on" credit and charge.

This means that high consumption customers will still pay the higher step 2 energy charge for their consumption above the RIB Rate threshold, mitigating the potential

[92] Appendix F, page 7.

for high consumption customers to save without shifting their On-Peak period electricity use to the Off-Peak or Overnight period.

Likewise, lower consumption customers whose current energy charges are lower under the RIB Rate can continue to benefit from the lower step 1 energy charge and still have opportunities to save under the Optional Residential TOU Rate.

The design of the Optional Residential TOU Rate is similar to an approach taken by the three investor-owned utilities in California. As explained by Dr. Sergici and Mr. Hledik:

> "To retain the inclining block structure of the existing rate, the California utilities also use charges and credits. However, they charge customers based on the TOU rate and then provide credits and charges for monthly usage falling within the various tiers of the inclining block rate. In other words, the California utilities use charges and credits to represent the price signals in the tiered rate, whereas BC Hydro uses charges and credits to represent the price signals of the peak and overnight periods in the TOU rate.
>
> In our opinion, both BC Hydro's approach and the California utilities' approach are conceptually pragmatic and reasonable solutions to an important problem. When the existing rate has an inclining block structure, a large number of smaller-than-average customers benefit from the discounted first tier of the rate. If the proposed TOU rate does not retain that usage-based discount, a majority of population is unlikely to experience bill savings by switching to the TOU rate.
>
> BC Hydro's proposed approach is an innovative way to overcome this challenge and improves the overall inclusiveness and customer attractiveness of the rate by providing virtually all customers with an opportunity to reduce their electricity bill once enrolled."[93]

[93] Ibid.

4.2.4 Optional Residential TOU Rate Helps Protect Customers Who Decide Not to Participate

In addition to providing a wide range of BC Hydro customers with the opportunity to save, the design of the Optional Residential TOU Rate also helps protect those customers decide to not participate by limiting the amount participating customers who can save without shifting any of their electricity use out of the On-Peak period.

As mentioned in section 4.2.3 above, the Optional Residential TOU Rate is designed to mitigate the potential for high consumption customers to save without shifting their On-Peak period electricity use to the Off-Peak or Overnight period. This is achieved through the "add-on" design of the Optional Residential TOU Rate which continues to charge the higher step 2 energy charge for consumption above the RIB Rate threshold.

While this approach prevents high consumption customers from achieving savings by simply paying lower time-based energy charges, BC Hydro also reviewed the consumption distribution between the On-Peak period and the Overnight period for customers with different levels of overall consumption.

Table 4-3 below shows how much lower or higher bills could be, on average, compared to the RIB Rate, for customers with different levels of annual consumption, if they participate in the Optional Residential TOU Rate but do not shift any of their electricity use out of the On-Peak period. As shown, because customers' consumption distribution between the On-Peak period and Overnight period is similar across different levels of annual consumption, the bill differences if customers do not shift any of their electricity use out of the On-Peak period are mostly mitigated.

Table 4-3 Consumption Distribution and Energy Charge Comparisons by Annual Consumption Segments Before Shifting

Customer Group	Number of Customers*	Average Annual Bill ($)	On-Peak Period Load %	Overnight Period Load %	Annual Bill Difference ($)
0 - 4,000 kWh	321,265	$329	27.2%	24.4%	$3
4,001 - 8,000 kWh	449,222	$697	26.9%	24.5%	$7
8,001 - 12,000 kWh	337,811	$1,175	26.5%	25.0%	$8
12,001 - 16,000 kWh	208,882	$1,715	25.9%	25.7%	$1
16,001 - 20,000 kWh	114,315	$2,271	25.2%	26.5%	$(11)
20,001 - 30,000 kWh	103,100	$3,107	24.4%	27.5%	$(37)
30,001 - 50,000 kWh	28,320	$4,840	23.3%	29.3%	$(108)
Greater than 50,000 kWh	7,007	$13,798	21.8%	32.3%	$(518)

* Based on fiscal 2022 RIB customers with a full year consumption history

As shown in Table 4-3 above, customers with very high annual consumption tend to have more consumption during the Overnight period. While this means these customers can benefit from the Optional Residential TOU Rate without shifting any of their electricity use out of the On-Peak period, these estimated bill savings reflect differences in their consumption patterns rather than their total level of consumption (i.e., the amount these customers pay for service reflects the time of day when they are consuming electricity).

The Brattle Group has conducted studies to consider whether customers who can save without shifting their electricity use (i.e., “structural winners”) will still respond to time-varying rates. This is an important consideration because if these types of customers respond to the price signals provided by time-varying rates by shifting their consumption, their participation will create benefits for all ratepayers. In an evaluation conducted in September 2020, The Brattle Group found that these customers achieved peak load reductions that were as large as other participants. As stated in that evaluation:

> “We also analyze customers’ response to TOU rates by subgroup. We find that impacts were generally similar… between structural winners and others. The latter finding is particularly important in the sense that customers who would

> observe bill savings on the TOU rates (due to their favorable load profiles) even without changing their usage did not tune out the price signals. On the contrary, they achieved peak load reductions as large as those of other customers who did not have similarly favorable load profiles. This contradicts a commonly held belief that opt-in pilots will only attract "structural winners" and that once on the rate, these customers will not respond to the price signals."[94]

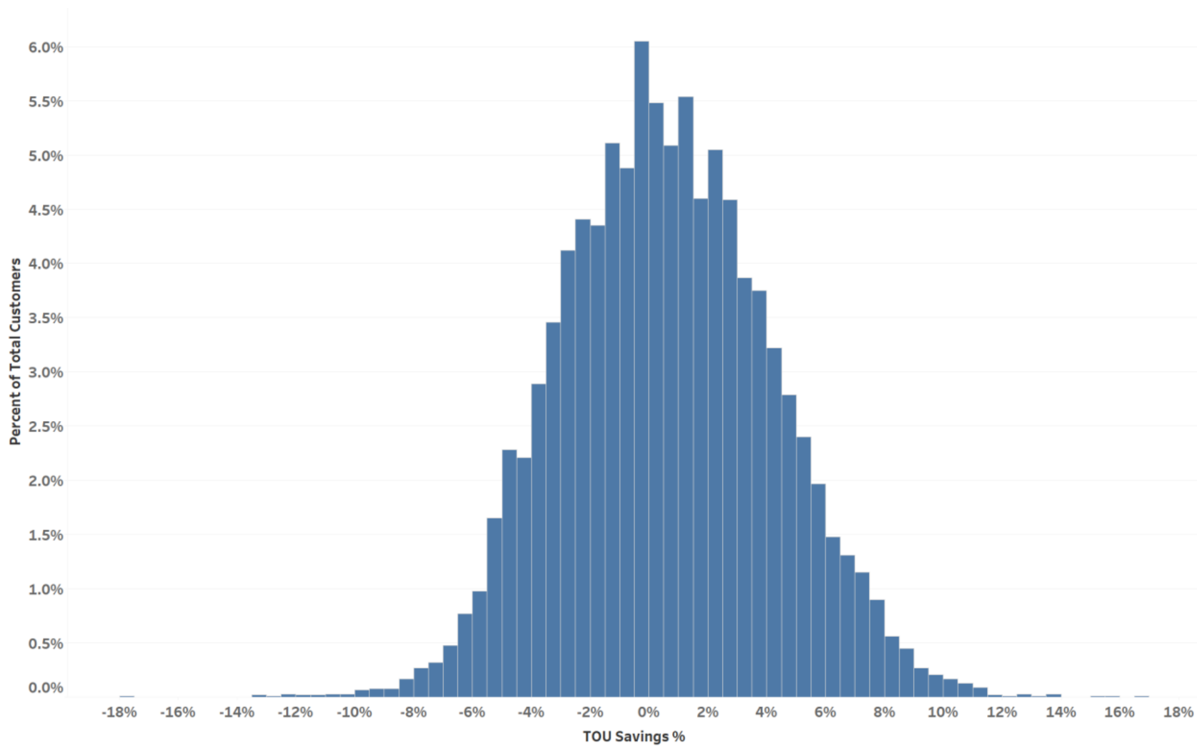
As a final summary, Figure 4-5 below provides a histogram comparing the bill differences between the Optional Residential TOU Rate and the RIB Rate for all customers on the RIB Rate. As shown, because most customers have consumption patterns that closely resemble the average Residential customer pattern, their starting position when enrolling in the Optional Residential TOU Rate, before shifting any electricity use, is relatively bill neutral. Specifically:

- Approximately 41% of customers would pay less than + or - 2% under the Optional Residential TOU Rate compared to the RIB Rate if they did not shift their electricity use;
- Approximately 84% of customers would pay less than + or – 5% under the Optional Residential TOU Rate compared to the RIB Rate if they did not shift their electricity use; and,
- Approximately 99% of customers would pay less than + or - 10% under the Optional Residential TOU Rate if they did not shift their electricity use.

As a result, the Optional Residential TOU Rate enables a wide range of customers to save by participating and helps protect customers who do not participate.

[94] Refer to page v at www.brattle.com/wp-content/uploads/2021/05/19973_pc44_time_of_use_pilots_-_year_one_evaluation.pdf

Figure 4-5 Histogram of Bill Difference Distribution Between Optional Residential TOU Rate and RIB Rate



4.3 Optional Residential TOU Rate Contributes to Meeting Customers' Future Electricity Needs

This section explains how the Optional Residential TOU Rate will contribute to meeting customers' future electricity needs. Consistent with the capacity savings targets set out in BC Hydro's 2021 IRP, which relies more on customer-based solutions over new infrastructure, it will help meet an expected increase in peak demand driven, in part, by electric vehicle adoption.

The capacity savings achieved by the Optional Residential TOU Rate depend on several factors including participation rates and the amount of electricity participants shift out of the On-Peak period to either the Off-Peak period or the Overnight period. To evaluate the potential outcomes from the Optional Residential TOU Rate, BC Hydro developed a Reference Case as well as low and high sensitivities, informed by recommendations, empirical evidence, and jurisdictional review information provided by Dr. Sergici and Mr. Hledik. As mentioned above, Dr. Sergici and Mr. Hledik's review of the Optional Residential TOU Rate concluded "…our review indicates that BC Hydro's assumptions about the potential participation in and load impacts of TOU rates are reasonable and consistent with the available empirical evidence on the subject".[95]

Based on this work, BC Hydro expects the Optional Residential TOU Rate to achieve approximately 135 MW[96] of capacity savings by fiscal 2030 at the customer-meter level, which equates to approximately 100 MW at the system level.[97] Table 4-4 below sets out the Reference Case and low-end and high-end sensitivity inputs. The basis for these inputs is explained further in the sub-sections below.

Table 4-4 Reference Case, Low-End Sensitivity and High-End Sensitivity Inputs

	Reference Case (Fiscal 2030)	Low-End Sensitivity (Fiscal 2030)	High End Sensitivity (Fiscal 2030)
Participants with no electric vehicle (section 4.3.2)	15% of customers expected to save (8% of all customers)	9% of customers expected to save (5% of all customers)	56% of customers expected to save (35% of all customers)
Participants with electric vehicle (section 4.3.3)	50% of customers expected to save and excluding apartments (22% of all customers)	40% of customers expected to save and excluding apartments (15% of all customers)	85% of customers expected to save and excluding apartments (40% of all customers)
% of On-Peak period household load shifted (section 4.3.4)	5%	3%	10%
% of shifted household load to Off-Peak vs. Overnight period (section 4.3.4.3)	50% / 50%	50% / 50%	50% / 50%
Average peak demand from electric vehicle charging (section 4.3.5.1)	1.17 kW	1.17 kW	1.17 kW

95 Appendix F, page 12.

96 Rounded to the nearest five.

97 After accounting for an Effective Load Carry Capacity factor of 66%, as explained in Appendix H-2 of BC Hydro's 2021 Integrated Resource Plan Application and adding 10% line losses.

	Reference Case (Fiscal 2030)	Low-End Sensitivity (Fiscal 2030)	High End Sensitivity (Fiscal 2030)
% of On-Peak period electric vehicle charging load shifted (section 4.3.5.2)	75%	50%	90%
% of shifted electric vehicle charging load to Off-Peak vs. Overnight period (section 4.3.5.3)	20% / 80%	20% / 80%	20% / 80%
% of household consumption reduced but not shifted (Conservation) (section 4.3.6)	0%	4%	0%
Resulting capacity savings at customer-meter level	135 MW	60 MW	415 MW
Resulting capacity savings at the system level[98]	100 MW	45 MW	300 MW

Table 4-5 below summarizes the Reference Case capacity forecast assuming the Optional Residential TOU Rate is offered to customers starting in fiscal 2025 (i.e., starting around April 1, 2024). This forecast reflects a six-year S-shaped participation ramp up period as follows: 10% of assumed participation levels achieved in year 1 (fiscal 2025), 30% in year 2 (fiscal 2026), 60% in year 3 (fiscal 2027), 90% in year 4 (fiscal 2028), 95% in year 5 (fiscal 2029), and 100% in year 6 (fiscal 2030).[99]

98 Ibid.

99 Dr. Faruqui stated that BC Hydro’s 5- to 6-year S-shaped participation ramp-up period is consistent with assumptions he has used in similar studies for other utilities. Refer to page 10, Appendix E (Brattle Report (Exhibit B-3 to 2021 IRP) Capacity Savings Estimates in BC Hydro’s 2021 IRP: An Independent Review).

Table 4-5 Capacity Saving Estimates – Reference Case

Fiscal Year (A)	Forecast Participants with No EV (B)	Forecast Capacity Saving from Participants with No EV (MW) (C)	Forecast Participants with EV (D)	Forecast Capacity Saving from Participants with EV (MW) (E)	Forecast Total Participants (F=B+D)	Forecast Total Capacity Saving (MW) (G=C+E)
F2024	0	0	0	0	0	0
F2025	14,077	2	6,306	6	20,383	8
F2026	41,596	5	20,519	21	62,115	26
F2027	81,251	10	44,616	45	125,867	55
F2028	118,472	15	74,486	75	192,958	90
F2029	120,960	15	95,163	96	216,123	111
F2030	122,464	16	119,051	120	241,515	136
F2031	116,848	15	142,750	144	259,598	159
F2032	110,629	14	168,847	170	279,476	185
F2033	103,729	13	197,463	199	301,192	213
F2034	96,195	12	228,755	231	324,950	243
F2035	87,935	11	262,745	265	350,680	276
F2036	78,856	10	299,464	302	378,320	312
F2037	69,854	9	338,683	342	408,537	351
F2038	60,984	8	379,876	384	440,860	391
F2039	52,295	7	422,036	426	474,331	433

4.3.1 Optional Residential TOU Rate Contributes to Achieving Capacity Savings Set Out in the 2021 Integrated Resource Plan

The Optional Residential TOU Rate is one part of a suite of measures that BC Hydro plans to advance to meet the capacity savings targets in the 2021 Integrated Resource Plan (**2021 IRP**). As shown in Table 4-5 above, based on the assumptions in BC Hydro's Reference Case, the Optional Residential TOU Rate is expected to achieve approximately 135 MW[100] of capacity savings at the customer meter level by fiscal 2030, which equates to approximately 100 MW at the system level.

[100] Rounded to the nearest five.

To develop the capacity savings estimates in the 2021 IRP, BC Hydro combined price elasticity estimates with assumed ratios between the peak and off-peak period prices for time-varying rates.[101] As explained by Dr. Ahmad Faruqui in Capacity Savings Estimates in BC Hydro's 2021 IRP: An Independent Review:

> "I helped BC Hydro develop the per-participant impact assumptions for the time-varying rates, with assistance from Brattle colleagues. Specifically, BC Hydro provided me with the company's assumed price elasticities of participants in the time-varying rate offerings, which I reviewed for reasonableness. Price elasticity is a measure of the extent to which customers will respond to price signals. In the context of BC Hydro's time-varying rates, the elasticity of substitution indicates the extent to which customers will shift their usage from higher price periods (i.e., peak periods) to lower priced periods (i.e., off-peak periods). BC Hydro combined these price elasticity estimates with assumed peak-to-off peak price ratios in the time-varying rates to establish an estimate of capacity savings."[102]

The Base Resource Plan in BC Hydro's 2021 IRP is BC Hydro's strategy to meet the future needs of our customers if future load aligns with our Reference Load Forecast. The Base Resource Plan consists of seven elements and two of those elements correspond to the Optional Residential TOU Rate. This is because the 2021 IRP modeled capacity savings from shifting electric vehicle charging load outside of system peak periods separately from other household load, resulting in two different elements.[103]

The second of seven elements in the Base Resource Plan of the 2021 IRP is to:

> "Pursue voluntary time-varying rates supported by demand response programs to achieve approximately 220 MW of capacity savings at the system level by fiscal 2030, and advance the Industrial Load Curtailment Program to achieve

[101] Refer to BC Hydro's response to BCOAPO IR 2.80.1 in the proceeding to review BC Hydro's 2021 Integrated Resource Plan.

[102] Appendix E, page 11.

[103] For further discussion on this point, refer to BC Hydro's response to AMPC IR 2.14.4 in the proceeding to review BC Hydro's 2021 Integrated Resource Plan.

> approximately 100 MW of incremental capacity savings at the system level by no later than fiscal 2030."[104]

This element and the total capacity savings it targets, includes time-varying rates for Residential, Commercial, and Industrial customers. The Residential time-varying rate portion is approximately 85 MW[105] at the system level, which equates to approximately 115 MW at the customer meter level. BC Hydro plans to meet the Residential portion through the Optional Residential TOU Rate (assumed to be approximately 30 MW[106] at the customer meter level) as well as through a future Residential Critical Peak Pricing rate.

The third element of the Base Resource Plan of the 2021 Integrated Resource Plan is to:

> "Pursue a combination of education and marketing efforts as well as incentives for smart-charging technology for customers to support a voluntary residential time-of-use rate to shift home charging by 50 per cent of residential electric vehicle drivers to off-peak demand periods (50 per cent electric vehicle driver participation) to achieve approximately 100 MW of capacity savings at the system level by fiscal 2030)."[107]

The 100 MW of capacity savings at the system level equates to approximately 170 MW at the customer meter level.[108] BC Hydro plans to meet the total capacity savings targeted by this element through the Optional Residential TOU Rate as well as through our Electric Vehicle Connected Charger rebate offer and our Electric Vehicle Demand Response offer, as set out in our Fiscal 2023 to Fiscal 2025 Demand-Side Management Expenditure Schedule.

---

[104] Refer to page 28, Appendix C (2021 IRP).
[105] Refer to BC Hydro's response to AMPC IR 2.11.1 in the proceeding to review BC Hydro's 2021 Integrated Resource Plan.
[106] Refer to Appendix C, page 30.
[107] Ibid., page 28.
[108] Ibid., page 30.

This Application for the Optional Residential TOU Rate fulfills the following Near-term Action from the 2021 Integrated Resource Plan:

> "BC Hydro will file a Residential Optional Time-of-Use Rates Application in early 2022. This application will include an optional whole home time-of-use rate and an optional end use time-of-use rate pertaining to electric vehicle charging.
> BC Hydro is undertaking customer engagement to inform the development of these rate designs."[109]

As described in section 1.2 in Chapter 1, we were delayed in filing the Residential Optional Time-of-Use Rates Application as outlined as a Near-term Action of the 2021 IRP. Section 4.7.3 below explains how we expect the Optional Residential TOU Rate will achieve better outcomes compared to alternatives and as mentioned above, customers with a separate BC Hydro meter for electric vehicle charging under the same Residential service account may choose to apply the Optional Residential TOU Rate to their electric vehicle charging consumption only, which means there is no need for BC Hydro to offer two separate rates. Table 4-6 below summarizes how the Optional Residential TOU Rate shows how the expected capacity savings from the Optional Residential TOU Rate are consistent with the capacity savings targets set out in the 2021 IRP.

Table 4-6 Optional Residential TOU Rate and Capacity Savings in the 2021 Integrated Resource Plan

Element or Sub-Element in 2021 IRP	Fiscal 2030 Capacity Savings Target System Level (MW)	Fiscal 2030 Capacity Savings Target Customer Meter Level (MW)	Contribution from Optional Residential TOU Rate - Reference Case Customer Meter Level (MW)
Time-varying rates supported by demand-response programs	220	300	

[109] Appendix C, page 58.

Element or Sub-Element in 2021 IRP	Fiscal 2030 Capacity Savings Target System Level (MW)	Fiscal 2030 Capacity Savings Target Customer Meter Level (MW)	Contribution from Optional Residential TOU Rate - Reference Case Customer Meter Level (MW)
Residential portion – TOU & Critical Peak	85	115	30
Shift home charging by residential electric vehicle drivers to Off-Peak demand periods			
50% Participation – Rates and Programs	100	170	105
Total Contribution			**135**

4.3.2 Reference Case Assumes 15% of Customers Without an Electric Vehicle Who Would Be Expected to Save Will Participate in Optional Residential TOU Rate

As set out in Table 4-4 above, the Reference Case assumes that 15% of customers without an electric vehicle who would be expected to save will participate in the Optional Residential TOU Rate.[110] This equates to 8% of customers overall in fiscal 2030. This forecast reflects an S-shaped participation ramp-up period.

For the low-end sensitivity, BC Hydro has assumed 5% of customers without an electric vehicle would participate and for the high-end sensitivity, BC Hydro has assumed 35% of all customers will participate. As explained by Dr. Sergici and Mr. Hledik:

> "The level of enrollment in opt-in residential TOU rates achieved by utilities to-date varies widely. This variation in participation can be attributed to a variety of factors, such as attractiveness of the rate design, the degree of marketing or educational outreach, and the presence or absence of enabling technology such as advance metering infrastructure (AMI)."[111]

[110] This expected to save approach assumes 5% of household load in the On-Peak period is shifted, consistent with the Reference Case assumption set out in section 4.3.4 below.

[111] Appendix F, page 4.

> "BC Hydro assumes that 15% of customers who are expected to experience bill savings on the proposed TOU rate choose to enroll in it. Given that not all customers will benefit from the proposed rate, BC Hydro's assumed participation rate is approximately 8% when expressed as a percentage of the entire residential population (excluding those with an EV, which are addressed separately). BC Hydro's assumption is conservative in this sense, but still broadly consistent with the range of achievable participation rates…We consider a steady state enrollment range of 5% to 35% to be reasonable as upper- and lower-bounds"[112]

The initial basis for the 15% Reference Case assumption was the recommendation from Dr. Ahmad Faruqui which informed the capacity savings estimates in BC Hydro's 2021 IRP. As stated by Dr. Faruqui in Capacity Savings Estimates in BC Hydro's 2021 IRP: An Independent Review:

> "I developed BC Hydro's enrollment assumptions for time-varying rates, with assistance from my Brattle colleagues. The base case enrollment assumptions are 15% for opt-in deployment, and 95% for opt-out deployment (depending on customer class). I developed these estimates through analysis of U.S. Energy Information Administration data on existing utility time-of-use rate offerings… The enrolment assumptions for time-varying rates that I provided to BC Hydro are consistent with the best available industry data and literature on the topic, and supported by my extensive experience designing and evaluating the rate offerings for utilities across North America and internationally."[113]

Table 4-7 below summarizes the Reference Case participation forecast for customers without an electric vehicle over a 15-year period assuming the Optional Residential TOU Rate is offered to customers starting in fiscal 2025 (i.e., starting around April 1, 2024).

[112] Ibid., pages 5-6.
[113] Appendix E, pages 9-10.

Table 4-7 Reference Case Participation Estimate for Customers Without an Electric Vehicle

Fiscal Year (A)	Number of Residential Customers (B)	Number of Customers with no EV (C)	Number of Winners (D)	15% of Winners (E)	Participant Estimate (F)	Participant % of Winners (F/D)	Participant % of All Customers with No EV (F/C)
F2024	1,937,455	1,781,938	948,347	142,252	0	0%	0%
F2025	1,963,798	1,763,325	938,442	140,766	14,077	2%	1%
F2026	1,988,250	1,736,876	924,365	138,655	41,596	5%	2%
F2027	2,010,571	1,696,325	902,784	135,418	81,251	9%	5%
F2028	2,032,932	1,648,952	877,572	131,636	118,472	14%	7%
F2029	2,055,293	1,594,966	848,841	127,326	120,960	14%	8%
F2030	2,077,609	1,534,061	816,427	122,464	122,464	15%	8%
F2031	2,099,100	1,463,706	778,984	116,848	116,848	15%	8%
F2032	2,122,192	1,385,811	737,529	110,629	110,629	15%	8%
F2033	2,145,284	1,299,374	691,527	103,729	103,729	15%	8%
F2034	2,168,376	1,204,993	641,297	96,195	96,195	15%	8%
F2035	2,191,468	1,101,525	586,232	87,935	87,935	15%	8%
F2036	2,214,560	987,805	525,710	78,856	78,856	15%	8%
F2037	2,237,652	875,040	465,696	69,854	69,854	15%	8%
F2038	2,260,744	763,920	406,558	60,984	60,984	15%	8%
F2039	2,283,836	655,079	348,633	52,295	52,295	15%	8%

As shown in the table above, the number of customers without an electric vehicle is forecast to decrease each year as electric vehicle adoption increases.

4.3.3 Reference Case Assumes 50% of Customers With an Electric Vehicle Who Would Be Expected to Save and Excluding Apartments Will Participate in Optional Residential TOU Rate

As set out in Table 4-4 above, the Reference Case assumes that 50% of customers with an electric vehicle who would be expected to save,[114] and excluding apartments,[115] will participate in the Optional Residential TOU Rate. This equates to

[114] This expected to save approach assumes 75% of electric vehicle charging load in the On-Peak period is shifted, consistent with the Reference Case assumption set out in section 4.3.5 below.

[115] Apartments are excluded because BC Hydro expects that customers in apartments have common area parking and would not have electric vehicle charging consumption under their residential service account.

22% of customers with an electric vehicle overall in fiscal 2030. This forecast also reflects an S-shaped participation ramp-up period. For the low-end sensitivity, BC Hydro has assumed 15% of customers with an electric vehicle would participate and for the high-end sensitivity, BC Hydro has assumed 40%. As explained by Dr. Sergici and Mr. Hledik:

> "The information on TOU enrollment among customers with electric vehicles (EVs) is more limited, given that material levels of EV adoption have occurred only recently."[116]

> "Our understanding is that BC Hydro assumes 22% of all EV owners will be enrolled in a TOU rate in 2030. That assumption is consistent with our review of early experience with EV TOU rates in other jurisdictions as described above. We consider a steady-state participation rate ranging from 15% to 40% of EV owners to be achievable upper- and lower-bounds in the long run, based on currently available data."[117]

Table 4-8 below summarizes the Reference Case participation forecast for customers with an electric vehicle over a 15-year period assuming the Optional Residential TOU Rate is offered to customers starting in fiscal 2025 (i.e., starting around April 1, 2024). The forecast of electric vehicle adoption aligns with the electric vehicle stock forecast in BC Hydro's December 2020 Reference Load Forecast and assumes that the total number of electric vehicles for each customer with an electric vehicle is one.

[116] Appendix F, page 5.
[117] Ibid., page 6.

Table 4-8 Reference Case Participation Estimate for Customers With an Electric Vehicle

Fiscal Year (A)	Number of Residential Customers (B)	Number of Customers with EV (C)	Number of Customers Who Can Save with EV and Excluding Apartment (D)	50% of Winners Excluding Apartment (E)[118]	Participant Estimate (F)	Participant % of Winners Excluding Apartment (F/D)[119]	Participant % of All Customers with EV (F/C)
F2024	1,937,455	155,517	97,836	48,918	0	0%	0%
F2025	1,963,798	200,473	126,118	63,059	6,306	5%	3%
F2026	1,988,250	251,374	158,139	79,070	20,519	13%	8%
F2027	2,010,571	314,246	197,692	98,846	44,616	23%	14%
F2028	2,032,932	383,980	241,562	120,781	74,486	31%	19%
F2029	2,055,293	460,327	289,592	144,796	95,163	33%	21%
F2030	2,077,609	543,548	341,946	170,973	119,051	35%	22%
F2031	2,099,100	635,394	399,726	199,863	142,750	36%	22%
F2032	2,122,192	736,381	463,257	231,629	168,847	36%	23%
F2033	2,145,284	845,910	532,162	266,081	197,463	37%	23%
F2034	2,168,376	963,383	606,064	303,032	228,755	38%	24%
F2035	2,191,468	1,089,943	685,683	342,842	262,745	38%	24%
F2036	2,214,560	1,226,755	771,752	385,876	299,464	39%	24%
F2037	2,237,652	1,362,612	857,219	428,610	338,683	40%	25%
F2038	2,260,744	1,496,824	941,652	470,826	379,876	40%	25%
F2039	2,283,836	1,628,757	1,024,651	512,326	422,036	41%	26%

The 50% Reference Case assumption also aligns with the December 2022 Time-of-Use Concept and Pricing Survey by Sentis.[120] Among the electric vehicle drivers and those who have ordered one, 59% responded they are likely to participate in the Optional Residential TOU Rate.

118 BC Hydro assumes among the new electric vehicle owners each year, 50% will take six years opt-in to the Optional Residential TOU Rate, following the six-year S-shaped adoption curve.

119 Because BC Hydro assumes new electric vehicle owners will take six years to opt-in to the Optional Residential TOU Rate, participant percentage will not reach 50% until electric vehicle adoption saturates.

120 Refer to Appendix D-7H.

4.3.4 Reference Case Assumes Average of 5% of Household Load in the On-Peak Period is Shifted to Other Periods

As set out in Table 4-4 above, the Reference Case assumes that participants in the Optional Residential TOU Rate will shift 5% of their household load out of the On-Peak period and to either the Off-Peak period or the Overnight period. For the low-end sensitivity, BC Hydro has assumed 3% is shifted and for the high-end sensitivity, BC Hydro has assumed 10%. There are four steps to these assumptions.

4.3.4.1 Step 1 – On-Peak to Off-Peak and Overnight Price Ratios Influence Load Shifting Response

The first step is to calculate the ratios between the On-Peak price and the Off-Peak price and the On-Peak price and the Overnight price. These ratios can be used to estimate how customers may respond to time-based price signals by shifting their electricity use.

As discussed in section 4.2 above, the Optional Residential TOU Rate is an "add-on" rate where participating customers are still billed for their total electricity usage during a billing period at their existing Residential rate. For most Residential customers, this is the RIB Rate which has a step 1 energy charge of 10.10 cents per kWh for consumption up to a set threshold and a step 2 energy charge of 14.08 cents per kWh for consumption over that threshold.[121]

After being billed at their existing Residential rate, customers will receive a 5-cent credit for each kWh of electricity consumed during the Overnight period (11 p.m. to 7 a.m.) and a 5-cent additional charge for each kWh of electricity consumed during the On-Peak period (4 p.m. to 9 p.m.). No credit or additional charge will be applied to consumption during the Off-Peak period (9 p.m. to 11 p.m. and 7 a.m. to 4 p.m.).

[121] In fiscal 2025 dollars, assuming BC Hydro's Fiscal 2023 to Fiscal 2025 Revenue Requirements Application is approved by the Commission and assuming the Fiscal 2023 Residential Pricing Principles are extended for fiscal 2024 and fiscal 2025.

Table 4-9 below summarizes the energy charges, and resulting price ratios, for the Optional Residential TOU Rate if it is added on to the RIB Rate.

Table 4-9 Energy Charges and Price Ratios of Optional Residential TOU Rate Added on to RIB Rate

Energy Charge	On-Peak Period (¢ / kWh)	Off-Peak Period (¢ / kWh)	Overnight Period (¢ / kWh)	On-Peak to Overnight Price Ratio	On-Peak to Off-Peak Price Ratio
Credit / Charge	+ 5	None	- 5		
Resulting Step 1 Charge	15.10	10.10	5.10	3.0 : 1	1.5 : 1
Resulting Step 2 Charge	19.08	14.08	9.08	2.1 : 1	1.4 : 1

4.3.4.2 Step 2 - Arcturus Database Informed Peak Demand Reduction Estimates

The second step is to use the price ratios set out in Table 4-9 above to estimate how customers may respond to time-based price signals by shifting their electricity use.

Dr. Sergici and Mr. Hledik used the price ratios set out in Table 4-9 above to estimate the amount of household load that customers may shift out of the On-Peak period and into either the Off-Peak period or the Overnight period, in response to the Optional Residential TOU Rate. As explained by Dr. Sergici and Mr. Hledik:

> "The Brattle Group maintains a database of pricing offerings and peak demand reductions achieved in those offerings since 2010. We have published analysis of this database in three journal articles in 2010, 2013, and 2017. We have continued to update the "Arcturus Database" over time, and as of the end of 2022, the database included 410 observations from 80 time-varying pricing pilots and full-scale offerings. Using the observations in this database, we estimated price response curves, which we refer to as "the Arc of Price Responsiveness". The Arc of Price Responsiveness returns an average peak demand reduction estimate for a given peak to off-peak (P/OP) price ratio, for various time-varying rates and availability of enabling technologies. The original Arc of Price Responsiveness estimated an average peak impact using the observations and relationships based on *all* of the pricing treatments in the database regardless of their enrollment mode (opt-in vs opt out) mainly to maximize the number of data points defining the

> relationship between peak impact and the P/OP price ratio. However, as more data points have been added to the database, it became possible to estimate different Arcs that account for different pricing treatments (i.e., TOU, CPP, etc.) and the enrollment mode (opt-in vs. opt-out). We are preparing to publish the results of Arcturus 3.0, which reports these updates and innovations that were implemented since the publication of prior studies.
>
> We relied on this updated Arcturus 3.0 to assist BC Hydro in developing a more precise peak demand impact estimate based on the company's proposed opt-in TOU rate."[122]

Table 4-10 below provides the On-Peak demand reduction estimates from The Brattle Group for each price ratio within the Optional Residential TOU Rate when added on to the RIB Rate.

Table 4-10 On-Peak Demand Reduction by Price Ratio – Optional Residential TOU Rate

	Price Ratio	On-Peak Demand Reduction
Tier 1 (On-Peak/Off-Peak)	1.5	3.5%
Tier 1 (On-Peak/Overnight)	3	9.4%
Tier 2 (On-Peak/Off-Peak)	1.4	2.9%
Tier 2 (On-Peak/Overnight)	2.1	6.4%

4.3.4.3 Step 3 - Reference Case Assumes 50% of On-Peak Consumption Reduction Is Shifted to Off-Peak Period and 50% to Overnight Period

Once the price ratios and corresponding On-Peak consumption reduction estimates are determined, the third step is to estimate how much of the electricity shifted out of the On-Peak period will move to the Off-Peak period and how much will move to the Overnight period. This is because the price ratios vary between those periods and the higher the price ratio, the higher the resulting On-Peak consumption reduction. Once these relative amounts are determined, a blended On-Peak consumption reduction estimate can be calculated. As there is limited empirical evidence on these

[122] Appendix F, page 9.

relative amounts, BC Hydro assumed a 50/50 split. As explained by Dr. Sergici and Mr. Hledik:

> "While there is extensive empirical evidence on the degree to which TOU participants shift their usage out of the peak period, we are not aware of data on the relative share of offsetting load building that occurs in the off-peak versus overnight periods.
>
> For non-EV owners, intuition suggests that some usage would be shifted to both periods. For example, programmable end-uses such as some washers, dryers, dishwashers, or pool pumps could be set to run during the overnight period, when the price is lowest. Other end-uses, such as air-conditioning, would need to be used during off-peak hours, to offset the impacts of load reductions during the peak period.
>
> Accordingly, BC Hydro assumes that, for non-EV owners, half of usage is shifted to the off-peak period and half is shifted to the overnight period. In the absence of empirical studies on the topic and based on the intuition described above, our opinion is that this is a reasonable assumption."[123]

4.3.4.4 Step 4 – Apply Step 1 / Step 2 Consumption Split

Similar to the third step described above, once the price ratios, corresponding On-Peak consumption reduction estimates and relative amounts shifted to the Off-Peak and Overnight periods are determined, the fourth step is to apply a split between step 1 and step 2 energy consumption. This is because the price ratios and corresponding On-Peak consumption reduction estimates vary depending on whether the credit or additional charge of the Optional Residential TOU Rate is being applied to the step 1 energy charge or the step 2 energy charge.

Historically, the proportion of total RIB Rate energy charge revenue received through the step 1 energy charge has ranged from 58% to 63%, with a five-year average of split of 61% at the step 1 energy charge and 39% at the step 2 energy charge.

[123] Ibid., page 8.

Figure 4-6 below shows how the inputs from each of the four steps are combined to calculate an estimate of the amount of household load that participants in the Optional Residential TOU Rate will shift from the On-Peak period and to either the Off-Peak period or the Overnight period. As shown, the resulting estimate is 5.75% which BC Hydro has rounded-down to 5% for use in the Reference Case.

Figure 4-6 Overall On-Peak Period Consumption Reduction Estimate Calculation

Consumption Shifting	Step 1 (61%)		Step 2 (39%)	
	Price Ratios	On–Peak Consumption Reduction	Price Ratios	On–Peak Consumption Reduction
50% to Off–Peak	1.5 : 1	3.5%	1.4 : 1	2.9%
50% to Overnight	3.0 : 1	9.4%	2.1 : 1	6.4%
Blended Average	(3.5% X 50%) + (9.4% X 50%) = 6.45%		(2.9% x 50%) + (6.4% + 50%) = 4.65%	
Overall Blended Average	(6.45% X 61%) + (4.65% X 39%) = 5.75%			

As explained by Dr. Sergici and Mr. Hledik:

> "…BC Hydro assumed that half of the load would be shifted to the off-peak period and the other half would be shifted to the overnight period, for non-EV owners. This implies that the customers respond to the peak/off-peak ratio half of the time and to the peak/overnight ratio the other half of the time. This assumption results in a blended impact of 6.5% for Tier 1, and 4.7% for Tier 2. On average, 61% of the consumption is in Step 1 and 39% of the consumption is in Step 2. Using these ratios in each consumption block, the weighted average is calculated as 5.8%. While this is our best point estimate of the peak impact, based on the range of observations in Arcturus we believe that impacts between 3% and 10% are plausible."[124]

[124] Appendix F, page 10.

4.3.4.5 Overall Blended Average Price Ratio

As a final step, BC Hydro calculated the overall blended average price ratio for household consumption for the Optional Residential TOU Rate, based on the assumptions set out above, to validate whether it was high enough to encourage customers to respond. This calculation is shown Figure 4-7 below.

Figure 4-7 Overall Price Ratio Calculation of Household Load Shifting

Household Consumption Shifting	Step 1 – 61%	Step 2 – 39%
	Price Ratios	
50% to Off-Peak	1.5 : 1	1.4 : 1
50% to Overnight	3.0 : 1	2.1 : 1
Blended Average	(1.5 X 50%) + (3.0 X 50%) = 2.25	(1.4 X 50%) + (2.1 X 50%) = 1.75
Overall Blended Average	(2.25 X 61%) + (1.75 X 39%) = 2.06	

Empirical studies show that the peak to off-peak price ratio (i.e., in this case the blended ratio between the On-Peak period and the Off-Peak period and the Overnight period) should be at least 2:1 to send a price signal that will result in customers shifting load outside of the On-Peak period.[125] At 2.06, the Optional Residential TOU Rate meets this threshold. As explained by Dr. Sergici and Mr. Hledik:

> "From a behavioral standpoint, BC Hydro's proposed price ratios are sufficient for incentivizing TOU participants to shift usage away from the peak period. Generally, we consider a price ratio of at least 2:1 as being necessary in this regard."[126]

4.3.5 Reference Case Assumes Average of 75% of Electric Vehicle Charging Load in the On-Peak Period is Shifted to Other Periods

As set out in Table 4-4 above, the Reference Case assumes that participants with an electric vehicle in the Optional Residential TOU Rate will shift 75% of their

[125] Ahmad Faruqui et al, "2.0: A meta-analysis of time-varying rates for electricity," The Electricity Journal 30 (2017), pages 64-72.

[126] Appendix F, page 8.

electric vehicle charging load out of the On-Peak period and primarily into the Overnight period. For the low-end sensitivity, BC Hydro has assumed 50% is shifted and for the high-end sensitivity, BC Hydro has assumed 90%. There are three steps to these assumptions.

4.3.5.1 Step 1 – Estimate Average Annual Consumption and On-Peak Demand From An Electric Vehicle

The first step is to estimate the average annual consumption and On-Peak demand from an electric vehicle to determine the On-Peak demand amount that the load shifting percentages should be applied against.

For this step, BC Hydro analyzed the consumption behaviours of a sample of Residential customers with separately metered electric vehicle charging to better understand customers' charging behaviours.[127]

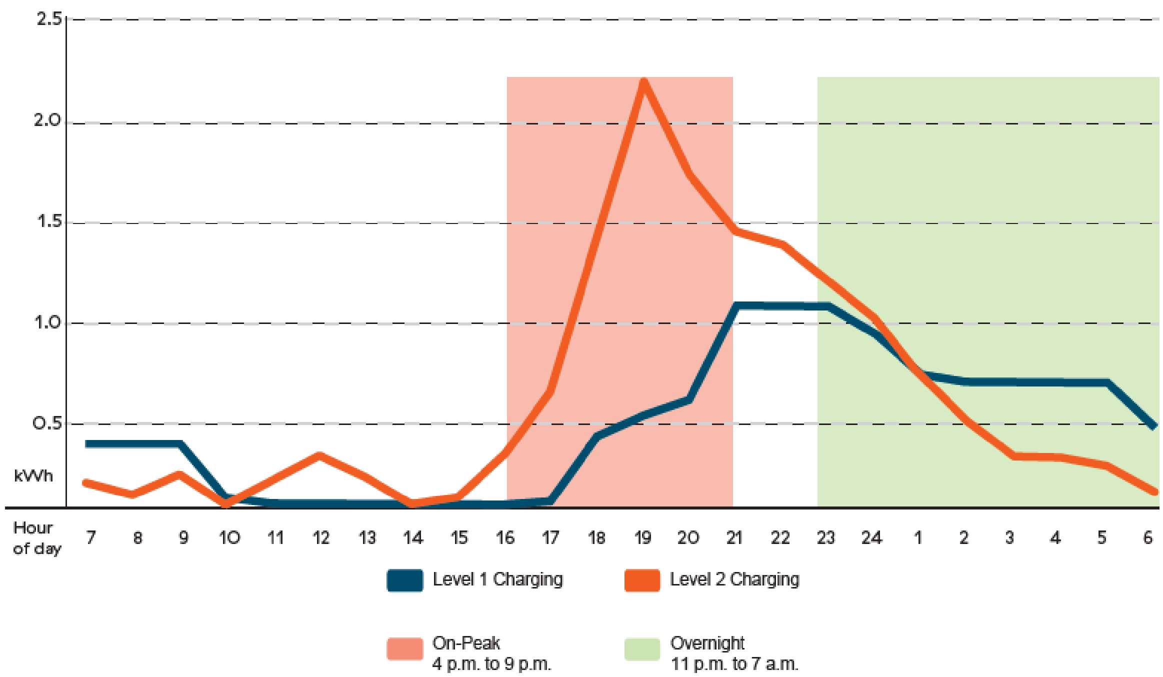
A key factor that influences electric vehicle charging load amounts and patterns is whether a customer is using Level 1 (120 volt) or Level 2 (240 volt) charging. Table 4-11 below summarizes Level 1 and Level 2 charging patterns, and Figure 4-8 below shows the load shape of Level 1 and Level 2 charging on peak days. As shown, Level 2 charging has a much higher impact on the system peak than Level 1 charging.

Table 4-11 Electric Vehicle Charging Pattern

Charging Level	Voltage	Power	Average Range Added per Hour	Time to charge for 100 km drive
Level 1	120 Volt	1-2 kW	6.5 km	15 hours
Level 2	240 Volt	3.8-20 kW	40 km	2.5 hours

[127] 40 Residential customers who indicated they installed a second meter for electric vehicle charging and 12 Residential customers who participated in BC Hydro's electric vehicle charging consumption measurement pilot project conducted in 2020.

Figure 4-8 Electric Vehicle Hourly Load Profile on Peak Days – Level 1 and Level 2



For the analysis provided in this Application, BC Hydro has assumed 50% of customers will charge their electric vehicles using Level 1 (120 volt) charging and 50% of customers will use Level 2 (240 volt) charging. This 50% / 50% distribution represents the approximate average of electric vehicle owners with Level 2 chargers based on the values in BC Hydro's 2020 Residential End Use Study and an October 2021 Survey conducted by Leger[128] which asked customers how they expect they may charge their electric vehicle in the future. The 2020 Residential End Use Study indicates a split of 62% and 38% between Level 1 and Level 2 charging[129] and the November 2021 Leger Survey indicates a split of 37% and 63% between Level 1 and Level 2 charging[130]. To recognize that customers' charging behaviours are likely to evolve over time while also reflecting the current status,

128 Refer to Appendix D-7E.
129 Based on BC Hydro's 2020 Residential End Use Study.
130 Refer to slide 15, Appendix D-7E (Time-of-Use Survey by Leger).

BC Hydro assumed a 50% / 50% split, representing an approximate mid-point between these two indicators.

Table 4-12 below summarizes the electric vehicle load profile statistics developed by BC Hydro to estimate the average electricity consumption from electric vehicle charging in each time period of the Optional Residential TOU Rate, based on the data and assumptions set out above.[131] As shown, the average annual electricity consumption from an electric vehicle is estimated to be 2,790 kWh and approximately 899 kWh (i.e., approximately 32%) of this consumption is estimated to occur during the On-Peak period.

Table 4-12 Electric Vehicle Charging Load Statistics

Time-Period	Level 1	Level 2	Weighted Average	% of Load
Annual Consumption (kWh)	2,177	3,404	2,790	100%
On-Peak (kWh)	525	1,274	899	32%
Overnight (kWh)	1,259	1,399	1,329	48%
Off-Peak (kWh)	393	731	562	20%

After estimating the average electricity consumption from electric vehicle charging load for each time-period of the Optional Residential TOU Rate, BC Hydro used this average charging pattern to estimate the capacity savings from shifting electric vehicle charging load outside of the On-Peak period during the four winter months (November, December, January, and February), when BC Hydro would be expected to experience its system peak.[132]

Table 4-13 below shows the estimated monthly coincidental peak and average coincidental peak across all four months of the previous winter from an average electric vehicle charging load (i.e., the amount of electric vehicle charging load that

[131] Due to the relatively small sample size and unknown population distribution, BC Hydro used bootstrapping with mean-per-unit estimation technique to develop the electric vehicle charging load profile for Level 1 and Level 2 charging. This approach involves pulling sample data repeatedly to create a pseudo-population and draw samples of size from the created population. A sample distribution for each hourly load is simulated as the number of samples becomes larger. The mean for each hourly load is then calculated to derive an average hourly profile.

[132] This approach is consistent with the methodology of our Fully Allocated Cost of Service Studies.

would occur at the same time that the BC Hydro system is experiencing its peak demand).

Table 4-13 Estimated Monthly Electric Vehicle Coincidental Peak

November 2021	December 2021	January 2022	February 2022	Average
0.85 kW	1.09 kW	1.53 kW	1.21 kW	1.17 kW

The average amount of 1.17 kW in Table 4-13 above represents the average On-Peak demand that the load shifting percentages in the Reference Case, low-end sensitivity and high-end sensitivity, should be applied against.

4.3.5.2 Step 2 - Reference Case Assumes 75% Electric Vehicle Charging Load Is Shifted Out of the On-Peak period

The second step is to apply the load shifting percentages in the Reference Case, low-end sensitivity and high-end sensitivity against the average On-Peak demand of 1.17 kW calculated in Step 1 above.

Empirical research indicates that electric vehicle charging load is highly responsive to time-of-use rates.[133] As explained by Dr. Sergici and Mr. Hledik:

> "BC Hydro assumes that, on average, TOU participants with an EV will reduce their peak period EV charging load by approximately 75%. A pilot study in San Diego found that participants in TOU rates for EV charging provided peak usage reductions that are generally consistent with this range. We generally consider 50% and 90% to be a reasonable range for EV charging load shifting, and BC Hydro's assumption falls into this range."[134]

As set out in Table 4-4 above, the Reference Case assumes that participants with an electric vehicle in the Optional Residential TOU Rate will shift 75% of their electric vehicle charging load out of the On-Peak period and primarily into the Overnight period. For the low-end sensitivity, BC Hydro has assumed 50% is shifted

[133] https://sepapower.org/resource/residential-electric-vehicle-time-varying-rates-that-work-attributes-that-increase-enrollment/

[134] Appendix F, page 11.

and for the high-end sensitivity, BC Hydro has assumed 90%. Table 4-14 below calculates the On-Peak demand reduction per electric vehicle under each of these assumptions.

In the December 2022 Time-of-Use Concepts and Pricing Survey by Sentis[135], the majority (83%) of electric vehicle owners and those who would order one also said they would be able to charge their electric vehicle during the Overnight period.

Table 4-14 On-Peak Demand Reduction per Electric Vehicle

Input	Reference Case	Low-End Sensitivity	High-End Sensitivity
Average On-Peak Demand	1.17 kW		
Load Shifting %	75%	50%	90%
Resulting Average On-Peak Demand Reduction	0.88 kW	0.59 kW	1.05 kW

4.3.5.3 Step 3 - Reference Case Assumes 20% of Peak Demand Reduction Is Shifted to Off-Peak Period and 80% to Overnight Period

The third step is to estimate how much of the electric vehicle charging load shifted out of the On-Peak period will move to the Off-Peak period and how much will move to the Overnight period. As explained by Dr. Sergici and Mr. Hledik:

> "For EV owners BC Hydro assumes that, of the consumption shifted, 80% will be shifted to the overnight period and 20% will be shifted to the off-peak period. EV charging can be conveniently programmed to occur during the overnight period, so it is logical that a greater share of the shifted peak period usage would occur during the lowest-priced overnight period than for non-EV owners. At the same time, we would expect some portion of the shifted load to occur during the off-peak period, due to diversity in the driving patterns and associated charging needs of residential customers. For these reasons, our opinion is that BC Hydro's EV TOU load shifting assumptions described above are reasonable."[136]

135 Refer to Appendix D-7H.
136 Refer to Appendix F, pages 8-9.

4.3.5.4 Overall Blended Average Price Ratio

As in section 4.3.4.5 above, as a final step, BC Hydro calculated the overall blended average price ratio for electric vehicle charging consumption for the Optional Residential TOU Rate to validate whether it was high enough to encourage customers to respond. This calculation is shown in Figure 4-9 below.

Figure 4-9 Overall Price Ratio Calculation of Electric Vehicle Charging Load Shifting

Electric Vehicle Charging Consumption Shifting	Step 1 – 61%	Step 2 – 39%
	Price Ratios	
20% to Off-Peak	1.5 : 1	1.4 : 1
80% to Overnight	3.0 : 1	2.1 : 1
Blended Average	(1.5 X 20%) + (3.0 X 80%) = 2.70	(1.4 X 20%) + (2.1 X 80%) = 1.96
Overall Blended Average	(2.70 X 61%) + (1.96 X 39%) = 2.41	

As mentioned above, a pilot San Diego found that participants in TOU rates for electric vehicle charging provided peak demand reductions that were generally consistent with the 75% reduction assumed by the Reference Case. The price ratios in this case ranged from 2 : 1 to 4 : 1.[137] The price ratio for electric vehicle charging load for the Optional Residential TOU Rate, based on the assumptions set out above, falls within this range at 2.41 : 1.

4.3.6 Reference Case Assumes No Energy Conservation in Response to Optional Residential TOU Rate

A final consideration is whether customers will respond to the Optional Residential TOU Rate by simply reducing energy consumption during the On-Peak period, without shifting that consumption to either the Off-Peak period or the Overnight period. In other words, whether the Optional Residential TOU Rate result in overall energy conservation. For example, participating customers may respond to the Optional Residential TOU Rate by turning off lights during the On-Peak period. In

[137] Appendix F, page 11.

this case, the reduced load in the On-Peak period would not be expected to be shifted to either the Off-Peak period or the Overnight period.

As set out in Table 4-4 above, the Reference Case assumes 0% energy conservation. For the low-end sensitivity, BC Hydro has assumed 4% energy conservation during the On-Peak period in response to the Optional Residential TOU Rate and for the high-end sensitivity, BC Hydro has maintained the Reference Case assumption of 0% energy conservation. As explained by Dr. Sergici and Mr. Hledik:

> "Virtually every empirical assessment of the load impacts of TOU rates has concluded that customers shift usage away from the peak period when enrolled in a TOU rate. However, the evidence on whether TOU rates result in an overall reduction in usage is inconclusive. Recent TOU pilots have quantitatively analyzed the conservation effect and concluded that it did not exist. In other words, in those studies, virtually all of the usage that was reduced during the peak period was shifted to the off-peak or overnight period. For example, Brattle's evaluation of the load impacts of Ontario's full-scale residential TOU rate transition did not identify any conservation effect. Alternatively, some studies have identified a statistically significant "conservation effect" of TOU rates. For example, a survey of TOU offerings prior to 2005 identified a range of conservation effects which average to approximately 4% energy savings across the studies.
>
> As a general matter, given uncertainty regarding the TOU conservation effect, we consider BC Hydro's base assumption that there is no conservation effect to be reasonable. This is particularly true for customers with EVs, who simply would set their timers to charge during non-peak hours. Through conversations with BC Hydro we understand that the company also has analyzed the impact of a modest conservation effect for customers without EVs through sensitivity analysis, which we consider to be a reasonable approach given the uncertainty in the available information on this topic."[138]

[138] Appendix F, page 6.

4.4 Optional Residential TOU Rate Provides Bill Savings to Encourage Customers to Shift Their Electricity Consumption

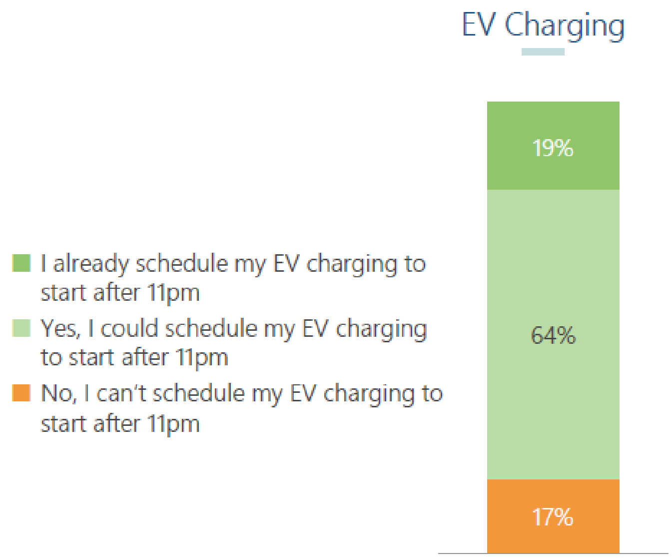
The Optional Residential TOU Rate provides bill savings to encourage customers to shift their electricity consumption from BC Hydro's system peak period to other hours of the day. For example, and as discussed further below, participating customers with an electric vehicle could save an average of $44 per year and up to $250 per year. Customers in electrically heated single-detached homes could save approximately $40 per year on average.

Under the Optional Residential TOU Rate, if a customer can shift some of their electricity usage such as electric vehicle charging, dishwashing or clothes washing and drying out of the On-Peak period, they can save 5 cents for each kWh shifted to the Off-Peak period and 10 cents (i.e., the avoided 5-cent additional charge plus the 5-cent credit) for each kWh shifted to the Overnight period.

In the December 2022 Time-of-Use Concepts and Pricing Survey by Sentis,[139] 27% of electric vehicle owners said they currently charge their electric vehicle during the On-Peak period. As mentioned in section 4.3.5.2 above, 83% of electric vehicle owners and those who plan to purchase an electric vehicle indicated that they could shift their electric vehicle charging to Overnight period.

[139] Refer to Appendix D-7H.

Figure 4-10 Customers' Ability to Shift Electric Vehicle Charging to Overnight Period



In addition, 18% of customers indicated they do laundry and 41% of customers indicated they do dishwashing during the On-Peak period. Customers generally demonstrated flexibility when it comes to laundry and dishwashing routines with 74% and 67% respectively saying they could shift these activities to the Off-Peak period, as shown in Figure 4-11 below. When considering only those customer respondents who indicated they would "definitely choose to add the [Optional Residential] TOU Rate", 91% say they can shift laundry and dishwashing from the On-Peak period to the Off-Peak period.

Figure 4-11 Customers' Ability to Shift Electricity Use Loads to Off-Peak Period

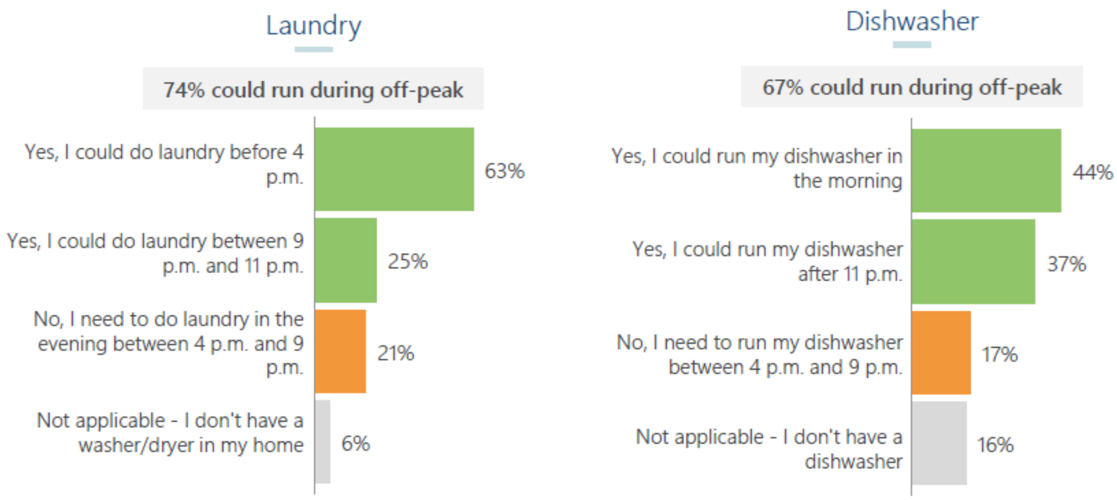


Figure 4-12 below provides some illustrative savings estimates for a few consumption shifting scenarios. Customers' individual bill savings will depend on their individual consumption behaviours.

Figure 4-12 Illustrative Consumption Shifting Scenarios

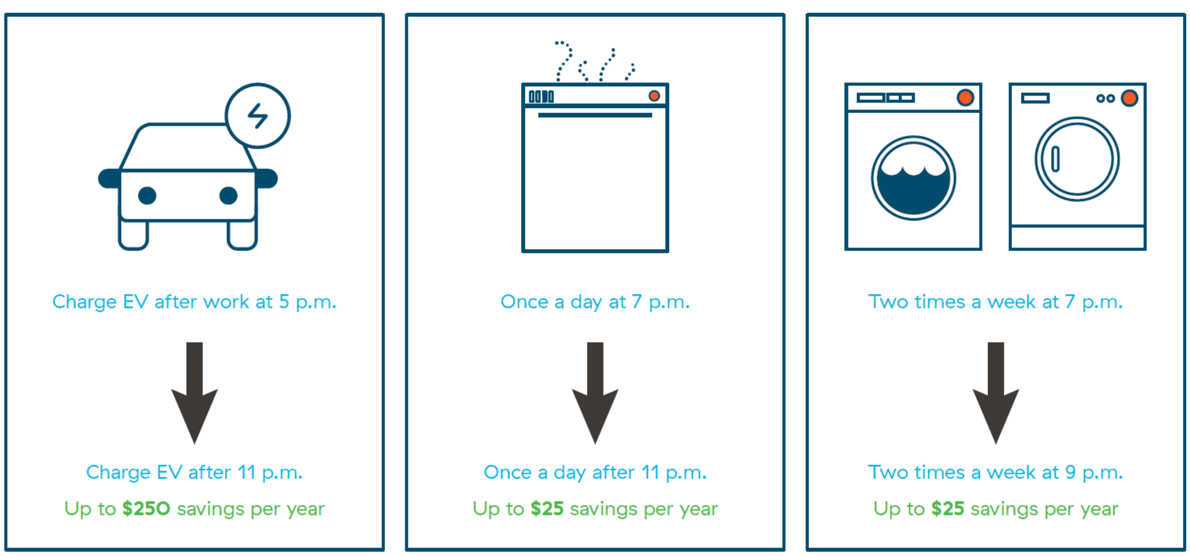


Table 4-15 below shows the estimated household load and electric vehicle charging load shifting bill savings estimates by housing and heating type and Table 4-16 below shows the same bill savings estimates by annual consumption segments. These estimates reflect the Reference Case assumptions set out in section 4.3 above.

Table 4-15 Estimated Bill Savings by Housing and Heating Type

Customer Group	Number of Customers	Average Annual Consumption (kWh)	Average Annual Bill ($)	Estimated Annual Household Load Saving ($)	Estimated Annual 2,790 kWh EV Load Saving ($)
Electrically heated					
Apartment	293,182	5,469	$670	$(5)	$(44)
Single-detached home	252,326	17,318	$2,236	$(43)	$(44)
Rowhome	88,231	11,177	$1,384	$(9)	$(44)
Manufactured home	13,218	12,966	$1,640	$(36)	$(44)
Other	12,482	18,249	$2,378	$(76)	$(44)
Non-electrically heated					
Apartment	141,258	3,115	$399	$2	$(44)
Single-detached home	644,710	10,991	$1,360	$(8)	$(44)
Rowhome	69,100	6,786	$810	$4	$(44)
Manufactured home	46,326	9,377	$1,151	$(9)	$(44)
Other	9,089	9,290	$1,230	$(41)	$(44)

Table 4-16 Estimated Bill savings by Annual Consumption

Customer Group	Number of Customers	Average Annual Consumption (kWh)	Average Annual Bill ($)	Estimated Annual Household Load Saving ($)	Estimated Annual 2,790 kWh EV Load Saving ($)
0 - 4,000 kWh	321,265	2,441	$329	$1	$(44)
4,001 - 8,000 kWh	449,222	5,961	$697	$1	$(44)
8,001 - 12,000 kWh	337,811	9,868	$1,175	$(2)	$(44)
12,001 - 16,000 kWh	208,882	13,813	$1,715	$(12)	$(44)
16,001 - 20,000 kWh	114,315	17,789	$2,271	$(28)	$(44)
20,001 - 30,000 kWh	103,100	23,744	$3,107	$(59)	$(44)
30,001 - 50,000 kWh	28,320	36,027	$4,840	$(139)	$(44)

Customer Group	Number of Customers	Average Annual Consumption (kWh)	Average Annual Bill ($)	Estimated Annual Household Load Saving ($)	Estimated Annual 2,790 kWh EV Load Saving ($)
Greater than 50,000 kWh	7,007	98,403	$13,798	$(598)	$(44)

As shown in Table 4-15 and Table 4-16 above, all customers can achieve meaningful savings if they own an electric vehicle and shift their electric vehicle charging load out of the On-Peak period. Meaningful savings opportunities are also available, on average, for customers without an electric vehicle, in single-detached homes with electric heat.

Savings for customers living in apartments and rowhomes or with low annual consumption are more limited if the Reference Case assumption of 5% of On-Peak load being shifted evenly to the Off-Peak and Overnight periods is applied. However, this assumption is an average and individual customers can save more than shown above if they can reduce their On-Peak period consumption by more than 5%.

4.5 Optional Residential TOU Rate Sends Price Signals That Reflect Cost of Service and Provides Benefits to All Customers Across a Range of Potential Outcomes

The Optional Residential TOU Rate sends price signals that reflect the cost of service and is expected to provide benefits to all customers across a range of potential outcomes.

4.5.1 Pricing for Optional Residential TOU Rate Reflects Embedded and Marginal Cost of Service

The Optional Residential TOU Rate is priced to reflect the embedded and marginal cost of providing electricity service to customers.

Embedded cost refers to the costs that make up BC Hydro’s existing revenue requirement. Rates that are aligned with the embedded cost of service result in a fair allocation of costs between customer classes. As discussed in section 4.5.1.1 below, BC Hydro considered embedded costs to determine that 5-cents per kWh was the appropriate credit to be applied to consumption during the Overnight period.

Marginal cost refers to the change in cost associated with a change in the quantity of production. Rates that are aligned with the marginal cost of service send price signals that encourage the efficient use of the electricity system. As discussed in section 4.5.1.2 below, BC Hydro considered marginal costs to validate that a 5-cents per kWh additional charge, applied to consumption during the On-Peak period, was reflective of the cost to serve an additional kWh of electricity consumption during that period.

While it is important to design rates that align with the cost of service, other considerations are also important such as ease of understanding, public acceptability, rate stability, and revenue sufficiency. As Dr. Sergici and Mr. Hledik explain:

> "The overarching principle of TOU rate design is cost reflectivity. Specifically, TOU rates should be designed to reflect the utility's underlying cost structure. The TOU pricing periods (peak, off-peak, and overnight) divide the day into clusters of hours when costs are relatively higher or lower than the other hours. The prices in each period are then set to reflect the cost of serving customer load in those hours.
>
> A cost-reflective rate promotes economic efficiency and fairness by ensuring that customers are generally charged based on the true cost of their consumption behavior, with an opportunity to reduce their electricity bill by shifting usage to lower cost periods of the TOU rate.
>
> However, TOU rate design also requires balancing the principle of cost reflectivity with other important considerations… simplicity (ease of understanding), public acceptability (rate design features that appeal to potential participants), rate stability (minimizing sudden dramatic changes in customer bills), and revenue sufficiency (a rate that yields the utility's revenue requirement).

> To balance the principle of cost reflectivity with these other objectives, it is typically necessary to depart from a purely cost-reflective rate design. This is particularly the case when setting the “price ratio” of a TOU rate…It is standard practice for utilities to use costs as a general guide for establishing price ratios, rather than as a strict determinant of the ratios.
>
> Therefore, within reason, it is appropriate for the TOU price ratio to be guided by, but deviate from, the precise ratio implied by a literal interpretation of the utility’s costs. Behavioral considerations must be accounted for in the rate’s design, in order to ensure that the rate is attractive to potential participants and satisfies important criteria beyond cost reflectivity.”[140]

As explained in the sub-sections below, the 5-cent per kWh credit and additional charge of the Optional Residential TOU Rate is generally cost reflective while balancing these other important rate design considerations.

4.5.1.1 5-Cent Overnight Period Credit Recovers Embedded Energy Cost

As Dr. Sergici and Mr. Hledik explain in the section above, the On-Peak, Off-Peak, and Overnight periods of the Optional Residential TOU Rate divide the day into clusters of hours when costs are relatively higher or lower than the other hours. The prices in each period are then set to reflect the cost of serving customer load in those hours.

BC Hydro uses our fully allocated cost of service studies[141] to provide unitized estimates of average embedded:

[140] Appendix F, pages 3-4.

[141] BC Hydro uses an embedded cost approach for our fully allocated cost of service methodology. The fully allocated cost of service methodology used by BC Hydro is the same methodology we have used since 2016 in our annual fully allocated cost of service study submissions to the Commission, in accordance with Commission Order No. G-47-16. This methodology was also used to demonstrate the cost of service justification for the two new optional rates proposed in BC Hydro’s Fleet Electrification Rates Application, approved by Commission Order No. G-67-20. The embedded cost approach is a widely accepted cost of service study approach that many Canadian utilities have adopted including BC Hydro, FortisBC, Manitoba Hydro, Hydro Quebec, Hydro One, New Brunswick Power, Newfoundland Power, Nova Scotia Power, and SaskPower.

- **Energy-related costs (¢/kWh):** costs that vary with the amount of energy provided;
- **Demand-related costs ($/kW-year):** costs that vary with the kilowatt demand imposed by the customer; and,
- **Customer-related costs ($/account-year):** costs that are directly related to the number of customers served.

BC Hydro considered these unitized estimates of embedded costs to determine that 5-cents per kWh was the appropriate credit to be applied to consumption during the Overnight period. As mentioned in section 4.5.1 above, embedded cost refers to the costs that make up BC Hydro's existing revenue requirement and rates that are aligned with the embedded cost of service result in a fair allocation of costs between customer classes. Accordingly, embedded cost is the appropriate perspective to consider when assessing whether the energy charge collected for consumption during the Overnight period is sufficient and protects customers who do not participate.

As mentioned in section 4.2.1 above, the Overnight period corresponds to times when system usage is lowest. Accordingly, under a time-of-use rate, charges for electricity consumption during the Overnight period should recover energy-related costs and make a contribution towards customer-related costs. However, it is not necessary for the Overnight period energy charge to cover demand-related costs because generally, since system usage is lowest during the Overnight period, demand-related costs would not increase as a result of additional consumption during that time.

As discussed in section 4.2.2 above, the Optional Residential TOU Rate is an "add-on" rate where customers are still billed for their total electricity usage during a billing period at their existing Residential rate. For most Residential customers, this is the RIB Rate, which has a step 1 energy charge of 10.10 cents per kWh for consumption up to a set threshold and a step 2 energy charge of 14.08 cents per kWh for consumption over that threshold.[142] After being billed at their existing Residential rate, customers enrolled in the Optional Residential TOU Rate will receive a 5-cent credit for each kWh of electricity consumed during the Overnight period and a 5-cent additional charge for each kWh of electricity consumed during the On-Peak period.

BC Hydro selected a 5-cent credit for the Overnight period (instead of a higher or lower amount) so that the energy charge paid by customers on the Optional Residential TOU Rate would be high enough to recover BC Hydro's embedded energy-related cost and make a contribution to customer-related costs while maximizing the amount of bill savings provided to participating customers.

Based on BC Hydro's Fiscal 2020 Fully Allocated Cost of Service Study[143], the average embedded energy cost is approximately 3.96 cents per kWh, which is approximately 4.10 cents per kWh when escalated to fiscal 2025 dollars.[144] With a 5-cent credit, the Overnight period energy charge will be at least 5.10 cents per kWh in fiscal 2025 dollars when the Optional Residential TOU Rate is added on to the RIB Rate (i.e., the step 1 energy charge of 10.10 cents per kWh minus 5 cents per kWh = 5.10 cents per kWh). This means that the 5-cent credit is close to the upper-limit of bill savings that can be provided to customers while still recovering the average embedded energy cost and making a contribution to customer-related costs.

Accordingly, BC Hydro considers the 5-cent per kWh credit of the Optional Residential TOU Rate to be generally cost reflective while also considering the need to provide meaningful bill savings to participating customers. In addition, as

[142] In fiscal 2025 dollars, assuming BC Hydro's Fiscal 2023 to Fiscal 2025 Revenue Requirements Application is approved by the Commission and assuming the Fiscal 2023 Residential Pricing Principles are extended for fiscal 2024 and fiscal 2025.

[143] The Fiscal 2020 Fully Allocated Cost of Service Study was selected as a reference to avoid considering time-limited impacts from the COVID-19 pandemic.

[144] Assuming a 2% per year inflation rate.

discussed further in section 4.6 below, the symmetrical nature of the credit and additional charge is simple and supports customer understanding. As Dr. Sergici and Mr. Hledik explain:

> "In the overnight period, the 5 cents/kWh credit results in customers paying a price of 5.1 cents/kWh when in Step 1 of the RIB rate. According to the company's 2021 Fully Allocated Cost of Service Study, BC Hydro's embedded energy cost is approximately 4 cents/kWh, so the overnight period price generally aligns with this estimate of the minimum cost of serving residential load."[145]

4.5.1.2 5-Cent On-Peak Period Charge Largely Reflects Marginal Costs

As mentioned in section 4.2.2 above, the average Residential customers' consumption during the On-Peak period is approximately the same as the Overnight period at approximately 26% each. Accordingly, to collect sufficient revenue, a corresponding 5 cents per kWh additional charge is added to consumption during On-Peak period. As Dr. Sergici and Mr. Hledik explain:

> "The 5 cents/kWh peak period charge was determined to maintain revenue neutrality (i.e., to produce incremental peak period revenue that offsets the revenue loss associated with the overnight period credit). By equalling the overnight period discount, the peak charge has the advantage of simplicity, which facilitates ease of understanding among participants."[146]

BC Hydro considered marginal costs to validate that a 5-cents per kWh additional charge, applied to consumption during the On-Peak period, was reflective of the cost to serve additional kWh of electricity consumption during that period. As mentioned in section 4.5.1 above, marginal cost refers to the change in cost associated with a change in the quantity of production. The objective of the Optional Residential TOU Rate is to change the amount of consumption during the On-Peak period.

[145] Appendix F, pages 7-8.
[146] Ibid., page 8.

Accordingly, marginal cost is the appropriate perspective to consider when validating whether the 5-cents per kWh additional charge is cost reflective.

BC Hydro's marginal costs are set out in Appendix L of our 2021 IRP Application, as follows:

- BC Hydro's generation capacity long-run marginal cost is set at $109/kW-year, in fiscal 2022 dollars.[147] It considers costs associated with the delivery of energy and capacity along with the bulk transmission system but does not include non-bulk transmission or distribution delivery costs;[148]
- BC Hydro's non-bulk transmission and distribution marginal cost is set at $65/kW-year, in fiscal 2022 dollars. This reflects the annual cost that BC Hydro incurs to serve additional kilowatt demand on our non-bulk transmission and distribution systems;[149] and,
- BC Hydro's generation energy long-run marginal cost is set at $65/MWh, in fiscal 2022 dollars.[150] These marginal costs and their timing are summarized in Figure 4-13 below. As shown, the generation capacity and energy long-run marginal costs represents a value of capacity and energy during times of deficit while the non-bulk transmission and distribution marginal cost applies over the entire planning period. This is because investments in the BC Hydro's non-bulk transmission and distribution system do not vary based on whether the generation system is in a state of surplus or deficit.

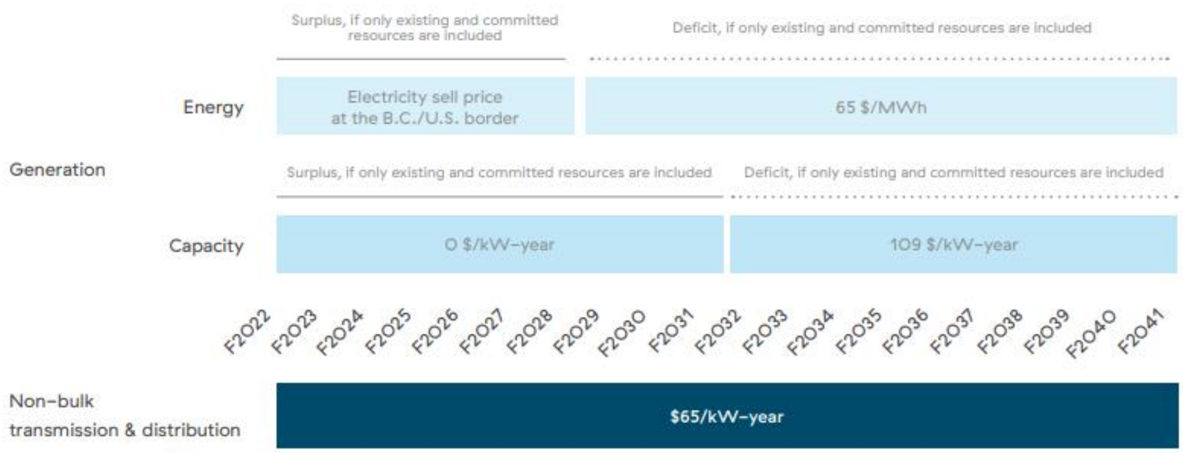
[147] Refer to section 2.2.5 in Appendix L (2021 IRP Application), https://docs.bcuc.com/Documents/Proceedings/2021/DOC_65194_B-1-BCH-IntegratedResourcePlan-Public.pdf.

[148] The inter-regional bulk transmission system in the 2021 IRP refers to those transmission paths between the 2021 IRP regions. The non-bulk transmission and distribution system refers to those wire systems within the 2021 IRP regions.

[149] Refer to section 3 in Appendix L (2021 IRP Application).

[150] Ibid., Appendix L, section 2.1.5.

Figure 4-13 BC Hydro's Reference Prices (Fiscal 2022 $)



A cost-based On-Peak period price would reflect the capacity and energy long-run marginal cost and the non-bulk transmission and distribution reference price. The On-Peak period price for the Optional Residential TOU Rate is billed on a per kWh basis. The energy long-run marginal cost is also set on a per kWh basis. However, the capacity long-run marginal cost and non-bulk transmission and distribution reference price are on a kW-year basis. To convert kW-year values to kWh values, the kW-year values need to be divided by (i.e., allocated across) the number of hours per year in the On-Peak period. The total number of hours in the On-Peak period is 1,825.

Figure 4-14 below calculates the allocation of marginal costs to the On-Peak period, in fiscal 2025 dollars. As shown, the result is 17.02 cents per kWh.

Figure 4-14 Calculation of On-Peak Marginal Capacity and Energy Cost per kWh

Non-bulk transmission and distribution marginal cost		Generation capacity long-run marginal cost		Energy long-run marginal cost
$65/kW-year (Fiscal 2022 – Fiscal 2038)		$109/kW-year (Fiscal 2032 – Fiscal 2038)		6.50 ¢ / kWh (Fiscal 2029 – Fiscal 2038)
↓		↓		↓
$68.98 (Fiscal 2025 dollar)		$115.67 (Fiscal 2025 dollar)		6.90 ¢ / kWh (Fiscal 2025 dollar)
÷		÷		
1,825 On-Peak hours		1,825 On-Peak hours		↓
3.78 ¢ / kWh (Fiscal 2025 dollar)	+	6.34 ¢ / kWh (Fiscal 2025 dollar)	+	6.90 ¢ / kWh (Fiscal 2025 dollar)
	=	17.02 ¢ per kWh		

The step 1 energy charge of 10.10 cents per kWh plus the 5-cent On-Peak period charge equals 15.10 cents per kWh and the step 2 energy charge of 14.08 cents per kWh plus the 5-cent On-Peak period charge equals 19.08 cents per kWh.[151] The blended On-Peak period charge, using the overall step 1 / step 2 consumption split for the RIB Rate of 61% step 1 and 39% step 2 is 16.65 cents per kWh.

The 17.02 cents per kWh marginal cost estimate falls between these two On-Peak period energy charges under the Optional Residential TOU Rate and is close to the blended charge, validating that the 5-cent per kWh additional charge applied to consumption during the On-Peak period is generally reflective of the cost to serve an additional kWh of electricity consumption during that period. Dr. Sergici and Mr. Hledik explain the same point in their review (using fiscal 2022 dollars instead of fiscal 2025 dollars). They state:

> "BC Hydro's marginal costs are consistent with the proposed peak charge. According to Appendix L of the company's 2021 IRP, BC Hydro's long run marginal capacity cost is $109/kW-yr and its non-bulk transmission and distribution reference price is

[151] In fiscal 2025 dollars, assuming BC Hydro's Fiscal 2023 to Fiscal 2025 Revenue Requirements Application is approved by the Commission and assuming the Fiscal 2023 Residential Pricing Principles are extended for fiscal 2024 and fiscal 2025.

> $65/kW-yr (in 2022 dollars). Summing and dividing those costs by 1,825 peak period hours of the year and adding the company's marginal energy cost of $65/MWh produces peak period-related marginal costs of 16 cents/kWh.[152] That marginal cost estimate falls within BC Hydro's implied peak period price of between 14.5 cents/kWh (tier 1) and 19.08 cents/kWh (tier 2)."[153]

As the Optional Residential TOU Rate is intended to achieve capacity savings by shifting On-Peak period consumption to other periods rather than by reducing overall consumption, BC Hydro also considered whether to use the embedded energy cost of 4.10 cents per kWh, rather than the energy long-run marginal cost of 6.90 cents per kWh, to validate whether the On-Peak period energy charges are cost reflective. Applying the 2.80 cents per kWh difference between these two values to the 17.02 cents per kWh marginal cost estimate results in an estimate of 14.22 cents per kWh, which is is also close to the blended On-Peak period charge of 16.65 cents per kWh.[154]

4.5.2 Optional Residential TOU Rate Has a Cost of Service and Economic Justification

The Commission has previously determined that, to be justified, a rate must have a cost-of-service justification or economic justification.[155] The Optional Residential TOU Rate has both and these justifications remain relatively consistent across the

---

152 In fiscal 2022 dollars.

153 Appendix F, page 9.

154 BC Hydro submits that the On-Peak charges remain appropriate under this perspective even though 14.22 cents per kWh is outside the range of 15.10 cents per kWh and 19.08 cents per kWh, set out above, because they reflect design features intended to improve customer understanding and acceptance. Specifically, the symmetrical 5-cent credit and additional charge design means it is not possible to price the On-Peak charges so that they are precisely cost-reflective and the year-round applicability of the Optional Residential TOU Rate means that the costs allocated to the On-Peak period are divided across a greater number of hours, reducing the per kWh cost. In other words, pricing the charges to be more cost reflective could harm the attractiveness of the Optional Residential TOU Rate to customers.

155 For example, previously, with regard to a proposed low-income rate, the Commission has stated: "The Panel finds there is no evidence that the [*Utilities Commission Act*] provides the Commission with the jurisdiction to approve a low-income rate in the absence of an economic or a cost of service basis reason." Refer to page 80 of BCUC Decision and Order No. G-5-17 (BC Hydro's 2015 Rate Design Application).

Reference Case, low-end sensitivity and high-end sensitivity assumptions set out in Table 4-4 above. Specifically:

- As shown in Table 4-17 below, the Optional Residential TOU Rate has a similar revenue to cost ratio as the overall Residential rate class, across a range of potential outcomes. This means that while customers who participate in the Optional Residential TOU Rate are expected to achieve bill savings, the overall amount of revenue collected from these customers relative to the cost to serve them is expected to remain generally consistent; and,
- As shown in Table 4-18 below, the Optional Residential TOU Rate has a positive benefit to cost ratio over the longer-term, across a range of potential outcomes. This means that all ratepayers, including those who do not participate in the rate, are expected to benefit as a result of the Optional Residential TOU Rate. This remains the case even in the low-end sensitivity which assumes lower participation and less electricity load being shifted out of the On-Peak period.

4.5.2.1 Forecast Revenue to Cost Ratio for Optional Residential TOU Rate is Similar to Average of Overall Residential Customer Class

Under the Reference Case, the revenue to cost ratio of participants on the Optional Residential TOU Rate is expected to be similar to the revenue to cost ratio for the overall Residential customer class, over time. This demonstrates that the pricing of the Optional Residential TOU Rate adequately recovers the cost of serving the customers participating in the rate.

While customers who participate in the Optional Residential TOU Rate are expected to achieve bill savings, these bill savings are generally correlated to the extent to which customers shift their electricity use from the On-Peak period to either the Off-Peak period or the Overnight period. This shifting reduces a customers’ On-Peak consumption, which reduces BC Hydro’s demand-related cost of service.

In BC Hydro's Fiscal 2020 Fully Allocated Cost of Service Study,[156] the revenue to cost ratio of the Residential rate class was 93%. A comparable revenue to cost ratio for the Optional Residential TOU Rate would provide reasonable certainty that the rates will have the same level of cost recovery as the Residential rate class, and therefore, will not result in cost shifting between customer classes.

Table 4-17 below provides annual revenue to cost ratios (i.e., Year 5 is the revenue to cost ratio for fiscal 2029). It shows that the forecast revenue to cost ratio for the Optional Residential TOU Rate is similar to the revenue to cost ratio for the Residential rate class, approaching and then exceeding a ratio of 93% over time, indicating that the Optional Residential TOU Rate is forecast to appropriately recover its costs over the long term. The lower revenue to cost ratio in the shorter term is expected due to up-front implementation costs which are attributed to the Optional Residential TOU Rate and considered in the revenue to cost ratio calculations as well as the time required for participation to ramp up. Additional information on BC Hydro's cost of service analysis on the Optional Residential TOU Rate is provided as Appendix G.

Table 4-17 Revenue to Cost Ratio for the Optional Residential TOU Rate

	Year 5	Year 10	Year 12	Year 15
Reference Case	90%	93%	93%	94%
Low-End Sensitivity	88%	90%	90%	91%
High-End Sensitivity	91%	95%	96%	98%

156 https://www.bchydro.com/content/dam/BCHydro/customer-portal/documents/corporate/regulatory-planning-documents/regulatory-filings/facos/00-2021-02-11-bchydro-facos-f2020.pdf. The Fiscal 2020 Fully Allocated Cost of Service Study was selected as a reference to avoid considering time-limited impacts from the COVID-19 pandemic.

4.5.2.2 *Forecast Benefit to Cost Ratio for Optional Residential TOU Rate is Positive Indicating All Customers Will Benefit Over the Long-Term*

BC Hydro analyzed the economic impact of the Optional Residential TOU Rate by comparing the value of capacity savings[157] achieved by the Optional Residential TOU Rate to the revenue loss associated with the corresponding bill savings for participants and the required implementation costs. The analysis demonstrates that the Optional Residential TOU Rate is expected to achieve positive benefits for all customers, over the long-term, across a range of potential outcomes.

A benefit to cost ratio greater than one indicates the value of capacity savings exceeds revenue loss and implementation costs, which means that economic benefits would be realized by all ratepayers and have a positive (i.e., downwards) impact on electricity rates. BC Hydro calculated the benefit to cost ratio of the Optional TOU Rate using the following formula:

$$\frac{Forecast\ Value\ of\ Capacity\ Savings}{(Estimated\ Implementation\ Cost + Forecast\ Revenue\ Loss)}$$

Under the Reference Case, the benefit to cost ratio will exceed one at 1.14 in fiscal 2033 (Year 9). Table 4-18 below provides levelized values (i.e., the Year 15 benefit to cost ratio calculates the total benefits and the total costs from fiscal 2025 (Year 1) to fiscal 2039 (Year 15)). It shows that, under the Reference Case, the Optional Residential TOU Rate has a benefit to cost ratio greater than one over a 10-year period and a 15-year period, indicating the Optional Residential TOU Rate is forecast to achieve benefits for all ratepayers over the long-term.

Table 4-18 Benefit to Cost Ratio of the Optional Residential TOU Rate

	Year 5	Year 10	Year 15
Reference Case	0.56	1.30	1.91
Low-End Sensitivity	0.32	0.87	1.40

157 Estimated based on BC Hydro's Generation capacity long-run marginal cost and the non-bulk transmission and distribution marginal cost as set up in in Appendix L of our 2021 IRP Application.

High-End Sensitivity	0.79	1.45	1.98

BC Hydro notes that as with the introduction of most optional rates, costs will exceed benefits over the shorter-term due to lower initial participation and up-front implementation costs. Before the forecast benefit exceeds cost in fiscal 2033, the implementation costs and forecast revenue loss will result in temporary cost shifting to non-participating customers. BC Hydro submits that this temporary cost shifting is reasonable because it enables the future benefits of the Optional Residential TOU Rate to occur and those longer-term benefits are more significant than the shorter-term cost-shifting.

Additional information on the economic analysis of the Optional Residential TOU Rate is provided as Appendix H.

4.6 Optional Residential TOU Rate Incorporates Customers' Feedback and is Designed to Achieve Customer Understanding and Acceptance

The Optional Residential TOU Rate incorporates customers' feedback, which demonstrates strong support for optional time-of-use rates and is designed to achieve customer understanding and acceptance.

4.6.1 There is Strong Customer Support for Optional Time-of-Use Rates

BC Hydro conducted extensive customer and stakeholder consultation to develop the 2021 Integrated Resource Plan. This consultation indicates strong support for time-varying rates. As described in Chapter 4 of our 2021 IRP Application:

> "BC Hydro asked public and customer participants in this consultation how the Base Resource Plan element to pursue voluntary time-varying rates and supporting demand response programs aligned with their values and interests and to state their reasons.
>
> - Overall, 77% of public survey respondents expressed positive alignment with this element, while 15% indicated

little or no support. Customer survey results were similar, with 72% positive alignment and 9% little or no alignment.

- Reasons why participants were aligned with this element included: because it's easy to implement, has worked elsewhere, is cost effective by deferring new infrastructure and provides customers with the opportunity to lower their electricity bills.
- Participants expressed support for the voluntary opt-in nature of this element. Participants also recognized this element could support them in managing their electricity use.
- Those not aligned cited the concern that some customers would be penalized if they cannot shift their electricity use." [158]

"BC Hydro also asked participants how the draft Base Resource Plan element to pursue voluntary time-varying rates and demand response programs targeting electric vehicle drivers aligned with their values and interests, and to state their reasons:

- Overall, 78% of public survey respondents expressed positive alignment with this element, while 12% indicated little or no support. Respondents thought this element was an effective, easy way to shift more demand to off-peak times.
- Participants who were not aligned stated that electric vehicle owners may not be able to shift their charging hours, or that they, personally, did not own an electric vehicle."[159]

4.6.2 Proposed Optional Residential TOU Rate Incorporates Customer Feedback and is Designed for Customer Understanding and Acceptance

As summarized in section 3.3.2.3 of Chapter 3, BC Hydro also conducted extensive customer engagement on our Residential rate designs in the past two years. In

[158] Refer to Chapter 4, section 4.5.3, page 4-28, (BC Hydro's 2021 IRP Application).
[159] Ibid., section 4.5.4, pages 4-29 to 4-30.

general, most Residential customers appreciate having a choice to decide what rate they take service under and an opportunity to control and save on their electricity bills. BC Hydro consulted with customers on specific design elements of time-of-use rate concepts. Our proposed Optional Residential TOU Rate incorporated the following feedback from customers:

- **The proposed TOU Rate is optional.**[160] Customers who cannot or do not want to shift their electricity usage behaviours can stay on the current RIB Rate or Flat Rate;
- **The proposed TOU Rate is year-round.**[161] This provides more opportunities for customers to save and allows customers to “set it and forget it” when it comes to behavioural or technology changes they may make to achieve savings;
- **The proposed TOU Rate applies everyday during the week.**[162] This helps customers easily build their daily electricity consumption routines;
- **The energy charge during On-Peak hours does not exceed 25 cents per kWh.**[163] Even if a customer has a lot of consumption at the Step 2 energy charge, the On-Peak period energy charge including the 5-cent additional charge will be 14.08 cents + 5 cents = 19.08 cents per kWh, which is lower than 25 cents per kWh threshold customers indicated is undesirable; and,
- **Customers with an electric vehicle do not need to install a second meter to achieve savings from electric vehicle charging.** Customers with electric vehicles can achieve bill savings if they shift charging their electric vehicle to during the Overnight period. They can save more if they also shift their household consumption from the On-Peak period but will pay relatively the

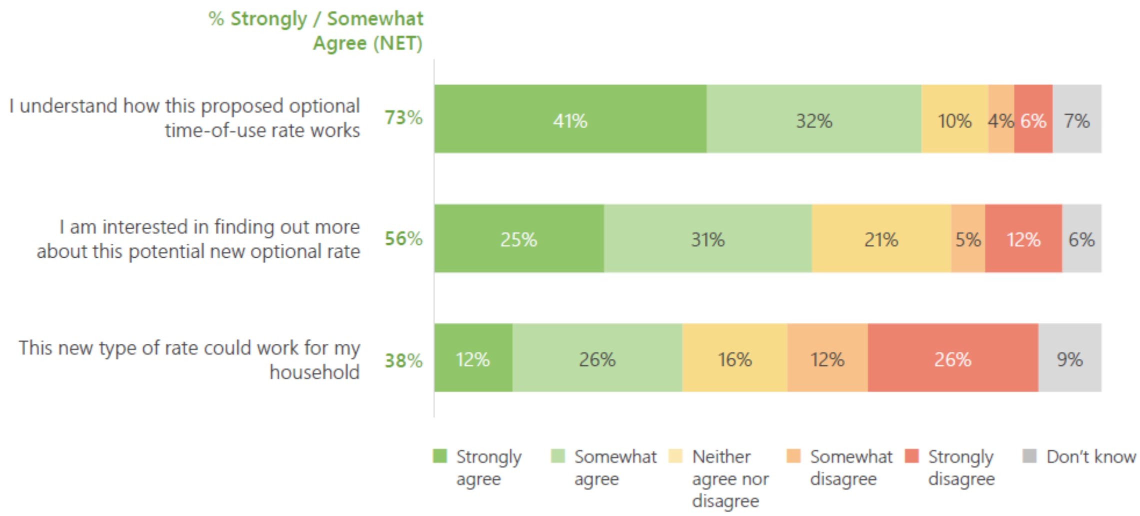
[160] Refer to slide 9 of Appendix D-7J (Focus Groups by Leger), January 2022.
[161] Refer to slide 34 of Appendix D-7E (Time-of-Use survey by Leger), October 2021.
[162] Refer to Appendix D-7J, slide 18.
[163] Ibid., slide 12.

same even if their non-electric vehicle charging electricity consumption habits remain unchanged. Further information is provided in section 4.7 below.

4.6.3 Proposed Optional Residential TOU Rate Received Strong Customer and Stakeholder Support

BC Hydro's proposed Optional Residential TOU Rate is also designed to achieve customer understanding and acceptance. As shown in Figure 4-15 below, in the December 2022 Time-of-Use Concepts and Pricing Survey by Sentis,[164] 73% of customers indicated that they understand the proposed Optional Residential TOU Rate and 56% are interested in learning more.

Figure 4-15 Customers Understanding of the Proposed Optional Time-of-Use Rate



As shown in Figure 4-16 below, overall, 39% of customer respondents indicated that they definitely or probably will choose to enrol in the Optional Residential TOU Rate.

[164] Refer to Appendix D-7H.

Figure 4-16 Customers' Likelihood of Choosing Optional Residential TOU Rate

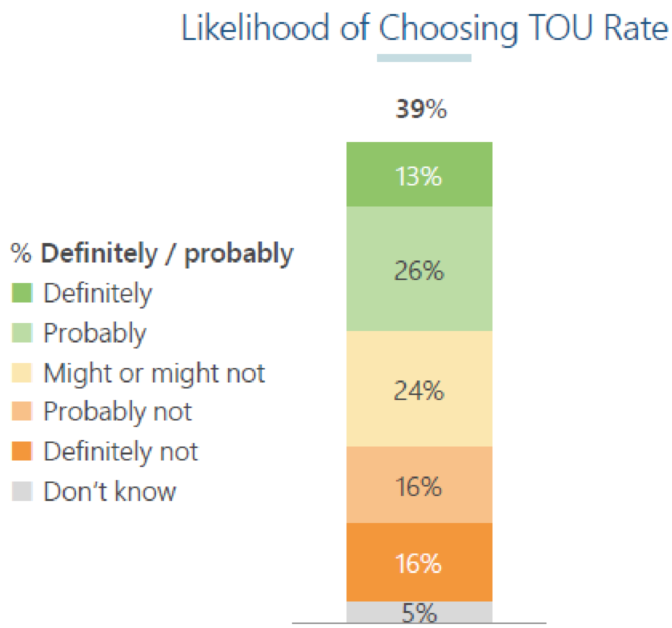


Figure 4-17 below shows a more detailed breakdown of the types of customers who are interested in participating in the Optional Residential TOU Rate. As expected, customers who own or have ordered an electric vehicle and those who indicated they can shift laundry and dishwashing responded with the highest interest of 59% and 56%, respectively:

Figure 4-17 Different Customers' Likelihood of Choosing Optional Residential TOU Rate

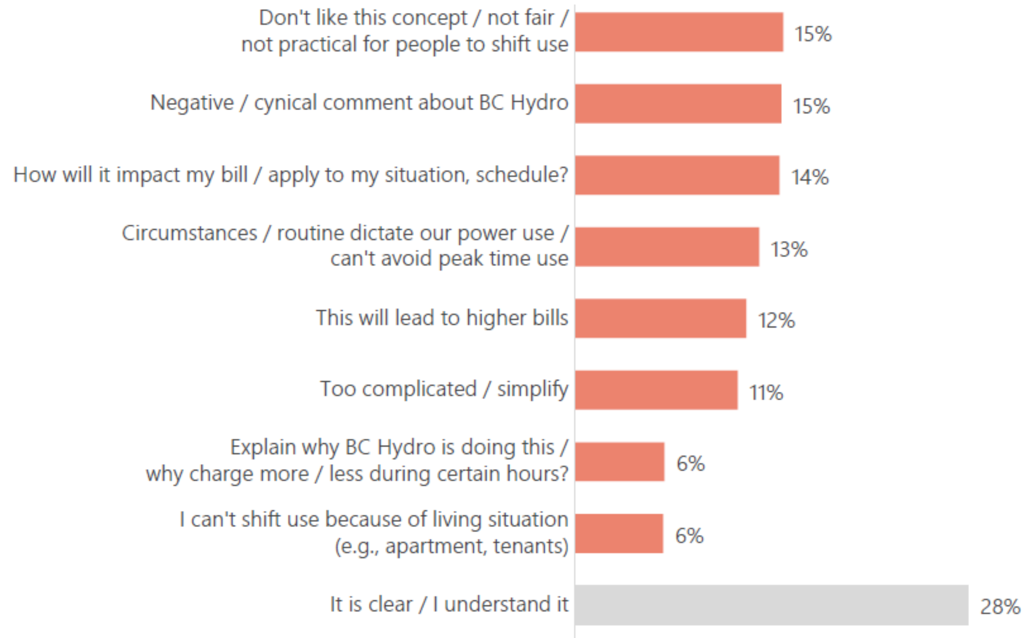
		EV Status			Ability to Shift	
	Total	Have / ordered EV	Interested in EV	Don't plan on getting EV	Could shift laundry & dishwasher	All Others
Base	838	116	415	307	504	334
Definitely / Probably (NET)	**39%**	**59%**	**39%**	**30%**	**56%**	**15%**
Definitely	13%	35%	12%	6%	21%	3%
Probably	26%	24%	28%	24%	36%	13%
Might or might not	24%	22%	24%	26%	28%	19%
Probably not	16%	11%	17%	17%	9%	26%
Definitely not	16%	7%	16%	22%	3%	34%
Don't know	5%	2%	5%	6%	4%	6%

Relatively higher than other subgroup(s)

About 10% of customers responded they do not understand the Optional Residential TOU Rate. As shown in Figure 4-18 below, when asked more about what they found unclear about the Optional Residential TOU Rate, customers who said they do not understand the rate tended to object to the time-of-use rate concept and indicate that this type of rate would not work for their household. [165]

[165] Refer to slide 17 of Appendix D-5H (Time-of-Use Concept and Pricing Survey by Sentis), December 2022.

Figure 4-18 What Customers Found Unclear About the Optional Residential Time-of-Use Rate

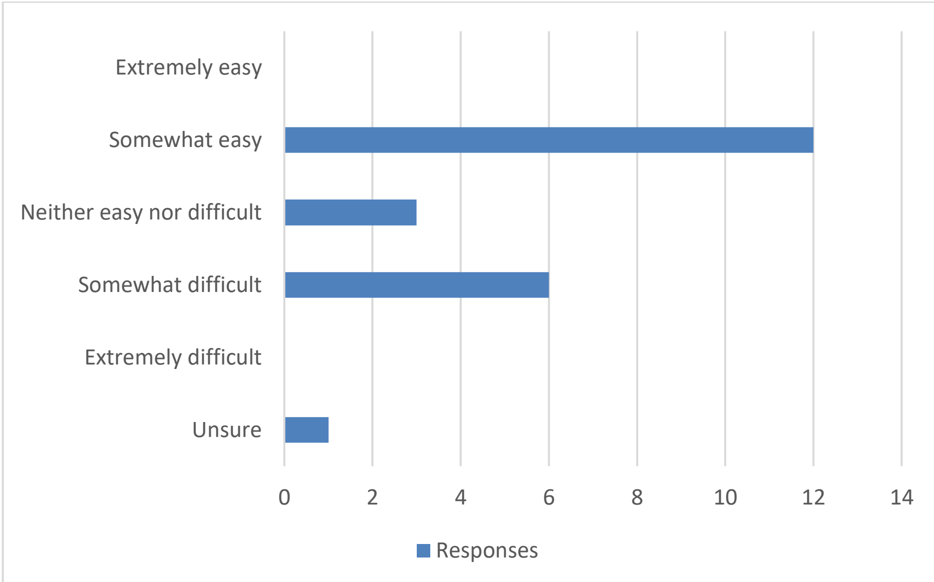


The feedback received from stakeholders participating in the November 29, 2022 stakeholder engagement workshop also indicated relatively high understanding and interest in the Optional Residential TOU Rate. Approximately 55% of stakeholders believe the customers they represent will understand the rate design and 65% support BC Hydro advancing the proposed Optional Residential Time-of-Use Rate.[166, 167]

[166] Refer to Appendix D-6 (November 2022 Stakeholder Workshop Feedback Summary).

[167] Sample size is too small to be considered statistically significant.

Figure 4-19 Stakeholders' Responses When Asked Do You Think This Rate is Easy for Customers to Understand?



These engagement results show that the Optional Residential TOU Rate is easy for customers to understand, and many are interested in taking advantage of the bill savings opportunities it offers.

BC Hydro recognizes that applying an additional credit and charge on top of an inclining block default rate with two energy charges could potentially cause some customer confusion. BC Hydro will develop clear bill presentment and customer education and communications when implementing the Optional Residential Time-of-Use Rate to best enhance customer understanding. The net result of the Optional Residential TOU Rate credit and charge can clearly show customers how much they have saved or paid more under the Optional Residential TOU Rate as compared to the RIB Rate.

4.6.4 Qualifying Customers Can Choose to Apply the Optional Residential TOU Rate to Electric Vehicle Charging Only

For Residential customers who have installed a second BC Hydro meter for their electric vehicle charging and do not wish to have the Optional Residential TOU Rate energy credit and charge applied to their household consumption, they can choose to have the proposed Optional Residential TOU Rate applied to their electric vehicle charging consumption only.

BC Hydro notes that our proposed Optional Residential TOU Rate largely eliminates customers' concern on a whole home time-of-use rate applied to both their household usage and electric vehicle charging. For customers with an electric vehicle who are only interested in shifting their electric vehicle charging, they can enjoy the bill savings from shifting the electric vehicle charging without changing other household electricity use. As shown in Figure 4-3 above, this is because the average total electricity use during On-Peak and Overnight periods are similar (26% / 26%) so customers would be charged approximately the same for their household consumption under the Optional Residential TOU Rate compared to the RIB Rate.

Electric vehicle end-use time-of-use rates are not yet common in North America because they usually require the installation of a separate utility meter to measure end-use electric vehicle consumption which is usually cost prohibitive.[168] Over time, we expect technology and metering standard advancements to enable service under end-use time-of-use rates to be provided without requiring separate metering.

BC Hydro started tracking Residential customers who requested to install a second BC Hydro meter at their premises for electric vehicle charging in October 2019 in accordance with Directive No. 2 of Commission Order No. G-92-19 to BC Hydro's January 15, 2019 Electric Tariff Terms and Conditions Amendments Application to facilitate charging of zero emission vehicles by Residential customers at their dwelling. As of December 2022, there have been 84 customers who have installed a second meter at their premises for electric vehicle charging purposes. Given that the proposed Optional Residential TOU Rate largely eliminates the need for customers to install a separate meter to benefit from shifting their electric vehicle charging,

[168] Refer to page 29 of "Residential Electric Vehicle Rates That Work," Smart Electric Power Alliance. https://sepapower.org/resource/residential-electric-vehicle-time-varying-rates-that-work-attributes-that-increase-enrollment/.

BC Hydro does not anticipate a significant growth of customers requesting to install a second BC Hydro meter for their electric vehicle charging.

In alignment with the reporting and evaluation proposed in section 4.8.5 below, BC Hydro is also seeking a rescindment of Directive No. 2 of Commission Order No. G-92-19 in this Application. Appendix I of this Application provides more information on BC Hydro's rescindment request and our January 15, 2019 Electric Tariff Terms and Conditions Amendments Application.

4.7 Optional Residential TOU Rate Aligns with Rate Design Criteria and Objectives and Compares Favourably to Alternatives

The Optional Residential TOU Rate aligns with both Bonbright rate design criteria and our rate design objectives and performs better against these considerations compared to alternatives.

4.7.1 Bonbright Rate Design Criteria Assessment

The Optional Residential TOU Rate considers and performs well against the Bonbright rate design criteria. As discussed in section 2.2.2 of Chapter 2, the rate design criteria set out by Dr. James Bonbright in "Principles of Public Utility Rates" help to guide BC Hydro's rate design proposals and the Commission has previously determined that these criteria are consistent with the *Utilities Commission Act* test of fair, just and not unduly discriminatory and form an appropriate foundation for rate structures.[169] BC Hydro assessed the Optional Residential TOU Rate against the eight Bonbright rate design criteria, as follows:

1. **Recovery of the Revenue Requirement**. As shown in section 4.5.2.1 above, the revenue to cost ratio for the Optional Residential TOU Rate is forecast to be

[169] Refer to page 51 of the BCUC's Reasons for Decision to Order G-124-08 (BC Hydro's Residential Inclining Block Rate Application), September 24, 2008.

similar to the overall Residential rate class, over the long-term and across a range of potential outcomes;

2. **Fair Apportionment of Costs Among Customers**. As discussed in section 4.2.3 above, the Optional Residential TOU Rate is designed to recover the same amount of revenue if participating customers do not shift their electricity consumption out of the On-Peak period and to either the Off-Peak period or the Overnight period. This means that, on average, participating customers will only achieve bill savings if they shift their electricity use, resulting in corresponding reductions in the cost to provide electricity service;

3. **Price Signals that Encourage Efficient Use and Discourage Inefficient Use**. The Optional Residential TOU Rate sends price signals to encourage participating customers to shift their electricity use to times when more system capacity is available. These price signals reflect the cost to provide electricity service. As discussed in section 4.2.4 above, the 5-cent credit during the Overnight period is designed to recover the embedded cost of energy and the 5-cent additional charge during the On-Peak period generally reflects the marginal cost of electricity consumption during that time;

4. **Customer Understanding and Acceptance; Practical and Cost-Effective to Implement**. As discussed in section 4.6.1 above, there is strong customer support for optional time-of-use rates. As discussed in section 4.6.2 above, the Optional Residential TOU Rate incorporates key customer feedback. As discussed in section 4.6.3 above, the Optional Residential TOU Rate was well understood and well received by participants in a December 2022 Time-of-Use Concepts and Pricing customer survey. The symmetrical “add-on” design of the Optional Residential TOU Rate is easy to implement, administer and communicate to customers. It is flexible because it can be added on to any rate structure;

5. **Freedom from controversies as to proper interpretation**. As discussed in section 4.6.2 above, based on customer feedback, the Optional Residential TOU Rate is optional. Customers will not be forced or defaulted into a rate that does not work for them. In addition, as discussed in section 4.5 above, the Optional Residential TOU Rate is expected to provide benefits to all customers over the long-term, whether they participate in the rate or not;
6. **Rate Stability**. As discussed in section 4.2.4 above, the Optional Residential TOU Rate is stable as the credit and additional charge are fixed and symmetrical. As Residential customer consumption is approximately equal between the On-Peak period and the Overnight period, both on average and across a range of different characteristics, participating customers' bills will not change much if they do not shift their consumption from the On-Peak period into either the Off-Peak period or the Overnight period;
7. **Revenue Stability**. As discussed in section 4.2.3 above, the Optional Residential TOU Rate preserves a customer's underlying rate structure. The credit and additional charge are added-on after a customer is billed at their existing rate. On average, revenue loss will generally only occur from customers' shifting their consumption out of the On-Peak period, which will have corresponding cost reductions for all ratepayers; and,
8. **Avoidance of undue discrimination**. As discussed in section 4.2.3 above, the Optional Residential TOU Rate is available to all Residential customers in Rate Zone I and provides a wide range of customers with the opportunity to save. All participating customers are provided the same credit and additional charge if they choose to take service under this Optional Residential TOU Rate.

4.7.2 Proposed Optional Residential TOU Rate Achieves BC Hydro's Rate Design Objectives

As discussed in section 2.2.3 of Chapter 2, BC Hydro has established four rate design objectives:

- Our **economic efficiency** objective is for rate design to reflect BC Hydro's marginal costs and send price signals that encourage efficient use of electricity and efficient investment decisions by customers. As discussed in section 4.5.1.2 above, the pricing of the Optional Residential TOU Rate aligns with BC Hydro's marginal costs and send price signals to encourage efficient use of the electricity system;
- Our **decarbonization** objective is for rate design to support greenhouse gas emission reductions through electrification where economically efficient. As discussed in section 4.3.3 above, the Optional Residential TOU Rate supports decarbonization by providing a capacity resource to meet the future peak demand driven, in part, by the increased adoption of electric vehicles. In addition, as shown in section 4.3.3 above, the Optional Residential TOU Rate provides meaningful bill savings to electric vehicle owners who are able to shift their electric vehicle charging load out of the On-Peak Period, particularly if that load is shifted to the Overnight period;
- Our **flexibility** objective is for rate design to incorporate flexibility to respond to changes in the economic and policy environment and anticipate the need for greater product and service differentiation in rate design. As discussed in section 4.2.3 above, the Optional Residential TOU Rate can be added on to any existing Residential rate. In addition, the "add-on" design of the rate means that future adjustments to the credit or additional charge should be easy to implement, if and as required;
- Our **affordability** rate design objective is to mitigate bill impacts to customers. As discussed in section 4.2.2 above, the Optional Residential TOU Rate provides opportunities for a wide range of customers to reduce their electricity bills if they can shift when they use electricity. Further, as discussed in section 4.2.4 above the Optional Residential TOU Rate helps protect ratepayers because the symmetrical credit and additional charge design

coupled with the fact that average Residential consumption between the On-Peak period and the Overnight period is approximately the same means that customers who enrol in the Optional Residential TOU Rate will pay, on average, the same for their electricity use if they do not reduce their consumption during the On-Peak period. Lastly, as shown in section 4.5.2 above, over the long term, the Optional Residential TOU Rate is expected to provide economic benefits to all ratepayers.

4.7.3 Optional Residential TOU Rate Performs Well Compared to Alternatives

Over the past two years, BC Hydro explored a number of different Residential time-of-use rate designs, including design options featuring a different number of time-of-use energy charge periods, different eligibility criteria and different price ratios. This section reviews the leading design alternatives that were considered by BC Hydro and explains why we decided not to advance these alternatives.

4.7.3.1 TOU Rate with Fixed Time-Based Energy Charges During Winter and a Flat Energy Charge for the Remainder of the Year

Prior to the development of the Optional Residential TOU Rate with its “add-on” credit and additional charge approach, BC Hydro’s leading rate design alternative was a rate with fixed time-based energy charges for On-Peak, Off-Peak and Overnight periods, applied during the winter months (i.e., November to February) only to align with BC Hydro’s system peak[170] with a flat energy charge applied to all consumption during the non-winter months. This rate design was presented at a stakeholder engagement workshop held on November 18, 2021.

Table 4-19 below provides illustrative revenue neutral energy charges for this rate design.

[170] As discussed in this chapter, the Optional Residential TOU Rate is a year-round rate, which is responsive to customer feedback. BC Hydro did not consider a year-round approach for this rate design because it would have further reduced the benefit to cost ratio of the rate, which was already less than one.

Table 4-19 Illustrative Energy Charges for Winter Only Fixed Time-of-Use Energy Charges with Flat Non-Winter Energy Charge in Fiscal 2024 Dollars

Basic Charge (same as RIB Rate)	21.10 ¢ per day
Winter On-Peak Period Energy Charge	22.82 ¢ per kWh
Winter Off-Peak Period Energy Charge	11.41 ¢ per kWh
Winter Overnight Period Energy Charge	5.93 ¢ per kWh
Non-Winter Energy Charge (All Periods)	11.41 ¢ per kWh

As explained in section 4.2.3 above, the majority of RIB Rate customers will not be able to benefit from this time-of-use rate design because they primarily pay the lower step 1 energy charge and would pay more under the revenue neutral time-based energy charges set out in Table 4-19 above. In addition, high consumption customers who pay the higher step 2 energy charge for much of their electricity consumption can achieve bill savings without shifting their consumption out of the On-Peak period.

Table 4-20 below provides the estimated number of participants, estimated average customer bill savings, estimated fiscal 2030 capacity savings, estimated revenue to cost ratio and estimated benefit to cost ratio for this rate design. For comparison, a summary of the same information is also provided for the Optional Residential TOU Rate, as discussed throughout this chapter.

Table 4-20 Assessment Results for Winter Only Fixed Time-of-Use Energy Charges with Flat Non-Winter Energy Charge[171]

Assessment Result	BC Hydro's Proposed Optional Residential TOU Rate	Winter Only Fixed Time-of-Use Energy Charges with Flat Non-Winter Energy Charge
Participant Estimate	242,000	60,000
Average Customer Bill Savings Estimate	$62	$169
Fiscal 2030 Capacity Savings Estimate	135 MW	48 MW

[171] Assuming 5% of household load shifting from the On-Peak period (80% to Off-Peak Period and 20% to Overnight Period) and 90% of electric vehicle charging load shifting (20% to Off-Peak Period and 80% to Overnight Period).

Assessment Result	BC Hydro's Proposed Optional Residential TOU Rate	Winter Only Fixed Time-of-Use Energy Charges with Flat Non-Winter Energy Charge
Year 4 (Fiscal 2028) Revenue to Cost Ratio[172]	88%	91%
Year 15 Benefit to Cost Ratio	1.91	0.91

As shown in Table 4-20 above, compared to the Optional Residential TOU Rate, this rate design is estimated to achieve fewer participants, less capacity savings and has a benefit to cost ratio of less than one indicating that it would not provide benefits to customers who decide not to participate. Accordingly, BC Hydro decided not to advance this rate design.[173]

4.7.3.2 TOU Rate with Fixed Time-Based Energy Charges During Winter and the RIB Rate for the Remainder of the Year

To improve the benefit to cost ratio of the rate design described in section 4.7.3.1 above, BC Hydro modified the design so that, during the non-winter months, the RIB Rate would apply instead of a flat energy charge rate. This approach introduces more complexity as customers would pay fixed time-based energy charges for four months of the year and then a consumption-based stepped rate for eight months of the year. However, it improves the benefit to cost ratio because high consumption customers don't achieve bill savings during the non-winter months as a result of paying a lower flat energy charge instead of a higher step 2 energy charge.

Table 4-21 below provides illustrative revenue neutral energy charges for this rate design.

[172] For considering alternatives, BC Hydro initially developed revenue to cost ratios for a single year only. This was for fiscal 2028 which is Year 4 of the Optional Residential TOU Rate but was Year 5 on BC Hydro's initial timeline.

[173] BC Hydro notes that the estimates for this rate design improve if the RIB Rate transitions to a flat energy charge rate (i.e., a single flat energy charge instead of consumption-based Step 1 and Step 2 energy charges which, as discussed, create challenges with fixed time-based energy charge designs). BC Hydro has been exploring a flat energy charge rate. However, at this time, BC Hydro has not advanced an application to transition the RIB Rate to a flat energy charge rate and is instead focusing on the development of a range of Residential rate designs to provide customers with more choice.

Table 4-21 Illustrative Energy Charges for the Winter Only Fixed Time-of-Use Energy Charges with Stepped Non-Winter Energy Charges in Fiscal 2024 Dollars

Basic Charge (same as RIB Rate)	21.10 ¢ per day
Winter On-Peak Period Energy Charge	22.82 ¢ per kWh
Winter Off-Peak Period Energy Charge	11.41 ¢ per kWh
Winter Overnight Period Energy Charge	5.93 ¢ per kWh
Non-Winter Energy Charge	Step 1: 9.68 ¢ per kWh Step 2: 14.08 ¢ per kWh

Table 4-22 below provides the estimated number of participants, estimated average customer bill savings, estimated fiscal 2030 capacity savings, estimated revenue to cost ratio and estimated benefit to cost ratio for this rate design. For comparison, a summary of the same information is also provided for the Optional Residential TOU Rate, as discussed throughout this chapter.

Table 4-22 Assessment Results for Winter Only Fixed Time-of-Use Energy Charges with Stepped Non-Winter Energy Charges[174]

Assessment Result	BC Hydro's Proposed Optional Residential TOU Rate	Winter Only Fixed Time-of-Use Energy Charges with Stepped Non-Winter Energy Charges
Participant Estimate	242,000	60,000
Average Customer Bill Saving Estimate	$62	$66
Fiscal 2030 Capacity Saving	135 MW	48 MW
Year 4 (Fiscal 2028) Revenue-Cost Ratio	88%	91%
Year 15 Benefit-Cost Ratio	1.91	1.39

As shown in Table 4-22 above, compared to the rate design described in section 4.7.3.1 above, this modified rate design has higher estimated participants and a positive benefit to cost ratio; however, this results in reduced bill savings for participating customers. In addition, compared to the Optional Residential TOU Rate, this rate design is estimated to achieve fewer participants, less capacity

[174] Assuming 5% of household load shifting from the On-Peak period (80% to Off-Peak Period and 20% to Overnight Period) and 90% of electric vehicle charging load shifting (20% to Off-Peak Period and 80% to Overnight Period).

savings and a lower benefit to cost ratio. Accordingly, BC Hydro decided not to advance this rate design.

4.7.3.3 Electric Vehicle Charging Rate

BC Hydro also explored a year-round end-use rate for electric vehicle charging only with fixed time-based energy charges. This design alternative would require the installation of a second BC Hydro meter to measure and bill electric vehicle charging consumption separately from other household consumption. The energy charges for the electric vehicle charging consumption would be added to the customers' Residential home account and there would be no additional basic charge.

Table 4-23 below provides illustrative revenue neutral energy charges for this rate design.

Table 4-23 Illustrative Energy Charges for Year- Round Fixed Time-of-Use Energy Charges Electric Vehicle Charging Rate in Fiscal 2024 Dollars

On-Peak Period Energy Charge	13.97 ¢ per kWh
Off-Peak Period Energy Charge	11.41 ¢ per kWh
Overnight Period Energy Charge	5.93 ¢ per kWh

As this rate design would require a separate BC Hydro meter, we expected that initial participation would be limited until more metering technology advancements make more practical solutions available.

Table 4-24 below provides the estimated number of participants, estimated average customer bill savings, estimated fiscal 2030 capacity savings, estimated revenue to cost ratio and estimated benefit to cost ratio for this rate design.

Table 4-24 Assessment Results for Electric Vehicle Charging Rate[175]

Assessment Result	Year-Round Fixed Time-of-Use Energy Charges for Separately Metered Electric Vehicle Home Charging
Participant Estimate	6,000
Average Customer Bill Savings Estimate	$120
Fiscal 2030 Capacity Savings	10 MW
Year 4 (Fiscal 2028) Revenue to Cost Ratio	82.6%
Year 15 Benefit to Cost Ratio	1.06

As discussed in section 4.2.2 above, because most customers have consumption patterns that closely resemble the average Residential customer pattern, their starting position when enrolling in the Optional Residential TOU Rate, before shifting any electricity use, is relatively bill neutral. This means that customers who want to participate in the Optional Residential TOU Rate but only shift their electric vehicle charging load should be able to achieve meaningful bill savings even though the credit and additional charge of the Optional Residential TOU Rate will apply to their overall household consumption. Accordingly, BC Hydro does not see a need to advance a stand-alone rate for electric vehicle charging load only at this time.

4.7.3.4 Alternative Amounts for Credit and Additional Charge

To assess customer preferences, understanding and acceptance with regard to the Optional Residential TOU Rate, BC Hydro tested two alternative designs which varied the amount of the credits and charges. Table 4-25 below summarizes the two alternatives that BC Hydro considered. The credit and additional charge selected for the Optional Residential TOU Rate are also shown for comparison.

[175] Assuming 90% of electric vehicle charging load shifting (20% to Off-Peak Period and 80% to Overnight Period).

Table 4-25 Alternative Credit / Charge Amounts Considered

Time-of-Use Period	Optional Residential TOU Rate	Alternative 1	Alternative 2
On-Peak	5 ¢ per kWh energy charge	3 ¢ per kWh energy charge	7 ¢ per kWh energy charge
Overnight	5 ¢ per kWh energy credit	3 ¢ per kWh energy credit	5 ¢ per kWh energy credit
Off-Peak	None	None	1 ¢ per kWh energy credit

Alternative 1 offers a lower symmetric credit and additional charge relative to the selected 5-cent credit and additional charge. While this alternative may be preferred by customers concerned about a higher On-Peak period energy charge, it reduces the bill savings that customers are able to achieve by shifting consumption.

Alternative 2 provides a stronger price signal to shift consumption out of the On-Peak period and offers a credit if some of that consumption is shifted into the Off-Peak period. It provides greater bill savings, but the higher On-Peak additional charge may be a concern for some customers and the rate is more complex, with no symmetry between the charge and credit amounts.

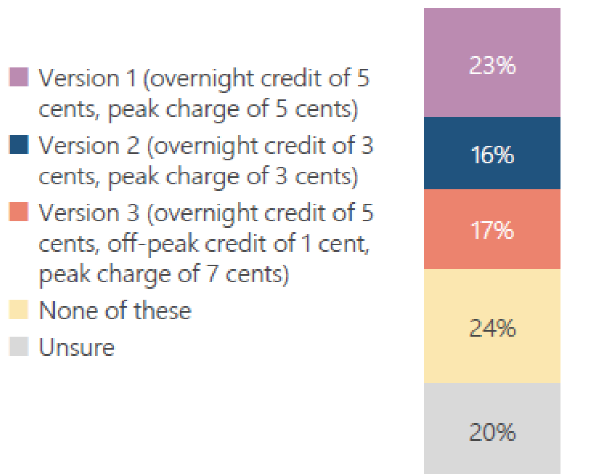
BC Hydro presented these two alternatives to stakeholders in a November 29, 2022 workshop and to customers through a December 2022 Time-of-Use Concepts and Pricing Survey by Sentis.[176] Both stakeholders and customers generally prefer BC Hydro's proposed 5-cent credit and additional charge over the two alternatives.

As shown in Figure 4-20 below, the Optional Residential TOU Rate was preferred by survey respondents as it was simple and easy to understand and seen to generate more bill savings and the smallest potential for increases in bills. Customers who prefer Alternative 1 felt it would be the least punitive option for On-Peak period

[176] Refer to Appendix D-7H.

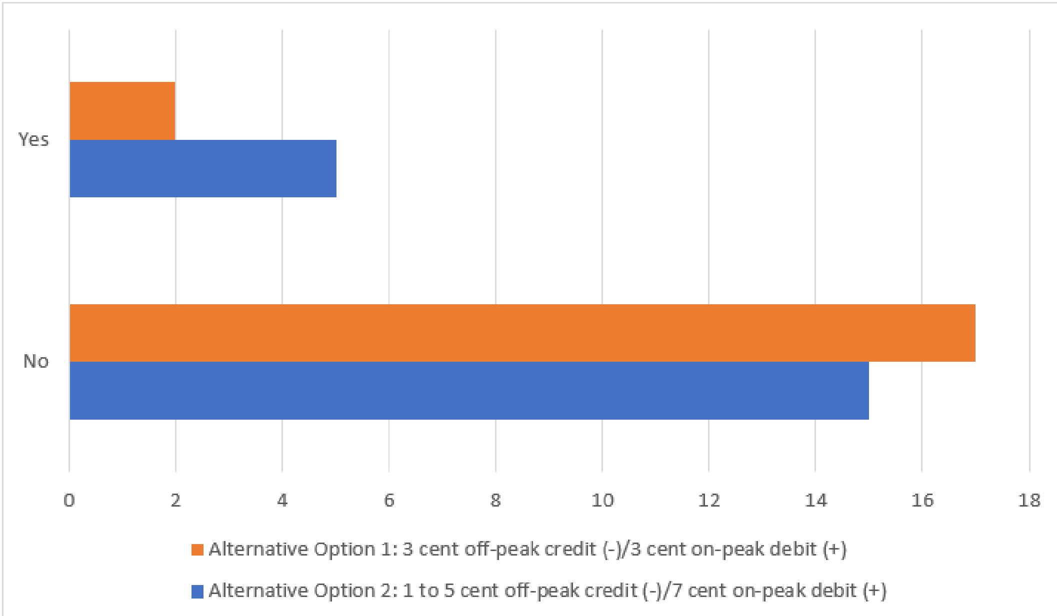
consumption while those who preferred Alternative 2 focused on the highest savings potential from the Overnight credit.

Figure 4-20 Customers Preferences for the Different Versions of the Proposed Optional Time-of-Use Rate



Stakeholder feedback was similar. As shown in Figure 4-21 below, when asked whether BC Hydro should further pursue either of the alternatives shown in Table 4-25 above, stakeholders expressed strong opposition to investing further time in developing either of those options.

Figure 4-21 Stakeholder Responses to the Alternative Credit / Charge Rate Design Options



Based on the above stakeholder and customer feedback, which demonstrated a preference for the selected credit and additional charge amounts of the proposed Optional Residential TOU Rate, BC Hydro did not advance these other alternatives any further.

4.8 Availability, Definitions and Special Conditions

The Optional Residential TOU Rate includes availability and special conditions to help protect customers and will be accompanied by an implementation plan so that customers receive the support they need to achieve bill savings and an evaluation plan to verify if the expected benefits are being achieved and to inform adjustments, if needed.

In the sub-sections below, we describe the proposed non-price terms and conditions of Service that would be set out in Rate Schedule 2101 – The Optional Residential TOU Rate as well as our implementation and evaluation plans for the Optional

Residential TOU Rate. Tariff-sheets for the proposed rate schedule are provided as Appendix B.

4.8.1 Availability

The Optional Residential TOU Rate is proposed to be available only to customers in the integrated service areas. There are fundamental differences in the cost of service and customer needs between BC Hydro's integrated and non-integrated service areas. The Optional Residential TOU Rate has been designed based on the economics, cost of service, and customer feedback for the integrated service area only.[177]

BC Hydro proposes the following Availability for the Optional Residential TOU Rate:

> "For Residential Service, at the Customer's election:
>
> 1. For use in a Dwelling or Premises concurrently receiving Service under Rate Schedule 1101, 1121, 1151, or 1161; or
>
> 2. For separately metered charging of Electric Vehicle concurrently receiving Service in a Dwelling or Premises under Rate Schedule 1101, 1121, 1151, or 1161.
>
> Service under this Rate Schedule is not available for use in separately metered common areas of multiple occupancy buildings or for Customers receiving Service under Rate Schedule 1289.
>
> Service is normally single phase, 60 hertz at the Secondary Voltage available. In BC Hydro's discretion, Service may be three phase 120/208 or 240 volts."

The Optional Residential TOU Rate includes an energy credit for consumption during the Overnight period and an additional energy charge for the On-Peak period which will be added to a participating customer's existing rate. Accordingly, the Optional Residential TOU Rate must be used in conjunction with one of the other

[177] Refer to section 1.6 of Chapter 1 for a discussion regarding Non-Integrated Area rates.

Rate Zone I Residential Rate Schedules: Rate Schedule 1101, 1121 (i.e., the RIB Rate) or Rate Schedule 1151 or 1161 (i.e., the Flat Rate).

Customers with a separate BC Hydro meter for their electric vehicle charging load can elect to have the Optional Residential TOU Rate applied to that consumption only. The total consumption of their premises, including household use and electric vehicle charging use, will be billed under the applicable RIB Rate or Flat Rate and the credit and additional charge of the Optional Residential TOU Rate will only be applied to their electric vehicle charging consumption.

BC Hydro proposes that common areas of multiple occupancy residential buildings would not be eligible for the Optional Residential TOU Rate. The Optional Residential TOU Rate is designed based on the consumption behaviours of typical Residential customers. Most Residential common areas have a flatter consumption pattern compared to typical Residential dwellings due to a large amount of lighting that is typically left on 24 hours per day, seven days per week. Most strata corporations will not be able to shift this common area load out of the On-Peak period, but their consumption pattern means they would likely still benefit from the Optional Residential TOU Rate due to the amount of consumption already occurring in the Overnight period where the credit would be applied. BC Hydro plans to explore other rate or demand side management program options to encourage Residential stratas to more efficiently manage their electric vehicle charging and other consumptions in the common areas.

In addition, BC Hydro proposes that a customer receiving service under Rate Schedule 1289 - Net Metering Service would not be eligible for the Optional Residential TOU Rate. This is because BC Hydro plans to bring forward a separate Application to the Commission later this year that will consider the Net Metering Rate from a more comprehensive perspective.[178]

[178] Refer to section 1.6 of Chapter 1 for further discussion on matters related to Net Metering Service.

4.8.2 Definitions

BC Hydro proposes the following self-explanatory definitions in RS 2101:

i. Electric Vehicle

A vehicle that is powered entirely or partially by electricity.

ii. Off-Peak Period

The time starting 07:00 and ending 16:00 daily, and the time starting 21:00 and ending 23:00 daily.

iii. On-Peak Period

The time starting 16:00 and ending 21:00 daily.

iv. Overnight Period

The time starting 23:00 and ending 07:00 the following day.

4.8.3 Special Conditions

BC Hydro proposes the following Special Conditions to the RS 2101 TOU Rate.

4.8.3.1 Special Condition 1 – Ability to Change Rate Schedules

Special Condition 1 of RS 2101 states:

> "Despite the provisions of section 6.1.1 (Application of Rate Schedules) a Customer may apply to be billed on a Residential Service Rate Schedule the Customer was billed on within the preceding 12-month period."

Electric Tariff section 6.1.1 (Application of Rate Schedules) states:

> "The Customer may also apply at any time to be billed on a different Rate Schedule and BC Hydro may, in its sole discretion, reject, defer or approve such application. BC Hydro will not approve a Customer request to move to another Rate Schedule where:
>
> i. The Customer was billed under such Rate Schedule at any time during the preceding 12-month period; or
>
> ii. Such Rate Schedule is, in the opinion of BC Hydro, not available to the Customer."

The intent of this Electric Tariff provision is to restrict frequent rate changes requested by customers. In addition to the administrative burden associated with processing rate change requests, allowing customers to frequently change rates within a 12-month period can create opportunities for those customers to take advantage of rates that benefit them more during the higher or lower consumption months. In some cases, this type of activity can result a revenue shortfall which would increase costs for all ratepayers.

However, BC Hydro acknowledges that some customers may be apprehensive about electing to be billed on the Optional Residential TOU Rate. In addition, because there are limited differences (i.e., an average difference of approximately 0.6%) between Residential customers' consumption during the On-Peak period and Overnight period in winter months compared to non-winter months, BC Hydro does not expect most customers to have the opportunity to benefit by making frequent requests to change their applicable rate schedule. Accordingly, BC Hydro is proposing this Special Condition to provide customers on the Optional Residential TOU Rate with an exemption from section 6.1.1 of the Electric Tariff so that they can choose to opt-in and opt-out of the Optional Residential TOU Rate at anytime.

4.8.3.2 Special Condition 2 – Metering

Special Condition 2 of RS 2101 states:

> "Measurement of Electricity provided under this Rate Schedule will be by a Smart Meter or, for the separately metered Electric Vehicle charging, by a Smart Meter or a BC Hydro-approved Electric Vehicle-specific metering solution."

This Special Condition is intended to ensure that appropriate Metering Equipment is installed to bill for the proposed TOU Rate. Smart Meter is defined as follows in section 1.2 of the Electric Tariff:

> "An Electricity meter that:

1. Meets the requirements set out in section 2 of the Smart Meters and Smart Grid Regulation, B.C. Reg. 368/2010, and
2. Has components that transmit data by radio and those components are activated."

Customers with a Legacy Meter or a Radio-off Meter that do not meet the Smart Meter definition would not be eligible to take service under the Optional Residential TOU Rate. This is because BC Hydro requires the hourly consumption data in Smart Meters to be received and processed by our billing system to enable time-of-use billing.

This Special Condition is also intended to enable the use of approved future electric vehicle charging solutions for billing once the electric vehicle charging market has evolved to make such an alternative viable.

4.8.4 Implementation of the Optional Residential TOU Rate

BC Hydro does not currently have the systems and process in place to bill a potentially large number of Residential customers on optional time-of-use rates. We also do not currently have the tools in place to support customers with choosing their rate option.

This section describes activities underway or planned to implement the necessary systems and processes. The estimated costs for these systems and processes have been included in the cost of service (refer to section 4.5.2.1 above and Appendix G) and economic analysis (refer to section 4.5.2.2 above and Appendix H).

4.8.4.1 Technology – Time-Based Billing Infrastructure Project

Almost all BC Hydro customers have a Smart Meter that can record the hourly interval consumption information required for time-based rate billing. As a result, BC Hydro's standard Smart Meters and communications network can support the introduction of optional time-of-use rates for distribution voltage customers without further investment in meters or communication infrastructure.

However, BC Hydro's current technology infrastructure has not been configured to support time-based rate billing for larger-scale enrolment processes for optional customer rates. In anticipation of upcoming demand for time-based rates and programs, BC Hydro has initiated the Time-Based Billing Infrastructure Project. The objectives of the project include:

- A scalable-technology solution which supports utilizing meter interval data for time-of-use rates billing;
- A flexible solution architecture that can be efficiently tailored or modified to meet changing customer needs and rate designs over time;
- A customer-friendly solution that can enable customer interactions, including rate comparison and enrolment, billing and energy usage presentment, through all customer channels (e.g., online or Interactive Voice Response system self-service and the Contact Centre); and,
- A solution that is integrated with all other enterprise systems for load, revenue and customer data analyses and reporting.

One of the most significant changes required to enable time-of-use rates is the need to process the interval consumption data together with the meter register readings for billing purposes. For the Optional Residential TOU Rate, this means processing 720 hourly interval data points from each meter per month in addition to monthly energy register readings.

The estimated completion date of the Time-Based Billing Infrastructure Project is the fourth quarter of fiscal 2024. The current project development plan is based on the design of the Optional Residential TOU Rate, as proposed in this Application. Assuming the Commission approves the Optional Residential TOU Rate either as proposed, or similar to the proposal set out in this Application, we would require approximately three months after the Commission's decision to complete the configuration and testing of the final approved rate. Therefore, BC Hydro proposes that the effective date of the Optional Residential TOU Rate should be the later of April 1, 2024 or the first day of the fourth full calendar month following the Commission's decision on this Application. If the final approved rate is substantially different from the Optional Residential TOU Rate as proposed in this Application, BC Hydro will assess the additional development effort and time required and propose a new effective date to the Commission for approval.

The current expected cost of the Time-Based Billing Infrastructure Project is approximately $12.6 million, with an accuracy range of +15% / -10%. These estimated costs have been included in the cost of service and economic analysis for the Optional Residential TOU Rate.

4.8.4.2 Operations

In addition to the Time-Based Billing Infrastructure Project, offering rate options to Residential service customers will require changes to BC Hydro's customer processes so that customers are supported when deciding which rate to choose. These changes are required throughout all points of interaction with Residential service customers given the wide range of customer preferences for contact channels and the complexity of their questions. The changes extend beyond a customer's initial enrollment in an optional rate. For instance, changes are also necessary throughout the "application for service" process (also known as "move-in/move-out") so that customers are provided rate options each time they set up a new account and so that account records and metering configurations are properly maintained when they move out.

Online channels will be a key channel for customers to learn about rate options and enroll in the rate of their choice. The Time-Based Billing Infrastructure Project includes development of online bill comparison and enrollment tools. We anticipate a significant percentage of customers will use these online self-service processes, which will help to mitigate operational impacts. Approximately 40% of move-in requests are currently received online and we would expect self-service enrollment in optional rates to be at a similar level.

BC Hydro's Contact Centre will be the primary point of contact for customers who prefer to speak with a customer service representative rather than using online tools for inquiries or to enrol in the proposed Optional Residential TOU Rate. This is expected to increase the number of calls received from customers, particularly during the first few years of the proposed Optional Residential TOU Rate.

The launch of an optional rate will also increase the average handle time of specific call types such as move-ins and billing inquiries. In particular, BC Hydro currently processes nearly 200,000 move-in requests each year through our Contact Centre, and the duration of these calls will increase while the customer service representative informs the customer of their rate options and supports them in making a decision.

Collectively, the increase in calls and longer call durations will increase labour requirements in the Contact Centre to avoid higher wait times for all customers wishing to speak with a customer service representative. In addition, the introduction of the Optional Residential TOU Rate will increase manual effort for our billing team to handle billing exceptions, as the use of interval data for billing creates the need for additional control thresholds so that bills are accurate. There will also be upfront costs for the associated process design and training of employees.

Overall, BC Hydro estimates the incremental operations cost to support the Optional Residential TOU Rate to be approximately $1.4 million per year in the initial years. Specific details on these costs will be included in future revenue requirements applications. These estimated costs have been included in the cost of service and economic analysis for the Optional Residential TOU Rate.

4.8.4.3 Customer Education and Communications

BC Hydro will educate customers on the new Optional Residential TOU Rate and encourage adoption of the new rate through several communications initiatives, including:

- Marketing efforts across touchpoints with customers, including BC Hydro's website, social media channels, customer bills, newsletters and email, as well as paid channel opportunities;
- Working to partner with electric vehicle dealers so that electric vehicle buyers are informed of their rate options when they are making their purchasing decisions; and
- Utilizing our Contact Centre to answer customer inquiries and explain their rate options during key interactions, such as when processing a customer's move-in request. The information provided to customers via these channels will explain what the new rate is are and highlight the benefits for those who want greater flexibility in how they manage and pay for their electricity use.

The estimated cost for these marketing, communication and support initiatives is approximately $0.3 million per year, not including the additional cost of Contact Centre labour described in section 4.8.4.2 above. Specific details on these costs will be included in future revenue requirements applications. These estimated costs have been included in the cost of service and economic analysis for the Optional Residential TOU Rate.

4.8.5 Evaluation

BC Hydro plans to evaluate the Optional Residential TOU Rate to verify whether it is achieving the expected benefits. The scope of this evaluation is expected to include:

- Analysis of the economic impact on all ratepayers;
- Fully allocated cost of service analysis;

- Assessment of structural winners;
- Net load impacts attributable to the rate;
- Customer and stakeholder feedback;
- Whether general rate increases should be applied to the 5-cent credit and additional charge going forward;[179] and,
- Incorporate any of the reporting requirements set out in Directive 2 of Commission Order No. G-92-19 to BC Hydro's January 15, 2019 Electric Tariff Terms and Conditions Amendments Application that the Commission still considers helpful.

To estimate the net load impacts attributable to the rate, a method for estimating what participating customers' usage patterns would have been in the absence of the rate is needed. For the Optional Residential TOU Rate, we anticipate following a quasi-experimental design approach. Customers who choose the rate will form a treatment group, and a number of non-participating customers will be selected from the eligible population to form a comparison group. Customers in the comparison group will be selected so that they individually match customers in the treatment group based on their consumption pattern before joining the new rate and based on various attributes that may affect their energy consumption behaviours. Regression analysis of customer load data can then be used to determine the net change in On-Peak load consumption that can be attributed to the rate.

In addition, to facilitate more efficient reporting to the Commission, BC Hydro proposes to include the reporting requirements set out in Directive 2 of Commission Order No. G-92-19 to BC Hydro's January 15, 2019 Electric Tariff Terms and Conditions Amendments Application as part of this evaluation. These requirements include:

[179] For further discussion on this point, refer to section 4.2.2 above.

- Number of accounts that have installed additional meters and whether BC Hydro is meeting the needs of customers;
- Analysis of having one basic charge per account with additional meters and any plans to review the basic charge in a future process; and,
- Whether additional amendments to the Electric Tariff are appropriate for other rate classes that may have similar multi-unit characteristics such as commercial strata developments.

Further information on these requirements is provided in Appendix I.

BC Hydro expects to complete the evaluation of the Optional Residential TOU Rate in fiscal 2029.

BC Hydro
Power smart

List of Appendices

BC Hydro Optional Residential Time-of-Use Rate Application

Appendix A

Draft Orders

BC Hydro Optional Residential Time-of-Use Rate Application

Appendix A-1

Draft Order - Approval of Optional Residential Time-of-Use Rate

Suite 410, 900 Howe Street
Vancouver, BC Canada V6Z 2N3
P: 604.660.4700
TF: 1.800.663.1385
F: 604.660.1102

ORDER NUMBER
G-xx-xx

IN THE MATTER OF
the *Utilities Commission Act*, RSBC 1996, Chapter 473

and

British Columbia Hydro and Power Authority (BC Hydro)
Optional Residential Time-of-Use Rate Application

BEFORE:
Commissioner
Commissioner
Commissioner

on Date

ORDER

WHEREAS:

A. On February 24, 2023, British Columbia Hydro and Power Authority (**BC Hydro**) filed the Optional Residential Time-of-Use Rate Application (**Application**) seeking approval of Rate Schedule 2101 – Residential Service – Time-of-Use Rate (**Optional Residential TOU Rate**), as shown in Appendix B of the Application, to be effective the later of April 1, 2024 or the first day of the fourth calendar month following the Commission order approving the rate schedule.

B. The Optional Residential TOU Rate is proposed to be as follows:

(i) Available to BC Hydro's Residential Service Customers on a voluntary, opt-in basis, in BC Hydro's integrated service area;

(ii) For all electricity consumption at a Residential Service account, including electric vehicle charging; and,

(iii) An "add-on" rate that applies year-round and every day of the year. Particiapting customers are first billed for their total electricity usage during a billing period based on their existing Residential Service rate, and then will receive a 5-cent credit for each kWh of electricity consumed during the Overnight period (11 p.m. to 7 a.m.) and a 5-cent additional charge for each kWh of electricity consumed during the On-Peak period (4 p.m. to 9 p.m.). No credit or additional charge will be applied to consumption during the Off-Peak period (9 p.m. to 11 p.m. and 7 a.m. to 4 p.m.).

C. BC Hydro proposes to submit an evaluation report for the proposed Optional Residential TOU Rate in fiscal 2029, as described in the Application.

D. By Order No. G-XXX-XX, the BCUC established a public hearing process and regulatory timetable for the review of the Application.

E. The Commission has reviewed the Application, evidence and arguments and considers that a determination on the proposed Optional Residential TOU Rate is warranted.

NOW THEREFORE pursuant to sections 58 to 60 of the UCA, and for the reasons attached to this order, the BCUC orders as follows:

1. Rate Schedule 2101 – Residential Service –Time-of-Use, as shown in Appendix B of the Application, is approved effective [the later of July 1, 2024 or the first day of the fourth calendar month following the Commission order approving this rate schedule].

2. BC Hydro is directed to submit an evaluation report for the Optional Residential TOU Rate as described in the Application in fiscal 2029.

DATED at the City of Vancouver, in the Province of British Columbia, this (XX) day of (Month Year).

BY ORDER

(X. X. last name)
Commissioner

Attachment Options

BC Hydro Optional Residential Time-of-Use Rate Application

Appendix A-2

Draft Order – Request to Rescind EV Reporting Requirements

bcuc
British Columbia
Utilities Commission

Suite 410, 900 Howe Street
Vancouver, BC Canada V6Z 2N3
P: 604.660.4700
TF: 1.800.663.1385
F: 604.660.1102

ORDER NUMBER
G-xx-xx

IN THE MATTER OF
the *Utilities Commission Act*, RSBC 1996, Chapter 473

and

British Columbia Hydro and Power Authority (BC Hydro)
Application for Relief from Reporting Requirements as per Directive No. 2 of Order No. G-92-19 - Residential Service Customers Charging Zero-Emission Vehicles at their Dwelling Annual Report (Application)

BEFORE:
Commissioner
Commissioner
Commissioner

on Date

ORDER

WHEREAS:

A. On January 15, 2019, the British Columbia Hydro and Power Authority (**BC Hydro**) filed an Electric Tariff Terms and Conditions Amendments Application (**Amendments Application**) for British Columbia Utilities Commission (**BCUC or Commission**) approval, pursuant to sections 58 to 61 of the *Utilities Commission Act* (**UCA**), to facilitate Residential Service Customers charging their Zero-Emission Vehicles at their Dwelling;

B. The Amendments Application sought to clarify that (i) a Dwelling may include spaces such as parking stalls, storage areas, garage areas and similar areas or spaces that are used only for the benefit of a Customer, (ii) more than one meter may be installed at a Customer's Premises (including a Dwelling) and (iii) energy consumption for multiple Residential Service to different spaces within a Dwelling will be billed in aggregate, thereby treating the Customer as having one single Residential Service account (Rate Schedule 1101 or Rate Schedule 1107);

C. On April 29, 2019, the BCUC approved amendments related to sections 1.2, 3.2, 3.4, 4.2, 4.4.1, and 6.6.1 of BC Hydro's Electric Tariff Terms and Conditions in Order No. G-92-19;

D. Directive No. 2 of Order No. G-92-19 required BC Hydro, starting in fiscal 2020, to file information regarding BC Hydro's experience resulting from the amended terms and conditions to facilitate Residential Service Customers to charge their Zero-Emission Vehicles at their Dwelling. The reporting includes, but is not limited to, the following:

   (a) Number of accounts that have installed additional meters and whether BC Hydro is meeting the needs of customers;

…/2

(b) Analysis of having one Basic Charge per account with additional meters and any plans to review the Basic Charge in a future process; and,

(c) Analysis as to whether additional amendments to the Electric Tariff are appropriate for other rate classes that may have similar multi-unit characteristics such as commercial strata developments;

E. On September 1, 2020, BC Hydro attached the required report in Appendix C of its Fiscal 2020 Annual Report to the BCUC;

F. On August 30, 2021, BC Hydro attached the required reporting in Appendix C of its Fiscal 2021 Annual Report to the BCUC;

G. On August 31, 2022, BC Hydro attached the required reporting in Appendix C of its Fiscal 2022 Annual Report to the BCUC; and,

H. On February 24, 2023, BC Hydro submitted as Appendix I to its Optional Residential Time-of-Use Rate Application a request to seek relief from the reporting requirements of Directive No. 2 of Order No. G-92-19 given the small number of additional meter requests for electric vehicle charging and the proposed evaluation of the Optional Residential Time-of-Use Rate.

NOW THEREFORE the Commission orders as follows:

1. Directive No. 2 of Order No. G-92-19 is rescinded.

DATED at the City of Vancouver, in the Province of British Columbia, this (XX) day of (Month Year).

BY ORDER

(X. X. last name)
Commissioner

BC Hydro Optional Residential Time-of-Use Rate Application

Appendix B

Rate Schedule 2101 - Residential Service - Time-of-Use

1. RESIDENTIAL SERVICE

RATE SCHEDULE 2101 – RESIDENTIAL SERVICE – TIME-OF-USE

Availability	For Residential Service, at the Customer's election: 1. For use in a Dwelling or Premises concurrently receiving Service under Rate Schedule 1101, 1121, 1151, or 1161; or 2. For separately metered charging of Electric Vehicles, concurrently receiving Service in a Dwelling or Premises under Rate Schedule 1101, 1121, 1151, or 1161. Service under this Rate Schedule is not available for use in separately metered common areas of multiple occupancy buildings or for Customers receiving Service under Rate Schedule 1289. Service is normally single phase, 60 hertz at the Secondary Voltage available. In BC Hydro's discretion, Service may be three phase 120/208 or 240 volts.
Applicable in	Rate Zone I.
Rate	**Energy Credit:** **Overnight Period:** (5) ¢ per kWh **Off-Peak Period:** 0 ¢ per kWh plus **Energy Charge:** **On-Peak Period:** 5 ¢ per kWh **Off-Peak Period:** 0 ¢ per kWh

ACCEPTED:______________________________

ORDER NO.______________________________

____
ACTING COMMISSION SECRETARY

Definitions	1. Electric Vehicle A vehicle that is powered entirely or partially by electricity. 2. Off-Peak Period The time starting 07:00 and ending 16:00 daily, and the time starting 21:00 and ending 23:00 daily. 3. On-Peak Period The time starting 16:00 and ending 21:00 daily. 4. Overnight Period The time starting 23:00 and ending 07:00 the following day.
Special Conditions	1. Despite section 6.1.1 (Application of Rate Schedules) of the Electric Tariff, a Customer may apply to be billed on a Residential Service Rate Schedule that the Customer was billed on within the preceding 12-month period. 2. Electricity supplied under this Rate Schedule will be measured by a Smart Meter, unless it is for separately metered Electric Vehicle charging, in which case it may also be measured by a BC Hydro-approved Electric Vehicle-specific metering solution.
Rate Rider	The Deferral Account Rate Rider, as set out in Rate Schedule 1901, applies to all charges payable under this Rate Schedule, before taxes and levies.
Rate Increases / Decreases	The rate increases/decreases approved through revenue requirements proceedings will not apply to this Rate Schedule.

ACCEPTED:______________________________

ORDER NO.______________________________

____
ACTING COMMISSION SECRETARY

BC Hydro Optional Residential Time-of-Use Rate Application

Appendix C

BC Hydro's 2021 Integrated Resource Plan

Clean Power 2040
Powering the future

BC Hydro
Power smart

BC Hydro and Power Authority

2021 Integrated Resource Plan

Table of contents

1

Executive summary

An integrated resource plan is a guidebook for what, when, and how to meet customers' evolving electricity needs. This 2021 Integrated Resource Plan (2021 IRP) looks at a 20-year time frame and will guide decisions on our integrated system to meet the future electricity needs of our customers.[1]

The 2021 IRP aligns with government policy objectives, such as greenhouse gas reduction targets and preference for demand-side measures (DSM) over new facilities and meets the requirements of the *Utilities Commission Act* and the British Columbia Utilities Commission (BCUC). Its development was also informed by our commitment to reconciliation with Indigenous communities. A broad consultation process occurred throughout the development of the 2021 IRP and final feedback showed overall positive or neutral alignment of the 2021 IRP elements to participants' values and interests.

Our planning objectives for the 2021 IRP are informed by the above policies, commitments and consultation feedback, and they are: keeping costs down for customers, reducing greenhouse gas (GHG) emissions through clean electricity, limiting land and water impacts, and supporting the growth of B.C.'s economy.

The 2021 IRP compares our existing and committed resources against our forecast of future customer needs and shows that we will have surplus electricity for some time. Before demand-side measures, new energy needs are not expected to occur until fiscal 2029, while capacity needs are not expected to occur until fiscal 2032. However, growing demand for electricity on the province's South Coast means we expect to need additional regional capacity resources in fiscal 2027.

Three defining features of this 2021 IRP are that it:

- Relies more on customer-based solutions through demand-side measures, including new voluntary rate structures, to encourage customers to use less electricity and use it more efficiently, and less on adding new physical assets with their land and water impacts, and financial commitment;
- Is flexible, preparing BC Hydro for a possible future of higher electricity demand due to electrification, and a possible future with lower demand resulting from economic downturns, making it a resilient plan; and
- Supports BC Hydro's mandate to incorporate the United Nations Declaration on the Rights of Indigenous Peoples (UNDRIP) and the Truth and Reconciliation Calls to Action into our business. Early engagement is an important part of advancing reconciliation and the 2021 IRP is the earliest BC Hydro can engage with Indigenous Nations on meeting our customers' future electricity needs.

The 2021 IRP consists of a Base Resource Plan and several Contingency Resource Plans. BC Hydro is taking steps to implement the Base Resource Plan and to ensure that we are able to implement elements of the Contingency Resource Plans on a timely basis. We call these steps our Near-term Actions. The first one is to submit our planned demand-side measures expenditures for fiscal years 2023-2025 to the BCUC for review and approval. Another Near-term Action is to apply to the BCUC for approval of voluntary time-of-use rates for residential customers. Another is to study, consult on and pilot utility-scale battery resources.

In developing the Base Resource Plan, we considered resource options, including demand side-measures, rates, acquiring power via renewing electricity purchase agreements (EPA), upgrading our facilities, and new clean or renewable sources.

1 This term and several terms and acronyms are defined in the 2021 IRP glossary, which can be found in Attachment 2.

The legal framework for the 2021 IRP indicates a clear policy preference for the priority use of demand-side measures, and much of what we heard from Indigenous communities, public, customers, and stakeholders during consultation was consistent with this preference. So, our first step was to decide the levels of demand-side measures which we ought to pursue. They make up the first part of our Base Resource Plan, as follows:

- Continue with a base level of energy efficiency programs and plan to ramp up to higher levels in future years to achieve 1700 gigawatt hours per year (GWh/year) of energy savings and 280 megawatts (MW) of capacity savings at the system level by fiscal 2030;
- Pursue voluntary time-varying rates supported by demand response programs to achieve approximately 220 MW of capacity savings at the system level by fiscal 2030, and advance the Industrial Load Curtailment Program to achieve approximately 100 MW of incremental capacity savings at the system level by no later than fiscal 2030; and
- Pursue a combination of education and marketing efforts as well as incentives for smart-charging technology for customers. These would support a voluntary residential time-of-use rate to shift home charging by 50 per cent of residential electric vehicle drivers to off-peak demand periods to achieve 100 MW of capacity savings at the system level by fiscal 2030.

After these demand-side measures, new energy needs are not expected to occur until fiscal 2030, while capacity needs are not expected to occur until fiscal 2037. Meanwhile, additional regional capacity resources to serve the South Coast are not required until fiscal 2032.

After demand-side measures, our Base Resource Plan also includes the following elements:

- Offer a market-price-based renewal option to existing clean or renewable independent power producers with electricity purchase agreements expiring within five years. There are 19 existing clean or renewable projects that produce a total of roughly 900 Gigawatt hours (GWh), with electricity purchase agreements set to expire before April 1, 2026;
- Advance the first sequential step of upgrades to existing transmission infrastructure into the South Coast region to achieve 750 MW of capacity for the South Coast region by fiscal 2033; prepare to initiate a second step of upgrades of existing equipment to achieve an additional 550 MW of capacity for the South Coast region by fiscal 2040;
- Beyond the elements identified above and after demand-side measures, plan to acquire new energy resources starting with 810 GWh in fiscal 2031, then shifting to primarily capacity resources starting with 160 MW in fiscal 2038. We'll select these future resources from amongst:
  - Expiring electricity purchase agreements with independent power producers;
  - New clean or renewable energy resources; and
  - Upgrades to BC Hydro facilities.
- Undertake a structured decision making approach to evaluate small BC Hydro plants that are requiring end of life investment decisions on a facility-by-facility basis to determine whether to decommission or refurbish these facilities.

Finally, Contingency Resource Plans were developed for scenarios where our customers' electricity needs are significantly higher or lower than our reference case and/or our Near-term Actions do not deliver as expected.

The scenarios included in the 2021 IRP are:

- Electricity demand stagnates;
- Electrification accelerates more quickly;
- Electrification accelerates and demand-side measures don't perform as expected; and
- North Coast (NC) electrification.

BC Hydro is taking steps now to ensure that we can implement the Contingency Resource Plans on a timely basis if the need arises. We will monitor the evolving policy environment and trends in our customers' electricity needs and be ready to adapt to these changes.

Many of the Near-term Actions will require further consultation and separate approvals from the BCUC, and the 2021 IRP will inform the consultation and the BCUC's consideration of those applications.

2

Introduction

2.1 About BC Hydro

BC Hydro is one of the largest electric utilities in Canada and is publicly owned by the people of British Columbia (B.C.). We generate and provide electricity to 95 per cent of B.C.'s population and serve over four million people. The electricity we generate and deliver to customers throughout the province powers our economy and quality of life.

BC Hydro's integrated system is backed by 30 hydroelectric plants, a thermal generating station, and approximately 80,000 kilometres of transmission and distribution lines. As of October 2021, we also have 123 electricity purchase agreements with independent power producer facilities in our integrated system, with fuel sources for electricity generation such as hydro, wind, solar, natural gas and biomass. In aggregate, our system electricity generation is 98 per cent clean or renewable.

As a Crown corporation, BC Hydro reports to the Provincial Government through the Minister of Energy, Mines and Low Carbon Innovation. BC Hydro is also a public utility regulated by the BCUC under the *Utilities Commission Act*.

2.2 What is the 2021 Integrated Resource Plan?

An integrated resource plan is a guidebook for what, when, and how to meet customers' evolving electricity needs.

This 2021 Integrated Resource Plan looks at a 20–year time frame and will guide decisions on meeting future customer needs for electricity until our next integrated resource plan. The 2021 IRP is aligned with government policy objectives, such as provincial greenhouse gas emission reduction targets and the requirements of the *Utilities Commission Act* and the BCUC.

The 2021 IRP consists of three main components:

- A Base Resource Plan, which is our strategy to meet the future needs of our customers if future needs reflect our Reference Load Forecast;
- Several Contingency Resource Plans, which are the strategies we will pursue if the future needs are higher or lower than those reflected under the Base Resource Plan; and
- Several Near–term Actions, which are the specific steps we will take to implement elements of the Base Resource Plan and prepare for the Contingency Resource Plans before our next integrated resource plan is filed. Many of the Near–term Actions in the 2021 IRP will require separate approvals from the BCUC to be implemented. The 2021 IRP will inform the BCUC's consideration of those applications.

The Near–term Actions for the Contingency Resource Plans are designed to prepare BC Hydro to implement elements of the Contingency Resource Plans if new information indicates the need to do so. This approach allows planned resources to be advanced incrementally as future customer needs become more certain.

The 2021 IRP, therefore, prepares BC Hydro to meet future customer needs under a range of scenarios, including an Accelerated electrification scenario where BC Hydro's Electrification Plan (Electrification Plan) targets are fully realized; B.C.'s greenhouse gas emission reduction targets are met; and, there are no offsetting reductions in load relative to what's included in the Reference Load Forecast. Our Electrification Plan was filed with the BCUC in August 2021 as part of our Fiscal 2023 to Fiscal 2025 Revenue Requirements Application. It includes our efforts supporting electrification and greenhouse gas emission reductions through low carbon electrification programs, electric vehicle charging infrastructure, support for customer connections, and expansions of the transmission system.

2.3 Our planning objectives in developing the 2021 IRP

BC Hydro's planning objectives were the subject of consultation in late 2020 and into 2021. Through this consultation, BC Hydro set its planning objectives for the 2021 IRP as keeping costs down for customers, reducing greenhouse gas emissions through clean electricity, limiting land and water impacts, and supporting the growth of B.C.'s economy.

As a Crown utility, BC Hydro has an important role in advancing reconciliation with Indigenous peoples. An initial objective was considered early in developing the Draft IRP: supporting reconciliation with Indigenous peoples. Although supporting reconciliation had strong support, input from Indigenous participants viewed it as being inappropriately expressed as an objective which could be traded off against other objectives when comparing alternatives. We heard that all the other planning objectives have Indigenous interests that cannot be easily separated from supporting reconciliation. Based on this perspective, BC Hydro considered Indigenous interests as part of each planning objective.

2.4 Our next integrated resource plan

The 2021 IRP has a 20–year planning horizon; however, that does not mean we will not prepare another IRP for 20 years. We will have a number of integrated resource plans over that period. The planning context will continue to evolve and forecasts will need to be updated. The Contingency Resource Plans included in the 2021 IRP address some related uncertainties, but they cannot address all of them.

We expect to complete integrated resource plans every five years, or sooner if load or supply updates show that the Near–term Actions in our 2021 IRP are not sufficient to meet future needs.

3

Where does BC Hydro find itself today?

3.1 Introduction

Reconciliation with Indigenous peoples, climate action, evolving customer needs and electricity consumption, and technological advancements are changing how electrical utilities do business. BC Hydro's 2021 IRP has been developed within this broader evolving planning context.

3.2 The importance of reconciliation with Indigenous Peoples

Canada's Truth and Reconciliation Commission has described the United Nations Declaration on the Rights of Indigenous Peoples as a framework for reconciliation for all sectors of Canadian society. The Truth and Reconciliation Commission has defined reconciliation as, "establishing and maintaining mutually respectful relationships between Indigenous and non-Indigenous peoples." As a Crown utility, we have an important role to play in supporting the broader societal effort of reconciliation. We recognize that maintaining and developing the system has impacts on the lives and interests of Indigenous Nations. We also recognize that relationships with Indigenous Nations are critical to operating and growing our system of clean electricity.

BC Hydro's Statement of Indigenous Principles forms part of our Code of Conduct and guides our approach to the ongoing work of reconciliation, and the implementation of United Nations Declaration on the Rights of Indigenous Peoples and the Truth and Reconciliation Commission Calls to Action. The Statement of Indigenous Principles includes a commitment that: We will inform First Nations communities, to the best of our ability, of our multi-year planning, identifying potential projects and works as early as possible for discussion. Early engagement is an important element of advancing reconciliation and the 2021 IRP is the earliest BC Hydro can engage with Indigenous Nations on meeting our customers' future electricity needs.

In addition, incorporating the United Nations Declaration on the Rights of Indigenous Peoples and the Truth and Reconciliation Commission Calls to Action into our business is much broader than the 2021 IRP. BC Hydro is working with Indigenous Nations to find meaningful paths to reconciliation through many areas of our business. Building relationships with Indigenous Nations, particularly those most impacted by our presence in their territory, will continue to be a focus for BC Hydro and will inform how we incorporate the declaration into our business.

3.3 We have an energy and capacity surplus

BC Hydro is well positioned to serve our customers' province-wide electricity needs for most of the next decade with additional demand-side measures, before adding any new clean or renewable energy resources. Our integrated system is currently in surplus. This is illustrated in Chapter 4, entitled "Load Resource Balances before Planned Resources."

This means we're ready to support growth in B.C.'s population and economy while playing our part in achieving the Provincial Government's greenhouse gas reduction targets. It also means we're prepared to deal with uncertainties such as the speed of our recovery from the COVID-19 pandemic or the incremental opportunities from electrification. Chapters 7 and 8, entitled "The Base Resource Plan – our strategy to meet the future electricity needs of our customers" and "The Contingency Resource Plans: preparing for change" respectively, detail our plans to move forward with certain "Near-term Actions" that prepare us for a range of potential future needs.

3.4 Our climate is changing

There is an important conversation happening around the globe about how we use energy, and the impact our choices have on climate change. And in B.C., we have an opportunity to switch from fossil fuels to clean electricity. B.C. is already western North America's leader in clean electricity generation.

BC Hydro's Electrification Plan aims to increase awareness of existing programs and further address barriers to electrification with new programs. It offers customers the support, tools and incentives to choose clean electricity over fossil fuels that are currently being used to power homes, businesses, industries and vehicles across the province. The Electrification Plan is expected to result in additional electric load and associated greenhouse gas emission reductions relative to BC Hydro's December 2020 Load Forecast, which is further discussed in section 4.2. The magnitude and timing of additional load and greenhouse gas emission reduction achieved through electrification will depend on the collective efforts of BC Hydro, our customers, and government initiatives. For example, as government funded initiatives and regulations change, BC Hydro's Electrification Plan may also be adjusted.

At this time, potential growth in electricity demand arising as a result of greenhouse gas reduction targets and Electrification Plan actions are included in our high electricity demand scenarios which inform the Contingency Resource Plans in the 2021 IRP.

With the 2021 IRP's Base Resource Plan, our power system will be ready to meet the future needs of customers across a range of scenarios. The 2021 IRP's Near-term Actions will allow BC Hydro to be ready and flexible, incrementally advancing planned resources as changing load and supply when there is a need to do so. We monitor our operating environment and update our supply and demand forecasts to reflect strategic changes in our operating environment and, if circumstances dictate, we can implement steps from the 2021 IRP's Contingency Resource Plans to address these changes continue meeting our customers' needs.

BC Hydro also plays an ongoing role in monitoring and considering the impacts of climate change on our ability to supply electricity and to remain reliable and resilient as our economy grows. Section 4.5 describes how the 2021 IRP has considered climate impacts on changes to future electricity demand and the generation capability of our system.

3.5 We're part of an evolving, regional energy landscape

B.C.'s electricity grid is connected to a much larger grid covering B.C., Alberta, portions of 14 western U.S. states and a small part of Mexico. Wholesale electricity trade is important both to B.C. and its neighbours for reliability and for lowering the costs to provide service.The 2021 IRP contains a wholesale electricity price forecast, including high and low bands, used in the valuation of aspects of the 2021 IRP, such as surplus electricity.

Capacity is produced by firm, dependable sources of power that can be relied upon whenever needed. Resources that provide dependable capacity at peak times and have flexibility associated with storage are key to integrating intermittent renewables, such as wind and solar. Hydroelectricity with storage, such as BC Hydro's system is a clean way of providing this dependable capacity and flexibility. Hydroelectric storage also enables water to be stored during periods of high supply / low demand and to be used for generation in times of low supply / high demand.

New technology is also introducing opportunities to develop flexibility and control for both electricity demand and supply. For example, the cost of small-scale battery storage technology has decreased in recent years. While still relatively early in their technology lifecycle, utility-scale batteries can provide short-term storage and shift output from renewables (such as solar power) into periods with more demand. While this technology remains relatively expensive and has limited storage duration today, costs are expected to decline, and its capabilities are expected to increase.

Another emerging trend is demand response technology – the ability to manage demand such as electric vehicle charging or home appliances (e.g., water heaters) by shifting electricity demand out of peak times and into periods when supply is more available.

Chapter 5 summarizes BC Hydro's Resource Options Database which discusses many of these technologies.

3.6 Our customers' demand for electricity is changing

Customer demand for electricity is also changing. Electrification activities are causing electricity growth, such as being seen in the transportation sector. With the passing of the *Zero–Emission Vehicle Act*, by 2040 every new light–duty vehicle sold in B.C. will be a zero–emission vehicle. B.C. currently leads North America in the sale of electric vehicles (EVs), with electric vehicles representing 10 per cent of all new cars sold in the province in 2020. TransLink and BC Transit are both moving to replace their diesel buses with battery electric versions.

However, in some resource–based industries, economic factors are combining to cause decreases in demand for electricity. New demand presents an opportunity for us to mitigate the risk of declines in demand, as declines in demand can result in the need for our existing system costs to be recovered from the remaining customers, which has rate impacts.

3.7 Our customers' expectations are changing

Customer expectations from energy providers are broadening beyond reliable service to include technology and data on energy use.

Demand–side measures (rates, measures, actions, or programs undertaken to conserve energy or promote energy efficiency) can reduce the amount of energy demand or shift the use of energy to periods of lower demand. Demand–side measures that reduce peak load can help defer the need for new capacity investments. Optional rates can provide customers with more choices, and programs can provide customers with new ways to manage their energy use and take advantage of those choices.

Affordability for all customers is a key priority for BC Hydro. BC Hydro can support affordability by advancing cost–effective demand–side measures to help meet our future electricity needs and to help customers save money on their bills.

Customers are also increasingly concerned about how their energy choices impact the environment and sustainability. By using clean or renewable electricity instead of higher emitting fuels to power their homes, vehicles, and businesses, customers can help to reduce greenhouse gas emissions and contribute to meeting climate goals.

We cover how we gathered and considered customer values and interests in Chapter 6, where we outline the process used to build the 2021 IRP.

4

Load Resource Balances before Planned Resources

4.1 Introduction

A Load Resource Balance is a comparison of the load and the resources over a 20-year planning horizon. When only existing and committed resources (i.e., resources that are already in place or are actively being implemented) are included, the Load Resource Balance shows the timing and volume of additional resources required to meet customers' demand. We call this the Load Resource Balance before planned resources.[1] It forms the basis for the 2021 IRP development.

Load Resource Balances are developed for both energy and capacity. An energy Load Resource Balance addresses the electrical energy needs for each year of our planning horizon (expressed as gigawatt-hours per year, GWh/year). A capacity Load Resource Balance addresses the peak electricity use at any point in time in the planning horizon (expressed as megawatts, MW).

4.2 Load forecast

A key input into Load Resource Balances is the load forecast. For the 2021 IRP, we use the reference case of the 20-year load forecast finalized in December 2020 (December 2020 Load Forecast).[2] The reference energy and peak forecasts have been adjusted for rate impacts but do not include demand-side measure savings. This will be referred to in the 2021 IRP as the Reference Load Forecast. The Reference Load Forecast is derived from deterministic forecasting models for the residential, commercial and portions of the light industrial forecasts. It also uses customer-based forecasts with probability weightings for the large industrial and portions of the light industrial sector forecasts.[3]

The Reference Load Forecast, which is used in developing the Base Resource Plan, projects moderate growth averaging about 1.4 per cent per year over the planning horizon (again, before accounting for demand-side measures). Growth is primarily due to electric vehicle and oil & gas sector load growth (including liquefied natural gas), but it is partially offset by declines in the forestry sub-sector.

Load forecasts are sensitive to many input variables, each of which has varying degrees of uncertainty. Uncertainties influence the risk that future demand will be lower or higher than forecast. They can exist at the customer-specific level up through to sector-wide or economy-wide levels. Alongside the Reference Load Forecast, other load scenarios were developed to explore the future customer needs associated with different future outcomes. Our Contingency Resource Plans are based on these scenarios.

4.3 Existing and committed resources

Another key input into the Load Resource Balances are resources already in place. These include existing and committed resources on both the supply-side and the demand-side. Existing resources are resources that are currently operating and are expected to continue to operate into, if not to the end of, the planning horizon. Committed resources are those resources that have received necessary internal authorizations to proceed to implementation as well as any required regulatory approvals and are expected to begin operating during the planning horizon. Existing and committed resources include BC Hydro generation resources and bulk transmission resources, electricity purchase agreements until the date of their expiry, and forecasted savings associated with current and/or approved demand-side measures.[4,5,6] A more detailed description of existing and committed resources is provided in Attachment 1.

1 Base and Contingency Resource Plans are also load resource balances, but they show the timing and volume of the additional resources required to fill any gaps.
2 The December 2020 Load Forecast includes a suite of forecasts including reference, high, and low cases for both energy and peak, before and after various adjustments.
3 This means that the reference load forecast is not derived from probabilistic, or stochastic, models that produce a probability distribution of load outcomes.
4 The transmission capabilities of bulk transmission resources are included as a 'resource' in the Load Resource Balances at regional levels.
5 Facilities under electricity purchase agreements, and certain potential electricity purchase agreements under the Standing Offer Program, that have yet to achieve commercial operation date but are expected to within the planning horizon of the 2021 IRP, are considered committed resources.
6 Existing and committed demand-side measures include forecasted savings from current and future codes and standards, current rate structures (including net metering), and the savings from the fiscal 2021 program expenditures which was approved in the fiscal 2020 – 2021 RRA.

4.4 Planning criteria

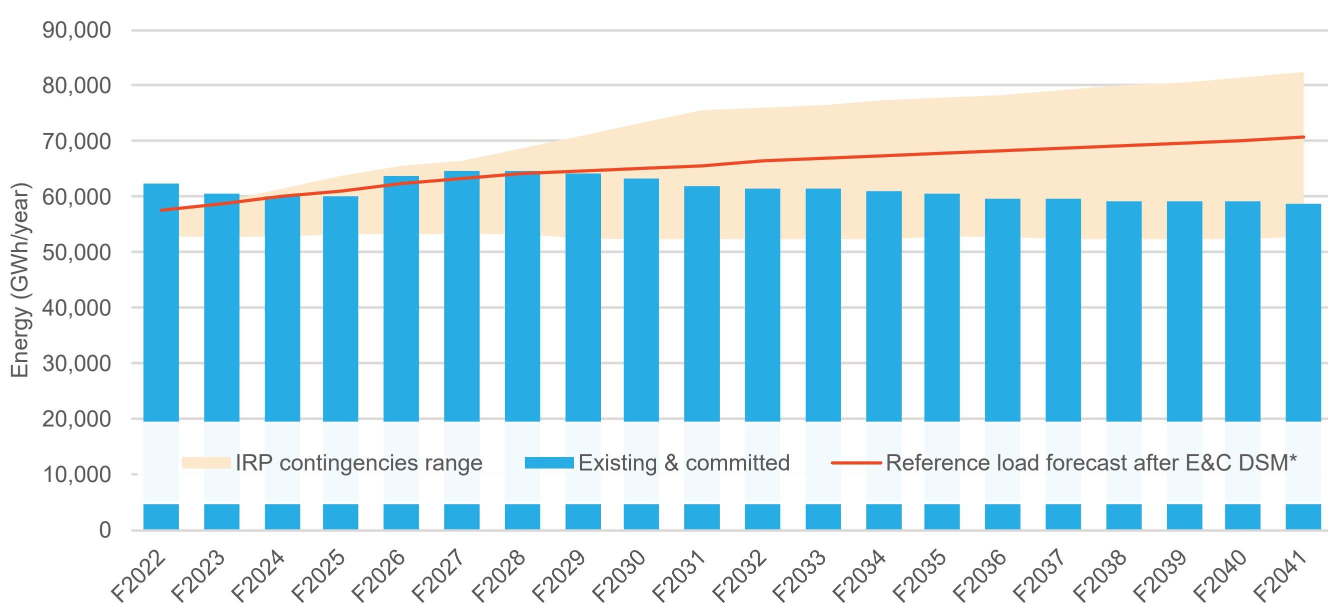
BC Hydro uses generation and transmission planning criteria in developing plans so that we have a reliable electrical system, including adequate generating capability (energy and capacity), and adequate transmission capability. They provide, in effect, the capability of the existing and committed generation and transmission resources, as well as planning guidance for the reliability contribution of future resources, used to develop the Base Resource Plan and Contingency Resource Plans. These criteria are periodically reviewed, and if necessary, updated, to reflect best electric utility practices and information about the performance of our electrical system. Our three criteria are:

- The energy planning criteria is used to determine the amount of electrical energy our generation system can be relied upon to generate for long-term planning purposes. In setting the energy planning criteria, BC Hydro must consider the variability of its primary fuel (water), the ability of its reservoir systems to store and regulate that water, and its access to other electricity sources, including external markets. Currently, BC Hydro uses a "self-sufficiency" energy planning criterion, consistent with the requirements of the *Clean Energy Act* and the *Electricity Self-Sufficiency Regulation*.
- The capacity planning criteria is used to determine, for long-term planning purposes, the amount of capacity our generation system can reliably generate to meet peak electricity demand. This is particularly important when considering resources whose output is uncertain (e.g., wind and solar) and resources that can only sustain their energy production (or savings) for short periods of time (e.g., batteries and demand response technologies). As with the energy planning criteria, BC Hydro's capacity planning criteria is consistent with the requirements of the *Clean Energy Act* and the *Electricity Self-Sufficiency Regulation*.
- BC Hydro's transmission planning criteria are a set of rules that define the transmission system capability when the system is operating normally and contingency conditions when some components of the system are malfunctioning.

4.5 How much electricity BC Hydro will require and when

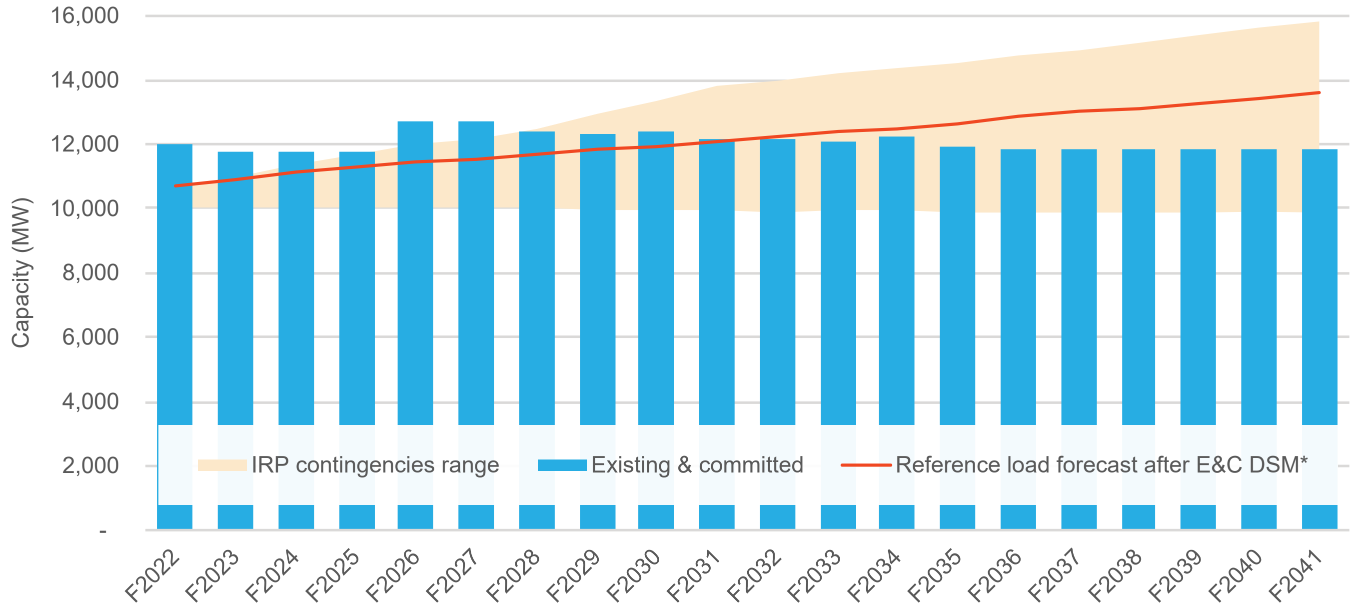
After applying the criteria laid out above to our existing and committed resources, we establish the capability of our electric system. By comparing these resources to the future electricity needs of our customers, as outlined by the Reference Load Forecast, we establish when we will need additional energy and capacity resources. The resulting Load Resource Balances before planned resources are illustrated in Figure 4-1 and 4-2.

Figure 4-1 System energy Load Resource Balance before planned resources



* E&C DSM denotes existing and committed demand-side measures

Figure 4-2 System capacity Load Resource Balance before planned resources



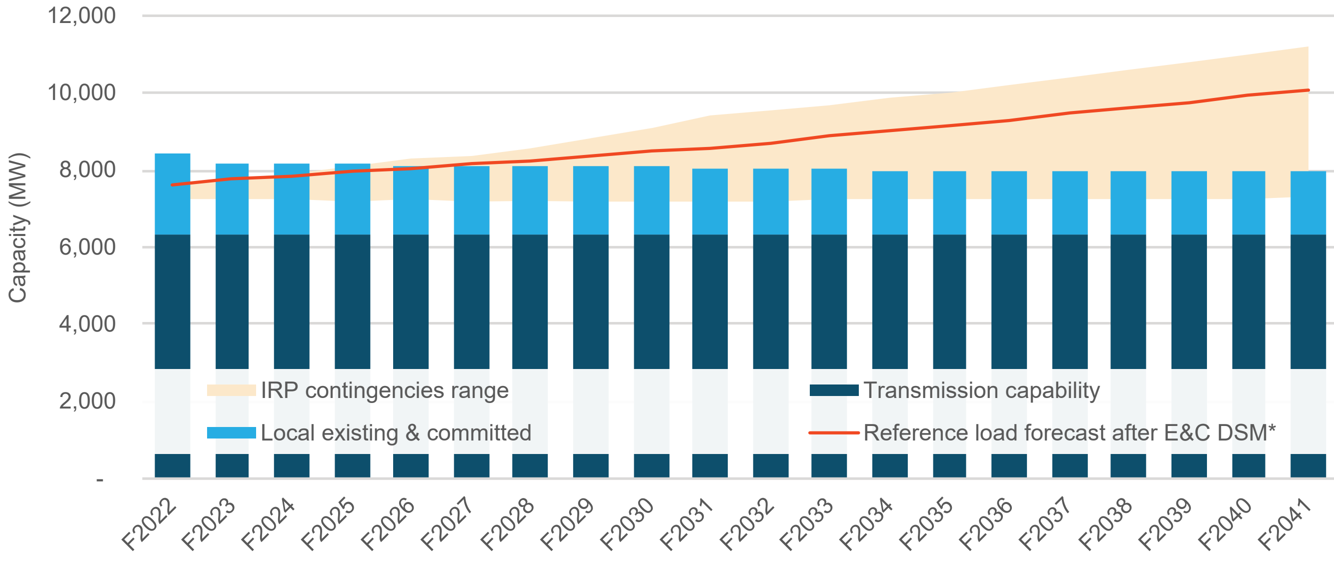
* E&C DSM denotes existing and committed demand-side measures

The blue bars represent the capability of our existing and committed resources according to our planning criteria. The orange line shows the Reference Load Forecast adjusted with the savings from the existing and committed demand-side measures. This is the net customer electricity demand over the next twenty years. The year that a gap begins between the orange line and the blue bar is the year we first need additional resources. The system-wide graphs show that, under the Reference Load Forecast, new energy needs occur in fiscal 2029 while capacity needs occur in fiscal 2032, in both cases before any planned resources.

In addition to the system-level Load Resource Balances, we also developed capacity Load Resource Balances for three regions – South Coast, Vancouver Island and North Coast – to address region-specific planning issues that result from large regional load growth and/or considerable disparity between regional supply and demand.[7] Whereas the system capacity Load Resource Balance shown in Figure 4-2 includes generation resources from a province-wide integrated system perspective, the regional capacity Load Resource Balances (shown in Figures 4-3, 4-4, and 4-5) consider load, generation resources and the transmission capability from a regional perspective. The latter reflects that future electricity needs could be met by both the local generation resources and transmitted from other regions of B.C.

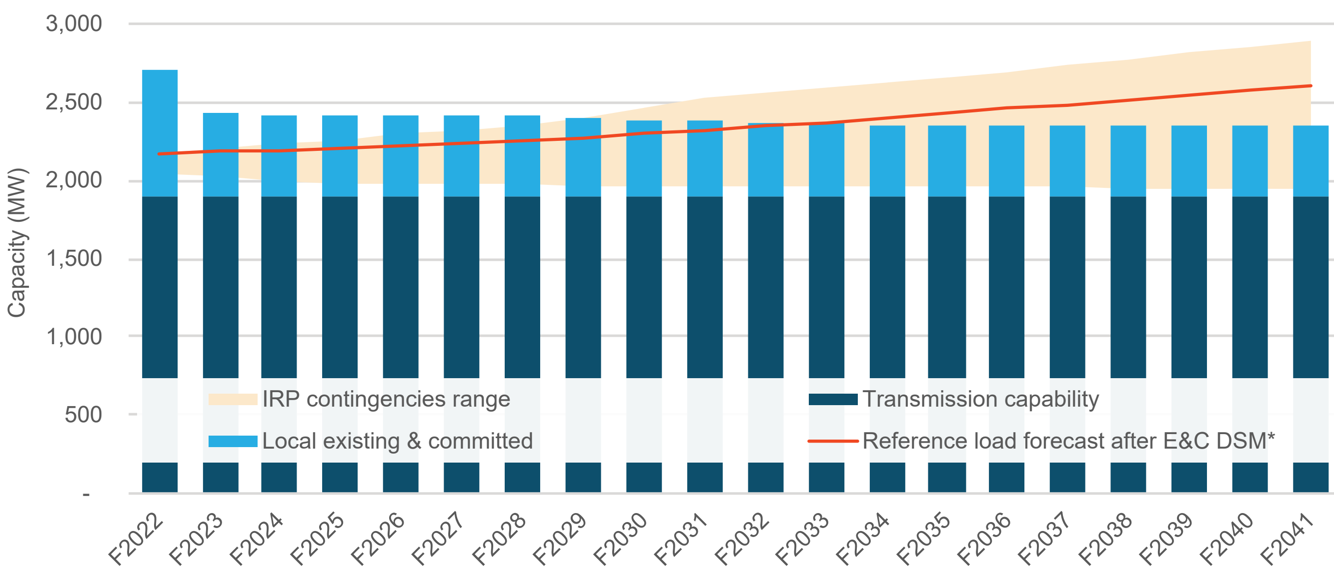
7 South Coast encompasses the Lower Mainland and Vancouver Island regions of B.C.

Figure 4-3 South Coast capacity Load Resource Balance before planned resources



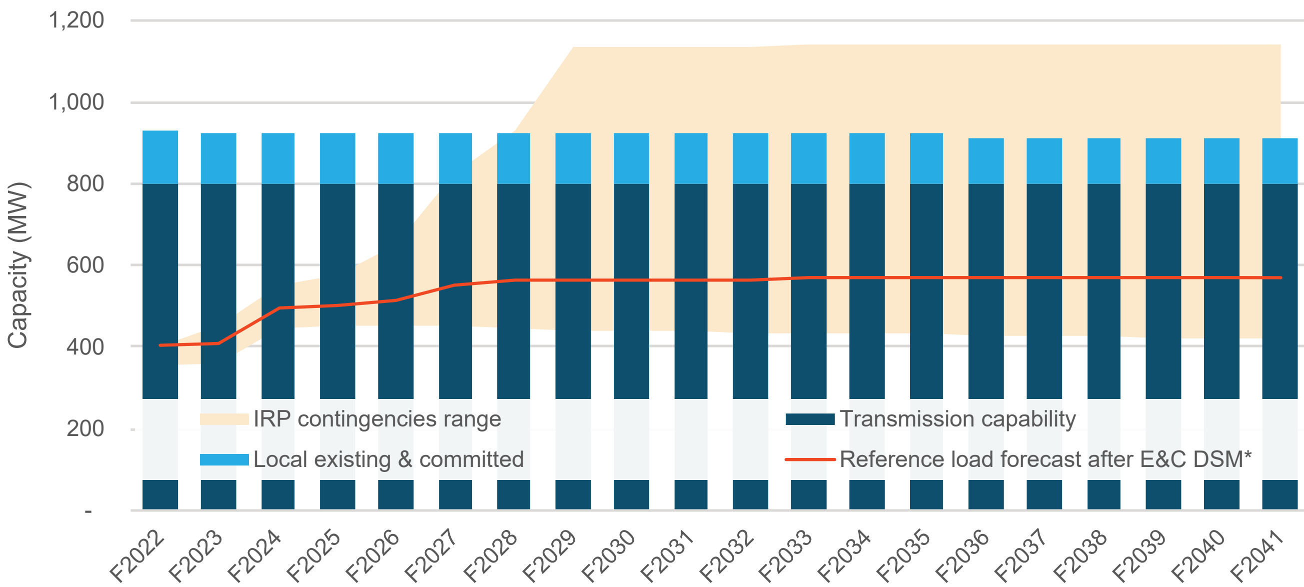
* E&C DSM denotes existing and committed demand-side measures

Figure 4-4 Vancouver Island capacity Load Resource Balance before planned resources



* E&C DSM denotes existing and committed demand-side measures

Figure 4-5 North Coast capacity Load Resource Balance before planned resources



* E&C DSM denotes existing and committed demand-side measures

The South Coast capacity Load Resource Balance before planned resources, shown in Figure 4-3, indicates that under the Reference Load Forecast, additional capacity resources are needed for the South Coast region by fiscal 2027 (before any planned resources), which is earlier than the need at the system level. The higher load growth in the South Coast region compared to the rest of the province is attributed, in part, to the adoption of electric vehicles. The Vancouver Island capacity Load Resource Balance before planned resources, shown in Figure 4-4, indicates that additional capacity resources are not required for the Vancouver Island region until fiscal 2034. Finally, the North Coast capacity Load Resource Balance before planned resources, shown in Figure 4-5, indicates that additional capacity resources are not required for the North Coast region under the Reference Load Forecast. However, the North Coast region has the potential for considerable load growth as a result of liquified natural gas and mining developments.

The 2021 IRP uncertainty band in all figures represents the unknowns surrounding the Reference Load Forecast. We plan for uncertainty by looking at situations where electricity demand could be higher or lower than our Reference Load Forecast. The 2021 IRP uncertainty band represents a range of possible electricity demand outcomes.

Relative to the Reference Load Forecast, the lower part of the 2021 IRP uncertainty band includes lower levels of electrification, no growth in residential and commercial demand, and some closures of industrial operations. The upper part of the 2021 IRP uncertainty band is represented by an Accelerated electrification scenario.[8] For the North Coast region, the upper part of the 2021 IRP uncertainty band assumes that several of the mines and liquified natural gas facilities that have been proposed in the region proceed into operation within the next decade. These scenarios are described further in Chapter 8.

In assessing the amount of electricity BC Hydro will require, we have examined how the two primary inputs to the Load Resource Balances may be impacted by climate change: (i) the system generation capability, and (ii) future electricity demand. Our studies show that, under a range of climate change scenarios drawn from the Intergovernmental Panel on Climate Change (IPCC), the system generation capability at the end of the century is within +/- five per cent of the existing system generation capability.

In terms of future electricity demand, we may see a roughly two per cent decrease in both energy and capacity demand, due to the impacts of climate change. While we have recently seen hotter summers with increased demand for electricity, we expect BC Hydro to remain a winter-peaking utility, meaning the most demand placed on our integrated system in the winter during the coldest days when space heating is required. With winters warming on average, we may see a reduction in the average amount of electricity required to serve winter demand. That said, the decrease in future electricity demand due to changes in temperature is small in comparison to other factors such as climate action policies, and hence is considered within the existing bounds of load uncertainty tested in the 2021 IRP.

8 The Accelerated electrification scenario is composed of the demand associated the BC Hydro Electrification Plan as well as an electrification scenario developed by Navius Research to meet all the provincial greenhouse gas reduction targets.

5

Resource options

5.1 Resource Options Database: new electricity resources available to meet the future needs of our customers

BC Hydro maintains a database of information on a broad range of resources to meet future electricity needs, including technical, financial, social and environmental attributes (Resource Options Database). The database includes information on upgrades to BC Hydro–owned generation facilities, demand–side measures, electricity purchase agreement renewals, upgrades to BC Hydro bulk transmission facilities, and new clean or renewable generation resources.

The technical attributes of each resource option describe how much energy and/or capacity can be delivered to the grid, how quickly a resource can be brought online, and the flexibility the resource adds to the system to respond to changes in load.

The financial attributes describe the cost to build, operate and maintain a resource option.

The social attributes are an estimate of the jobs created from resource development.

The environmental attributes are an estimate of the greenhouse gas and impacts on land from resource development. These attributes are currently only ascribed to new supply–side resources.

5.2 Demand–side measures

Demand–side measures include energy efficiency programs, as well as time–varying rates and demand response programs. We describe each below.

5.2.1 ENERGY EFFICIENCY PROGRAMS

Energy efficiency programs generally include incentives for customer studies and projects, and marketing and awareness initiatives. Energy efficiency programs provide energy as well as capacity savings.

Several different portfolios of energy efficiency resource options have been defined, reflecting differing scales of marketing and education efforts and incentive levels. They include an array of custom and prescriptive offers to residential, commercial, and industrial customers in B.C. for energy efficiency projects, energy management and operational improvements, and new construction. The portfolios of options we developed and that are in our Resource Options Database are as follows:

- Base energy efficiency: maintain a base level of demand–side measure programs that can readily be scaled up in future years.
- Higher energy efficiency: increased incentives and marketing efforts relative to the Base energy efficiency portfolio.
- Higher plus energy efficiency: further increase marketing efforts and incentives, relative to the Higher energy efficiency portfolio, to cover 100 per cent of incremental customer costs.
- New construction: incentives for new buildings to achieve a higher efficiency level than the current building code.
- Customer solar: capital incentives to support customer adoption of small solar rooftop systems.
- Customer batteries with solar: capital incentives for both solar and batteries on single–family homes, with utility management of batteries to help meet system capacity.

5.2.2 TIME-VARYING RATES AND DEMAND RESPONSE PROGRAMS

The options developed to reduce electricity use during high demand, or peak periods, include time-varying rates and demand response programs.

Time-varying rates encourage customers to shift their electricity consumption from periods of high system electrical demand to periods of lower demand in response to a price signal. Common examples of time-varying rates include time-of-use and critical peak pricing rates. These can be offered to different types of customers (residential, commercial, and industrial) and may be offered as voluntary (opt-in), default (with an option to opt-out), or mandatory.

Individual rate options were arranged into four rate suites which combined different voluntary and default rate options across the various customer classes.

Demand response programs enable customers to shift their load away from peak demand periods through voluntary programs that manage and control customers' electricity demand. Demand response programs can be coordinated with time-of-use rates to give customers different options to reduce their electricity consumption during peak periods. For example, a customer can participate in a program where the utility controls a customer's device (e.g., space or water heating equipment). The utility turns off the device during a peak event, and the customer receives an incentive. In a load curtailment program, commercial and industrial customers commit to providing a firm load reduction during a peak event in exchange for an incentive. In the peak saver incentive program, residential customers are given 24-hours notice of an upcoming peak event and receive an incentive if they successfully reduce load during that event.

Individual demand response programs were arranged into Demand Response Program A or B, which are groups of demand response programs with a base or higher level of funding, respectively.

Table 5-1 Summary of rate suite and demand response option combinations

Rates suite 1 Voluntary time-of-use rates (for residential and large commercial customers) and voluntary critical peak pricing (for large commercial and industrial customers).	**Demand Response Program A** Base level of funding for direct control incentive programs and marketing and education activities; load curtailment for commercial customers; and peak saver incentives for residential customers.
Rates suite 2 Voluntary time-of-use rates (for residential, large commercial and industrial customers) and voluntary critical peak pricing (for residential and large commercial customers).	**Demand Response Program A** Base level of funding for direct control incentive programs and marketing and education activities; load curtailment for commercial customers; and peak saver incentives for residential customers.
Rates suite 3 Default time-of-use rates (for residential, large commercial and industrial customers) and voluntary critical peak pricing (for residential and commercial customers).	**Demand Response Program B** Higher level of funding for direct control incentive programs and marketing and education activities; load curtailment for commercial customers; and peak saver incentives for residential customers.
Rates suite 4 Default time-of-use rates and critical peak pricing (for residential, large commercial and industrial customers).	**Demand Response Program B** Higher level of funding for direct control incentive programs and marketing and education activities; load curtailment for commercial customers; and peak saver incentives for residential customers.

To determine how much time-varying rates and demand response programs to pursue in the 2021 IRP, we analyzed combinations of rate suites and demand response programs.[1,2] The groupings compared in the analysis are shown in the table above.

For industrial customers, a potential industrial load curtailment resource option was also developed.

Industrial load curtailment has substantial development and operational history from a pilot conducted in the late 2010s. As there are relatively few large customers in the industrial group, it is possible to tailor individual agreements, enabling more customers to participate in the program. Industrial load curtailment targets similar savings as voluntary critical peak pricing but allows for more flexibility for BC Hydro and the customer. Many large industrial customers have expressed support for an Industrial Load Curtailment Program; and, given BC Hydro and customers' previous experience, we believe industrial load curtailment can be implemented with shorter lead times compared to time-varying rates or demand response programs.

Electric vehicle peak reduction is focused on encouraging customers to defer electric vehicle charging to off-peak periods. The electric vehicle market is rapidly increasing in size. From a utility perspective, the ability to satisfy electric vehicle charging demand can be a challenge if most electric vehicles are charged during peak demand periods, such as in the early evening.

Electric vehicle peak reduction in the 2021 IRP, combine time-varying rates with supporting programs to shift electric vehicle charging outside of system peak periods:

- 35 per cent electric vehicle driver participation: marketing and education efforts to support a voluntary residential time-of-use rate intended to shift home charging by 35 per cent of residential electric vehicle drivers to off-peak demand periods;
- 50 per cent electric vehicle driver participation: more aggressive marketing and education efforts, combined with customer smart-charging technology incentives to support a voluntary residential time-of-use rate intended to shift home charging by 50 per cent of residential electric vehicle drivers to off-peak demand periods; and
- 75 per cent electric vehicle driver participation: most aggressive combination of marketing and education efforts and customer smart-charging technology incentives to support a residential time-of-use rate intended to shift home charging by 75 per cent of residential electric vehicle drivers to off-peak demand periods.

5.3 Electricity purchase agreement renewals

As of October 2021, BC Hydro had 123 electricity purchase agreements with independent power producers. About 70 of these agreements are expiring over the next 20 years, representing approximately 9,100 GWh of firm energy and 1,300 MW of dependable capacity. The expiring agreements are primarily small run-of-river facilities. There are also larger run-of-river, storage hydro, biomass, municipal solid waste, wind, solar, waste heat, biogas, and natural gas-fired generation facilities. These agreements are all considered as existing resources until the year they expire.

As BC Hydro does not own these facilities, we must make assumptions, for the purposes of evaluation, about the viability of each facility and the potential for entering into a renewal agreement with the independent power producer based on the resource type and facility age.

1 Rate suite 1 with Demand Response Program A was defined in the Resource Options Database but not included as an option in portfolio analysis because it offered far fewer MW savings at a comparable cost to Rate Suite 2 with Demand Response Program A.

2 Rate suite 4 with Demand Response Program B was defined in the Resource Options Database but not included as an option in portfolio analysis because of the challenges associated with implementing all-default time-varying rates.

5.4 Upgrades to BC Hydro generation and transmission resources

5.4.1 UPGRADES TO BC HYDRO TRANSMISSION SYSTEM

Upgrades to BC Hydro's bulk transmission system increase the ability to transfer electricity from where it is generated to where it is needed. Transmission upgrades may be required in response to either new customer demand or new generation supply, and typically have long project lead times. Several conceptual transmission upgrades are presented in our Resource Options Database and include improvements to existing infrastructure as well as options to add additional transmission facilities.

Most of BC Hydro's customer load is located in the South Coast region of the province with most of the electricity required to serve this customer load transmitted to the region from the Interior of the province through five transmission lines.

Table 5–2 outlines the incremental upgrades to transmission lines serving the South Coast that are identified in the Resource Options Database and are considered in the 2021 IRP.

Table 5–2 South Coast transmission upgrade resource options

Transmission resource options (sequential)	**Capacity**	**Lead time**
Step 1 upgrades (series compensation, shunt capacitors, thermal upgrades)	750 MW (–200 / +100)	10 years
Step 2 upgrades (static volt–ampere reactive (VAR) compensators)	800 MW (–200 / +100)	10 years
Step 3 upgrades (new stations, transformers and more thermal upgrades)	500 MW (–200 / +100)	10 years

The North Coast region has the potential for significant load growth, especially from new liquified natural gas (LNG) or mining customers. Existing customers in the region are served by a single transmission line from Prince George to Terrace.

Table 5–3 outlines the upgrade to the line serving the North Coast included in the Resource Options Database.

Table 5–3 North Coast transmission upgrade resource options

Transmission resource options	**Capacity**	**Lead time**
Prince George to Terrace upgrade (transformer, series capacitors)	500 MW	6 years

5.4.2 UPGRADES TO BC HYDRO GENERATING FACILITIES

Expansions to existing BC Hydro generating facilities can provide additional generation capacity but typically have long lead times. Potential expansions include an additional generating unit at the Revelstoke generating facility or upgrades to existing units at the G.M. Shrum generating facility. There is also a range of reliability–focused upgrades that could be undertaken at other facilities.

In addition, BC Hydro has a number of older, smaller generating facilities that are the subject of future decisions to decommission or to refurbish. The facilities currently in service are considered existing resources for the entire time horizon of the 2021 IRP, while those facilities not in service are not considered either existing or committed resources. Our Resource Options Database includes all previously identified potential upgrades to BC Hydro generation facilities except those with very high incremental energy or capacity costs.

5.5 Future resources

Many different types of new sources of electricity are available across B.C. BC Hydro monitors the potential and characteristics of these resources.

Table 5–4 illustrates the range of new supply options currently included in our Resource Options Database.

Table 5–4 New supply resource options in the Resource Options Database

New supply and renewable resources	
Primarily energy options	**Primarily capacity options**
Biomass	Battery storage – utility–scale
Distributed Solar	Battery storage – distribution–scale
Geothermal	Natural gas or renewable natural gas
Municipal solid waste	Pumped hydro storage
Natural gas	
Offshore wind	
Onshore wind	
Renewable natural gas	
Run–of–river hydro	
Small storage hydro	
Solar – utility–scale	
Solar – distribution–scale	

Current costs of these resources were assessed based on input from technical stakeholders and previous BC Hydro studies. Future costs of these resources were assessed based on the National Renewable Energy Laboratory's 2019 Annual Technology Baseline report, which accounts for future cost reductions associated with evolving technologies.

Based on BC Hydro's high–level analysis of comparative unit energy costs, onshore wind resources are likely the lowest cost supply–side energy resource in the near–term. While difficult to predict decades out, large–scale solar resources are expected to become more competitive over the long–term.

Utility–scale batteries are a newer capacity resource with a relatively short lead–time, which can be deployed on a flexible and scalable basis, and are expected to see cost declines over the next 10 years.

5.6 Reference Prices

Our Resource Options Database provides us with information necessary for building our Base Resource Plan and Contingency Resource Plans. The resource options information is also an input to the development of our reference prices. Reference prices (including a set of cost numbers) are used as a cost benchmark against which the cost of potential projects, programs, or initiatives are compared. These reference prices are applied in various ways to evaluate the cost-effectiveness of BC Hydro's capital investments, electricity purchase agreements, and demand-side management measures (including rates).

While they help create a consistent price signal, it's important to note that reference prices are not adjusted for reliability, safety, risk, or other considerations (e.g., environmental) of the underlying investments.

Where the reference prices are based on the expected cost of greenfield clean or renewable resources, they are not intended as clearing prices for electricity purchase agreements. BC Hydro does not use reference prices as the sole decision-making factor for any business case.

BC Hydro uses two sets of reference prices:

- One set is for generation, for each of energy and capacity; it is generally representative of resource costs utilized in BC Hydro's Base Resource Plan and includes the cost of bulk transmission upgrades required to deliver generation from remote regions to the Lower Mainland load centre.
- Another set is for non-bulk transmission and distribution; it is applicable for capacity only and is based on the cost of load growth driven non-bulk transmission and distribution upgrades.

The two figures below illustrate the transition from surplus to deficit, specifically with existing and committed resources compared to when planned demand-side measures, and market-price based electricity purchase agreement renewals in the next five years are added into the resource mix.

Figure 5-1 Reference prices (fiscal 2022$) for the duration of the 2021 Integrated Resource Plan

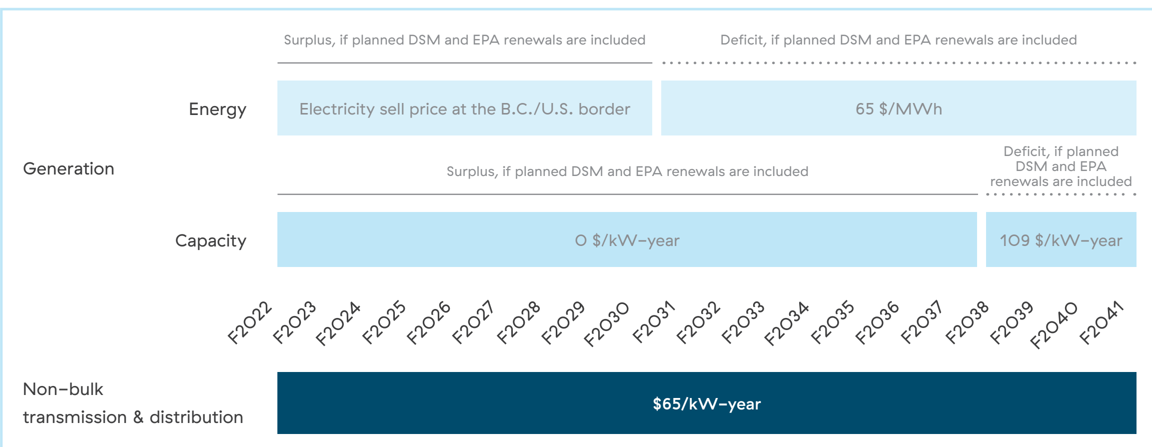


Figure 5-1 illustrates the two sets of reference prices, all in fiscal 2022 dollars, for the 2021 IRP duration after existing and committed resource and the demand-side measures and electricity purchase agreement renewals in the Base Resource Plan.

Figure 5–2 Reference prices (fiscal 2022$) without planned demand-side measures and electricity purchase agreement renewals included

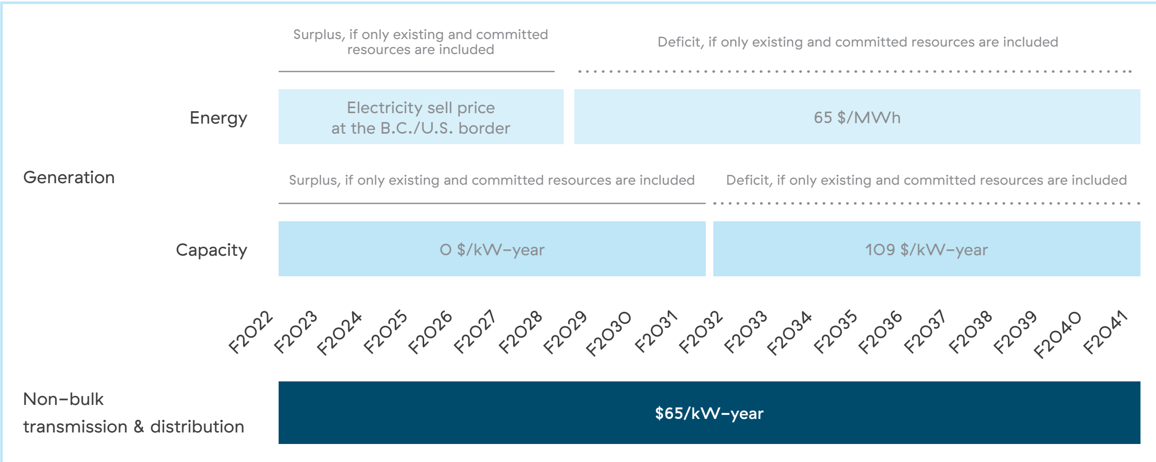


Figure 5–2 illustrates the reference prices (fiscal 2022$) with the transition from surplus to deficit reflecting only existing and committed resources and before the demand-side measures and electricity purchase agreement renewals in the Base Resource Plan. In this case, the transition from surplus to deficit would occur for energy in fiscal 2029 and for capacity in fiscal 2032.

Table 5–5 Non-bulk Transmission and Distribution reference prices (fiscal 2022$)

Cost Element	$/kW-year; fiscal 2022$
Non-bulk transmission	30
Distribution	35
Total	**65**

Table 5–5 provides the references prices for non-bulk transmission and distribution for the 2021 IRP duration.

The non-bulk transmission and distribution reference price provides a system average view of the wire system investment costs and applies to provincial wide projects. For any project impacting the non-bulk transmission and distribution network at a specific location, BC Hydro would assess the cost or value specifically to the project.

6

The process used to build the 2021 IRP

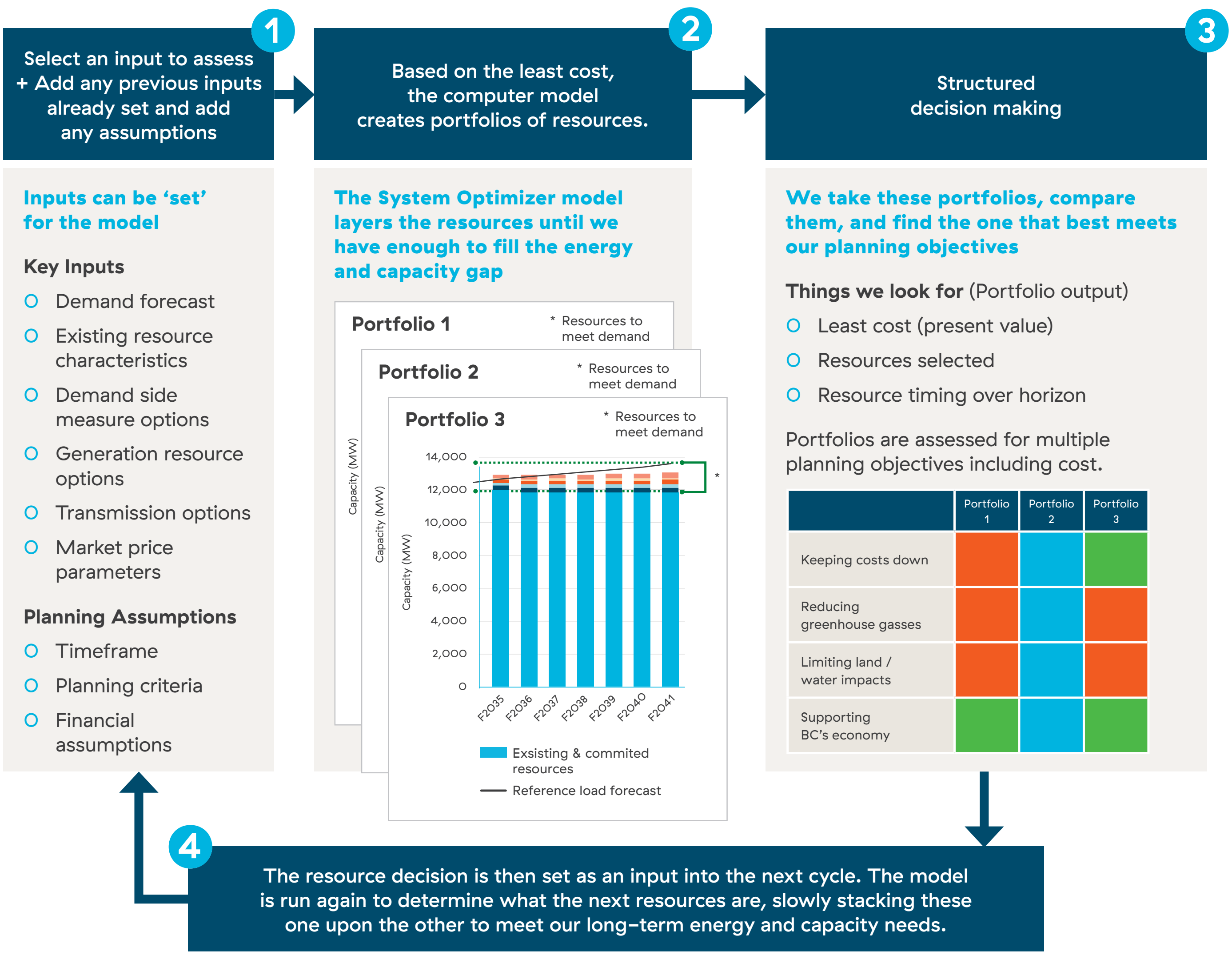
6.1 Introduction

To develop our plan, we used a structured decision making approach. This approach allowed us to be explicit about our planning objectives and the measures we used to evaluate whether we have met these objectives. The approach helped clarify the choices and trade-offs we made between potential options.

6.2 The process we used to generate portfolios and make decisions

Figure 6-1 illustrates the process of developing and evaluating portfolios of options using portfolio modelling and structured decision making.

Figure 6-1 Process of developing and evaluating portfolios



Section 44.1 of the *Utilities Commission Act* sets out the requirements for an integrated resource plan. It indicates a clear policy preference for the priority use of cost-effective demand-side measures. This priority was also consistent with the consultation feedback we received as we developed the 2021 IRP. Accordingly, developing and evaluating portfolios to create a Base Resource Plan started with examining demand-side measures by testing in sequence the cost-effective levels of energy efficiency, time-varying rates and demand response programs. Once the cost-effective level of demand-side measures was determined, supply-side resources were established to round out what resources, what timing and what volumes would make up a complete Base Resource Plan.

The general process steps are as follows:

1. We gather our technical inputs and assumptions. These include all our potential resource options in our Resource Options Database and other inputs like our load forecast, our planning criteria, major bulk transmission options, and other technical inputs.
2. We use a computer model (System Optimizer) to select the available resources to fill the gap between the forecast load and the available supply. The process starts with the selection of a particular resource and different assumptions about the size or volume of that particular resource. We then generate least-cost portfolios around each of the assumptions to compile a complete set of resources, the timing of those resources, and an overall portfolio cost.

   System Optimizer also calculates some non-financial impacts (e.g., greenhouse gas emissions). Additional non-financial impacts are then modelled outside of System Optimizer to develop a broader view of how the portfolio of resources impacts all the relevant decision objectives.

   Inputs to the model (e.g., load scenarios, resource availability, resource choices) can be changed to generate new portfolios, based on those inputs, to explore uncertainties or policy options.
3. We then conduct a trade-off analysis, including considering consultation input, between the different portfolios to determine how they perform relative to one another and against the planning objectives and measures. This comparison is a qualitative exercise conducted using a consequence table. A trade-off analysis is not an exact science. Rather it is used to inform decisions and to be transparent about the reasons for those decisions.
4. The resource option analyzed is then set at its selected level for the remainder of the analyses and the process is repeated using the next resource under consideration.

This process is repeated until the gap between forecasted load and the supply is filled by choices balancing the decision objectives.

6.3 The decision objectives we used to compare IRP options

As discussed in section 2.3, our planning objectives are keeping costs down for customers, reducing greenhouse gas emissions through clean electricity, limiting land and water impacts, and supporting the growth of B.C.'s economy.

Table 6-1 expands on the list of planning objectives by providing sub-objectives and associated measures that were used to evaluate the relative performance of portfolios against the planning objectives. These measures are used in the consequence tables that evaluate the trade-offs between different portfolios.[1]

1 Not all of the objectives and sub-objectives in Table 6-1 will be relevant for each portfolio being considered.

Table 6-1 Planning objectives

Planning Objective (sub-objective)	Measure	What is better	Description
Keep costs low for customers			
Minimize Net Total Resource Cost	$M PV	Lower	Millions of dollars in present value (**PV**).[2] Net Total Resource Cost measures the total costs to the utility and program participants.
Minimize Net Utility Cost	$M PV	Lower	Millions of dollars in PV. Net utility cost measures the costs of resources in terms of utility expenditures (program costs and incentive payments).
Minimize cost risk from demand-side measures' under-delivery	MW below fiscal 2030 planned estimates	Lower	The amount of megawatts (MW) change between planned savings and lower than expected savings in fiscal 2030. This is a proxy measure for cost risk as larger divergences could lead to the addition of more costly resources.
Minimize cost risk from transmission upgrade schedule uncertainty	In-service date for Step 2 and Step 3 transmission upgrades to the South Coast	Later	The earliest in-service date for the transmission upgrade. This is a proxy measure for cost risk as shorter lead times increase the likelihood that temporary stop gaps might be needed to bridge to the in-service date, incurring additional costs.
Minimize rate impact	Per cent	Lower	Rate increases incremental to the portfolio of existing and committed resources.
Maximize the ability for all to benefit from a rate	Opt-in or opt-out time-varying rate	Opt-in	Customers who choose to enroll in an opt-in time-varying rate are more likely to be those who can achieve bill savings, relative to customers who are automatically enrolled in a rate by the electric utility on an opt-out basis.
Limit land and water impacts			
Minimize land and water impacts	Index	Lower	The index represents an aggregate score for each portfolio based on its biophysical footprint which considers many land and water-based environmental attributes.

2 A present value calculation considers the fact that financial impacts (costs or benefits) that occur in the future have less weight from today's perspective. A present value calculation will take a stream of annual financial impacts (costs or benefits), translate them using a discount rate into current values, and them sum them up into one present value.

Planning Objective (sub-objective)	Measure	What is better	Description
Reduce greenhouse gas emissions			
Minimize greenhouse gas emissions	t CO_2e	Lower	Tonnes (t) of carbon dioxide equivalent emissions from system generation.
Support growth of B.C.'s economy			
Maximize economic development of communities	Gross provincial full-time equivalent positions, annualized over 20 years	Higher	Number of jobs (construction and operations) arising from direct, indirect, and induced spending on supply side resources (new and contract renewals), incremental transmission, and new energy efficiency demand-side measures.

6.4 How consultation helped build the 2021 IRP

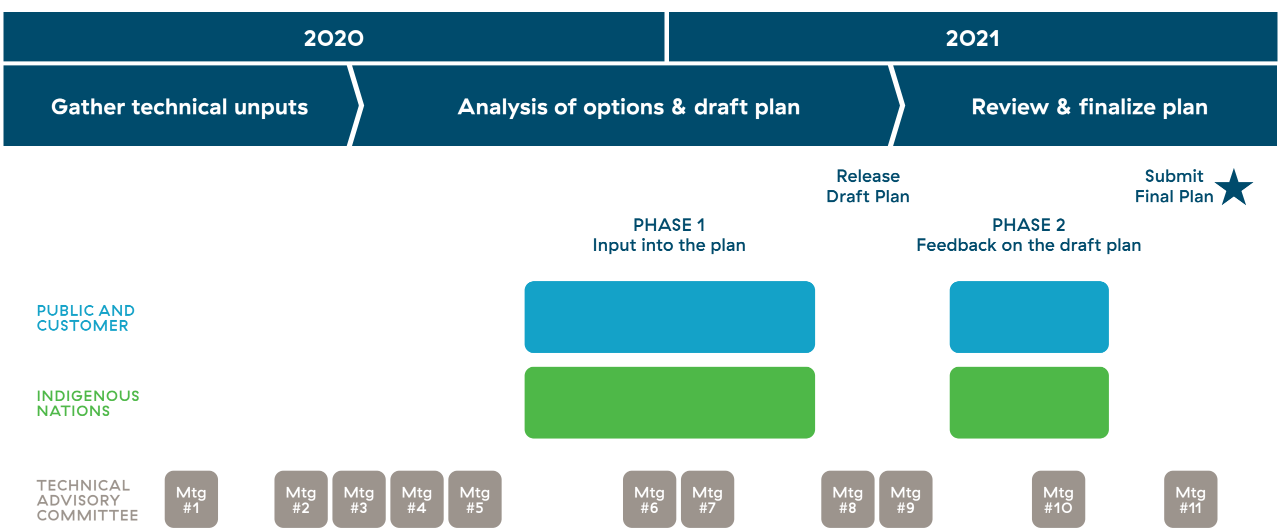
Building the 2021 IRP incorporated a broad consultation process consisting of three consultation streams: the public and customers; Indigenous Nations; and a technical stream. Engagement efforts were valuable in supporting the alignment of the 2021 IRP elements with broad values and interests, understanding related interests for future planning and subsequent applications, and checking our planning assumptions and analysis with technical experts along the way.

An additional objective in the Indigenous consultation stream was to fulfil our legal obligations to consult, and demonstrate our commitment to implementing the United Nations Declaration of the Rights of Indigenous Peoples.

The consultation process occurred throughout the development of the 2021 IRP and was referred to as "Clean Power 2040". Information about our engagement activities for all three streams is available at **bchydro.com/cleanpower2040**.

Figure 6-2 illustrates the consultation that occurred in building the 2021 IRP.

Figure 6-2 Consultation streams and phases



Public and customers, and Indigenous Nations streams

We undertook consultation with the public and customers, and with Indigenous Nations in two broad phases. All sessions during both phases were virtual in adherence to provincial public health guidelines.

Phase One (input), which occurred in fall/winter 2020/2021, gathered input on interests and values by finding out 'what matters' to people about various planning topics, including the initial planning objectives. We gathered input using methods tailored to each stream.

For the public and customer stream we sought diverse perspectives through an array of forums, including online engagement surveys (a short and a long survey), public interactive workshops, local government sessions, an online digital dialogue, a telephone town hall, and a youth engagement. Over 6,000 members of the public and customers participated in Phase One of the consultation.

The Indigenous Nations stream included three five-hour regional workshops in which all Indigenous Nations in the province were invited to attend, supplemental meetings with some individual Indigenous Nations, an online engagement survey (long survey) and written correspondence. Sixty-four Indigenous Nations and organizations participated in Phase One of the consultation.

Input from Phase One was considered, along with technical, financial, and other environmental and economic development analysis, to develop the Draft IRP.

Phase Two (feedback) occurred through the summer of 2021 and gathered feedback on how the Draft IRP elements aligned with participants' values and interests.

The methods used to gather feedback on the Draft IRP were similar to those used in Phase One in that all of the same forums were used, with some notable differences. For Phase Two, we made the full Draft IRP available for review. The public and customer stream added a customer survey that provided a representative sample of BC Hydro's residential customers, and also provided an online comment form for organization representatives to be used for feedback in conjunction with the Draft IRP.

Over 2,300 members of the public and customers and fifty-three Indigenous Nations and organizations participated in Phase Two of the consultation. Feedback from the second phase of consultation was considered as we finalized the 2021 IRP.

Technical stream

The technical stream consisted of a Technical Advisory Committee established to provide ongoing, detailed, technical advice and feedback from a group of knowledgeable parties with experience relevant to BC Hydro's resource planning.

The Technical Advisory Committee members represented a variety of interests such as customer groups, Indigenous, environmental, independent power producers, sustainable energy, municipal government, low income, other utilities, and academic. Staff representatives from the Ministry of Energy, Mines and Low Carbon Innovation and the BCUC were invited to attend Technical Advisory Committee meetings as observers.

The Technical Advisory Committee met 11 times from March 2020 to October 2021 for discussions on planning assumptions, planning inputs and analysis, and to provide feedback on the Draft IRP.

Ongoing advice and feedback from the Technical Advisory Committee was considered as we developed the 2021 IRP.

The progression of consultation input and feedback used to build the 2021 IRP

As the public and customers, and Indigenous consultations were undertaken in two distinct phases, there was a logical progression to how results of those engagement efforts informed the development of the 2021 IRP. Phase One gathered input on values and interests that informed the development of the Draft IRP. Phase Two gathered feedback on how the Draft IRP elements aligned with participants' values and interests.

Within Chapters 7 and 8, where we describe the elements of the Base Resource Plan and the Contingency Resource Plans, we've included summaries of how the overall consultation results show alignment with each of the plan elements.

7

The Base Resource Plan: our strategy to meet the future electricity needs of our customers

7.1 Introduction

The Base Resource Plan is BC Hydro's strategy to meet the future needs of our customers if the future load aligns with our Reference Load Forecast. In the 2021 IRP, the Base Resource Plan was developed through the process set out in Chapter 6 and with consideration of input and feedback received during consultation. Some of the Base Resource Plan elements require further approvals from the BCUC or other regulatory bodies, such as those who issue permits for capital projects.

7.2 The elements of the Base Resource Plan

The Base Resource Plan consists of seven elements, as follows:[1]

- Continue with a base level of energy efficiency programs (Base energy efficiency) and plan to ramp up to higher levels (Higher energy efficiency) in future years to achieve approximately 1,700 GWh/year of energy savings and approximately 280 MW of capacity savings at the system level by fiscal 2030;
- Pursue voluntary time-varying rates supported by demand response programs to achieve approximately 220 MW of capacity savings at the system level by fiscal 2030, and advance the Industrial Load Curtailment Program to achieve approximately 100 MW of incremental capacity savings at the system level by no later than fiscal 2030;
- Pursue a combination of education and marketing efforts as well as incentives for smart-charging technology for customers to support a voluntary residential time-of-use rate to shift home charging by 50 per cent of residential electric vehicle drivers to off-peak demand periods (50 per cent electric vehicle driver participation) to achieve approximately 100 MW of capacity savings at the system level by fiscal 2030;
- Offer a market-price-based renewal option to existing clean or renewable independent power producers with electricity purchase agreements expiring in the next five years. There are 19 existing clean or renewable projects that produce a total of approximately 900 GWh, with electricity purchase agreements set to expire before April 1, 2026;
- Advance the first step of sequential upgrades to transmission infrastructure into the South Coast region, including series compensation, shunt capacitors, and thermal upgrades to achieve approximately 750 MW of capacity by fiscal 2033. Prepare to initiate a second step of upgrades to achieve approximately 550 additional megawatts of capacity for the South Coast region by fiscal 2040;
- Undertake a structured decision making approach to evaluate small BC Hydro plants requiring end-of-life investment decisions on a facility-by-facility basis to determine whether to decommission or refurbish these facilities. These facilities would be evaluated on the following schedule:

1 The GWh/yr and MW numbers quoted in the Base Resource Plan are consistent with the volumes in the Load Resource Balances with Base Resource Plan Actions shown in section 7.3.

Table 7–1 BC Hydro small plants at or reaching end-of-life

Facility	Timing to review end-of-life investment decision
Shuswap (near Vernon)	Analysis in progress
Elko (near Cranbrook)	2025
Spillimacheen (near Golden)	2029
Alouette (near Maple Ridge)	2030
Falls River (near Kitimat)	In operation – date not set
Walter Hardman (near Revelstoke)	In operation – date not set

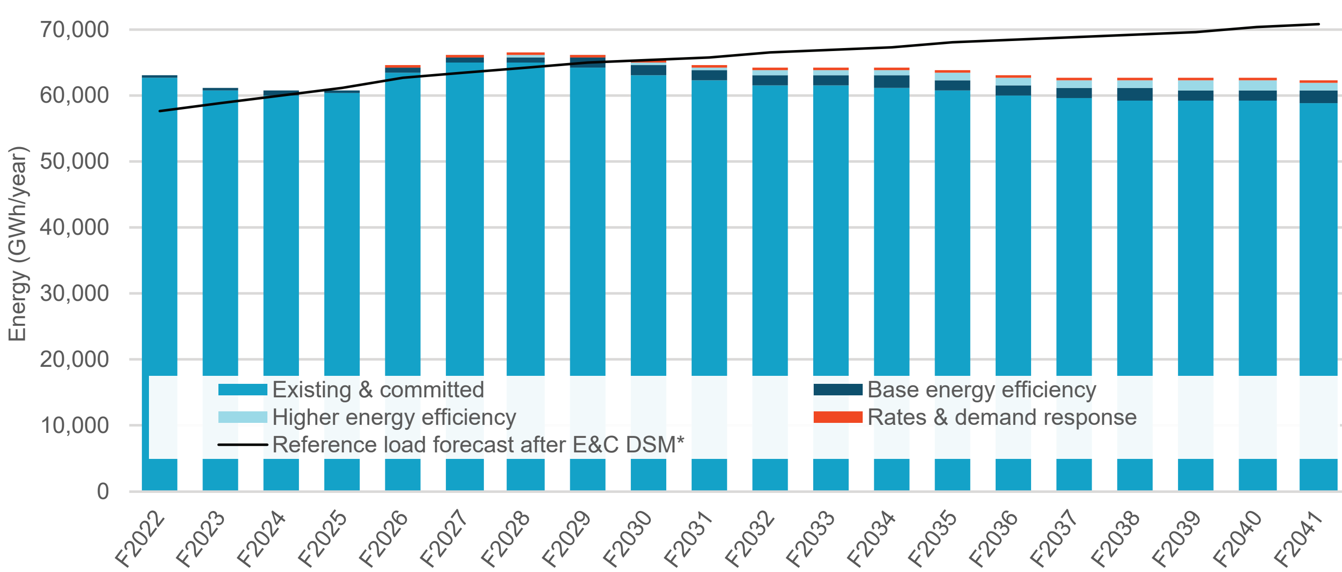
- Beyond the elements identified above and after demand-side measures, plan to acquire new energy and capacity resources as follows: 810 GWh in fiscal 2031 ramping up to 7,800 GWh by fiscal 2041, and 160 MW in fiscal 2038 ramping up to 510 MW by fiscal 2041. These future resources would be selected from:
  - Expiring electricity purchase agreements with independent power producers;
  - New clean and renewable energy resources; and
  - Upgrades to BC Hydro facilities.

7.3 How the plan meets the future electricity needs of our customers over time

The Base Resource Plan described in section 7.2 is shown here in Figures 7–1 through 7–6. The figures illustrate which resources come online, when they come online, and how much of that resource will be used.

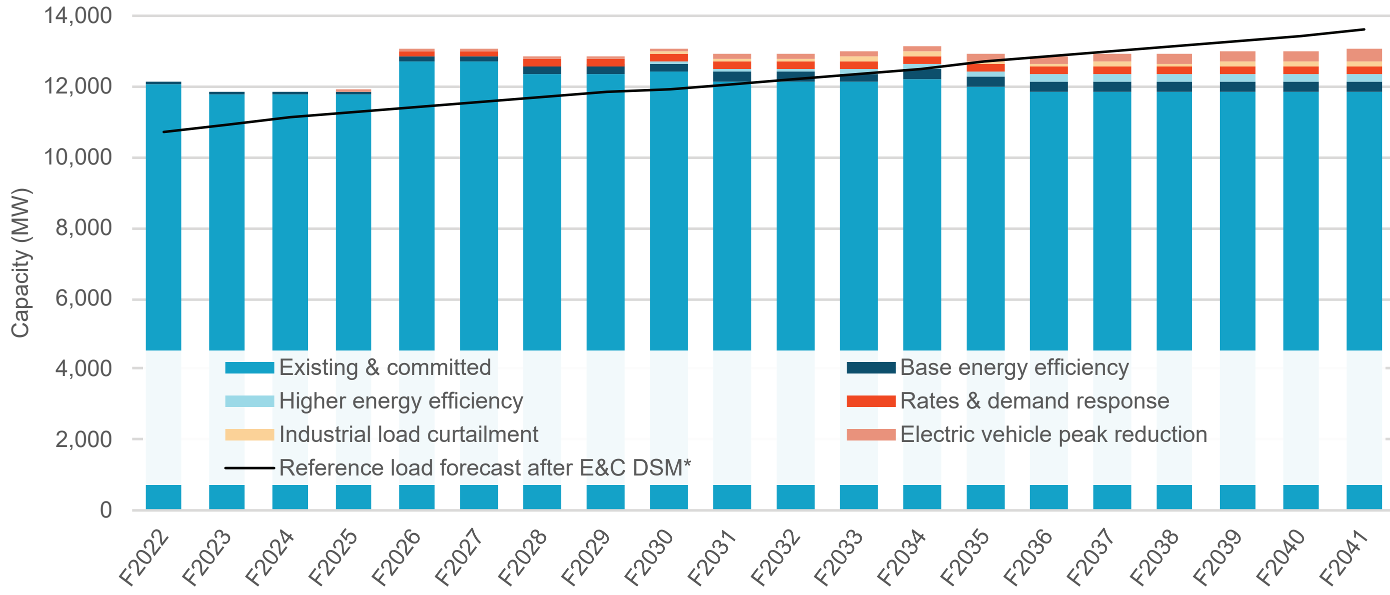
Figures 7–1 and 7–2 show how "Planned demand-side measures" (i.e., the demand-side measure elements as described in the Base Resource Plan) would help to serve our customers' anticipated future needs for energy and capacity, respectively. Figure 7–3 provides a similar view of capacity on the South Coast.

Figure 7–1 System energy Load Resource Balance with planned demand-side measures only



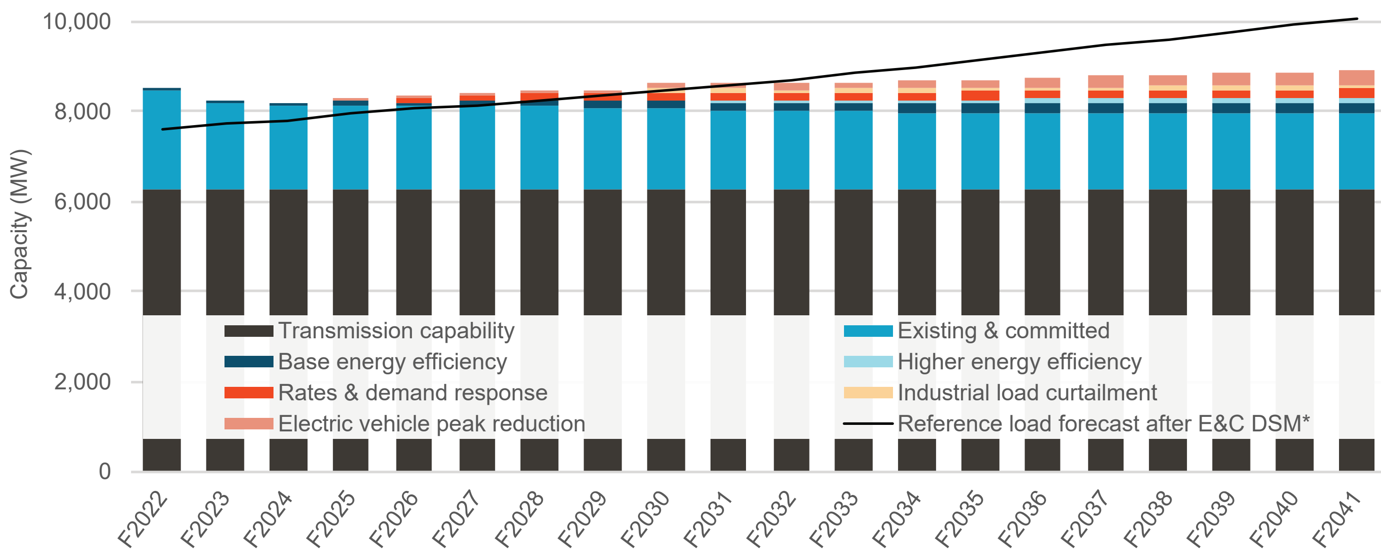
* E&C DSM denotes existing and committed demand-side measures

Figure 7-2 System capacity Load Resource Balance with planned demand-side measures only



* E&C DSM denotes existing and committed demand-side measures

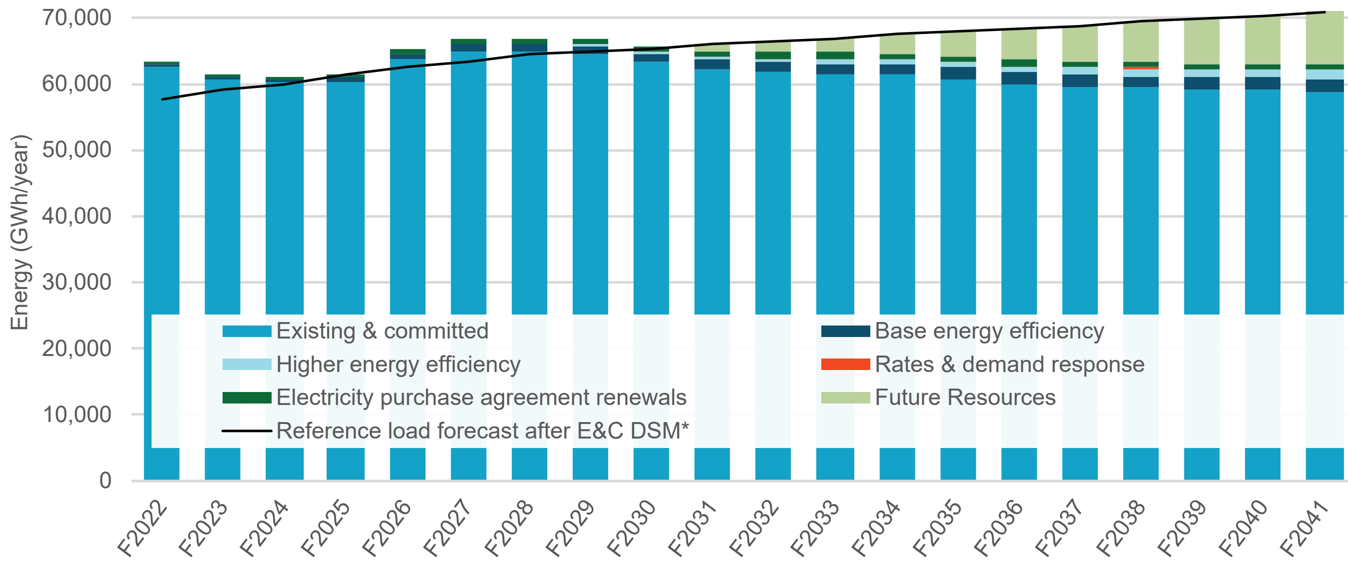
Figure 7-3 South Coast capacity Load Resource Balance with planned demand-side measures only



* E&C DSM denotes existing and committed demand-side measures

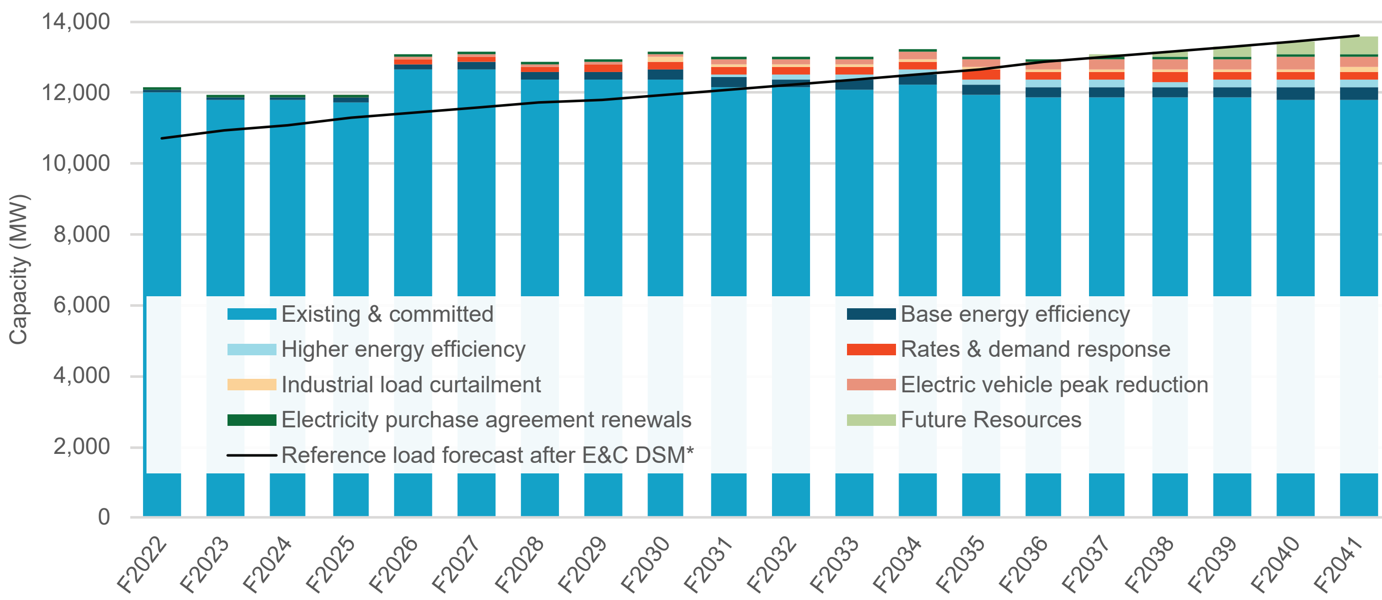
Figures 7–4 and 7–5 present the same view but with the full suite of Base Resource Plan elements. Similarly, Figure 7–6 provides that view for capacity on the South Coast.

Figure 7–4 System energy Load Resource Balance with all Base Resource Plan elements



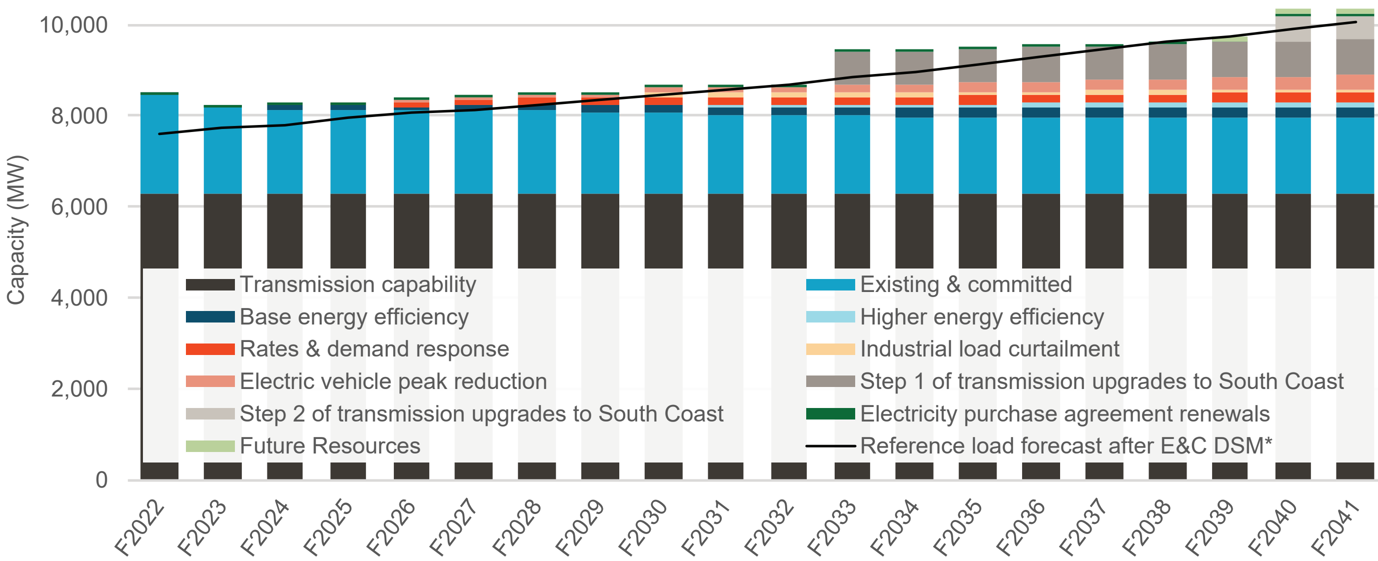
* E&C DSM denotes existing and committed demand–side measures

Figure 7–5 System capacity Load Resource Balance with all Base Resource Plan elements



* E&C DSM denotes existing and committed demand–side measures

Figure 7–6 South Coast capacity Load Resource Balance with all Base Resource Plan elements



* E&C DSM denotes existing and committed demand-side measures

7.4 The analysis that led to the Base Resource Plan

We developed and evaluated portfolios for the Base Resource Plan starting with demand-side measures (energy efficiency, time-varying rates, and demand response programs). Once we determined the demand-side measures resources, we established the other resources required to fill the remaining gap. The following sections describe each step of this process.

7.4.1 HOW THE ENERGY EFFICIENCY PROGRAMS WERE SELECTED

Energy efficiency programs provide both energy and capacity savings and are flexible and scalable. We analyzed four levels of energy efficiency savings: No energy efficiency, Base energy efficiency, Higher energy efficiency; and Higher Plus energy efficiency. Table 7–2 provides a consequence table outlining the trade-offs between portfolios.

Table 7–2 Consequence table of portfolios comparing levels of energy efficiency demand-side measures

ABOUT THIS TABLE

Each column corresponds to a portfolio, or a bundle of resource options. Each portfolio was created by selecting a specific level of energy efficiency and then letting the optimization model fill in the rest of the resource choices. The table shows the consequences, or impacts, of these different portfolios on identified objectives and measures. Choosing one portfolio as a base of comparison against the alternatives lets us identify where a portfolio performs better or worse than the base for each objective (colour-coded for ease of reference).

Legend

- (blue) This portfolio is used as the basis of comparison
- (orange) This alternative is worse than the base portfolio
- (green) This alternative is better than the base portfolio
- (light grey) This alternative is roughly the same as the base portfolio

Planning Objective (measure)	What is better	No energy efficiency	Base energy efficiency	Higher energy efficiency	Higher plus energy efficiency
Net Total Resource Cost ($M PV)	Lower	$2,510	$1,280	$680	$110
Net Utility Cost ($M PV)	Lower	$2,510	$1,630	$1,410	$1,210
Cost risk from DSM under-delivery* (MW below plan by 2030)	Lower	0	80	130	140
Cost risk from transmission schedule uncertainty* (year in service, Step 1)	Later	2032	2032	2033	2033
Cost risk from transmission schedule uncertainty* (year in service, Step 2)	Later	2036	2037	2038	2039
Rate Impact (% change in F2030)	Lower	-1.0%	0.0%	1.0%	1.8%
Rate Impact (% change in F2041)	Lower	-0.8%	0.0%	1.5%	3.8%
Land and Water Impacts (Index)	Lower	5.0	3.5	2.7	1.5
Economic Development (provincial gross FTEs, annualized)	Higher	4,040	4,030	4,060	4,510

*These are not represented in dollars as they are a proxy for cost risk, not an assessment of financial risk.

7.4.1.1 Trade–offs in the consequence table

Pursuing different levels of energy efficiency impacts multiple objectives. BC Hydro views the major trade–offs as balancing portfolio cost, rate increases, and land and water impacts. The magnitude to which these portfolios impact the other objectives (i.e., under–delivery risk and new provincial employment) is relatively small in comparison.

Across the full range of options, Table 7–2 shows that pursuing higher levels of energy efficiency results in lower portfolio costs. Table 7–2 also shows that doing any energy efficiency, as opposed to no energy efficiency, avoids significant land and water impacts.

However, while higher levels of energy efficiency cause overall costs to decrease, the amount of electricity being sold to customers to recover those costs also decreases. This means that pursuing higher levels of energy efficiency can also result in higher rates for customers.

For example, moving from Base energy efficiency to Higher energy efficiency, and then from Higher energy efficiency to Higher plus energy efficiency results in approximately $600 million portfolio cost savings at each incremental level (measured as Net Total Resource Cost). However, moving from Base energy efficiency to Higher energy efficiency means 1.5 per cent higher cumulative long–term (i.e., by fiscal 2041) rate increases. Similarly, moving from Base energy efficiency to Higher plus energy efficiency means 3.8 per cent higher cumulative long–term rate increases.

The consequence table also shows that pursuing higher levels of energy efficiency comes with increased under–delivery risk.

7.4.1.2 What level of energy efficiency was chosen?

We have chosen the Base energy efficiency level for the near-term, ramping up to the Higher energy efficiency level over time, as described in section 7.2 and shown in section 7.3.

Our assessment is that:

- The lower cost, and lower land and water impacts of moving from a portfolio with No energy efficiency to one with Base energy efficiency is worth the incremental rate increase;
- Some level of energy efficiency programs is needed to provide the flexibility to ramp up energy efficiency efforts as needed;
- The lower cost, and lower land and water impacts of moving from a portfolio with Base energy efficiency to one with Higher energy efficiency is worth the incremental rate increase;
- Because load growth is uncertain, a staged approach – moving from Base energy efficiency to Higher energy efficiency, can take advantage of the flexibility of energy efficiency and allow us to minimize incremental rate impacts while in surplus and ramp up to the Higher energy efficiency as load growth in the Reference load forecast emerges;
- Moving to Higher Plus energy efficiency is not warranted at this time:
    - With their slow ramp up, the early years of Higher and Higher Plus show outcomes that are largely the same, meaning that there are neither substantial differences in target outcomes by fiscal 2030 nor substantial present value benefits over the same time period. This gives us additional flexibility to monitor and ramp up from Higher to Higher Plus in support of the Base Resource Plan or a Contingency Resource Plan as needed;
    - There is heightened under-delivery risk around the level of savings that will be achieved with Higher Plus as well as the expected PV benefits.[2] An analysis has shown the PV benefits of Higher Plus drop by roughly $600 million if the lower end of the range of savings is achieved;
    - Gaining experience with the Higher level of energy efficiency programs will provide operational experience which will inform our understanding of the uncertainty with Higher Plus levels and support a ramp up to Higher Plus levels when needed; and
    - Under currently expected load conditions, there are additional incremental rate increases associated with the Higher plus energy efficiency option.

Consultation occurred in two phases. Input during Phase One informed the development of this element of the plan, while Phase Two sought feedback on how this element aligned with values and interests. Results from our consultation show:

- Input (Phase One) results showed strong support for our energy efficiency programs and for increasing those programs when needed. Public and customers', and Indigenous Nations' input indicates support for these programs because they keep costs down and limit land and water impacts by mitigating the need to build new infrastructure. BC Hydro was encouraged to consider accessibility issues, including the unique circumstances of Indigenous communities.
- Feedback (Phase Two) results from the public and customers showed broad alignment with their values and interests on this element. Indigenous feedback was mainly aligned with or neutral on this element of the plan. Similar to what we heard in Phase One, BC Hydro was encouraged to consider accessibility issues, including the unique circumstances of Indigenous communities.[3]

The Near-term Actions needed to be undertaken in the first five years of the planning period can be found in Chapter 9.

2 This proxy measure of cost risk focuses on differences in fiscal 2030. The full timeline of savings shows that this downside is small in the early years when Higher and Higher Plus ramp slowly and track closely to each other. But the downside grows substantially larger for Higher Plus in the latter part of the plan as Higher Plus is moving to a level of savings at incentive levels well outside BC Hydro's experience.

3 The information provided is a summary of the consultation results and does not reflect the full record of input and feedback. For detailed summaries of what we heard and how we considered the input and feedback, please see **bchydro.com/cleanpower2040**.

7.4.2 HOW THE TIME-VARYING RATE SUITE AND SUPPORTING DEMAND RESPONSE PROGRAMS WERE SELECTED

With the level of energy efficiency selected, we then addressed capacity-focused demand-side measures. Time-varying rates and demand response programs are two measures to encourage customers to shift their consumption out of peak periods. We analyzed rates suites and supporting demand response programs, and an industrial load curtailment program, all of which are outlined in section 5.2.2.

Table 7-3 Consequence table of portfolios comparing levels of voluntary time-varying rates and demand response programs

ABOUT THIS TABLE

Each column corresponds to a portfolio, or a bundle of resource options. Each portfolio was created by selecting a specific Rate suite and level of demand response programs, combining these with the previously selected levels of energy efficiency and then letting the optimization model fill in the rest of the resource choices. The table shows the consequences, or impacts, of these different portfolios on identified objectives and measures. Choosing one portfolio as a base of comparison against the alternatives lets us identify where an alternative portfolio performs better or worse than the base for each objective (colour-coded for ease of reference).

Legend

- (blue) This portfolio is used as the basis of comparison
- (orange) This alternative is worse than the base portfolio
- (green) This alternative is better than the base portfolio
- (light grey) This alternative is roughly the same as the base portfolio

Planning Objective (measure)	What is better	No rate suite or Demand Response Programs	Rate suite 2 with Demand Response Program A	Rate suite 3 with Demand Response Program B
Net Total Resource Cost ($M PV)	Lower	$680	$650	$590
Net Utility Cost ($M PV)	Lower	$1,410	$1,440	$1,290
Cost risk from DSM under-delivery* (MW below plan by 2030)	Lower	130	270	330
Cost risk from transmission schedule uncertainty* (year in service, Step 2)	Later	2038	2038	2038
Rate Impact (% change in F2030)	Lower	1.0%	1.1%	1.2%
Rate Impact (% change in F2041)	Lower	1.5%	1.9%	1.7%
Default Rate (Y/N)	No	No	No	Yes
Land and Water Impacts (Index)	Lower	2.7	2.2	2.6
Economic Development (provincial gross FTEs, annualized)	Higher	4,060	3,820	3,870

*These are not represented in dollars as they are a proxy for cost risk, not an assessment of financial risk.

Table 7-3 provides a consequence table outlining the trade-offs between three portfolios. Each portfolio consists of the Higher level of energy efficiency programs, and each suite of time-varying rates and supporting demand response programs are fixed at different levels. Finally, any remaining gap is filled by non-demand-side measure resources to complete a set of contrasting portfolios that meet our load-serving obligations.

7.4.2.1 Trade–offs in the consequence table

Table 7–3 shows that several of the objectives are in conflict when choosing the "best" level of rate suites and demand response programs and that these trade–offs are not simple. However, the range of modelled outcomes across the three options is relatively small, which increases the importance of other factors not included in the modelling when comparing options.

Table 7–3 shows that pursuing more savings via time–varying rates and demand response programs provides modest financial benefits.

Adopting Rate suite 3 and Demand Response Program B will yield financial savings and result in only a moderate rate increase from the "No rate suite" starting point. However, getting there would require imposing default rate structures, under which the time–varying rates are opt–out. In other words, the time–varying rates are voluntary, but customers would make a request to BC Hydro in order to not take service on a time–varying rate.

Through the consultation process some customers raised concerns with the concept of time–varying rates, expressing the concern they may unduly penalize those that cannot shift their electricity use. If an opt–out rate was implemented and customers did not have adequate knowledge about their choice to opt–out, or have the resources to understand whether or not a time–varying rate would increase or decrease their bill, then they may be unable to take appropriate action, and they may experience higher electricity bills. This would be counter to BC Hydro's planning objective of keeping costs down for customers.

The middle option, Rate suite 2 and Demand Response Program A, is an intermediate step between no changes and Rate suite 3 with Demand Response Program B. This intermediate step has smaller financial benefits compared to the larger change but avoids the use of Default time–varying rates.

Rate suite 2 and Demand Response Program A, by relying on opt–in time–varying rates, does represent the highest level of savings uncertainty. It also poses the largest rate increase to customers by the end of the planning horizon.

7.4.2.2 What time–varying rate and supporting demand response programs were chosen?

We have chosen Rate suite 2 with Demand Response Program A, as described in section 7.2 and shown in section 7.3.

Our assessment is that Rates suite 2 and Demand Response Program A:

- Allows BC Hydro and our customers to gain more experience in this area, which is relatively new to us, improving our ability to successfully implement more challenging options, as required, in response to future needs;
  - Relative to other electric utilities and other resource options, BC Hydro has little experience in the use of time–varying rates as a resource option. Advancing voluntary time–varying rates on an opt–in basis will allow BC Hydro to build capability and reduce uncertainty in the use of this resource option;
- Provides a platform to enable various electric vehicle peak reduction resource options (covered in the next section);
- Achieves the above benefits with no net cost and provides a modest financial benefit compared to the No rate, No demand response option;
- Avoids the potential customer concerns associated with implementing default (opt–out) time–of–use rates, justifying the modest foregone financial benefits associated with Rate suite 3 and Demand Response Program B;
- Can provide the same or greater product and service differentiation as the Default (opt–out) rates of Rate suite 3;

- Has the flexibility to be advanced in the sequence that best aligns with the timing of the need for capacity, the current state of knowledge regarding suitable pricing terms and conditions, and the expected level of customer interest.
  - For example, an opt-in residential time of use rate could be advanced earlier than other time-varying rates, given that an opt-in residential time of use rate would provide capacity in the South Coast where it is needed earliest, has broad customer support as demonstrated by consultation, and would benefit from well developed industry knowledge of appropriate pricing, terms and conditions given its widespread adoption by electric utilities across North America; and,
- Aligns with Section 44.1 of the *Utilities Commission Act* which indicates a clear policy preference for the priority use of cost-effective demand-side measures.

Consultation occurred in two phases. Input during Phase One informed the development of this element of the plan, while Phase Two sought feedback on how this element aligned with values and interests. Results from our consultation show:

- Input (Phase One) results from results from the public and customers, and Indigenous Nations results, showed an overall openness and support for time-varying rates; however, concerns were raised about equity for customers who cannot take advantage of time-varying rates to lower their bills may be penalized.
- Input (Phase One) results showed an overall openness and support for demand response technologies; however, many participants were not familiar with these technologies and concerns were raised about data privacy.
- Feedback (Phase Two) results from the public and customers showed broad alignment with their values and interests on this element. Indigenous feedback was mainly aligned with or neutral on this element of the plan. Across both streams, there remained some concerns for customers who may be penalized because they were not able to shift their electricity use.[4]

The Near-term Actions needed to be undertaken in the first five years of the planning period can be found in Chapter 9.

7.4.3 HOW THE ELECTRIC VEHICLE PEAK REDUCTION WAS SELECTED

With the level of energy efficiency, rate design, and supporting demand response programs in place, we next considered specific measures to target electric vehicle loads. Electric vehicle peak reduction options provide capacity benefits, with most of those benefits realized in the South Coast region. We analyzed each of the electric vehicle peak reduction options from section 5.3.2: No electric vehicle driver participation, 35 per cent electric vehicle driver participation, 50 per cent electric vehicle driver participation, and 75 per cent electric vehicle driver participation.

4 The information provided is a summary of the consultation results and does not reflect the full record of input and feedback received by BC Hydro during the consultation process. For detailed summaries of what we heard and how we considered the input and feedback, please see **bchydro.com/cleanpower2040**.

Table 7-4 Consequence table of portfolios comparing levels of electric vehicle peak reduction

ABOUT THIS TABLE

Each column corresponds to a portfolio, or a bundle of resource options. Each portfolio was created by selecting a specific level of EV driver participation, combining this with the previously selected levels of energy efficiency, demand response, and rate suite, and then letting the optimization model fill in the rest of the resource choices. The table shows the consequences, or impacts, of these different portfolios on identified objectives and measures. Choosing one portfolio as a base of comparison against the alternatives lets us identify where a portfolio performs better or worse than the base for each objective (colour-coded for ease of reference).

Legend

- (blue) This portfolio is used as the basis of comparison
- (orange) This alternative is worse than the base portfolio
- (green) This alternative is better than the base portfolio
- (light) This alternative is roughly the same as the base portfolio

Planning Objective (measure)	EV driver participation portfolios				
	What is better	No EV driver Participation	35% EV driver Participation	50% EV driver Participation	75% EV driver Participation
Net Total Resource Cost ($M PV)	Lower	$650	$540	$500	$390
Net Utility Cost ($M PV)	Lower	$1,440	$1,320	$1,220	$1,220
Cost risk from DSM under-delivery* (MW below plan by 2030)	Lower	270	310	390	270
Cost risk from transmission schedule uncertainty* (year in service, Step 1)	Later	2033	2033	2034	2034
Cost risk from transmission schedule uncertainty* (year in service, Step 2)	Later	2038	2038	2039	>2042
Rate Impact (% change in F2030)	Lower	1.1%	1.1%	1.2%	1.3%
Rate Impact (% change in F2041)	Lower	1.9%	1.6%	1.6%	1.8%
Default Rate (Y/N)	No	No	No	No	Yes
Land and Water Impacts (Index)	Lower	2.2	2.6	2.2	2.6
Economic Development (provincial gross FTEs, annualized)	Higher	3,820	3,810	3,740	3,860

*These are not represented in dollars as they are a proxy for cost risk, not an assessment of financial risk.

Table 7-4 provides a consequence table outlining the trade-offs between portfolios where the level of energy efficiency programs, rates suites, and demand response are set at the solutions described in the previous sections. Then the electric vehicle peak reduction options are varied to create contrasting portfolios. Finally, any remaining gap is filled by non-demand-side measure resources to complete a set of contrasting portfolios that meet our load-serving obligations.

7.4.3.1 Trade-offs in the consequence table

Table 7-4 shows that higher levels of participation by electric vehicle drivers in voluntary residential time-varying rates to shift home charging demand to off-peak periods has portfolio cost benefits from a Net Total Resource Cost perspective. In addition, implementing some electric vehicle peak reduction also provides cost benefits from a Net Utility Cost perspective. However, the forecast cost differences amongst the three portfolios with electric vehicle rates are small enough to fall within the precision of the modelling estimates.

Increased participation also pushes out the required in-service date of Step 2 of the transmission upgrades to the South Coast. However, counting on higher levels of electric vehicle driver participation comes with large level of savings uncertainty, both in incremental and total portfolio terms.

We view the major trade-offs here to be the upside of portfolio cost reductions and the further delay of the need for the sequential steps of transmission upgrades to the South Coast, balanced against the increased savings uncertainty arising from a capacity resource that is relatively new to us, customers, and to electric utilities across North America.

7.4.3.2 What electric vehicle peak reduction option was chosen?

We have chosen the 50 per cent electric vehicle driver participation option, as described in section 7.2 and shown in section 7.3.

Our assessment is that:

- Higher participation levels for electric vehicle peak reduction result in lower portfolio costs;
- The 50 per cent electric vehicle driver participation option has portfolio cost benefits over the no participation option and the 35 per cent electric vehicle driver participation option with only a small increase in the relative risk of under-performance;
- There are practical barriers to achieving the 75 per cent electric vehicle driver participation.

Consultation occurred in two phases. Input during Phase One informed the development of this element of the plan, while Phase Two sought feedback on how this element aligned with values and interests. Results from our consultation show:

- Electric vehicle peak reduction was not identified as a planning topic in Phase One, but was added for feedback in Phase Two.
- Feedback (Phase Two) results from the public and customers showed broad positive alignment of this element with their values and interests. Indigenous feedback was mainly neutral on this element of the plan.[5]

The Near-term Actions needed to be undertaken in the first five years of the planning period can be found in Chapter 9.

5 The information provided is a summary of the consultation results and does not reflect the full record of input and feedback. For detailed summaries of what we heard and how we considered the input and feedback, please see **bchydro.com/cleanpower2040**.

7.4.4 HOW THE INDUSTRIAL LOAD CURTAILMENT PROGRAM WAS SELECTED

The Industrial Load Curtailment Program is a low-cost option to meet capacity needs compared to new supply-side capacity resources. For all the demand-side measures options modelled above, the System Optimizer selected Industrial Load Curtailment over other built capacity options whenever it was given the choice. The inference here is that the curtailment of industrial load is a lower cost solution than the other built capacity options not chosen.

Over and above the advantages it offered to the modelled Base Resource Plan solution, Industrial Load Curtailment Program can also be tailored to meet customers' needs, has greater curtailment period capability than other demand response programs and can be implemented quickly, and with relatively low risk, given BC Hydro's previous pilot activity in this area. No additional modelling was carried out on this question.

The detailed actions needed to be undertaken in the first five years of the planning period to support this aspect of the plan can be found in Chapter 9, Near-term Actions.

7.4.5 OUR APPROACH TO ELECTRICITY PURCHASE AGREEMENT RENEWALS

We focused on developing an approach for electricity purchase agreement renewals in the next five years leading up to the development of the next IRP. There are 19 clean or renewable projects, totaling approximately 900 GWh of annual energy, with electricity purchase agreements set to expire before April 1, 2026. There are two additional existing electricity purchase agreements, for the Island Generation and SEEGEN facilities, with contracts set to expire before April 1, 2026.[6]

We expect to have sufficient energy and capacity until the early 2030s with the demand-side measures outlined in the previous sections. Additional energy from electricity purchase agreement renewals would be surplus to domestic need for a period of time but may be required later in the 20-year planning period. However, since most of these projects are expected to have a low cost of service (because they have remaining asset life, have had time to pay off their fixed investments, and have low operating costs), we expect that they will want to continue operating and will be able to operate economically with market based prices in contracts. Contracts with the Independent Power Producers keep these facilities available for a situation in which the generation is required to meet domestic need.

Portfolio analysis demonstrated that longer-term contracts at market-based pricing that would be surplus to need in the near term would be cost-effective options for meeting longer-term requirements compared to meeting future load with new clean resources acquired at a later date. In particular, System Optimizer selected all available electricity purchase agreement renewals in the first five years of the modelling horizon over the purchase of new clean resources timed more closely to the emergence of need.[7]

To explore the cost effectiveness of the modelled Base Resource Plan solution for electricity purchase agreement renewals for the first five years, a more in-depth comparison was carried out where the following two portfolios were tested against the Reference Load Forecast:

- Renew all clean or renewable electricity purchase agreements during the first five years of the plan (up to 2026) for a term extending for 18 to 20 years based on the remaining asset life of the facility ("All renewals portfolio"); and
- Renew none of the larger clean or renewable electricity purchase agreements (those that provide greater than 50 GWh per year) during the first five years of the plan ("No renewals portfolio").

For these two approaches, the model was free to optimize to find a least-cost solution outside of these assumptions and the demand-side measure solutions described in previous sections. This included other electricity purchase agreement renewals (i.e., SEEGEN and electricity purchase agreements expiring after five years) and greenfield resources. Table 7-5 shows a comparison of the results of these two approaches.

6 SEEGEN is a municipal solid waste project located in Burnaby and owned by Metro Vancouver. A portion of the electricity from the SEEGEN facility is considered clean or renewable because a portion of the feedstock used to generate electricity is biogenic. Biogenic waste is a clean or renewable resource according to the Clean or Renewable Resource Regulation (B.C. Reg. 81/2011).

7 The modelling focused on the larger projects (i.e., greater than 50 GWh/yr) with System Optimizer being given the option of selecting them in coming up with a least cost portfolio. A number of smaller projects were assumed to be renewed in order to reduce modelling time and effort. Of the 19 clean or renewable projects with electricity purchase agreements expiring in the next five years, thirteen were included in this group of assumed electricity purchase agreements renewals making up ~275GWh/year. The remaining six projects were available for selection in System Optimizer.

Table 7–5 Consequence table of portfolios comparing electricity purchase agreement renewal options

ABOUT THIS TABLE

Each column corresponds to a portfolio, or a bundle of resource options. Each portfolio was created by selecting a specific level of EPA Renewal, and combining this with the previously selected levels of energy efficiency, demand repsonse, and rate suite, and electric vehicle peak reduction, and then letting the optimization model fill in the rest of the resource choices. The table shows the consequences, or impacts, of these different portfolios on identified objectives and measures. Choosing one portfolio as a base of comparison against the alternatives lets us identify where a portfolio performs better or worse than the base for each objective (colour-coded for ease of reference).

Legend

- (blue) This portfolio is used as the basis of comparison
- (orange) This alternative is worse than the base portfolio
- (green) This alternative is better than the base portfolio
- (light grey) This alternative is roughly the same as the base portfolio

Planning Objective (measure)	What is better	No renewals portfolio	All renewals portfolio
Net Total Resource Cost ($M PV)	Lower	690	500
Cost risk from transmission schedule uncertainty* (year in service, Step 1)	Later	2034	2034
Cost risk from transmission schedule uncertainty* (year in service, Step 2)	Later	2039	2039
Land and Water Impacts (Index)	Lower	3.0	2.2
Economic Development (provincial gross FTEs, annualized)	Higher	3,780	3,660

*These are not represented in dollars as they are a proxy for cost risk, not an assessment of financial risk.

7.4.5.1 Trade-offs in the consequence table

The modelling shows that renewing all of the electricity purchase agreements over the first five years of the plan (for an assumed term of 18 to 20 years) is a lower-cost solution than renewing none of the electricity purchase agreements over that time period and then meeting system needs through least cost future generation options in later years.

A key assumption in the portfolio modelling is that we can renew all electricity purchase agreements at market prices and that the electricity purchase agreements can be renewed at this price for terms of 18 to 20 years. Both assumptions are uncertain because:

- Some independent power producers with expiring electricity purchase agreements in the next five years may choose not to renew their electricity purchase agreement; and
- For those independent power producers that choose to renew, the term of the renewals will be the subject of future discussions.

As a result, the analysis above serves as bookends on the potential value of the electricity purchase agreement renewal approach in the next five years based on the assumptions utilized.

BC Hydro notes that renewing these agreements now, even for shorter-term periods, provides us with greater certainty that the independent power producer facilities will continue to be available when needed to displace new greenfield supply. If we do not renew, these projects may be available later, but there is less certainty.

In terms of non-financial trade-offs, not renewing electricity purchase agreements in the first five years of the plan results in a greater need for greenfield generation in the long term that comes with additional gross employment across the province primarily driven by new construction. However, this also leads to an increase in land and water impacts.

7.4.5.2 Sensitivity analysis

We carried out additional sensitivity analysis to examine the implications of a decision to proceed with the All renewals portfolio and ending up in a situation where load or market prices are higher or lower than expected. Table 7-6 below provides the net total resource cost of both sensitivity portfolios. In Table 7-6 below, a lower value indicates a greater benefit.

Table 7-6 Comparing Electricity Purchase Agreement renewal options under various outcomes ($M, PV)

	No renewals portfolio	All renewals portfolio
Net Total Resource Cost ($M, PV)		
Reference load and mid market price	690	500
Sensitivity Analysis		
Reference load and low market price	1,110	890
Reference load and high market price	-460	-590
Accelerated electrification load and mid market price	8,830	8,560
Low load and mid market price	-7,660	-7,630

In Table 7–6, the Reference Load and mid-market price scenario indicates a $190M net benefit for the All renewals portfolio relative to the No renewals portfolio. The sensitivity analysis demonstrates the following:

- Under all but the Low load scenario, the All renewals portfolio has a lower cost relative to the No renewals portfolio;
- Under the Reference Load with a low market price, the net benefit of the All renewals portfolio increases a small amount. This is because the cost of electricity purchase agreement renewals that are tied to the market price become more favourable than the cost of alternative greenfield projects that need to be developed over the longer term.
- Under a Reference Load with a high market price, the net benefit of the All renewals portfolio decreases a small amount. This is because the cost of electricity purchase agreement renewals that are tied to the market price become less favourable than the cost of alternative greenfield projects that need to be developed over the longer term.
- The net benefit of the All renewals portfolio increases under the Accelerated electrification scenario as alternative greenfield resources are advanced in the No renewals portfolio relative to the timing in the reference load scenario.
- There is a small net cost of the All renewals portfolio in the Low load scenario as the electricity purchase agreement renewals increase the load resource balance surplus relative to the No renewals portfolio and result in lower valued market sales.

7.4.5.3 Our approach to renewing clean or renewable electricity purchase agreements

In order to maintain flexibility for the future and to limit cost-risk to ratepayers we have chosen to offer market-based pricing agreements to all 19 clean or renewable electricity purchase agreements expiring in the plan's first five years. This approach has the following key results:

- There are $190M in financial benefits to BC Hydro ratepayers;
- Using existing electricity purchase agreements to meet future load would reduce or avoid land and water footprint impacts arising from the construction of new generation and the associated transmission interconnections.
- Provided the electricity purchase agreement renewals are structured properly and are based on market prices that can adjust to market conditions, the cost risk to BC Hydro's customers in low market conditions and low load scenarios should be limited;
- Acquiring electricity purchase agreement renewals with market-based pricing now could provide significant benefits if load is higher than expected; and
- Electricity purchase agreement renewals result in less economic development due to a relative reduction in incremental construction activity.

Consultation occurred in two phases. Input during Phase One informed the development of this element of the plan, while Phase Two sought feedback on how this element aligned with values and interests. Results from our consultation show:

- Input (Phase One) results from the public and customers showed an interest in keeping costs down and maintaining these facilities to meet future demand growth while prioritizing contracts that have Indigenous interests. Indigenous input emphasized the economic benefits associated with renewing electricity purchase agreements that have Indigenous participation. A number of participants indicated that renewing electricity purchase agreements would help limit land and water impacts by making use of existing facilities to meet future need.
- Feedback (Phase Two) results from the public and customers showed broad positive alignment of this element with their values and interests. Indigenous feedback was mainly aligned with or neutral on this element of the plan. Concerns were raised by stakeholder participants regarding the proposed market price-based approach. Indigenous participants sought incentives which would encourage Indigenous economic participation and/or benefits, including higher than market prices for renewals with Indigenous owned projects.[8]

The Near-term Actions needed to be undertaken in the first five years of the planning period can be found in Chapter 9.

8 The information provided is a summary of the consultation results and does not reflect the full record of input and feedback. For detailed summaries of what we heard and how we considered the input and feedback, please see **bchydro.com/cleanpower2040**.

7.4.5.4 Our approach to renewing natural gas electricity purchase agreements

Two of the biggest sources of greenhouse gas emissions within our integrated system are the gas-fired independent power producer facilities: McMahon and Island Generation. The renewal of these contracts will be examined separately below.

As a gas cogeneration facility, the McMahon facility (located in the Peace region) operates as a baseload facility to meet neighbouring industrial requirements. With an installed capacity of 105 MW and a high capacity factor, this facility is the single largest source of greenhouse gas emissions on the system at about 340,000 tonnes of carbon dioxide equivalent (CO_2e) per year. The electricity purchase agreement with McMahon expires in fiscal 2030.

We ran two portfolios, each of which contained the demand-side measures identified previously. One allowed System Optimizer to select the remaining generation resources in an optimal (low-cost) manner. The second portfolio assumed McMahon is renewed in 2030. The portfolio with McMahon renewed in 2030 is roughly $100 million (PV) more expensive.[9]

Based on this result, McMahon is not assumed to be renewed in the applicable Load Resource Balances after fiscal 2030, and its renewal is not contemplated in the Base Resource Plan.

The 275 MW Island Generation facility (located on Vancouver Island in the South Coast region) operates as a dispatchable facility based on system requirements and market conditions. Generally, we operate the facility on an infrequent basis, which means that its greenhouse gas emissions (about 10,000 tonnes of carbon dioxide equivalent per year) are lower than a facility like McMahon. The electricity purchase agreement with Island Generation expires at the end of fiscal 2022.

In the past, we have had discussions with the owner of Island Generation – Capital Power – to understand potential terms of a long-term renewal. More recently, BC Hydro has been in discussions with Capital Power to determine if the Island Generation facility can provide additional economic back-up capacity and supply over the next two to four years while repairs are being made to the shore-end segments of some of our submarine cables that incurred some damage in July 2021.[10]

Despite these discussions, there is no basis, at this time, to assume that the electricity purchase agreement with this facility will be renewed. Accordingly, Island Generation is not assumed to be renewed in the Base Resource Plan. As the Load Resource Balances demonstrate, Island Generation is not required to meet system planning requirements. As discussions with the Island Generation counterparty are ongoing, no modelling results will be presented in the 2021 IRP.

While no input or feedback was asked about the renewal of any specific facility, input (Phase One) results from the public and customers showed a top priority ranking of the objective to reduce greenhouse gas emissions through clean electricity.

During the feedback phase (Phase Two), we heard concerns from the local community about not assuming Island Generation would be renewed, citing loss of jobs, community tax benefits, and reliability of the power supply for Vancouver Island.

9 Includes a $30M adjustment in relative costs for region-specific transmission required in the No McMahon portfolio. This assessment was performed outside of System Optimizer.

10 In July, BC Hydro detected oil leaks and buckling in the above-ground portions of some of its submarine cables, which extend from the Sunshine Coast to Vancouver Island. Initial repairs to the cables were completed by October 2021. However, additional work will likely be required over the next two to four years. BC Hydro expects to take the cables out of service for short periods of time to ensure that the repairs can be completed safely.

7.4.6 HOW THE UPGRADES TO THE TRANSMISSION SYSTEM WERE SELECTED

In section 5.5.1, we describe the three sequential steps of transmission upgrades developed and analyzed as options to serve the South Coast region. The transmission upgrade options were identified through detailed analysis of various portfolios. In all cases the transmission options are conceptual, and the required scope options will be refined in further transmission studies after the 2021 IRP is complete.

The portfolio analysis outlined in section 6.1 shows that these transmission upgrade options competed with other options to meet South Coast regional capacity needs (for example, pumped hydro storage, small storage hydro, and utility-scale batteries). In all cases, the first step of the transmission upgrades to the South Coast was selected for meeting these capacity needs. When given the option, the System Optimizer software almost always selected the second step of the transmission upgrades to the South Coast as part of the lowest cost portfolio to meet capacity needs on the South Coast.

The portfolio assembled as the Base Resource Plan is detailed in Attachment 1. The inference to be taken from System Optimizer's selections is that these first and second steps of the transmission upgrades to the South Coast, when selected, are the lowest cost solutions available.

In no cases was the third step selected by System Optimizer when creating portfolios to meet the Reference Load Forecast, as lower-cost solutions were available to meet system needs. Since the third step of the transmission upgrades to the South Coast requires more impactful greenfield developments, this outcome aligns with feedback from customers, the public and from Indigenous Nations who emphasized the importance of avoiding land and water impacts and keeping costs low. Accordingly, further analysis of strategies that included the third step as a way of meeting the Reference Load Forecast was not undertaken.

Consultation occurred in two phases. Input during Phase One informed the development of this element of the plan, while Phase Two sought feedback on how this element aligned with values and interests. Results from our consultation show:

- Input (Phase One) results showed keeping costs down and limiting land and water impacts as a key priority for the public and customers. Many participants supported upgrading our system; however, participants also raised concerns if upgrades included new large transmission lines. Indigenous Nations input indicated a strong interest in limiting land and water impacts.
- Feedback (Phase Two) results showed broad positive alignment from the public and customers on this element with their values and interests. Indigenous feedback was mainly aligned with or neutral on this element of the plan.[11]

The Near-term Actions needed to be undertaken in the first five years of the planning period can be found in Chapter 9.

11 The information provided is a summary of the consultation results and does not reflect the full record of input and feedback received by BC Hydro during the consultation process. For detailed summaries of what we heard and how we considered the input and feedback, please see **bchydro.com/cleanpower2040**.

7.4.7 WHAT THE ROLE IS FOR EXISTING BC HYDRO GENERATING FACILITIES

We considered upgrades to existing BC Hydro facilities, as described in section 5.4.2, in conjunction with other sources of generation when building least cost portfolios to meet future customer needs. Of the potential upgrades of BC Hydro's generation facilities, a sixth unit at the Revelstoke Generating Station and the capacity upgrades at the G.M. Shrum facilities are two of the largest. However, neither was selected as part of a least-cost portfolio, and neither is included in the Base Resource Plan.

As described in section 5.4.2, six small plants will require end-of-life investment decisions within the planning horizon of the 2021 IRP. Our assessment is that:

- With the current energy surplus BC Hydro does not need to accelerate decisions on the future of its small plants. A later decision allows BC Hydro to respond, as required, based on future needs; and
- A staged approach provides an opportunity to align refurbishment with evolving load requirements and the extent to which BC Hydro's planned demand and supply-side resources perform as expected.

> **Consultation occurred in two phases. Input during Phase One informed the development of this element of the plan, while Phase Two sought feedback on how this element aligned with values and interests. Results from our consultation show:**
>
> - Input (Phase One) results from the public and customers showed an interest in decommissioning, habitat restoration and keeping costs low, as well as focusing on newer, more viable options. Input also favoured evaluations being conducted on a facility-by-facility basis. Indigenous Nations input emphasized the need for consultation with the Nations where the specific facility is located. Indigenous interests could include decommissioning and restoring habitat or refurbishment and associated economic development opportunities.
> - Feedback (Phase Two) results showed positive or neutral alignment from the public and customers on this element with their values and interests. Indigenous feedback was mainly aligned with or neutral on this element of the plan. One Indigenous Nation was opposed to the proposed timeframe for addressing the future of the Alouette facility.[12]

The Near-term Actions needed to be undertaken in the first five years of the planning period can be found in Chapter 9.

12 The information provided is a summary of the consultation results and does not reflect the full record of input and feedback. For detailed summaries of what we heard and how we considered the input and feedback, please see **bchydro.com/cleanpower2040**.

7.4.8 HOW FUTURE RESOURCES WERE CONSIDERED

The selected demand-side measures and other elements described above push out the need for new clean resources into the 2030's.

Under our current forecasts of technology capabilities and costs, preliminary modelling results suggest wind will be the predominant source of new energy supply in the Base Resource Plan from the second half of the planning horizon onwards. The remaining capacity needs could be met with different sources of new clean resources since specific location and size attributes play an important role in meeting regional capacity needs. While these assumptions were inputs into the System Optimizer modelling, when the need arises BC Hydro will choose from amongst a variety of types of supply options (developing new clean resources, renewing expiring electricity purchase agreements, and expanding BC Hydro generation assets) closer to the time they are required in order to benefit from more up-to-date cost and system information.

> **Consultation occurred in two phases. Input during Phase One informed the development of this element of the plan, while Phase Two sought feedback on how this element aligned with values and interests. Results from our consultation show:**
>
> Input (Phase One) results from public and customers showed a strong interest in renewable power as well as customer generated distributed resources. Indigenous input showed a strong interest in new clean energy development opportunities.
>
> Feedback (Phase Two) results showed broad positive alignment from public and customers on this element with their values and interests. Similar to what we heard in Phase One, interest continued to focus on renewable power (wind and solar) and distributed generation opportunities. Indigenous feedback was mainly aligned with or neutral on this element of the plan, with a strong interest in Indigenous participation in clean energy development opportunities.[13]

As the need for new clean resources does not occur until the latter half of the planning horizon, BC Hydro does not anticipate any Near-term Actions related to this element of the Base Resource Plan.

7.4.9 WHY WE DON'T PURSUE MORE DEMAND DEMAND-SIDE MEASURES TO MEET ALL OF OUR FUTURE NEEDS

Sections 7.3.1 to 7.3.3 show that we can meet much of our future needs through demand-side measures. In particular, advancing the demand-side measures described in the Base Resource Plan will shift the date of system energy and capacity shortfalls from fiscal 2029 to fiscal 2030 and from fiscal 2032 to fiscal 2037, respectively, and shift the South Coast capacity shortfall from fiscal 2027 to fiscal 2032.

We did not choose the demand-side measure portfolios that would result in the highest energy and capacity savings level. On balance, our assessment is that the selected portfolios of demand-side measures represent a cost-effective way to meet future customer needs.

Our assessment is that pursuing more demand-side measures could:

- Increase bills for those not able to take advantage of energy efficiency programs;
- Default customers into opt-out time-varying rates that are not well-suited to them; and
- Increase the risk to ratepayers of demand-side measures under-delivering on their expected savings, leading BC Hydro to pursue quicker but more expensive options in response.

Our assessment of our chosen level of demand-side measures is that they:

- Provide time for BC Hydro to learn, and gain customer acceptance, which will reduce savings uncertainty and potentially improve ramp up rates to higher levels of savings if needed; and
- Leave us in a balanced, flexible position to increase or decrease savings, depending on future load conditions.

13 The information provided is a summary of the consultation results and does not reflect the full record of input and feedback received by BC Hydro during the consultation process. For detailed summaries of what we heard and how we considered the input and feedback, please see **bchydro.com/cleanpower2040**.

7.4.10 HOW THE BASE RESOURCE PLAN MEETS OUR PLANNING OBJECTIVES

The planning objectives laid out in Section 2.3 are:

- Keeping costs down for customers;
- Reducing greenhouse gas emissions;
- Limiting land and water impacts; and
- Supporting the growth of B.C.'s economy.

The Base Resource Plan addresses these objectives in the following ways:

- Keeping costs down for customers: the Base Resource Plan positions us to meet load growth cost-effectively. It provides flexibility for a wide range of options upon which we then develop the Contingency Resource Plans. While the Base Resource Plan does not represent the lowest cost portfolio studied, it prudently allows BC Hydro to manage cost risk if load decreases or market prices decline. In addition, it reflects the input and feedback from our consultation process and provides opportunities for us to gain experience with time-varying rates and additional demand-side measures in order to ramp up quickly if load growth accelerates.
- Reducing greenhouse gas emissions: None of the Base Resource Plan elements would increase greenhouse gas emissions from our system, and, over time, these Base Resource Plan elements will allow us to reduce the greenhouse gas emissions associated with electricity generation. In addition, demand-side measures for electric vehicle charging will support the adoption of electric vehicles and reduce greenhouse gas emissions more broadly.
- Limiting land and water impacts: our Base Resource Plan relies on cost-effective demand-side measures to meet our customers growing needs; this avoids the land and water impacts of new generation and transmission projects. Where we do rely on additional generation, we will be looking to renew our agreements with existing power producers' projects; this will also avoid land and water impacts. Finally, we have focused on upgrades – as opposed to new lines – to increase transmission capabilities to the South Coast to once again minimize land and water impacts.
- Supporting the growth of B.C.'s economy: our analysis of the employment impacts arising from our portfolio choices shows that the options considered in the 2021 IRP do not have a significant impact at a provincial scale – positively or negatively. The main way we can support B.C.'s economy is by providing reliable, affordable, clean electricity to meet the needs of our customers.

8

The Contingency Resource Plans: preparing for change

8.1 Introduction

Our Contingency Resource Plans set out our plans for scenarios other than the Reference Load Forecast. As outlined at the end of Chapter 7, the Base Resource Plan is a starting point for these contingencies that provides flexibility for both higher and lower load scenarios, alongside potential electricity supply challenges that could arise. The Base Resource Plan prudently allows for a wide range of options upon which we developed Contingency Resource Plans, ranging from a prolonged stagnation in electricity consumption that might occur from a 2008 like recession on the low side through to full implementation of federal and provincial climate action plans on the high side.

The analyses supporting the Contingency Resource Plans are not as extensive as those underpinning the Base Resource Plan. Given the uncertainty around the scenarios, our focus has been on developing plausible plans rather than optimizing the plans. The intent was to identify any necessary Near-term Actions required to prepare for each scenario.

With approval of the 2021 IRP by our Board of Directors, BC Hydro begins monitoring whether the IRP's Near-term Actions continue to be appropriate as the future unfolds. We will watch for signposts including updates to policies and legislation, deviations in our load forecast, and changes in our existing, committed and planned resources. As changes are identified and incorporated into our planning, we will determine whether the 2021 IRP's Near-term Actions to meet future demand remain enough to meet the projected future needs of our customers. We will take steps, guided by the Contingency Resource Plans to position BC Hydro to meet future customer demand while also managing costs. If the 2021 IRP's Near-term Actions are not enough, we will initiate the development of the next integrated resource plan.

The first signpost for the 2021 IRP has already arrived, in the form of the CleanBC Roadmap to 2030, released by the Provincial Government on October 25, 2021. BC Hydro will assess the implications of this announcement on future electricity demand and supply. We will also be watching for corresponding legislation, regulation, programs, and funding to implement the Roadmap.

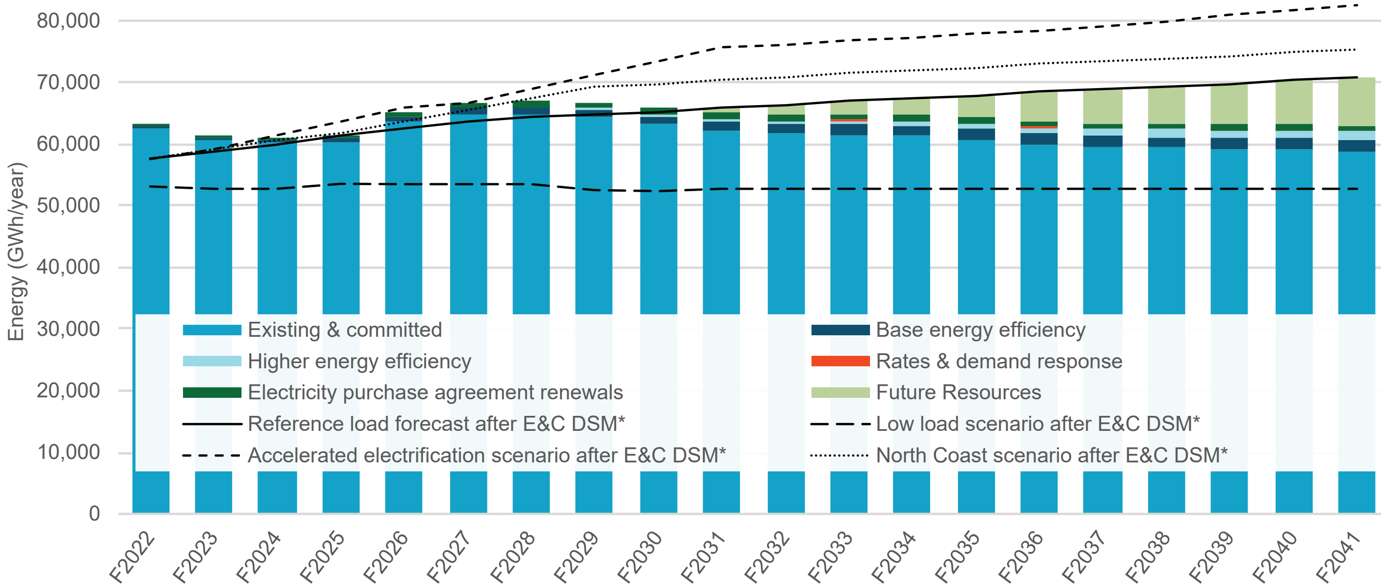
8.2 The contingency scenarios we are preparing for

We have developed four contingency scenarios for the 2021 IRP. These scenarios cover a broad range of potential future demand both above and below the Reference Load Forecast. In addition, they look into uncertainties at the system and regional level, particularly in the South and North Coast regions, where potential supply constraints might arise:

- Accelerated electrification load scenario represents a case where load grows rapidly. It looks at the demand that could arise from BC Hydro's Electrification Plan and electricity demand from actions to meet the Province's 2025, 2030, and 2040 greenhouse gas reduction targets. This scenario examines significant load growth in the South Coast region.
- Accelerated electrification load scenario with under-delivery of the Base Resource Plan's rates and demand-side measures programs is a variation of the Accelerated electrification scenario and looks at a situation in which our demand-side measures efforts underperform at the same time as the Accelerated electrification scenario is unfolding.
- Low load forecast (Low load scenario) looks at a situation where demand drops somewhat and then stagnates throughout the planning period.
- North Coast liquified natural gas & mining load scenario looks at the possibility of significant industrial activity in that region.

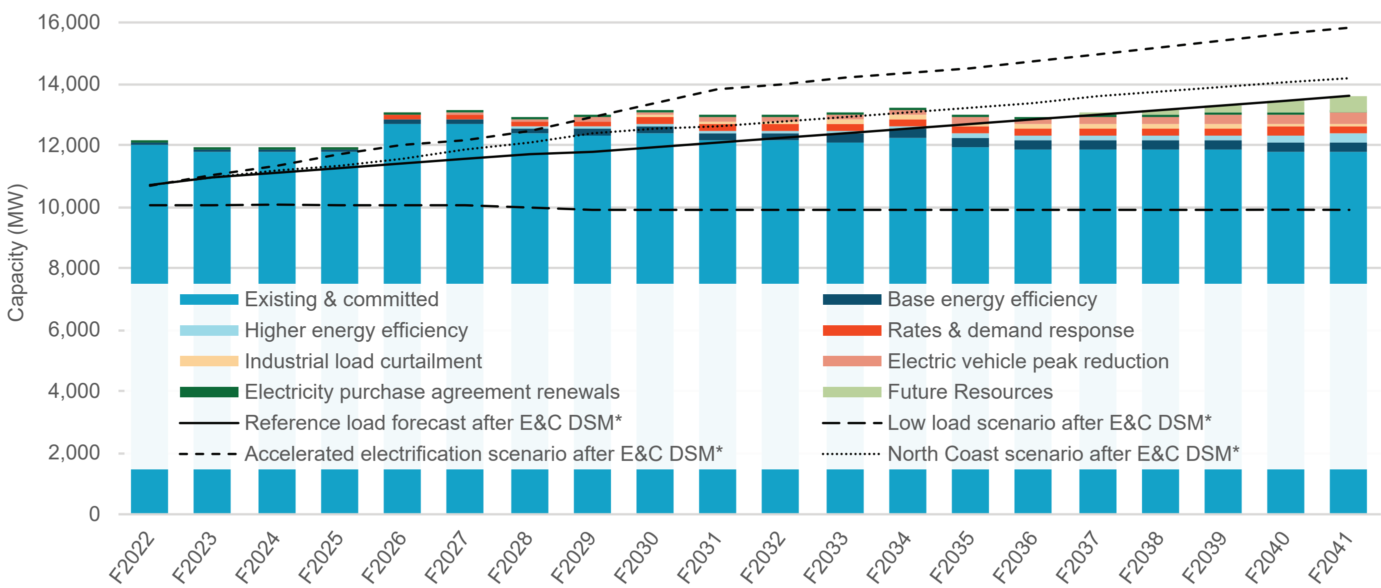
Figures 8-1 and 8-2 show system-level views of the energy and capacity outlook for the contingency scenarios, while Figures 8-3 and 8-4 show the outlook for the South Coast and North Coast regions, respectively.

Figure 8-1 System energy Load Resource Balance with Base Resource Plan and contingency scenarios



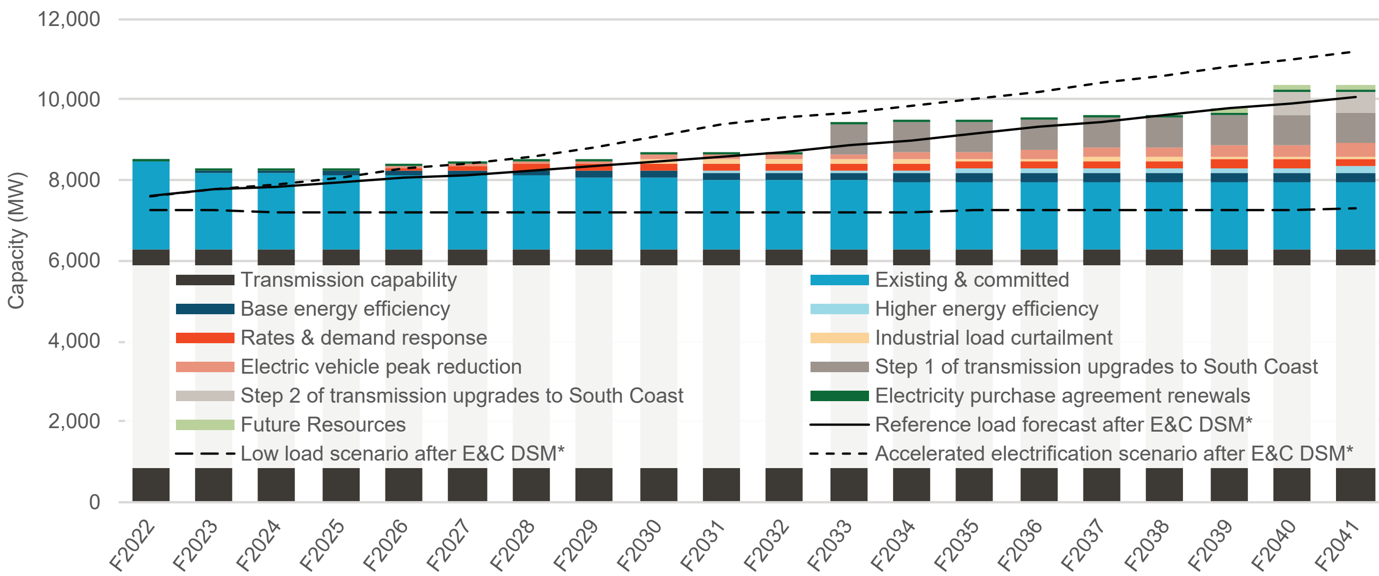
* E&C DSM denotes existing and committed demand-side measures

Figure 8-2 System capacity Load Resource Balance with Base Resource Plan and contingency scenarios



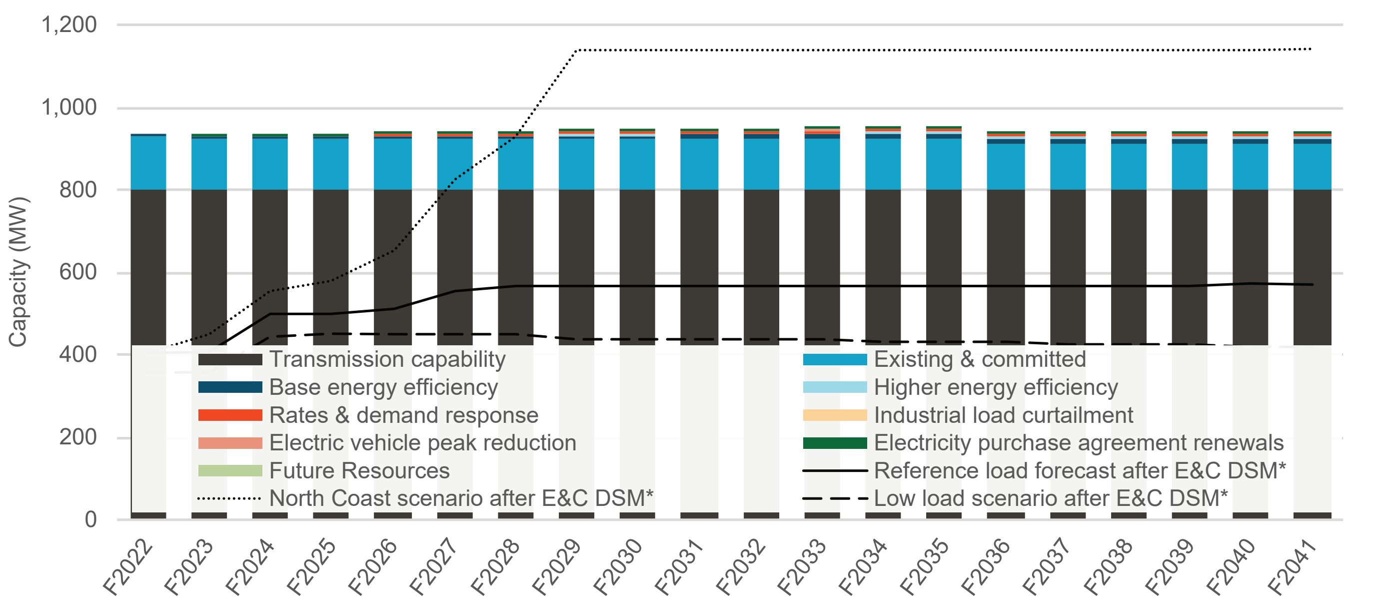
* E&C DSM denotes existing and committed demand-side measures

Figure 8–3 South Coast region capacity Load Resource Balance with Base Resource Plan and contingency scenarios



* E&C DSM denotes existing and committed demand-side measures

Figure 8–4 North Coast region capacity Load Resource Balance with Base Resource Plan and contingency scenarios



* E&C DSM denotes existing and committed demand-side measures

8.3 Accelerated electrification scenario

The Accelerated electrification scenario assumes a full realization of the load growth in the Electrification Plan and that the Province moves forward with the development and implementation of a plan to fully meet Provincial greenhouse gas reduction targets in 2025, 2030, and 2040.[1] In addition, this scenario assumes that downside risks to the Reference Load Forecast do not materialize.

This scenario has load impacts almost immediately across the province, both in the South Coast, where our main load centre is, and elsewhere in the province, where the natural gas sector would be expected to electrify.

If there is rapid growth in electricity use consistent with this scenario, BC Hydro will initiate processes to draw on future resources in the Base Resource Plan earlier than planned and will rely on temporary supply of market energy to meet near-term needs. The following illustrative elements of this Contingency Resource Plan demonstrate the resources needed to meet this higher load growth scenario in the timeframe and volume required.[2]

- Ramping-up from base to higher levels of energy efficiency programs to achieve approximately 2,080 GWh/year of energy savings and approximately 380 MW of capacity savings at the system level by fiscal 2030;
- Implementing voluntary time-varying rates and supporting programs to achieve approximately 320 MW of capacity savings at the system level by fiscal 2030;[3,4]
- Implementing electric vehicle peak reduction initiatives to achieve 75 per cent electric vehicle driver participation and approximately 170 MW of capacity savings by fiscal 2030;
- Initiating processes to renew electricity purchase agreements expiring in the next five years to provide approximately 900 GWh/year of energy supply by fiscal 2030;[5]
- Advance the first step of sequential upgrades to transmission infrastructure into the South Coast region, including series compensation, shunt capacitors, and thermal upgrades by fiscal 2033 and prepare to initiate a second step of upgrades to the South Coast region by fiscal 2039;
- Initiating processes to acquire future resources to achieve approximately 7,100 GWh/year of energy supply and approximately 400 MW of capacity at the system level by fiscal 2030. These future resources would be selected from expiring electricity purchase agreements with independent power producers and new clean and renewable energy resources;
- Implementing BC Hydro facility upgrades at Revelstoke, G.M. Shrum, and Wahleach in the later years of the IRP period to achieve 530 MW of capacity at the system level by fiscal 2038;
- Temporarily bridging load with market supply of up to 2,000 GWh/year of energy for a total of five years; and
- Advancing utility-scale batteries, with the first units installed in fiscal 2029, ramping up to provide approximately 480 MW of additional dependable capacity by fiscal 2032.

> A broad theme of the public and customers' consultation was interest in electrification and climate action, including how the 2021 IRP would adequately prepare us for meeting Provincial greenhouse gas reduction targets.

1 The Accelerated Electrification scenario in the final 2021 Integrated Resource Plan has been updated to assume the full realization of the load growth in the Electrification Plan and that the Province moves forward with the development and implementation of a plan to fully meet Provincial greenhouse gas reduction targets in 2025, 2030, and 2040. This scenario also assumes that downside risks to the Reference Load Forecast do not materialize.
2 Energy and capacity additions are described here as incremental to existing and committed resources rather than as incremental to the Base Resource Plan.
3 This element entails the same level of effort as the corresponding element in the Base Resource Plan.
4 Supporting programs include demand response and load curtailment initiatives.
5 This element is the same as the corresponding element in the Base Resource Plan.

8.3.1 ACCELERATED ELECTRIFICATION – DEMAND-SIDE MEASURES UNDER-DELIVERY SCENARIO

The Accelerated electrification – demand-side measures under-delivery scenario is the most challenging scenario with a near-term need for system energy and the medium-term need for capacity in the South Coast region. It combines the load growth of the Accelerated electrification scenario with a reduction in the delivered savings from demand-side measures. To develop this scenario demand-side measures savings forecasts were split into a "mid-level", a "low level", and a "high level". Demand-side measures under-performance is when all demand-side measures perform at the "low level", and was the level used in this scenario.

The rapid changes in load and the diminished success of demand-side measures that define this scenario would provide early signposts indicating that additional actions are required to meet the future load. If there are indications that this scenario is being realized, BC Hydro will initiate processes to draw on future resources in the Base Resource Plan earlier than planned and rely on temporary supply of market energy to meet near-term needs. The following illustrative elements of this Contingency Resource Plan demonstrate the future resources needed to meet this higher load growth scenario in the timeframe and volume required.[6]

- Adjusting our energy efficiency programs and program designs to achieve approximately 1,300 GWh/year of energy savings and approximately 230 MW of capacity savings by fiscal 2030, based on learnings from the under-delivery of previous initiatives;
- Adjusting our voluntary time-varying rates and/or supporting programs to achieve 100 MW of capacity savings at the system level by fiscal 2030, based on learnings from recent performance;[7,8]
- Implementing electric vehicle peak reduction initiatives to achieve 75 per cent electric vehicle driver participation and approximately 170 MW of capacity savings by fiscal 2030;
- Initiating processes to renew electricity purchase agreements expiring in the next five years to provide approximately 900 GWh/year of energy supply by fiscal 2030;[9]
- Initiating processes to acquire future resources to achieve approximately 6,000 GWh/year of energy supply and approximately 380 MW of capacity supply at the system level by fiscal 2030. These future resources would be selected from expiring electricity purchase agreements with independent power producers and new clean and renewable energy resources;
- Advance the first step of sequential upgrades to transmission infrastructure into the South Coast region, including series compensation, shunt capacitors, and thermal upgrades by fiscal 2033 and prepare to initiate a second step of upgrades to the South Coast region by fiscal 2038;
- Implementing BC Hydro facility upgrades at Revelstoke, G.M. Shrum, and Wahleach in the later years of the IRP period to achieve 530 MW of capacity at the system level by fiscal 2038;
- Temporarily bridging load with market supply of up to 2,000 GWh/year of energy for a total of six years; and,
- Advancing utility-scale batteries, with the first units installed in fiscal 2028, ramping to approximately 800 MW of additional capacity by fiscal 2032.[10]

This Contingency Resource Plan requires future resources that provide capacity to the South Coast. The capacity need in this scenario has two defining characteristics: early (as soon as fiscal 2028) and large (nearly 800 MW in fiscal 2032). Utility-scale batteries are uniquely suited to meet some or all of this need due to the technology's short lead times and scalability.

6 Energy and capacity additions are described here as incremental to existing and committed resources rather than as incremental to the Base Resource Plan.
7 This illustrative element entails the same level of effort as the corresponding element in the Base Resource Plan, but with a lower level of achieved capacity savings due to the assumed demand-side measures under-delivery in this scenario.
8 Supporting programs include demand response and load curtailment initiatives.
9 This element is the same as the corresponding element in the Base Resource Plan.
10 The volume of batteries required will depend on the nature and capacity contribution from the future resources. In this illustration, future resources have been assumed to be wind that provides a relatively small amount of capacity contribution.

Utility-scale battery resources are a relatively new technology within the utility sector and a novel technology at this scale within the BC Hydro system. Therefore, in order to include utility-scale batteries as a viable option for Contingency Resource Plans, the 2021 IRP includes a Near-term Action that will allow BC Hydro to explore integration and operationalization of utility-scale batteries. This Near-term Action is an effective way to:

- De-risk the schedule of implementing utility-scale batteries, which are an important element of the Accelerated electrification – demand-side measures under-delivery scenario Contingency Resource Plan; and
- Gain experience integrating the operations of utility-scale batteries into our grid.

> **Consultation occurred in two phases. Input during Phase One informed the development of this element of the plan, while Phase Two sought feedback on how this element aligned with values and interests. Results from our consultation show:**
>
> - Input (Phase One) results from the public and customers showed support for the use of utility-scale batteries. Indigenous Nations input showed openness for new power sources such as batteries and stated BC Hydro should be working with local Nations to develop opportunities for Indigenous partnerships. Both streams raised some environmental concerns about their production and disposal.
> - Feedback (Phase Two) results from the public and customers showed broad positive alignment of this element with their values and interests. Overall, feedback from Indigenous participants was supportive or neutral of this element. Participants across both streams expressed some concerns over environmental impacts. Interest in Indigenous economic opportunities were also expressed.[11]

8.4 Low load scenario

The Low load scenario assumes lower economic growth and resource sector development relative to the Reference Load Forecast, combined with lower light-duty electric vehicle penetration rates and lower industrial electrification uptake. This scenario also assumes long-term structural changes occur in the B.C. economy that reduce electricity consumption. These changes could result from several factors, including the way people interact and approach economic activities after the COVID-19 pandemic ends, and reduced industrial load in the province.

The decline in load across multiple sectors in this scenario would provide an early signpost that the Near-term Actions described in the Base Resource Plan should be deferred for an indefinite period or discontinued. The Base Resource Plan, as we have constructed it, allows for significant flexibility in response to this type of scenario because of its priority on demand-side measures. The Low load scenario Contingency Resource Plan elements are described below in terms of adjustments to the Base Resource Plan.

- Defer the implementation of Higher energy efficiency programs;
- Defer implementation of new voluntary time-varying rates and supporting programs, and scale back efforts to enroll and support customer response to any time-varying rates already implemented;
- Scale back efforts to enroll customers and support customer response to electric vehicle peak reduction initiatives;
- Defer implementation of the Industrial Load Curtailment Program;
- Discontinue offers to renew electricity purchase agreements past fiscal 2026; and
- Defer the first step of sequential upgrades to transmission infrastructure into the South Coast region and the initiation of the second step of transmission upgrades.

11 The information provided is a summary of the consultation results and does not reflect the full record of input and feedback. For detailed summaries of what we heard and how we considered the input and feedback, please see **bchydro.com/cleanpower2040**.

8.5 North Coast liquified natural gas and mining scenario

The North Coast region in northwestern B.C. is connected to the rest of the BC Hydro system via a 450 km single radial 500 kilovolt transmission line from Prince George to Terrace. The North Coast region poses unique planning challenges due to its remote location, large range of load potential, and limited local clean or renewable capacity resources.

The North Coast liquified natural gas and mining scenario considers potential liquified natural gas and mining loads that may materialize in the North Coast over and above the Reference Load Forecast. The scenario assumes several of the proposed mines and liquified natural gas facilities in the region proceed into operation within the next decade. These loads increase the system need for energy and capacity in the first decade of the 2021 IRP relative to the Reference Load Forecast, but do so to a lesser extent than the Accelerated electrification scenario. In this scenario, the North Coast region sees a rapid increase in the need for capacity relative to the Reference Load Forecast, with the need reaching a plateau by fiscal 2029. Final investment decisions by project proponents would provide strong signposts to indicate that this scenario is unfolding. At that time, BC Hydro will initiate processes to draw on future resources earlier than indicated in the Base Resource Plan and rely on a temporary supply of market energy to meet near-term needs at the system level.

The rapid load growth in the North Coast exceeds the region's existing and committed capacity resources. As mentioned, there are few local resources that could meet these needs. Higher demand-side measures or new local generation resources are not likely to be available at the volume or within the timeframe that this scenario requires. In addition, utility-scale batteries and pumped hydro storage systems are ill-suited to support the operations of the new industrial loads that operate nearly 24-hours per day.

The Prince George to Terrace Capacitor Project (PGTC Project) is an existing project first initiated in 2012 and represents a cost-effective means of delivering capacity to the North Coast region. It has been the subject of extensive and continuing consultation for several years. The project will provide sufficient capacity to the region and can be in-service as early as fiscal 2028. The need and feasibility of the PGTC Project has already been determined and it is now in the detailed design phase. The PGTC Project anticipates early construction work beginning in early 2023. To meet the rapid increase in load described in this scenario, the 2021 IRP includes a Near-term Action that reflects the continuation of PGTC Project and its earliest in-service date of fiscal 2028. This will ensure that we are able meet the potential demand under this scenario for liquified natural gas initiatives, mines, and other customers on a timeline that aligns with their investment decisions and project in-service dates.

The following illustrative set of elements for this Contingency Resource Plan demonstrate that there are adequate future resources to meet this higher load growth scenario in the timeframe and at the volume required.[12]

- Ramping-up from base to higher levels of energy efficiency programs to achieve approximately 1,700 GWh/year of energy savings and approximately 280 MW of capacity savings at the system level by fiscal 2030;[13]
- Implementing voluntary time-varying rates and supporting programs to achieve approximately 310 MW of capacity savings at the system level by fiscal 2030;[14,15]
- Implementing electric vehicle peak reduction initiatives to achieve 50 per cent electric vehicle driver participation and approximately 100 MW of capacity savings by fiscal 2030;[16]
- Initiating processes to renew electricity purchase agreements expiring in the next five years to provide 900 GWh/year of energy supply by fiscal 2030;[17]
- Continue to advance the Prince George to Terrace Capacitor Project to maintain its earliest in-service date of fiscal 2028;
- Initiating processes to acquire future resources to achieve approximately 4,100 GWh/year of energy supply and approximately 340 MW of capacity at the system level by fiscal 2030. These future resources would be selected from expiring electricity purchase agreements with independent power producers and/or new clean and renewable energy resources; and
- Temporarily bridging load with market supply of up to 2,000 GWh/year of energy for two years (fiscal 2025 and fiscal 2028).

> During consultation, the First Nations Climate Initiative and the First Nations Major Projects Coalition raised an interest in proactively advancing transmission infrastructure to the North Coast to facilitate low-carbon economic development opportunities in the region.

12 Energy and capacity additions are here described as incremental to existing and committed resources rather than as incremental to the Base Resource Plan.
13 This illustrative element is the same as the corresponding element in the Base Resource Plan.
14 This element entails the same level of effort as the corresponding element in the Base Resource Plan.
15 Supporting programs include demand response and load curtailment initiatives.
16 This illustrative element is the same as the corresponding element in the Base Resource Plan.
17 This illustrative element is the same as the corresponding element in the Base Resource Plan.

9

Near-term Actions

9.1 Introduction

BC Hydro is taking steps to implement the Base Resource Plan and to ensure that we are able to implement the Contingency Resource Plans on a timely basis. These are called Near-term Actions and are provided below.

2021 IRP Near-term Actions		
FROM THE BASE RESOURCE PLAN		
Category	**Base Resource Plan element**	**Near-term Actions**
Demand-side measures	Continue with a base level of energy efficiency programs (Base energy efficiency) and plan to ramp up to higher levels (Higher energy efficiency) in future years to achieve approximately 1,700 GWh/year of energy savings and approximately 280 MW of capacity savings at the system level by fiscal 2030.	1. BC Hydro is filing its fiscal 2023 to 2025 Demand-side Measures Expenditure Request with the BCUC to seek approval for the expenditures over that period to achieve the savings. The Demand-side Measures Expenditure Requests for the years beyond fiscal 2025 will be filed at a subsequent date.
	Pursue voluntary time-varying rates supported by demand response programs to achieve approximately 220 MW of capacity savings at the system level by fiscal 2030, and advance the Industrial Load Curtailment Program to achieve approximately 100 MW of incremental capacity savings at the system level by no later than fiscal 2030; Pursue a combination of education and marketing efforts as well as incentives for smart-charging technology for customers to support a voluntary residential time-of-use rate to shift home charging by 50 per cent of residential electric vehicle drivers to off-peak demand periods (50 per cent electric vehicle driver participation) to achieve approximately 100 MW of capacity savings at the system level by fiscal 2030.	2. The fiscal 2023 to 2025 Demand-side Measures Expenditure Request will seek approval for expenditures related to these capacity savings. BC Hydro will file a Residential Optional Time-of-Use Rates Application in early 2022. This application will include an optional whole home time-of-use rate and an optional end use time-of-use rate pertaining to electric vehicle charging. BC Hydro is undertaking customer engagement to inform the development of these rate designs.

<table>
<tr><th colspan="3">2021 IRP Near-term Actions</th></tr>
<tr><th colspan="3">FROM THE BASE RESOURCE PLAN</th></tr>
<tr><th>Category</th><th>Base Resource Plan Element</th><th>Near-term Actions</th></tr>
<tr><td>Electricity Purchase Agreements</td><td>Offer a market-price-based renewal option to existing clean or renewable independent power producers with electricity purchase agreements expiring in the next five years. There are 19 existing clean or renewable projects that produce a total of approximately 900 GWh, with electricity purchase agreements set to expire before April 1, 2026.</td><td>3. All electricity purchase agreements will be filed pursuant to section 71 of the Utilities Commission Act as they are renewed. The first two electricity purchase agreements in this category expire in October 2022.</td></tr>
<tr><td>Transmission</td><td>Advance the first step of sequential upgrades to transmission infrastructure into the South Coast region, including series compensation, shunt capacitors, and thermal upgrades to achieve approximately 750 MW of capacity for the South Coast region by fiscal 2033; prepare to initiate a second step of upgrades to achieve approximately an additional 550 MW of capacity for the South Coast region by fiscal 2040.</td><td>4. The project to deliver the first step of sequential upgrades will be included in the fiscal 2024 to 2033 capital plan and relevant expenditures will be detailed in the Revenue Requirements Application, anticipated to be filed in the summer of 2024 for a test period starting on April 1, 2025.

As appropriate, we will engage early with Indigenous Nations and the public that may be potentially affected. BC Hydro will further work towards filing a future Certificate of Public Convenience and Necessity Application for this project.</td></tr>
<tr><td>Existing BC Hydro generating facilities</td><td>Undertake a structured decision making approach to evaluate small BC Hydro plants requiring end-of-life investment decisions on a facility-by-facility basis to determine whether to decommission or refurbish these facilities. These facilities would be evaluated on the following schedule:
<table>
<tr><th>Facility</th><th>Evaluation Timing</th></tr>
<tr><td>Shuswap</td><td>Analysis in progress</td></tr>
<tr><td>Elko</td><td>2025</td></tr>
<tr><td>Spillimacheen</td><td>2029</td></tr>
<tr><td>Alouette</td><td>2030</td></tr>
<tr><td>Falls River</td><td>In operation—date not set</td></tr>
<tr><td>Walter Hardman</td><td>In operation—date not set</td></tr>
</table></td><td>5. BC Hydro will make filings with the BCUC that align with the decision for each facility, as applicable.

As appropriate, we will engage early with Indigenous Nations and the public that may be potentially affected.</td></tr>
</table>

2021 IRP Near-term Actions

FROM THE CONTINGENCY RESOURCE PLANS

Category	Contingency Resource Plan elements that require near-term action	Near-term Actions
Utility-scale batteries	Advancing utility-scale batteries, with the first units installed in fiscal 2028, ramping to approximately 800 MW of additional capacity by fiscal 2032.	6. BC Hydro will operationalize and integrate battery energy storage systems of varying capacities (at locations to be determined) and evaluate their performance. BC Hydro will detail the expenditures for these installations in the Revenue Requirements Application anticipated to be filed in the summer of 2024 for a test period starting on April 1, 2025. As appropriate, we will engage early with Indigenous Nations and the public that may be potentially affected.
Transmission	Continue to advance the Prince George to Terrace Capacitor Project to maintain its earliest in-service date of fiscal 2028.	7. Expenditures for the project will be detailed in the Revenue Requirements Application anticipated to be filed in the summer of 2024 for a test period starting on April 1, 2025.
	Reserve transmission capacity to allow BC Hydro to designate contingency resources to serve higher load if the contingency scenarios materialize.	8. Within the 2021 IRP Application, we are seeking BCUC approval to use the Contingency Resource Plans within future Network Integration Transmission Service submissions.

Clean Power 2040
Powering the future

BC Hydro
Power smart

Attachments

2021 Integrated Resource Plan

A1

Attachment 1: Load Resource Balances

Table of Contents

List of Figures

List of Tables

1 Introduction

In this Attachment, we present the Load Resource Balances before planned resources (i.e., based on existing and committed resources) that show when we expect to need new resources, and Load Resource Balances after planned resources that show how we will meet future electricitiy demand under the reference load forecast (Base Resource Plan) and a number of other scenarios (Contigency Resource Plans). The existing and committed resources, which includes both supply- and demand-side resources, are described in section 2. It is noted that in the Load Resource Balance graphs, the existing and committed demand-side resources are included in the load.

The Load Resource Balances are shown at the integrated system level for both energy and capacity. In addition, we consider capacity Load Resource Balances for three regions of the province – South Coast, Vancouver Island and North Coast. The regional peak loads are served by power generated from the regional supply resources as well as transmitted from other regions through the bulk transmission system. Regional Load Resource Balances are used to illustrate potential regional supply constraints.

2 Existing and committed resources

Existing and committed resources are resources that are already operating or are expected to be operating during the planning horizon. They include both supply- and demand-side resources.

Existing resources are resources that are currently operating and expected to continue to operate into, if not to the end of, the planning horizon. They include the following:

- Existing BC Hydro generation facilities (except for Alouette, Elko, Spillimacheen and one unit at Shuswap, which are currently out of service);
- Independent power producer projects currently in commercial operation (until their electricity purchase agreements expire); and
- Forecasted savings from current codes and standards, current rate structures (including net metering service) and Revenue Requirement Application-approved demand-side measures program expenditures up to, and including, fiscal 2021.[1,2]

1 Major outages, defined as 100 MW or larger and lasting longer than one year, are included in load resource balances for the first 10 years of the planning horizon.

2 At the time of the IRP analysis, demand-side measures program expenditures for fiscal 2022 had not been approved. Hence, the demand-side measures program savings for fiscal 2022 are included in planned demand-side measures savings. The fiscal 2022 demand-side measures program savings are approximately 400 GWh/year in fiscal 2030.

Committed resources are those that have received necessary internal authorizations to proceed to implementation as well as any required regulatory approvals and are expected to begin operating during the planning horizon. They include the following:

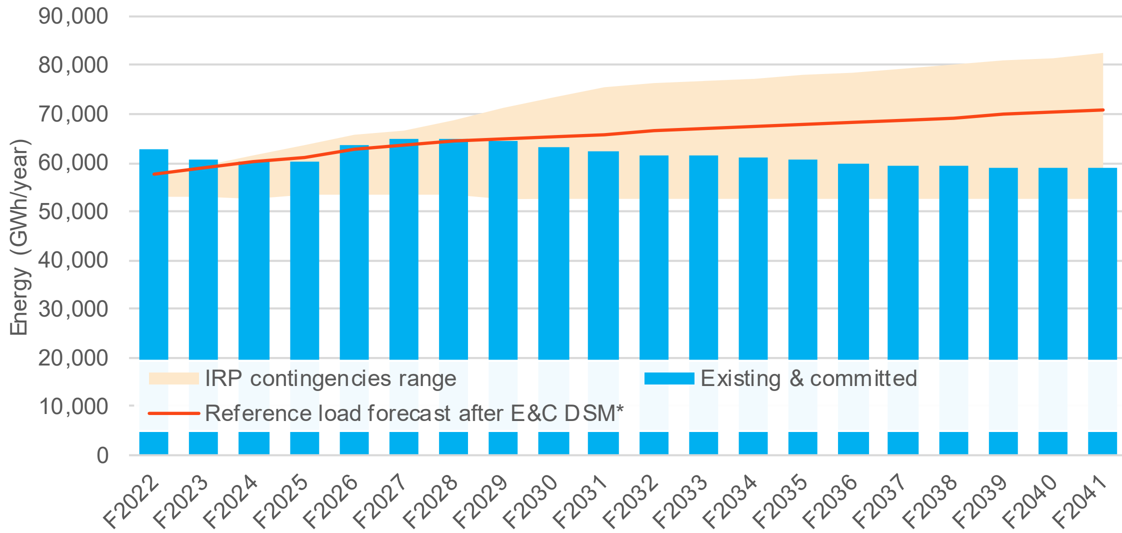
- Site C;
- Lake Buntzen Unit 1 generator replacement project;
- Future forecast codes and standards savings;
- Three electricity purchase agreements with projects currently under construction (expected in-service dates fiscal 2022 to fiscal 2023);
- One biomass project under the Biomass Energy Program, where a 10-year renewal agreement is expected to be executed;
- Two Standing Offer Program run-of-river projects with Indigenous Nations ownership/involvement excepted from the indefinite suspension of the Standing Offer Program; and
- Five electricity purchase agreements that include a seller's option to extend.

3 Load Resource Balances before planned resources

3.1 System energy and capacity Load Resource Balances before planned resources

Figure 1-1, Table 1-1, Figure 1-2, and Table 1-2 show the system-wide energy and capacity Load Resource Balances before planned resources.

Figure 1-1 System energy Load Resource Balance before planned resources

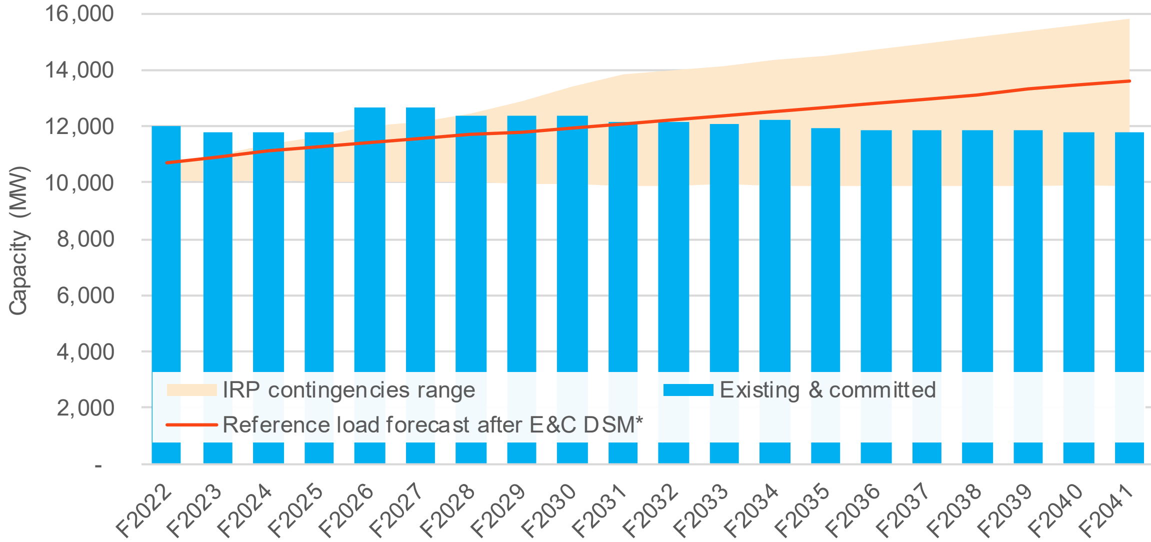


* E&C DSM denotes existing and committed demand-side measures.

Table 1-1 System energy Load Resource Balance before planned resources

	(GWh/year)		F2022	F2023	F2024	F2025	F2026	F2027	F2028	F2029	F2030	F2031	F2032	F2033	F2034	F2035	F2036	F2037	F2038	F2039	F2040	F2041
	LRB with Existing and Committed Supply																					
1	***Existing and Committed Heritage Resources***	(a)	46,898	46,898	46,898	47,264	50,790	52,184	52,184	52,184	52,184	52,184	52,184	52,184	52,184	52,184	52,184	52,184	52,184	52,184	52,184	52,184
2	***Existing and Committed Electricity Purchase Agreements***	(b)	15,719	13,717	13,278	13,059	12,807	12,728	12,638	12,210	10,997	9,997	9,501	9,323	9,055	8,541	7,716	7,350	7,212	6,952	6,922	6,736
3	**System Capability (before planned resources)**	(c) = a + b	62,617	60,615	60,176	60,323	63,597	64,912	64,822	64,394	63,181	62,181	61,685	61,507	61,239	60,725	59,900	59,534	59,396	59,136	59,106	58,920
	Demand - Integrated System Total Gross Requirements																					
4	Reference Load Forecast	(d)	(58,526)	(60,140)	(61,545)	(63,029)	(64,573)	(65,696)	(66,789)	(67,435)	(68,127)	(68,811)	(69,594)	(70,214)	(70,903)	(71,612)	(72,371)	(73,002)	(73,698)	(74,379)	(75,121)	(75,829)
	Existing and Committed Demand-side Measures																					
5	F21 Energy Conservations Programs Savings		105	117	117	118	112	112	112	109	104	71	60	47	47	43	17	12	12	12	11	10
6	Codes & Standards plus Voltage and VAR Optimization		589	854	1,111	1,355	1,586	1,804	1,996	2,181	2,356	2,523	2,684	2,838	2,992	3,148	3,304	3,459	3,615	3,771	3,927	3,995
7	Energy Conservation Rate Structures		138	177	210	239	156	147	138	139	139	115	86	58	29	-	-	-	-	-	-	-
8	Sub-total	(e)	833	1,148	1,438	1,711	1,853	2,064	2,247	2,429	2,599	2,709	2,830	2,943	3,069	3,191	3,321	3,471	3,627	3,782	3,938	4,005
9	***Net Metering***	(f)	40	50	62	77	95	117	143	174	212	258	311	371	438	510	588	667	749	832	915	998
10	**Surplus / (Deficit) before planned resources**	(g) = c + d + e + f	**4,963**	**1,673**	**132**	**(918)**	**973**	**1,397**	**423**	**(438)**	**(2,134)**	**(3,662)**	**(4,767)**	**(5,393)**	**(6,157)**	**(7,185)**	**(8,563)**	**(9,330)**	**(9,927)**	**(10,629)**	**(11,162)**	**(11,906)**

Figure 1-2 System capacity Load Resource Balance before planned resources



* E&C DSM denotes existing and committed demand-side measures.

Table 1-2 System capacity Load Resource Balance before planned resources

	(MW)		F2022	F2023	F2024	F2025	F2026	F2027	F2028	F2029	F2030	F2031	F2032	F2033	F2034	F2035	F2036	F2037	F2038	F2039	F2040	F2041
	LRB with Existing and Committed Supply																					
1	***Existing and Committed Heritage Resources*** [1]	(a)	11,818	11,818	11,818	11,818	12,965	12,965	12,618	12,618	12,965	12,791	12,791	12,791	12,965	12,965	12,965	12,965	12,965	12,965	12,965	12,965
2	***Existing and Committed Electricity Purchase Agreements***	(b)	1,795	1,512	1,495	1,481	1,400	1,400	1,391	1,362	1,068	974	940	917	885	580	480	480	445	445	437	437
3	***12% Reserves*** [2]	(c)	(1,574)	(1,540)	(1,540)	(1,540)	(1,674)	(1,674)	(1,633)	(1,629)	(1,636)	(1,604)	(1,600)	(1,597)	(1,617)	(1,583)	(1,576)	(1,576)	(1,576)	(1,576)	(1,576)	(1,576)
4	**System Peak Load Carrying Capability (before Planned Resources)**	(d) = a + b + c	12,039	11,789	11,773	11,759	12,691	12,691	12,376	12,350	12,397	12,162	12,131	12,111	12,233	11,962	11,869	11,869	11,834	11,834	11,826	11,826
	Demand - Integrated System Total Gross Requirements																					
5	Reference Load Forecast	(e)	(10,862)	(11,140)	(11,363)	(11,560)	(11,753)	(11,936)	(12,100)	(12,247)	(12,399)	(12,550)	(12,718)	(12,882)	(13,052)	(13,230)	(13,420)	(13,605)	(13,788)	(13,970)	(14,149)	(14,318)
	Existing and Committed Demand-side Measures																					
6	F21 Energy Conservations Programs Savings		21	21	21	20	18	18	17	17	16	12	10	8	8	8	4	3	3	3	3	3
7	Codes & Standards plus Voltage and VAR Optimization		118	166	212	254	293	329	361	391	419	445	470	493	520	548	576	604	632	659	687	700
8	Energy Conservation Rate Structures		11	16	19	23	15	14	13	13	13	11	8	5	3	-	-	-	-	-	-	-
9	Sub-total	(f)	150	203	252	297	326	361	392	421	448	468	488	506	531	556	580	607	635	663	690	703
10	***Net Metering***	(g)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
11	**Surplus / (Deficit) before planned resources**	(h) = d + e + f + g	**1,327**	**853**	**662**	**496**	**1,264**	**1,116**	**668**	**524**	**446**	**80**	**(99)**	**(264)**	**(288)**	**(713)**	**(971)**	**(1,128)**	**(1,320)**	**(1,474)**	**(1,633)**	**(1,789)**

Notes:

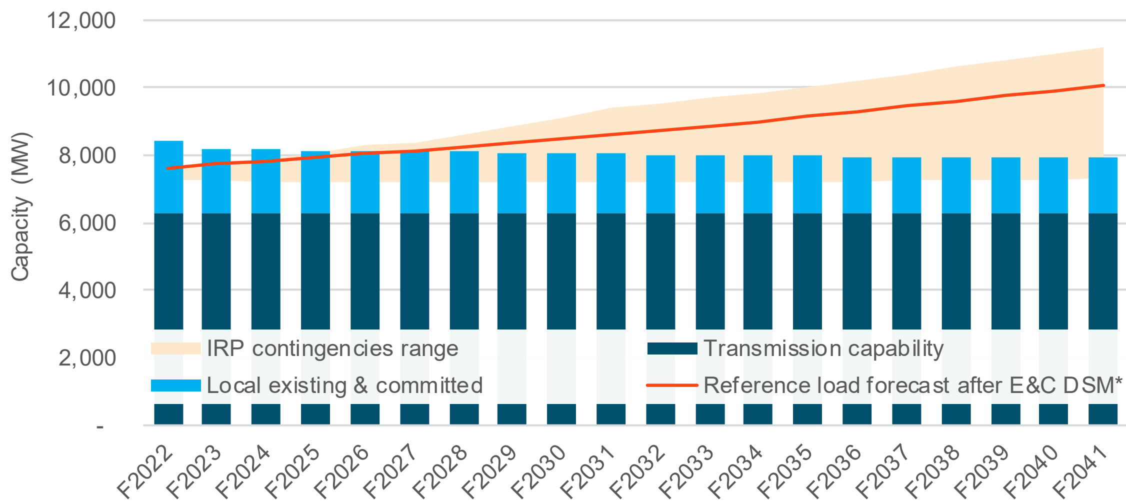
[1] Includes outages for Mica and Seven Mile

[2] The 12% reserve margin is applied to dependable capacity resources only

3.2 Regional capacity Load Resource Balances before planned resources

Figure 1-3, Table 1-3, Figure 1-4, and Table 1-4 show the capacity Load Resource Balances before planned resources for the South Coast, Vancouver Island and the North Coast.

Figure 1-3 South Coast capacity Load Resource Balance before planned resources

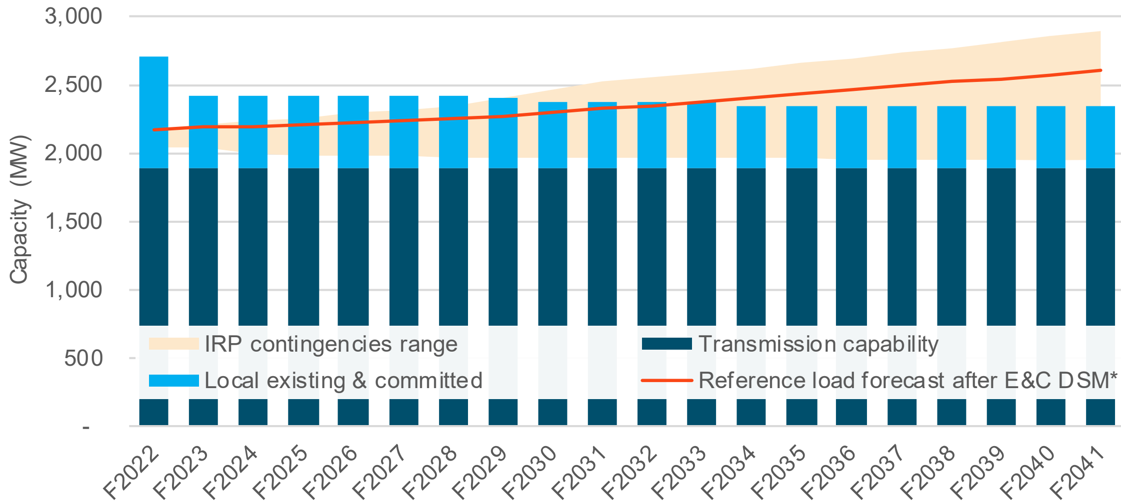


* E&C DSM denotes existing and committed demand-side measures.

Table 1-3 South Coast capacity Load Resource Balance before planned resources

	(MW)		F2022	F2023	F2024	F2025	F2026	F2027	F2028	F2029	F2030	F2031	F2032	F2033	F2034	F2035	F2036	F2037	F2038	F2039	F2040	F2041
	LRB with Existing and Committed Supply																					
1	***Existing and Committed Heritage Resources***	(a)	1,517	1,517	1,517	1,517	1,519	1,519	1,519	1,519	1,519	1,519	1,519	1,519	1,519	1,519	1,519	1,519	1,519	1,519	1,519	1,519
2	***Existing and Committed Electricity Purchase Agreements***	(b)	635	357	347	336	305	305	296	273	256	214	185	185	161	161	150	150	150	150	142	142
3	**Regional Supply Capacity (before planned resources)**	(c) = a+b	2,152	1,874	1,864	1,853	1,824	1,824	1,815	1,792	1,775	1,733	1,704	1,704	1,680	1,680	1,669	1,669	1,669	1,669	1,661	1,661
4	***Transmission Capability***	(d)	6,300	6,300	6,300	6,300	6,300	6,300	6,300	6,300	6,300	6,300	6,300	6,300	6,300	6,300	6,300	6,300	6,300	6,300	6,300	6,300
	Demand - Local Gross Requirements																					
5	Reference Load Forecast	(e)	(7,726)	(7,911)	(8,019)	(8,174)	(8,313)	(8,433)	(8,558)	(8,687)	(8,822)	(8,963)	(9,112)	(9,268)	(9,430)	(9,601)	(9,781)	(9,959)	(10,136)	(10,310)	(10,481)	(10,646)
	Existing and Committed Demand-side Measures																					
6	F21 Programs Savings, Codes & Standards, Rates	(f)	113	153	190	225	253	282	308	332	354	373	391	408	431	453	473	495	518	541	563	574
7	**Regional Surplus / (Deficit) before planned resources**	(g) = c+d+e+f	**838**	**416**	**335**	**203**	**64**	**(27)**	**(135)**	**(263)**	**(392)**	**(557)**	**(716)**	**(855)**	**(1,019)**	**(1,168)**	**(1,340)**	**(1,496)**	**(1,649)**	**(1,801)**	**(1,957)**	**(2,111)**

Figure 1-4 Vancouver Island capacity Load Resource Balance before planned resources

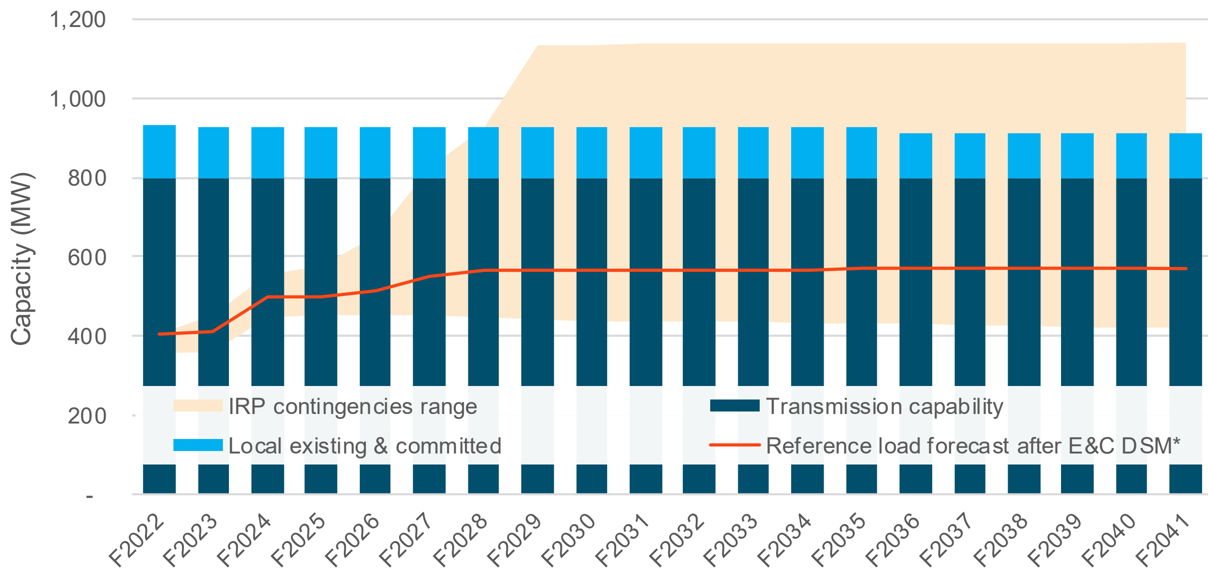


* E&C DSM denotes existing and committed demand-side measures.

Table 1-4 Vancouver Island capacity Load Resource Balance before planned resources

	(MW)		F2022	F2023	F2024	F2025	F2026	F2027	F2028	F2029	F2030	F2031	F2032	F2033	F2034	F2035	F2036	F2037	F2038	F2039	F2040	F2041
	LRB with Existing and Committed Supply																					
1	***Existing and Committed Heritage Resources***	(a)	448	448	448	448	448	448	448	448	448	448	448	448	448	448	448	448	448	448	448	448
2	***Existing and Committed Electricity Purchase Agreements***	(b)	361	86	84	83	82	82	82	59	41	41	35	35	11	11	11	11	11	11	11	11
3	**Regional Supply Capacity (before planned resources)**	(c) = a+b	809	534	532	531	530	530	530	507	489	489	483	483	459	459	459	459	459	459	459	459
4	***Transmission Capability***	(d)	1,890	1,890	1,890	1,890	1,890	1,890	1,890	1,890	1,890	1,890	1,890	1,890	1,890	1,890	1,890	1,890	1,890	1,890	1,890	1,890
	Demand - Local Gross Requirements																					
5	Reference Load Forecast	(e)	(2,200)	(2,231)	(2,243)	(2,259)	(2,285)	(2,309)	(2,335)	(2,361)	(2,389)	(2,417)	(2,447)	(2,477)	(2,510)	(2,543)	(2,580)	(2,614)	(2,650)	(2,684)	(2,719)	(2,751)
	Existing and Committed Demand-side Measures																					
6	F21 Programs Savings, Codes & Standards, Rates	(f)	31	41	51	60	67	75	81	87	93	97	102	106	112	117	122	127	133	138	144	147
7	**Regional Surplus / (Deficit) before planned resources**	(g) = c+d+e+f	**530**	**234**	**229**	**222**	**202**	**185**	**166**	**123**	**83**	**60**	**28**	**2**	**(49)**	**(77)**	**(109)**	**(138)**	**(168)**	**(197)**	**(226)**	**(256)**

Figure 1-5 North Coast capacity Load Resource Balance before planned resources



* E&C DSM denotes existing and committed demand-side measures.

Table 1-5 North Coast capacity Load Resource Balance before planned resources

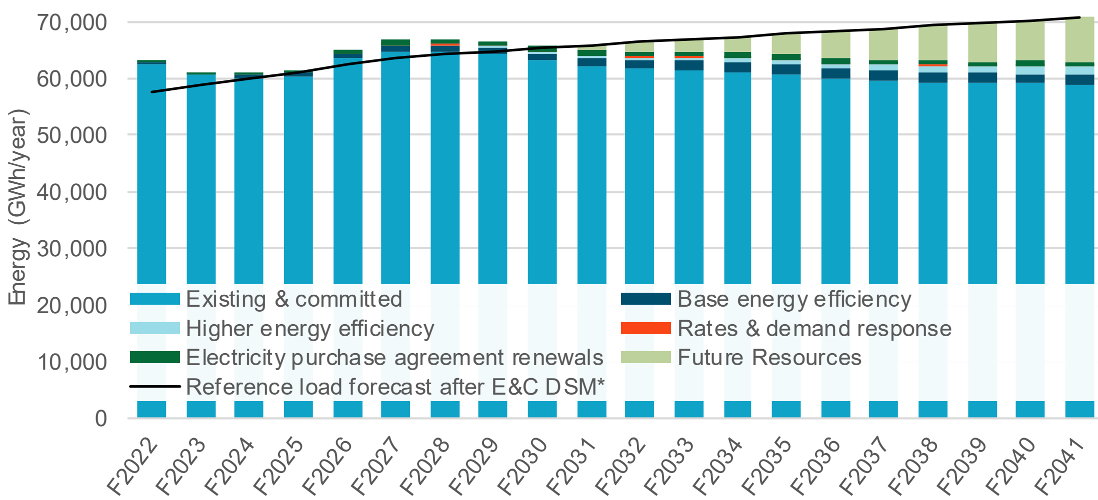
	(MW)		F2022	F2023	F2024	F2025	F2026	F2027	F2028	F2029	F2030	F2031	F2032	F2033	F2034	F2035	F2036	F2037	F2038	F2039	F2040	F2041
	LRB with Existing and Committed Supply																					
1	***Existing and Committed Heritage Resources***	(a)	7	7	7	7	7	7	7	7	7	7	7	7	7	7	7	7	7	7	7	7
2	***Existing and Committed Electricity Purchase Agreements***	(b)	124	118	118	118	118	118	118	118	118	118	118	118	118	118	107	107	107	107	107	107
3	**Regional Supply Capacity (before planned resources)**	(c) = a+b	131	125	125	125	125	125	125	125	125	125	125	125	125	125	114	114	114	114	114	114
4	***Transmission Capability***	(d)	800	800	800	800	800	800	800	800	800	800	800	800	800	800	800	800	800	800	800	800
	Demand - Local Gross Requirements																					
5	Reference Load Forecast	(e)	(409)	(415)	(504)	(508)	(521)	(560)	(572)	(573)	(574)	(575)	(576)	(577)	(577)	(578)	(579)	(580)	(580)	(581)	(582)	(582)
	Existing and Committed Demand-side Measures																					
6	F21 Programs Savings, Codes & Standards, Rates	(f)	4	5	6	7	7	8	8	9	9	9	9	9	9	10	10	10	11	11	12	12
7	**Regional Surplus / (Deficit) before planned resources**	(g) = c+d+e+f	**526**	**516**	**428**	**424**	**411**	**373**	**362**	**361**	**361**	**360**	**359**	**358**	**357**	**357**	**345**	**345**	**344**	**344**	**344**	**344**

4 Load Resource Balances – Base Resource Plan

4.1 System Load Resource Balances with Base Resource Plan

Figure 1-6, Table 1-6, Figure 1-7 and Table 1-7 present the system-wide energy and capacity Load Resource Balances with selected resources in place to “fill” the energy and capacity “gaps” based on the reference load forecast. The figures and tables illustrate the timing of the resources and their energy/capacity contributions.

Figure 1-6 System energy Load Resource Balance with Base Resource Plan resources

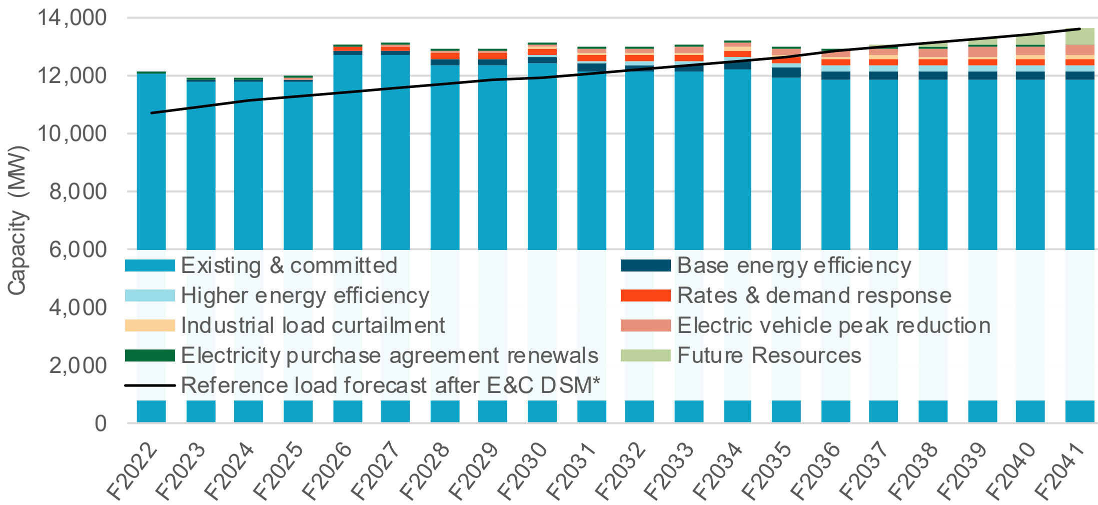


* E&C DSM denotes existing and committed demand-side measures.

Table 1-6 System energy Load Resource Balance with Base Resource Plan resources

	(GWh/year)		F2022	F2023	F2024	F2025	F2026	F2027	F2028	F2029	F2030	F2031	F2032	F2033	F2034	F2035	F2036	F2037	F2038	F2039	F2040	F2041
	LRB with Existing and Committed Supply																					
1	***Existing and Committed Heritage Resources***	(a)	46,898	46,898	46,898	47,264	50,790	52,184	52,184	52,184	52,184	52,184	52,184	52,184	52,184	52,184	52,184	52,184	52,184	52,184	52,184	52,184
2	***Existing and Committed Electricity Purchase Agreements***	(b)	15,719	13,717	13,278	13,059	12,807	12,728	12,638	12,210	10,997	9,997	9,501	9,323	9,055	8,541	7,716	7,350	7,212	6,952	6,922	6,736
3	**System Capability (before planned resources)**	(c) = a+b	62,617	60,615	60,176	60,323	63,597	64,912	64,822	64,394	63,181	62,181	61,685	61,507	61,239	60,725	59,900	59,534	59,396	59,136	59,106	58,920
	Demand - Integrated System Total Gross Requirements																					
4	Reference Load Forecast	(d)	(58,526)	(60,140)	(61,545)	(63,029)	(64,573)	(65,696)	(66,789)	(67,435)	(68,127)	(68,811)	(69,594)	(70,214)	(70,903)	(71,612)	(72,371)	(73,002)	(73,698)	(74,379)	(75,121)	(75,829)
	Existing and Committed Demand-side Measures																					
5	F21 Energy Conservations Programs Savings		105	117	117	118	112	112	112	109	104	71	60	47	47	43	17	12	12	12	11	10
6	Codes & Standards plus Voltage and VAR Optimization		589	854	1,111	1,355	1,586	1,804	1,996	2,181	2,356	2,523	2,684	2,838	2,992	3,148	3,304	3,459	3,615	3,771	3,927	3,995
7	Energy Conservation Rate Structures		138	177	210	239	156	147	138	139	139	115	86	58	29	-	-	-	-	-	-	-
8	Sub-total	(e)	833	1,148	1,438	1,711	1,853	2,064	2,247	2,429	2,599	2,709	2,830	2,943	3,069	3,191	3,321	3,471	3,627	3,782	3,938	4,005
9	***Net Metering***	(f)	40	50	62	77	95	117	143	174	212	258	311	371	438	510	588	667	749	832	915	998
10	**Surplus / (Deficit) before planned resources**	(g) = c+d+e+f	**4,963**	**1,673**	**132**	**(918)**	**973**	**1,397**	**423**	**(438)**	**(2,134)**	**(3,662)**	**(4,767)**	**(5,393)**	**(6,157)**	**(7,185)**	**(8,563)**	**(9,330)**	**(9,927)**	**(10,629)**	**(11,162)**	**(11,906)**
	Base Resource Plan																					
	Future Demand-side Measures																					
11	Base Energy Efficiency		161	296	472	649	814	948	1,090	1,224	1,347	1,483	1,558	1,616	1,666	1,706	1,768	1,779	1,788	1,794	1,795	1,795
12	Higher Energy Efficiency		-	-	-	-	-	35	118	222	327	448	576	709	813	926	1,025	1,108	1,192	1,255	1,320	1,387
13	Time-Varying Rates & Demand Response		-	-	-	-	25	25	26	26	26	26	26	26	27	27	27	27	27	27	27	27
14	Industrial Load Curtailment		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
15	Electric Vehicle Peak Reduction		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
16	Sub-total	(h)	161	296	472	649	839	1,008	1,233	1,471	1,700	1,958	2,160	2,351	2,505	2,659	2,820	2,914	3,008	3,076	3,142	3,209
17	**Surplus / (Deficit) after planned DSM**	**(i) = g+h**	**5,125**	**1,969**	**604**	**(268)**	**1,812**	**2,405**	**1,657**	**1,033**	**(434)**	**(1,705)**	**(2,607)**	**(3,042)**	**(3,651)**	**(4,526)**	**(5,743)**	**(6,416)**	**(6,919)**	**(7,553)**	**(8,020)**	**(8,697)**
18	***Electricity Purchase Agreement Renewals***	(j)	0	59	312	535	816	895	895	895	895	895	895	895	895	895	895	895	895	895	895	895
19	***Future Resources***	(k)	-	-	-	-	-	-	-	-	-	809	1,712	2,147	2,756	3,631	4,847	5,521	6,024	6,658	7,125	7,801
20	**Surplus / (Deficit) after planned resources**	(l) = i+j+k	**5,125**	**2,028**	**917**	**266**	**2,628**	**3,300**	**2,552**	**1,928**	**461**	**0**	**0**	**0**	**(0)**	**(0)**	**0**	**0**	**(0)**	**0**	**0**	**0**

Figure 1-7 System capacity Load Resource Balance with Base Resource Plan resources



* E&C DSM denotes existing and committed demand-side measures.

Table 1-7 System capacity Load Resource Balance with Base Resource Plan resources

	(MW)		F2022	F2023	F2024	F2025	F2026	F2027	F2028	F2029	F2030	F2031	F2032	F2033	F2034	F2035	F2036	F2037	F2038	F2039	F2040	F2041
	LRB with Existing and Committed Supply																					
1	***Existing and Committed Heritage Resources*** [1]	(a)	11,818	11,818	11,818	11,818	12,965	12,965	12,618	12,618	12,965	12,791	12,791	12,791	12,965	12,965	12,965	12,965	12,965	12,965	12,965	12,965
2	***Existing and Committed Electricity Purchase Agreements***	(b)	1,795	1,512	1,495	1,481	1,400	1,400	1,391	1,362	1,068	974	940	917	885	580	480	480	445	445	437	437
3	***12% Reserves*** [2]	(c)	(1,574)	(1,540)	(1,540)	(1,540)	(1,674)	(1,674)	(1,633)	(1,629)	(1,636)	(1,604)	(1,600)	(1,597)	(1,617)	(1,583)	(1,576)	(1,576)	(1,576)	(1,576)	(1,576)	(1,576)
4	**System Peak Load Carrying Capability (before Planned Resources)**	(d) = a+b+c	12,039	11,789	11,773	11,759	12,691	12,691	12,376	12,350	12,397	12,162	12,131	12,111	12,233	11,962	11,869	11,869	11,834	11,834	11,826	11,826
	Demand - Integrated System Total Gross Requirements																					
5	Reference Load Forecast	(e)	(10,862)	(11,140)	(11,363)	(11,560)	(11,753)	(11,936)	(12,100)	(12,247)	(12,399)	(12,550)	(12,718)	(12,882)	(13,052)	(13,230)	(13,420)	(13,605)	(13,788)	(13,970)	(14,149)	(14,318)
	Existing and Committed Demand-side Measures																					
6	F21 Energy Conservations Programs Savings		21	21	21	20	18	18	17	17	16	12	10	8	8	8	4	3	3	3	3	3
7	Codes & Standards plus Voltage and VAR Optimization		118	166	212	254	293	329	361	391	419	445	470	493	520	548	576	604	632	659	687	700
8	Energy Conservation Rate Structures		11	16	19	23	15	14	13	13	13	11	8	5	3	-	-	-	-	-	-	-
9	Sub-total	(f)	150	203	252	297	326	361	392	421	448	468	488	506	531	556	580	607	635	663	690	703
10	***Net Metering***	(g)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
11	**Surplus / (Deficit) before planned resources**	(h) = d+e+f+g	**1,327**	**853**	**662**	**496**	**1,264**	**1,116**	**668**	**524**	**446**	**80**	**(99)**	**(264)**	**(288)**	**(713)**	**(971)**	**(1,128)**	**(1,320)**	**(1,474)**	**(1,633)**	**(1,789)**
	Base Resource Plan																					
	Future Demand-side Measures																					
12	Base Energy Efficiency		30	56	85	115	142	164	187	209	229	248	261	272	281	290	299	302	303	304	302	302
13	Higher Energy Efficiency		-	-	-	-	-	10	23	39	57	75	94	115	132	151	168	184	199	212	226	240
14	Time-Varying Rates & Demand Response		-	-	-	-	134	151	177	203	216	219	221	222	224	225	226	228	229	231	232	233
15	Industrial Load Curtailment		-	-	-	-	-	-	-	-	98	98	98	98	98	98	98	98	98	98	98	98
16	Electric Vehicle Peak Reduction		-	-	-	24	40	60	73	87	102	119	138	157	178	201	224	247	270	293	315	339
17	Sub-total	(i)	30	56	85	139	316	386	460	537	701	760	812	864	913	964	1,015	1,058	1,099	1,138	1,174	1,212
18	**Surplus / (Deficit) after planned DSM**	(j) = h+i	**1,357**	**909**	**747**	**635**	**1,579**	**1,502**	**1,128**	**1,062**	**1,148**	**839**	**712**	**600**	**625**	**252**	**45**	**(70)**	**(221)**	**(336)**	**(459)**	**(577)**
19	***Electricity Purchase Agreement Renewals*** [3]	(k)	0	8	24	38	66	66	66	66	66	66	66	66	66	66	66	66	66	66	66	66
20	***Future Resources*** [3]	(l)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	4	155	270	393	510
21	**Surplus / (Deficit) after planned resources**	(m) = j+k+l	**1,357**	**916**	**771**	**673**	**1,645**	**1,568**	**1,194**	**1,128**	**1,214**	**906**	**779**	**666**	**691**	**318**	**111**	**0**	**0**	**0**	**0**	**0**

Notes:

[1] Includes outages for Mica and Seven Mile

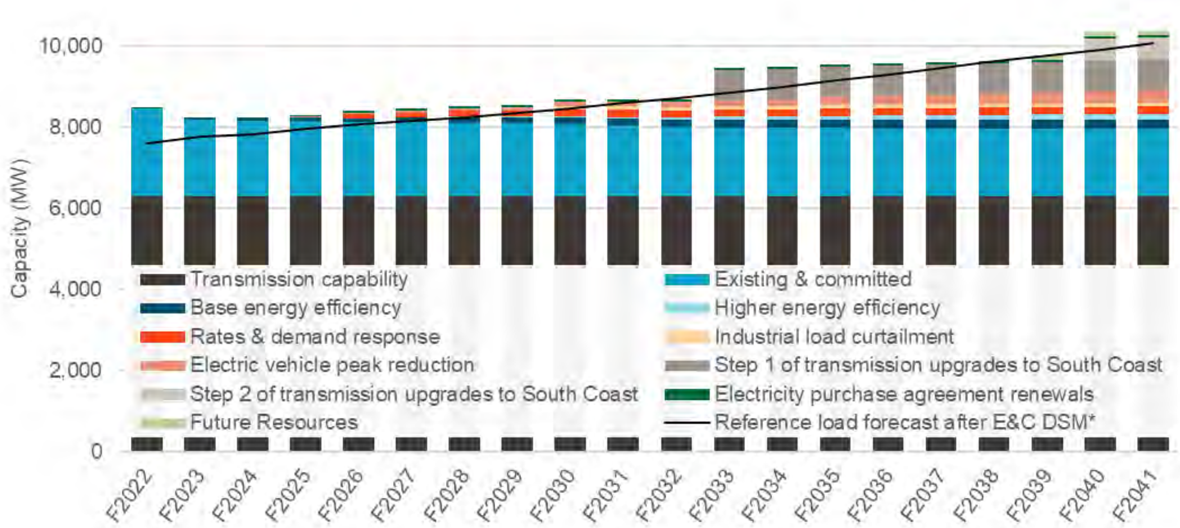
[2] The 12% reserve margin is applied to dependable capacity resources only

[3] The numbers shown include the 12% reserve margin

4.2 Regional capacity Load Resource Balances with Base Resource Plan

Figure 1-8, Table 1-8, Figure 1-9, and Table 1-9 present the capacity Load Resource Balances for the South Coast and Vancouver Island with selected resources in place to “fill” the energy and capacity “gaps” based on the reference load forecast.[3] The figures and tables illustrate the timing of the resources and their energy/capacity contributions.

Figure 1-8 South Coast capacity Load Resource Balance with Base Resource Plan resources



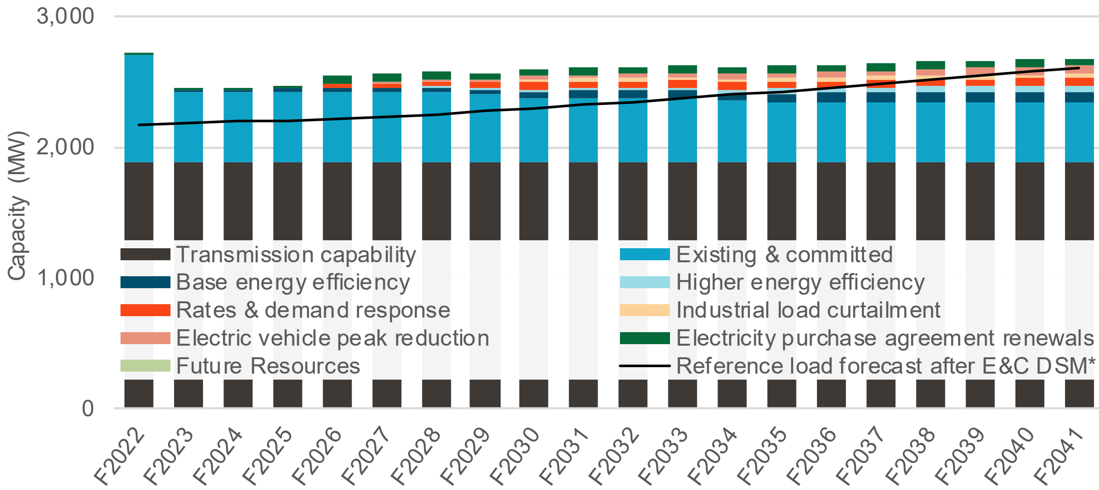
* E&C DSM denotes existing and committed demand-side measures.

3 A Base Resource Plan for the North Coast region was not created as there is no gap based on the Reference Load Forecast.

Table 1-8 South Coast Capacity Load Resource Balance with Base Resource Plan Resources

	(MW)		F2022	F2023	F2024	F2025	F2026	F2027	F2028	F2029	F2030	F2031	F2032	F2033	F2034	F2035	F2036	F2037	F2038	F2039	F2040	F2041
	LRB with Existing and Committed Supply																					
1	***Existing and Committed Heritage Resources***	(a)	1,517	1,517	1,517	1,517	1,519	1,519	1,519	1,519	1,519	1,519	1,519	1,519	1,519	1,519	1,519	1,519	1,519	1,519	1,519	1,519
2	***Existing and Committed Electricity Purchase Agreements***	(b)	635	357	347	336	305	305	296	273	256	214	185	185	161	161	150	150	150	150	142	142
3	**Regional Supply Capacity (before planned resources)**	(c) = a+b	2,152	1,874	1,864	1,853	1,824	1,824	1,815	1,792	1,775	1,733	1,704	1,704	1,680	1,680	1,669	1,669	1,669	1,669	1,661	1,661
4	***Transmission Capability***	(d)	6,300	6,300	6,300	6,300	6,300	6,300	6,300	6,300	6,300	6,300	6,300	6,300	6,300	6,300	6,300	6,300	6,300	6,300	6,300	6,300
	Demand - Regional Gross Requirements																					
5	Reference Load Forecast	(e)	(7,726)	(7,911)	(8,019)	(8,174)	(8,313)	(8,433)	(8,558)	(8,687)	(8,822)	(8,963)	(9,112)	(9,268)	(9,430)	(9,601)	(9,781)	(9,959)	(10,136)	(10,310)	(10,481)	(10,646)
	Existing and Committed Demand-side Measures																					
6	F21 Programs Savings, Codes & Standards, Rates	(f)	113	153	190	225	253	282	308	332	354	373	391	408	431	453	473	495	518	541	563	574
7	***Net Metering***	(g)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
8	**Regional Surplus / (Deficit) before planned resources**	(h) = c+d+e+f+g	**838**	**416**	**335**	**203**	**64**	**(27)**	**(135)**	**(263)**	**(392)**	**(557)**	**(716)**	**(855)**	**(1,019)**	**(1,168)**	**(1,340)**	**(1,496)**	**(1,649)**	**(1,801)**	**(1,957)**	**(2,111)**
	Base Resource Plan																					
	Future Demand-side Measures																					
9	Base Energy Efficiency		21	39	59	79	98	113	129	143	157	171	181	189	195	202	208	210	211	212	211	211
10	Higher Energy Efficiency		-	-	-	-	-	7	15	24	35	46	57	69	81	93	106	117	128	139	150	161
11	Time-Varying Rates & Demand Response		-	-	-	-	101	115	136	158	169	172	173	174	175	176	177	179	180	181	182	183
12	Industrial Load Curtailment		-	-	-	-	-	-	-	-	86	86	86	86	86	86	86	86	86	86	86	86
13	Electric Vehicle Peak Reduction		-	-	-	23	37	57	69	82	97	113	130	149	169	190	212	234	256	277	298	321
14	Sub-total	(i)	21	39	59	102	236	291	348	408	544	587	627	666	706	747	789	825	860	895	927	961
15	**Surplus / (Deficit) after planned DSM**	**(j) = h+i**	**859**	**455**	**394**	**306**	**300**	**265**	**213**	**144**	**151**	**30**	**(90)**	**(189)**	**(314)**	**(421)**	**(551)**	**(670)**	**(789)**	**(906)**	**(1,030)**	**(1,150)**
	Transmission Upgrades																					
16	Step 1 of transmission upgrades to South Coast		-	-	-	-	-	-	-	-	-	-	-	750	750	750	750	750	750	750	750	750
17	Step 2 of transmission upgrades to South Coast		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	550	550
18	Sub-total	(k)	-	-	-	-	-	-	-	-	-	-	-	750	750	750	750	750	750	750	1,300	1,300
19	***Electricity Purchase Agreement Renewals***	(l)	0	3	13	24	55	55	55	55	55	55	55	55	55	55	55	55	55	55	55	55
20	***Future Resources***	(m)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	100	100	100
21	**Regional Surplus / (Deficit) after planned resources**	(n) = j+k+l+m	**859**	**457**	**407**	**330**	**355**	**320**	**268**	**200**	**207**	**86**	**(35)**	**616**	**492**	**384**	**254**	**135**	**17**	**0**	**426**	**306**

Figure 1-9 Vancouver Island capacity Load Resource Balance with Base Resource Plan resources



* E&C DSM denotes existing and committed demand-side measures.

Table 1-9 Vancouver Island capacity Load Resource Balance with Base Resource Plan resources

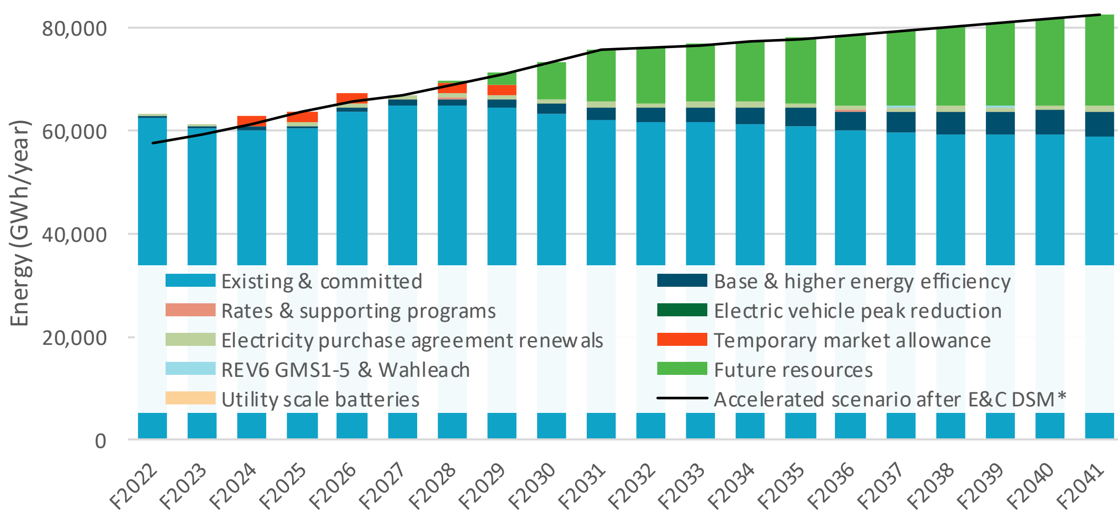
	(MW)		F2022	F2023	F2024	F2025	F2026	F2027	F2028	F2029	F2030	F2031	F2032	F2033	F2034	F2035	F2036	F2037	F2038	F2039	F2040	F2041
	LRB with Existing and Committed Supply																					
1	***Existing and Committed Heritage Resources***	(a)	448	448	448	448	448	448	448	448	448	448	448	448	448	448	448	448	448	448	448	448
2	***Existing and Committed Electricity Purchase Agreements***	(b)	361	86	84	83	82	82	82	59	41	41	35	35	11	11	11	11	11	11	11	11
3	**Regional Supply Capacity (before planned resources)**	(c) = a+b	809	534	532	531	530	530	530	507	489	489	483	483	459	459	459	459	459	459	459	459
4	***Transmission Capability***	(d)	1,890	1,890	1,890	1,890	1,890	1,890	1,890	1,890	1,890	1,890	1,890	1,890	1,890	1,890	1,890	1,890	1,890	1,890	1,890	1,890
	Demand - Regional Gross Requirements																					
5	Reference Load Forecast	(e)	(2,200)	(2,231)	(2,243)	(2,259)	(2,285)	(2,309)	(2,335)	(2,361)	(2,389)	(2,417)	(2,447)	(2,477)	(2,510)	(2,543)	(2,580)	(2,614)	(2,650)	(2,684)	(2,719)	(2,751)
	Existing and Committed Demand-side Measures																					
6	F21 Programs Savings, Codes & Standards, Rates	(f)	31	41	51	60	67	75	81	87	93	97	102	106	112	117	122	127	133	138	144	147
7	***Net Metering***	(g)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
8	**Regional Surplus / (Deficit) before planned resources**	(h) = c+d+e+f+g	**530**	**234**	**229**	**222**	**202**	**185**	**166**	**123**	**83**	**60**	**28**	**2**	**(49)**	**(77)**	**(109)**	**(138)**	**(168)**	**(197)**	**(226)**	**(256)**
	Base Resource Plan																					
	Future Demand-side Measures																					
9	Base Energy Efficiency		6	12	18	24	29	34	39	44	48	53	56	59	61	63	65	65	65	65	65	65
10	Higher Energy Efficiency		-	-	-	-	-	3	6	9	13	17	21	25	29	34	38	43	47	51	55	59
11	Time-Varying Rates & Demand Response		-	-	-	-	28	33	41	48	51	52	52	52	53	53	53	54	54	54	55	55
12	Industrial Load Curtailment		-	-	-	-	-	-	-	-	29	29	29	29	29	29	29	29	29	29	29	29
13	Electric Vehicle Peak Reduction		-	-	-	4	7	11	13	16	19	22	25	29	33	37	41	46	50	54	58	63
14	Sub-total	(i)	6	12	18	28	65	81	99	117	161	173	184	195	205	216	227	236	245	254	262	271
15	**Surplus / (Deficit) after planned DSM**	**(j) = h+i**	**536**	**246**	**247**	**250**	**267**	**266**	**264**	**240**	**244**	**232**	**211**	**196**	**157**	**139**	**118**	**98**	**78**	**58**	**36**	**16**
16	***Electricity Purchase Agreement Renewals***	(k)	0	0	2	3	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4
17	***Future Resources***	(l)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
18	**Regional Surplus / (Deficit) after planned resources**	(m) = j+k+l	**536**	**246**	**249**	**252**	**271**	**271**	**269**	**244**	**248**	**237**	**216**	**201**	**161**	**143**	**123**	**103**	**82**	**62**	**41**	**20**

5 Load Resource Balances – Contingency Resource Plans

5.1 System Load Resource Balances with Contingency Resource Plan for Accelerated electrification scenario

Figure 1-10, Table 1-10, Figure 1-11 and Table 1-11 present the system-wide energy and capacity Load Resource Balances with selected resources in place to “fill” the energy and capacity “gaps” under the Contingency Resource Plan for the Accelerated electrification scenario. The figures and tables illustrate the timing of the resources and their energy/capacity contributions.

Figure 1-10 System energy Load Resource Balance with Contingency Resource Plan for Accelerated electrification scenario

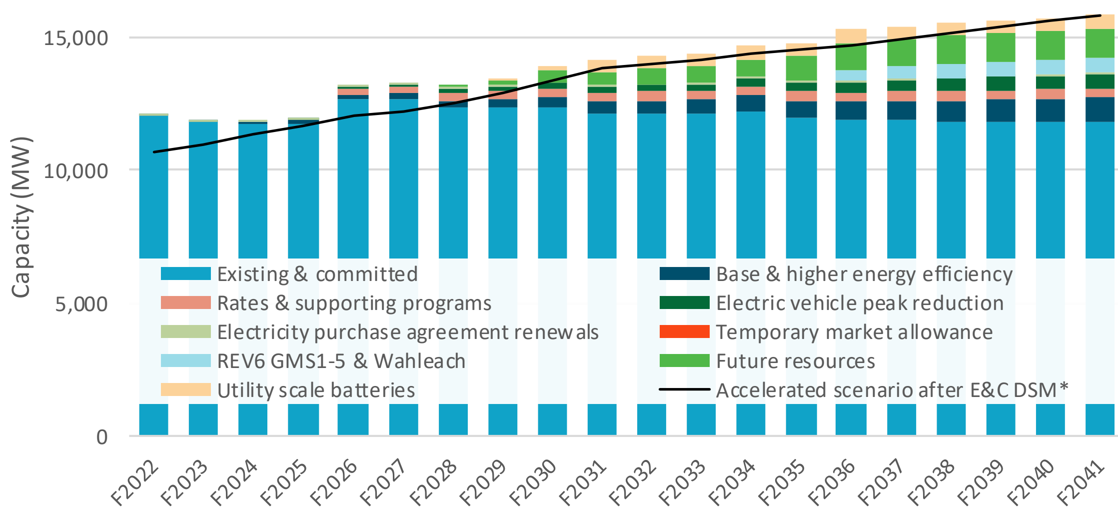


* E&C DSM denotes existing and committed demand-side measures.

Table 1-10 System energy Load Resource Balance with Contingency Resource Plan for Accelerated electrification scenario

	(GWh/year)		F2022	F2023	F2024	F2025	F2026	F2027	F2028	F2029	F2030	F2031	F2032	F2033	F2034	F2035	F2036	F2037	F2038	F2039	F2040	F2041
	LRB with Existing and Committed Supply																					
1	***Existing and Committed Heritage Resources***	(a)	46,898	46,898	46,898	47,264	50,790	52,184	52,184	52,184	52,184	52,184	52,184	52,184	52,184	52,184	52,184	52,184	52,184	52,184	52,184	52,184
2	***Existing and Committed Electricity Purchase Agreements***	(b)	15,719	13,717	13,278	13,059	12,807	12,728	12,638	12,210	10,997	9,997	9,501	9,323	9,055	8,541	7,716	7,350	7,212	6,952	6,922	6,736
3	**System Capability (before planned resources)**	(c) = a+b	62,617	60,615	60,176	60,323	63,597	64,912	64,822	64,394	63,181	62,181	61,685	61,507	61,239	60,725	59,900	59,534	59,396	59,136	59,106	58,920
	Demand - Integrated System Total Gross Requirements																					
4	Accelerated Electrification Scenario	(d)	(58,443)	(60,475)	(62,951)	(65,416)	(67,764)	(68,881)	(71,278)	(73,661)	(76,089)	(78,510)	(79,357)	(80,041)	(80,793)	(81,566)	(82,390)	(83,358)	(84,391)	(85,408)	(86,488)	(87,532)
	Existing and Committed Demand-side Measures																					
5	F21 Energy Conservations Programs Savings		105	117	117	118	112	112	112	109	104	71	60	47	47	43	17	12	12	12	11	10
6	Codes & Standards plus Voltage and VAR Optimization		589	854	1,111	1,355	1,586	1,804	1,996	2,181	2,356	2,523	2,684	2,838	2,992	3,148	3,304	3,459	3,615	3,771	3,927	3,995
7	Energy Conservation Rate Structures		138	177	210	239	156	147	138	139	139	115	86	58	29	-	-	-	-	-	-	-
8	Sub-total	(e)	833	1,148	1,438	1,711	1,853	2,064	2,247	2,429	2,599	2,709	2,830	2,943	3,069	3,191	3,321	3,471	3,627	3,782	3,938	4,005
9	***Net Metering***	(f)	40	50	62	77	95	117	143	174	212	258	311	371	438	510	588	667	749	832	915	998
10	**Surplus / (Deficit) before planned resources**	(g) = c+d+e+f	**5,047**	**1,338**	**(1,274)**	**(3,305)**	**(2,219)**	**(1,788)**	**(4,066)**	**(6,664)**	**(10,097)**	**(13,362)**	**(14,531)**	**(15,220)**	**(16,048)**	**(17,140)**	**(18,582)**	**(19,685)**	**(20,619)**	**(21,658)**	**(22,529)**	**(23,609)**
	Contingency Resource Plan																					
	Future Demand-side Measures																					
11	Base & Higher Energy Efficiency		161	296	472	649	870	1,137	1,452	1,754	2,083	2,450	2,780	3,064	3,369	3,651	3,947	4,196	4,402	4,598	4,782	4,887
12	Rates & Supporting Programs		-	-	-	-	28	29	29	30	30	30	30	31	31	31	31	31	32	32	32	32
13	Electric Vehicle Peak Reduction		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
14	Sub-total	(h)	161	296	472	649	898	1,166	1,481	1,783	2,113	2,481	2,810	3,094	3,400	3,682	3,978	4,227	4,434	4,630	4,814	4,919
15	***Electricity Purchase Agreement Renewals***	(i)	0	59	312	535	816	895	895	895	895	895	895	895	895	895	895	895	895	895	895	895
16	***Market Allowance***	(j)	-	-	2,000	2,000	2,000	-	2,000	2,000	-	-	-	-	-	-	-	-	-	-	-	-
17	***REV6 GMS1-5 & Wahleach***	(k)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	26	26	26	26	26	26
18	***Future Resources***	(l)	-	-	-	-	-	-	89	1,985	7,088	9,986	10,825	11,230	11,752	12,562	13,682	14,536	15,264	16,107	16,793	17,768
19	***Utility Scale Batteries***	(m)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
20	**Surplus / (Deficit) after planned resources**	(n) = g+h+i+j+k+l+m	**5,209**	**1,693**	**1,510**	**(121)**	**1,495**	**273**	**400**	**0**	**0**	**0**	**0**	**0**	**(0)**	**(0)**	**(0)**	**0**	**(0)**	**(0)**	**0**	**0**

Figure 1-11 System capacity Load Resource Balance with Contingency Resource Plan for Accelerated electrification scenario



* E&C DSM denotes existing and committed demand-side measures.

Table 1-11 System capacity Load Resource Balance with Contingency Resource Plan for Accelerated electrification scenario

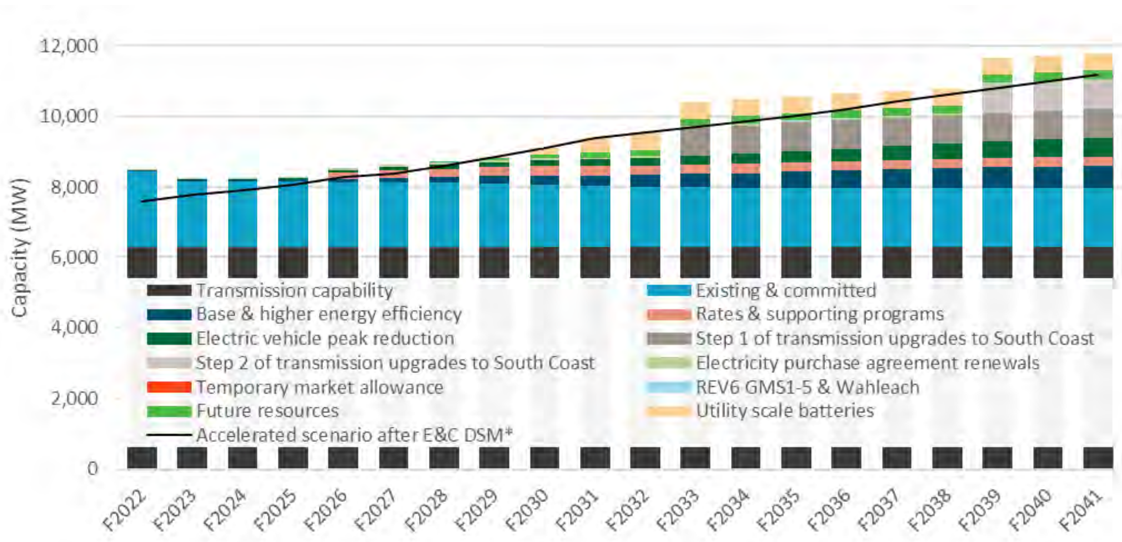
	(MW)		F2022	F2023	F2024	F2025	F2026	F2027	F2028	F2029	F2030	F2031	F2032	F2033	F2034	F2035	F2036	F2037	F2038	F2039	F2040	F2041
	LRB with Existing and Committed Supply																					
1	***Existing and Committed Heritage Resources*** [1]	(a)	11,818	11,818	11,818	11,818	12,965	12,965	12,618	12,618	12,965	12,791	12,791	12,791	12,965	12,965	12,965	12,965	12,965	12,965	12,965	12,965
2	***Existing and Committed Electricity Purchase Agreements***	(b)	1,795	1,512	1,495	1,481	1,400	1,400	1,391	1,362	1,068	974	940	917	885	580	480	480	445	445	437	437
3	***12% Reserves*** [2]	(c)	(1,574)	(1,540)	(1,540)	(1,540)	(1,674)	(1,674)	(1,633)	(1,629)	(1,636)	(1,604)	(1,600)	(1,597)	(1,617)	(1,583)	(1,576)	(1,576)	(1,576)	(1,576)	(1,576)	(1,576)
4	**System Peak Load Carrying Capability (before Planned Resources)**	(d) = a+b+c	12,039	11,789	11,773	11,759	12,691	12,691	12,376	12,350	12,397	12,162	12,131	12,111	12,233	11,962	11,869	11,869	11,834	11,834	11,826	11,826
	Demand - Integrated System Total Gross Requirements																					
5	Accelerated Electrification Scenario	(e)	(10,837)	(11,208)	(11,613)	(11,977)	(12,362)	(12,544)	(12,885)	(13,352)	(13,824)	(14,294)	(14,494)	(14,688)	(14,889)	(15,097)	(15,317)	(15,565)	(15,813)	(16,058)	(16,300)	(16,532)
	Existing and Committed Demand-side Measures																					
6	F21 Energy Conservations Programs Savings		21	21	21	20	18	18	17	17	16	12	10	8	8	8	4	3	3	3	3	3
7	Codes & Standards plus Voltage and VAR Optimization		118	166	212	254	293	329	361	391	419	445	470	493	520	548	576	604	632	659	687	700
8	Energy Conservation Rate Structures		11	16	19	23	15	14	13	13	13	11	8	5	3	-	-	-	-	-	-	-
9	Sub-total	(f)	150	203	252	297	326	361	392	421	448	468	488	506	531	556	580	607	635	663	690	703
10	***Net Metering***	(g)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
11	**Surplus / (Deficit) before planned resources**	(h) = d+e+f+g	**1,351**	**785**	**412**	**79**	**654**	**508**	**(116)**	**(580)**	**(978)**	**(1,665)**	**(1,875)**	**(2,070)**	**(2,125)**	**(2,580)**	**(2,868)**	**(3,089)**	**(3,344)**	**(3,562)**	**(3,784)**	**(4,003)**
	Contingency Resource Plan																					
	Future Demand-side Measures																					
12	Base & Higher Energy Efficiency		30	56	85	115	162	210	263	318	376	437	496	551	607	662	717	762	803	842	876	901
13	Rates & Supporting Programs		-	-	-	-	240	258	284	311	324	328	329	331	332	334	336	337	339	341	343	344
14	Electric Vehicle Peak Reduction		-	-	-	40	66	100	121	146	171	199	230	263	299	336	375	414	453	491	528	568
15	Sub-total	(i)	30	56	85	155	468	567	668	774	872	964	1,056	1,145	1,238	1,332	1,428	1,513	1,594	1,674	1,747	1,813
16	***Electricity Purchase Agreement Renewals*** [3]	(j)	0	8	24	38	66	66	66	66	66	66	66	66	66	66	66	66	66	66	66	66
17	***Temporary Market Allowance***	(k)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
18	***REV6 GMS1-5 & Wahleach*** [3]	(l)	-	-	-	-	-	-	-	-	-	-	-	-	12	12	442	442	530	530	530	530
19	***Future Resources*** [3]	(m)	-	-	-	-	-	-	9	154	405	534	572	597	634	911	1,012	1,022	1,069	1,081	1,102	1,119
20	***Utility Scale Batteries***	(n)	-	-	-	-	-	-	-	21	192	397	482	482	482	482	482	482	482	482	482	482
21	**Surplus / (Deficit) after planned resources**	(o) = h+i+j+k+l+m+n	**1,381**	**849**	**521**	**272**	**1,188**	**1,141**	**627**	**436**	**557**	**297**	**301**	**220**	**307**	**224**	**561**	**435**	**397**	**271**	**143**	**7**

[1] Includes outages at Mica and Seven Mile
[2] The 12% reserve margin is applied to dependable capacity resources only
[3] The numbers shown include the 12% reserve margin

5.2 Regional capacity Load Resource Balances with Contingency Resource Plan for Accelerated electrification scenario

Figure 1-12, Table 1-12, Figure 1-13 and Table 1-13 present the capacity Load Resource Balances for the South Coast and Vancouver Island with selected resources in place to "fill" the capacity "gaps" under the Contingency Resource Plan for the Accelerated electrification scenario.[4] The figures and tables illustrate the timing of the resources and their energy/capacity contributions.

Figure 1-12 South Coast capacity Load Resource Balance with Contingency Resource Plan for Accelerated electrification scenario



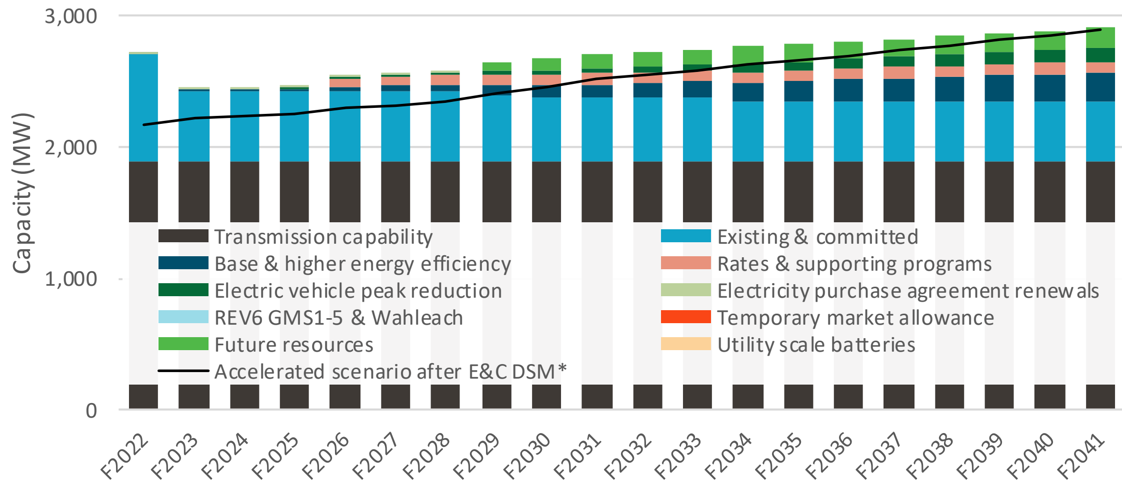
* E&C DSM denotes existing and committed demand-side measures.

4 A Contingency Resource Plan was not created for the North Coast region as the load growth associated with the accelerated electrification scenario primarily occurs in the South Coast.

Table 1-12 South Coast capacity Load Resource Balance with Contingency Resource Plan for Accelerated electrification scenario

	(MW)		F2022	F2023	F2024	F2025	F2026	F2027	F2028	F2029	F2030	F2031	F2032	F2033	F2034	F2035	F2036	F2037	F2038	F2039	F2040	F2041
	LRB with Existing and Committed Supply																					
1	***Existing and Committed Heritage Resources***	(a)	1,517	1,517	1,517	1,517	1,519	1,519	1,519	1,519	1,519	1,519	1,519	1,519	1,519	1,519	1,519	1,519	1,519	1,519	1,519	1,519
2	***Existing and Committed Electricity Purchase Agreements***	(b)	635	357	347	336	305	305	296	273	256	214	185	185	161	161	150	150	150	150	142	142
3	**Regional Supply Capacity (before planned resources)**	(c) = a+b	2,152	1,874	1,864	1,853	1,824	1,824	1,815	1,792	1,775	1,733	1,704	1,704	1,680	1,680	1,669	1,669	1,669	1,669	1,661	1,661
4	***Firm Transmission Capability***	(d)	6,300	6,300	6,300	6,300	6,300	6,300	6,300	6,300	6,300	6,300	6,300	6,300	6,300	6,300	6,300	6,300	6,300	6,300	6,300	6,300
	Demand - Regional Gross Requirements																					
5	Accelerated Electrification Scenario	(e)	(7,714)	(7,942)	(8,099)	(8,293)	(8,550)	(8,669)	(8,895)	(9,176)	(9,463)	(9,757)	(9,930)	(10,108)	(10,294)	(10,488)	(10,692)	(10,914)	(11,135)	(11,353)	(11,568)	(11,777)
	Existing and Committed Demand-side Measures																					
6	F21 Programs Savings, Codes & Standards, Rates	(f)	113	153	190	225	253	282	308	332	354	373	391	408	431	453	473	495	518	541	563	574
7	***Net Metering***	(g)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
8	**Regional Surplus / (Deficit) before planned resources**	(h) = c+d+e+f+g	**850**	**385**	**255**	**84**	**(173)**	**(263)**	**(472)**	**(752)**	**(1,034)**	**(1,351)**	**(1,534)**	**(1,696)**	**(1,883)**	**(2,055)**	**(2,250)**	**(2,450)**	**(2,648)**	**(2,844)**	**(3,044)**	**(3,243)**
	Contingency Resource Plan																					
	Future Demand-side Measures																					
9	Base & Higher Energy Efficiency		21	39	59	79	112	144	179	216	255	296	335	374	414	453	493	526	557	587	613	632
10	Rates & Supporting Programs		-	-	-	-	191	206	227	249	260	263	264	265	267	268	269	271	272	274	275	275
11	Electric Vehicle Peak Reduction		-	-	-	38	62	94	115	138	162	189	218	249	282	318	355	391	428	464	499	537
12	Sub-total	(i)	21	39	59	118	365	443	521	603	677	747	817	888	963	1,039	1,117	1,188	1,257	1,324	1,387	1,444
	Transmission Upgrades																					
13	Step 1 of transmission upgrades to South Coast		-	-	-	-	-	-	-	-	-	-	-	800	800	800	800	800	800	800	800	800
14	Step 2 of transmission upgrades to South Coast		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	800	800	800
15	Sub-total	(j)	-	-	-	-	-	-	-	-	-	-	-	800	800	800	800	800	800	1,600	1,600	1,600
16	***Electricity Purchase Agreement Renewals***	(k)	0	3	13	24	55	55	55	55	55	55	55	55	55	55	55	55	55	55	55	55
17	***Temporary Market Allowance***	(l)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
18	***REV6 GMS1-5 & Wahleach***	(m)	-	-	-	-	-	-	-	-	-	-	-	-	12	12	12	12	12	12	12	12
19	***Future Resources***	(n)	-	-	-	-	-	-	9	73	110	152	181	181	205	205	216	216	219	226	234	245
20	***Utility Scale Batteries***	(o)	-	-	-	-	-	-	-	21	192	397	482	482	482	482	482	482	482	482	482	482
21	**Regional Surplus / (Deficit) after planned resources**	(p) = h+i+j+k+l+m+n+o	**871**	**426**	**327**	**226**	**247**	**235**	**113**	**0**	**0**	**0**	**0**	**710**	**633**	**538**	**432**	**303**	**177**	**856**	**726**	**596**

Figure 1-13 Vancouver Island capacity Load Resource Balance with Contingency Resource Plan for Accelerated electrification scenario



* E&C DSM denotes existing and committed demand-side measures.

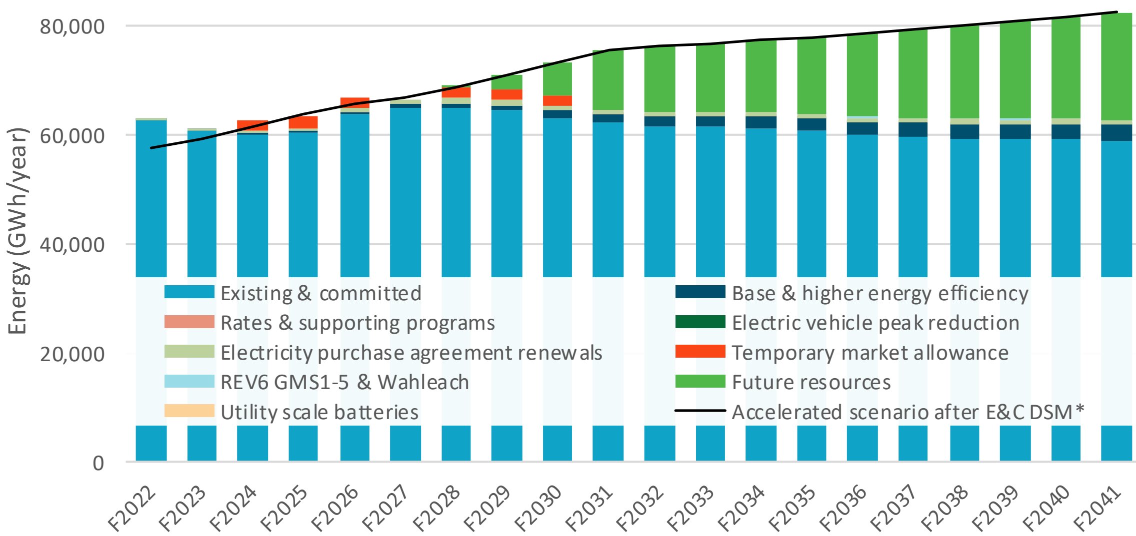
Table 1-13 Vancouver Island capacity Load Resource Balance with Contingency Resource Plan for Accelerated electrification scenario

	(MW)		F2022	F2023	F2024	F2025	F2026	F2027	F2028	F2029	F2030	F2031	F2032	F2033	F2034	F2035	F2036	F2037	F2038	F2039	F2040	F2041
	LRB with Existing and Committed Supply																					
1	***Existing and Committed Heritage Resources***	(a)	448	448	448	448	448	448	448	448	448	448	448	448	448	448	448	448	448	448	448	448
2	***Existing and Committed Electricity Purchase Agreements***	(b)	361	86	84	83	82	82	82	59	41	41	35	35	11	11	11	11	11	11	11	11
3	**Regional Supply Capacity (before planned resources)**	(c) = a+b	809	534	532	531	530	530	530	507	489	489	483	483	459	459	459	459	459	459	459	459
4	***Firm Transmission Capability***	(d)	1,890	1,890	1,890	1,890	1,890	1,890	1,890	1,890	1,890	1,890	1,890	1,890	1,890	1,890	1,890	1,890	1,890	1,890	1,890	1,890
	Demand - Regional Gross Requirements																					
5	Accelerated Electrification Scenario	(e)	(2,198)	(2,252)	(2,285)	(2,308)	(2,367)	(2,391)	(2,427)	(2,490)	(2,554)	(2,619)	(2,656)	(2,692)	(2,731)	(2,771)	(2,815)	(2,860)	(2,905)	(2,951)	(2,996)	(3,039)
	Existing and Committed Demand-side Measures																					
6	F21 Programs Savings, Codes & Standards, Rates	(f)	31	41	51	60	67	75	81	87	93	97	102	106	112	117	122	127	133	138	144	147
7	***Net Metering***	(g)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
8	**Regional Surplus / (Deficit) before planned resources**	(h) = c+d+e+f+g	**532**	**213**	**188**	**173**	**119**	**103**	**74**	**(6)**	**(82)**	**(142)**	**(180)**	**(213)**	**(270)**	**(305)**	**(344)**	**(383)**	**(423)**	**(463)**	**(503)**	**(543)**
	Contingency Resource Plan																					
	Future Demand-side Measures																					
9	Base & Higher Energy Efficiency		6	12	18	24	34	45	57	70	83	97	110	124	137	151	164	174	185	195	203	209
10	Rates & Supporting Programs		-	-	-	-	59	64	71	79	82	83	83	83	84	84	85	85	85	86	86	86
11	Electric Vehicle Peak Reduction		-	-	-	7	12	18	22	27	32	37	43	49	55	62	69	77	84	91	98	105
12	Sub-total	(i)	6	12	18	31	106	128	151	176	197	216	236	256	276	297	318	336	354	371	387	401
13	***Electricity Purchase Agreement Renewals***	(j)	0	0	2	3	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4
14	***Temporary Market Allowance***	(k)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
15	***REV6 GMS1-5 & Wahleach***	(l)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
16	***Future Resources***	(m)	-	-	-	-	-	-	-	65	101	101	107	108	131	132	132	132	135	142	142	153
17	***Utility Scale Batteries***	(n)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
18	**Surplus / (Deficit) after planned resources**	(o) = h+i+j+k+l+m+n	**538**	**225**	**207**	**207**	**229**	**235**	**229**	**239**	**220**	**180**	**167**	**154**	**142**	**127**	**110**	**88**	**69**	**54**	**31**	**15**

5.3 System Load Resource Balances with Contingency Resource Plan for Accelerated electrification with demand-side measures under-delivery scenario

Figure 1-14, Table 1-14 Figure 1-15 and Table 1-15 present the system-wide energy and capacity Load Resource Balances with selected resources in place to "fill" the energy and capacity "gaps" under the Contingency Resource Plan for the Accelerated electrification with demand-side measures under-delivery scenario. The figures and tables illustrate the timing of the resources and their energy/capacity contributions.

Figure 1-14 System energy Load Resource Balance with Contingency Resource Plan for Accelerated electrification with demand-side measures under-delivery scenario

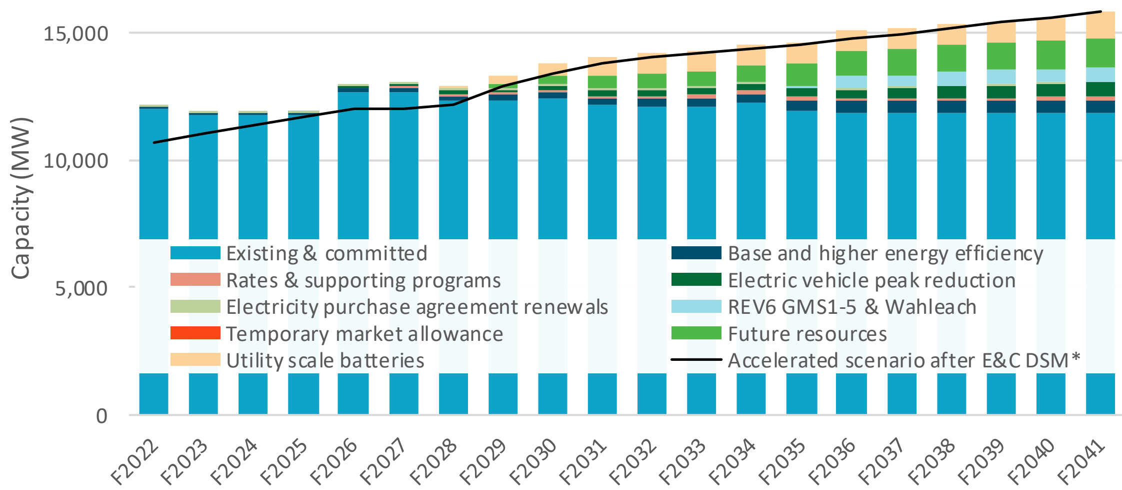


* E&C DSM denotes existing and committed demand-side measures.

Table 1-14 System energy Load Resource Balance with Contingency Resource Plan for Accelerated electrification with demand-side measures under-delivery scenario

	(GWh/year)		F2022	F2023	F2024	F2025	F2026	F2027	F2028	F2029	F2030	F2031	F2032	F2033	F2034	F2035	F2036	F2037	F2038	F2039	F2040	F2041
	LRB with Existing and Committed Supply																					
1	***Existing and Committed Heritage Resources***	(a)	46,898	46,898	46,898	47,264	50,790	52,184	52,184	52,184	52,184	52,184	52,184	52,184	52,184	52,184	52,184	52,184	52,184	52,184	52,184	52,184
2	***Existing and Committed Electricity Purchase Agreements***	(b)	15,719	13,717	13,278	13,059	12,807	12,728	12,638	12,210	10,997	9,997	9,501	9,323	9,055	8,541	7,716	7,350	7,212	6,952	6,922	6,736
3	**System Capability (before planned resources)**	(c) = a + b	62,617	60,615	60,176	60,323	63,597	64,912	64,822	64,394	63,181	62,181	61,685	61,507	61,239	60,725	59,900	59,534	59,396	59,136	59,106	58,920
	Demand - Integrated System Total Gross Requirements																					
4	Accelerated Electrification Scenario	(d)	(58,443)	(60,475)	(62,951)	(65,416)	(67,764)	(68,881)	(71,278)	(73,661)	(76,089)	(78,510)	(79,357)	(80,041)	(80,793)	(81,566)	(82,390)	(83,358)	(84,391)	(85,408)	(86,488)	(87,532)
	Existing and Committed Demand-side Measures																					
5	F21 Energy Conservations Programs Savings		105	117	117	118	112	112	112	109	104	71	60	47	47	43	17	12	12	12	11	10
6	Codes & Standards plus Voltage and VAR Optimization		589	854	1,111	1,355	1,586	1,804	1,996	2,181	2,356	2,523	2,684	2,838	2,992	3,148	3,304	3,459	3,615	3,771	3,927	3,995
7	Energy Conservation Rate Structures		138	177	210	239	156	147	138	139	139	115	86	58	29	-	-	-	-	-	-	-
8	Sub-total	(e)	833	1,148	1,438	1,711	1,853	2,064	2,247	2,429	2,599	2,709	2,830	2,943	3,069	3,191	3,321	3,471	3,627	3,782	3,938	4,005
9	***Net Metering***	(f)	40	50	62	77	95	117	143	174	212	258	311	371	438	510	588	667	749	832	915	998
10	**Surplus / (Deficit) before planned resources**	(g) = c+d+e+f	**5,047**	**1,338**	**(1,274)**	**(3,305)**	**(2,219)**	**(1,788)**	**(4,066)**	**(6,664)**	**(10,097)**	**(13,362)**	**(14,531)**	**(15,220)**	**(16,048)**	**(17,140)**	**(18,582)**	**(19,685)**	**(20,619)**	**(21,658)**	**(22,529)**	**(23,609)**
	Contingency Resource Plan																					
	Future Demand-side Measures																					
11	Base & Higher Energy Efficiency		102	187	297	409	546	709	900	1,084	1,284	1,505	1,703	1,872	2,055	2,222	2,399	2,547	2,669	2,785	2,893	2,955
12	Rates & Supporting Programs		-	-	-	-	6	6	6	6	6	6	6	6	6	7	7	7	7	7	7	7
13	Electric Vehicle Peak Reduction		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
14	Sub-total	(h)	102	187	297	409	552	715	906	1,090	1,290	1,512	1,709	1,878	2,061	2,228	2,405	2,553	2,675	2,792	2,900	2,962
15	***Electricity Purchase Agreement Renewals***	(i)	0	59	312	535	816	895	895	895	895	895	895	895	895	895	895	895	895	895	895	895
16	***Market Allowance***	(j)	-	-	2,000	2,000	2,000	-	2,000	2,000	2,000	-	-	-	-	-	-	-	-	-	-	-
17	***REV6 GMS1-5 & Wahleach***	(k)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	26	26	26	26	26	26
18	***Future Resources***	(l)	-	-	-	-	-	-	89	2,679	5,912	10,955	11,926	12,446	13,091	14,016	15,255	16,211	17,023	17,945	18,708	19,726
19	***Utility Scale Batteries***	(m)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
20	**Surplus / (Deficit) after planned resources**	(n) = g+h+i+j+k+l+m	**5,149**	**1,584**	**1,336**	**(361)**	**1,149**	**(178)**	**(175)**	**0**	**0**	**0**	**0**	**0**	**(0)**	**(0)**	**(0)**	**0**	**(0)**	**0**	**0**	**0**

Figure 1-15 System capacity Load Resource Balance with Contingency Resource Plan for Accelerated electrification with demand-side measures under-delivery scenario



* E&C DSM denotes existing and committed demand-side measures.

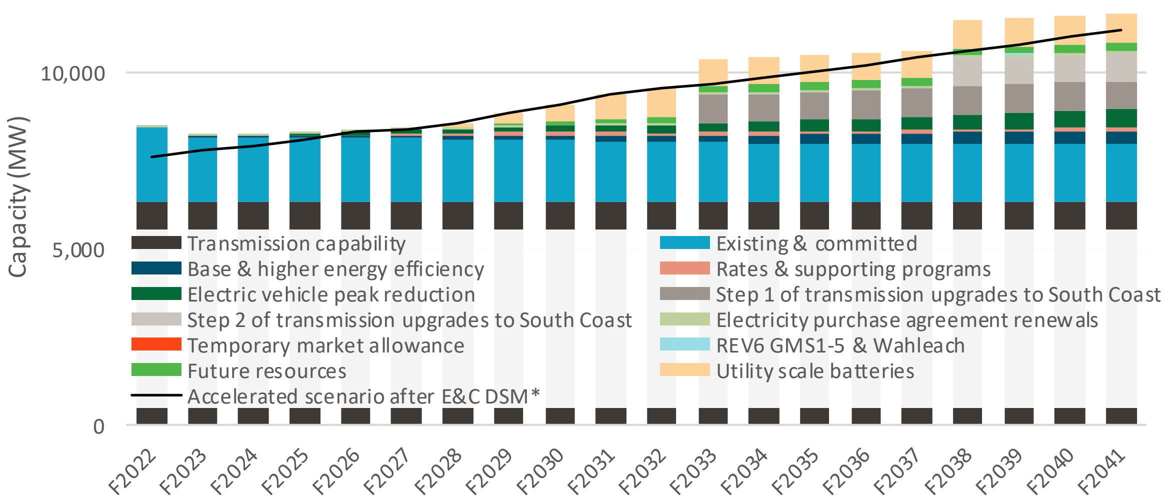
Table 1-15 System capacity Load Resource Balance with Contingency Resource Plan for Accelerated electrification with demand-side measures under-delivery scenario

	(MW)		F2022	F2023	F2024	F2025	F2026	F2027	F2028	F2029	F2030	F2031	F2032	F2033	F2034	F2035	F2036	F2037	F2038	F2039	F2040	F2041
	LRB with Existing and Committed Supply																					
1	Existing and Committed Heritage Resources [1]	(a)	11,818	11,818	11,818	11,818	12,965	12,965	12,618	12,618	12,965	12,791	12,791	12,791	12,965	12,965	12,965	12,965	12,965	12,965	12,965	12,965
2	Existing and Committed Electricity Purchase Agreements	(b)	1,795	1,512	1,495	1,481	1,400	1,400	1,391	1,362	1,068	974	940	917	885	580	480	480	445	445	437	437
3	12% Reserves [2]	(c)	(1,574)	(1,540)	(1,540)	(1,540)	(1,674)	(1,674)	(1,633)	(1,629)	(1,636)	(1,604)	(1,600)	(1,597)	(1,617)	(1,583)	(1,576)	(1,576)	(1,576)	(1,576)	(1,576)	(1,576)
4	**System Peak Load Carrying Capability (before Planned Resources)**	(d) = a+b+c	12,039	11,789	11,773	11,759	12,691	12,691	12,376	12,350	12,397	12,162	12,131	12,111	12,233	11,962	11,869	11,869	11,834	11,834	11,826	11,826
	Demand - Integrated System Total Gross Requirements																					
5	Accelerated Electrification Scenario	(e)	(10,837)	(11,208)	(11,613)	(11,977)	(12,362)	(12,544)	(12,885)	(13,352)	(13,824)	(14,294)	(14,494)	(14,688)	(14,889)	(15,097)	(15,317)	(15,565)	(15,813)	(16,058)	(16,300)	(16,532)
	Existing and Committed Demand-side Measures																					
6	F21 Energy Conservations Programs Savings		21	21	21	20	18	18	17	17	16	12	10	8	8	8	4	3	3	3	3	3
7	Codes & Standards plus Voltage and VAR Optimization		118	166	212	254	293	329	361	391	419	445	470	493	520	548	576	604	632	659	687	700
8	Energy Conservation Rate Structures		11	16	19	23	15	14	13	13	13	11	8	5	3	-	-	-	-	-	-	-
9	Sub-total	(f)	150	203	252	297	326	361	392	421	448	468	488	506	531	556	580	607	635	663	690	703
10	Net Metering	(g)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
11	**Surplus / (Deficit) before planned resources**	(h) = d+e+f+g	**1,351**	**785**	**412**	**79**	**654**	**508**	**(116)**	**(580)**	**(978)**	**(1,665)**	**(1,875)**	**(2,070)**	**(2,125)**	**(2,580)**	**(2,868)**	**(3,089)**	**(3,344)**	**(3,562)**	**(3,784)**	**(4,003)**
	Contingency Resource Plan																					
	Future Demand-side Measures																					
12	Base & Higher Energy Efficiency		19	35	54	72	101	130	162	196	231	268	303	336	369	402	435	461	486	509	529	544
13	Rates & Supporting Programs		-	-	-	-	52	62	77	92	100	101	102	102	103	103	104	104	105	106	106	107
14	Electric Vehicle Peak Reduction		-	-	-	40	65	98	119	143	168	195	226	258	293	330	368	406	443	481	517	557
15	Sub-total	(i)	19	35	54	112	218	290	358	431	499	565	631	696	765	835	907	972	1,034	1,096	1,153	1,207
16	Electricity Purchase Agreement Renewals [3]	(j)	0	8	24	38	66	66	66	66	66	66	66	66	66	66	66	66	66	66	66	66
17	Temporary Market Allowance	(k)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
18	REV6 GMS1-5 & Wahleach [3]	(l)	-	-	-	-	-	-	-	-	-	-	-	-	12	12	442	442	530	530	530	530
19	Future Resources [3]	(m)	-	-	-	-	-	-	9	171	381	554	594	622	661	940	1,043	1,055	1,104	1,118	1,141	1,158
20	Utility Scale Batteries	(n)	-	-	-	-	-	-	123	281	473	696	798	798	798	798	798	798	798	798	895	1,042
21	**Surplus / (Deficit) after planned resources**	(o) = h+i+j+k+l+m+n	**1,370**	**828**	**490**	**228**	**938**	**864**	**440**	**369**	**441**	**216**	**214**	**111**	**177**	**72**	**387**	**243**	**188**	**46**	**0**	**0**

5.4 Regional capacity Load Resource Balances with Contingency Resource Plan for Accelerated electrification with demand-side measures under-delivery scenario

Figure 1-16, Table 1-16, Figure 1-17 and Table 1-17 present the capacity Load Resource Balances for the South Coast and Vancouver Island with selected resources in place to "fill" the capacity "gaps" under the Contingency Resource Plan for the Accelerated electrification with demand-side measures under-delivery scenario.[5] The figures and tables illustrate the timing of the resources and their energy/capacity contributions.

Figure 1-16 South Coast capacity Load Resource Balance with Contingency Resource Plan for Accelerated electrification with demand-side measures under-delivery scenario



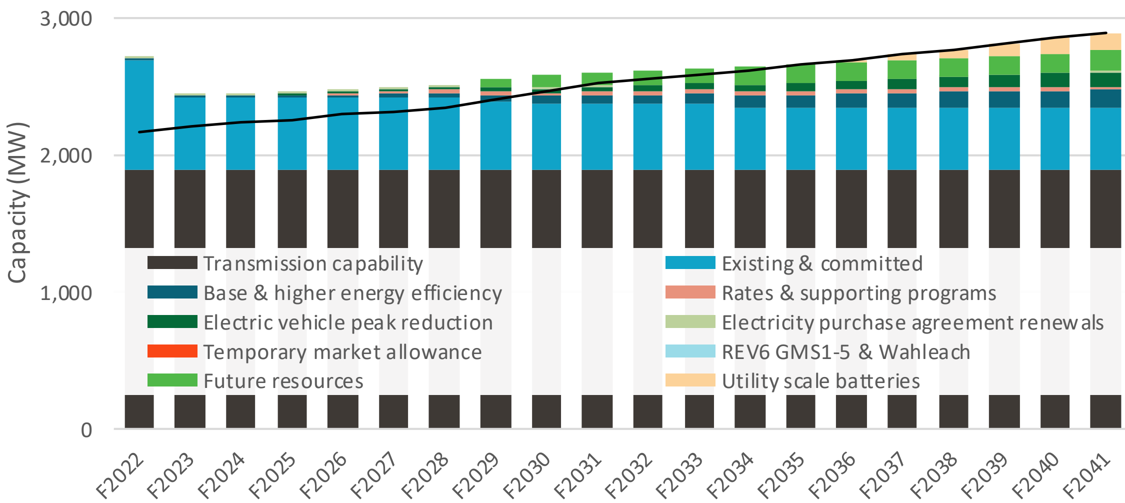
* E&C DSM denotes existing and committed demand-side measures.

[5] A Contingency Resource Plan was not created for the North Coast region as the load growth associated with the Accelerated electrification scenario primarily occurs in the South Coast.

Table 1-16 South Coast capacity Load Resource Balance with Contingency Resource Plan for Accelerated electrification with demand-side measures under-delivery scenario

	(MW)		F2022	F2023	F2024	F2025	F2026	F2027	F2028	F2029	F2030	F2031	F2032	F2033	F2034	F2035	F2036	F2037	F2038	F2039	F2040	F2041
	LRB with Existing and Committed Supply																					
1	***Existing and Committed Heritage Resources***	(a)	1,517	1,517	1,517	1,517	1,519	1,519	1,519	1,519	1,519	1,519	1,519	1,519	1,519	1,519	1,519	1,519	1,519	1,519	1,519	1,519
2	***Existing and Committed Electricity Purchase Agreements***	(b)	635	357	347	336	305	305	296	273	256	214	185	185	161	161	150	150	150	150	142	142
3	**Regional Supply Capacity (before planned resources)**	(c) = a+b	2,152	1,874	1,864	1,853	1,824	1,824	1,815	1,792	1,775	1,733	1,704	1,704	1,680	1,680	1,669	1,669	1,669	1,669	1,661	1,661
4	***Firm Transmission Capability***	(d)	6,300	6,300	6,300	6,300	6,300	6,300	6,300	6,300	6,300	6,300	6,300	6,300	6,300	6,300	6,300	6,300	6,300	6,300	6,300	6,300
	Demand - Regional Gross Requirements																					
5	Accelerated Electrification Scenario	(e)	(7,714)	(7,942)	(8,099)	(8,293)	(8,550)	(8,669)	(8,895)	(9,176)	(9,463)	(9,757)	(9,930)	(10,108)	(10,294)	(10,488)	(10,692)	(10,914)	(11,135)	(11,353)	(11,568)	(11,777)
	Existing and Committed Demand-side Measures																					
6	F21 Programs Savings, Codes & Standards, Rates	(f)	113	153	190	225	253	282	308	332	354	373	391	408	431	453	473	495	518	541	563	574
7	***Net Metering***	(g)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
8	**Regional Surplus / (Deficit) before planned resources**	(h) = c+d+e+f+g	**850**	**385**	**255**	**84**	**(173)**	**(263)**	**(472)**	**(752)**	**(1,034)**	**(1,351)**	**(1,534)**	**(1,696)**	**(1,883)**	**(2,055)**	**(2,250)**	**(2,450)**	**(2,648)**	**(2,844)**	**(3,044)**	**(3,243)**
	Contingency Resource Plan																					
	Future Demand-side Measures																					
9	Base & Higher Energy Efficiency		13	25	37	50	70	89	111	133	157	182	205	228	252	276	299	319	337	355	370	381
10	Rates & Supporting Programs		-	-	-	-	41	49	62	74	81	82	83	83	83	84	84	85	85	86	86	87
11	Electric Vehicle Peak Reduction		-	-	-	38	61	92	113	135	159	185	213	244	277	312	348	384	419	454	489	526
12	Sub-total	(i)	13	25	37	87	172	231	285	342	396	448	501	555	612	671	731	787	841	895	945	995
	Transmission Upgrades																					
13	Step 1 of transmission upgrades to South Coast		-	-	-	-	-	-	-	-	-	-	-	800	800	800	800	800	800	800	800	800
14	Step 2 of transmission upgrades to South Coast		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	800	800	800	800
15	Sub-total	(j)	-	-	-	-	-	-	-	-	-	-	-	800	800	800	800	800	1,600	1,600	1,600	1,600
16	***Electricity Purchase Agreement Renewals***	(k)	0	3	13	24	55	55	55	55	55	55	55	55	55	55	55	55	55	55	55	55
17	***Temporary Market Allowance***	(l)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
18	***REV6 GMS1-5 & Wahleach***	(m)	-	-	-	-	-	-	-	-	-	-	-	-	12	12	12	12	12	12	12	12
19	***Future Resources***	(n)	-	-	-	-	-	-	9	73	110	152	181	181	205	205	216	216	219	226	234	245
20	***Utility Scale Batteries***	(o)	-	-	-	-	-	-	123	281	473	696	798	798	798	798	798	798	798	798	798	798
21	**Regional Surplus / (Deficit) after planned resources**	(p) = h+i+j+k+l+m+n+o	**863**	**412**	**305**	**196**	**54**	**23**	**0**	**0**	**0**	**0**	**0**	**693**	**599**	**486**	**362**	**218**	**878**	**743**	**600**	**462**

Figure 1-17 Vancouver Island capacity Load Resource Balance with Contingency Resource Plan for Accelerated electrification with demand-side measures under-delivery scenario



* E&C DSM denotes existing and committed demand-side measures.

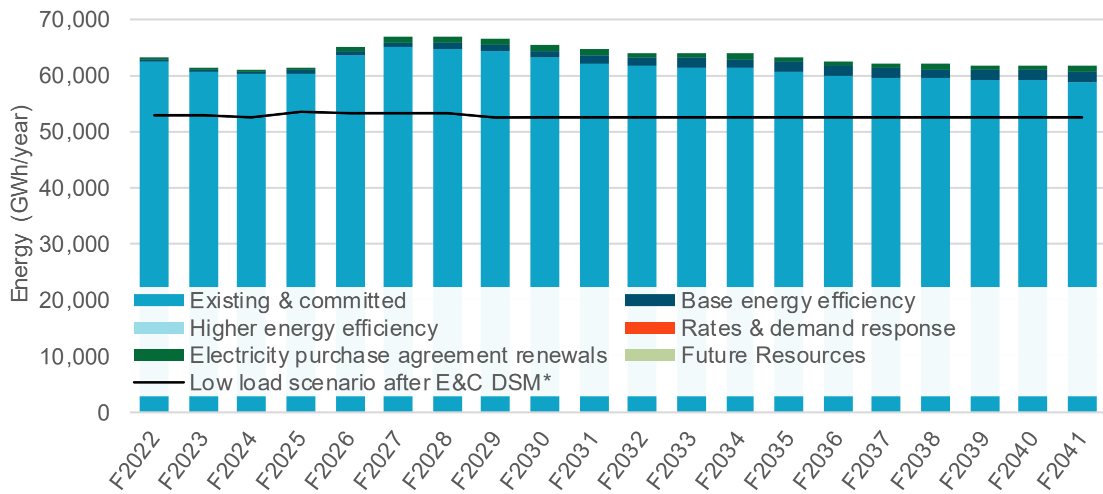
Table 1-17 Vancouver Island capacity Load Resource Balance with Contingency Resource Plan for Accelerated electrification with demand-side measures under-delivery scenario

	(MW)		F2022	F2023	F2024	F2025	F2026	F2027	F2028	F2029	F2030	F2031	F2032	F2033	F2034	F2035	F2036	F2037	F2038	F2039	F2040	F2041
	LRB with Existing and Committed Supply																					
1	***Existing and Committed Heritage Resources***	(a)	448	448	448	448	448	448	448	448	448	448	448	448	448	448	448	448	448	448	448	448
2	***Existing and Committed Electricity Purchase Agreements***	(b)	361	86	84	83	82	82	82	59	41	41	35	35	11	11	11	11	11	11	11	11
3	**Regional Supply Capacity (before planned resources)**	(c) = a+b	809	534	532	531	530	530	530	507	489	489	483	483	459	459	459	459	459	459	459	459
4	***Firm Transmission Capability***	(d)	1,890	1,890	1,890	1,890	1,890	1,890	1,890	1,890	1,890	1,890	1,890	1,890	1,890	1,890	1,890	1,890	1,890	1,890	1,890	1,890
	Demand - Regional Gross Requirements																					
5	Accelerated Electrification Scenario	(e)	(2,198)	(2,252)	(2,285)	(2,308)	(2,367)	(2,391)	(2,427)	(2,490)	(2,554)	(2,619)	(2,656)	(2,692)	(2,731)	(2,771)	(2,815)	(2,860)	(2,905)	(2,951)	(2,996)	(3,039)
	Existing and Committed Demand-side Measures																					
6	F21 Programs Savings, Codes & Standards, Rates	(f)	31	41	51	60	67	75	81	87	93	97	102	106	112	117	122	127	133	138	144	147
7	***Net Metering***	(g)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
8	**Regional Surplus / (Deficit) before planned resources**	(h) = c+d+e+f+g	**532**	**213**	**188**	**173**	**119**	**103**	**74**	**(6)**	**(82)**	**(142)**	**(180)**	**(213)**	**(270)**	**(305)**	**(344)**	**(383)**	**(423)**	**(463)**	**(503)**	**(543)**
	Contingency Resource Plan																					
	Future Demand-side Measures																					
9	Base & Higher Energy Efficiency		4	7	11	15	21	28	35	43	51	59	67	75	83	91	99	106	112	117	123	126
10	Rates & Supporting Programs		-	-	-	-	13	16	20	24	26	26	27	27	27	27	27	27	27	28	28	28
11	Electric Vehicle Peak Reduction		-	-	-	7	12	18	22	26	31	36	42	48	54	61	68	75	82	89	96	103
12	Sub-total	(i)	4	7	11	22	46	62	77	94	108	122	136	150	164	179	194	208	221	234	246	257
13	***Electricity Purchase Agreement Renewals***	(j)	0	0	2	3	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4
14	***Temporary Market Allowance***	(k)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
15	***REV6 GMS1-5 & Wahleach***	(l)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
16	***Future Resources***	(m)	-	-	-	-	-	-	-	65	101	101	107	108	131	132	132	132	135	142	142	153
17	***Utility Scale Batteries***	(n)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	14	40	64	83	111	129
18	**Surplus / (Deficit) after planned resources**	(p) = h+i+j+k+l+m+n	**536**	**220**	**201**	**198**	**170**	**169**	**155**	**157**	**132**	**85**	**67**	**48**	**30**	**10**	**0**	**0**	**0**	**0**	**0**	**0**

5.5 System Load Resource Balances with Contingency Resource Plan for Low load scenario

Figure 1-18, Table 1-18 Figure 1-19 and Table 1-19 present the system-wide energy and capacity Load Resource Balances under the Contingency Resource Plan for the Low load scenario.

Figure 1-18 System energy Load Resource Balance with Contingency Resource Plan for Low load scenario

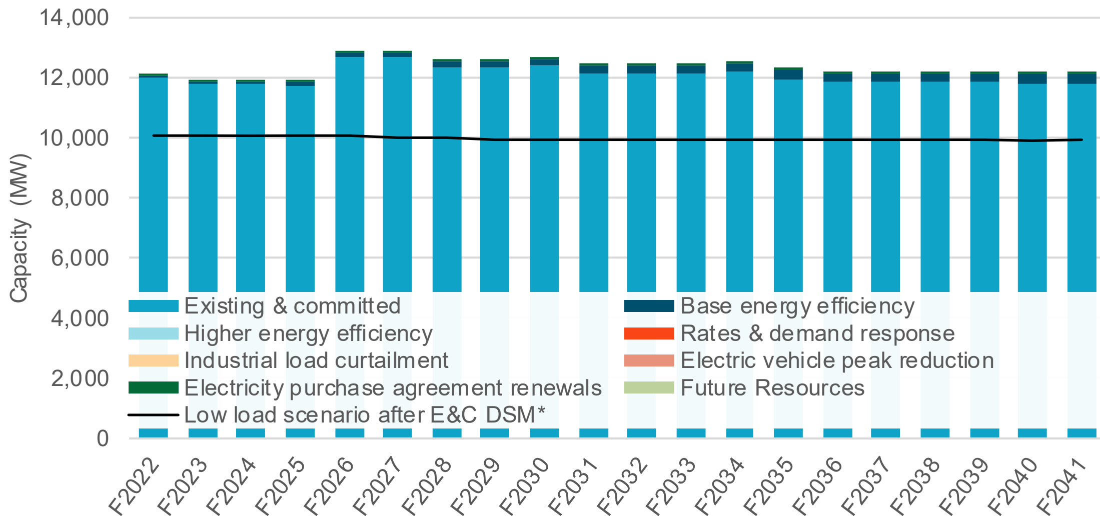


* E&C DSM denotes existing and committed demand-side measures.

Table 1-18 System energy Load Resource Balance with Contingency Resource Plan for Low load scenario

	(GWh/year)		F2022	F2023	F2024	F2025	F2026	F2027	F2028	F2029	F2030	F2031	F2032	F2033	F2034	F2035	F2036	F2037	F2038	F2039	F2040	F2041
	LRB with Existing and Committed Supply																					
1	***Existing and Committed Heritage Resources***	(a)	46,898	46,898	46,898	47,264	50,790	52,184	52,184	52,184	52,184	52,184	52,184	52,184	52,184	52,184	52,184	52,184	52,184	52,184	52,184	52,184
2	***Existing and Committed Electricity Purchase Agreements***	(b)	15,719	13,717	13,278	13,059	12,807	12,728	12,638	12,210	10,997	9,997	9,501	9,323	9,055	8,541	7,716	7,350	7,212	6,952	6,922	6,736
3	**System Capability (before planned resources)**	(c) = a+b	62,617	60,615	60,176	60,323	63,597	64,912	64,822	64,394	63,181	62,181	61,685	61,507	61,239	60,725	59,900	59,534	59,396	59,136	59,106	58,920
	Demand - Integrated System Total Gross Requirements																					
4	Dec 2020 Low Load Forecast before DSM	(d)	(53,881)	(53,982)	(54,051)	(55,172)	(55,224)	(55,446)	(55,643)	(54,901)	(55,093)	(55,284)	(55,466)	(55,647)	(55,856)	(56,066)	(56,267)	(56,422)	(56,626)	(56,826)	(57,075)	(57,351)
	Existing and Committed Demand-side Measures																					
5	F21 Energy Conservations Programs Savings		95	105	106	106	101	101	101	98	93	64	54	43	43	39	15	11	11	11	10	9
6	Codes & Standards plus Voltage and VAR Optimization		534	773	1,005	1,224	1,433	1,631	1,805	1,972	2,130	2,281	2,426	2,566	2,705	2,846	2,987	3,127	3,268	3,409	3,550	3,612
7	Energy Conservation Rate Structures		124	159	189	215	140	133	125	125	125	104	78	52	26	-	-	-	-	-	-	-
8	Sub-total	(e)	753	1,038	1,300	1,546	1,674	1,865	2,030	2,195	2,349	2,448	2,558	2,660	2,774	2,885	3,002	3,138	3,279	3,419	3,560	3,621
9	***Net Metering***	(f)	40	50	62	77	95	117	143	174	212	258	311	371	438	510	588	667	749	832	915	998
10	**Surplus / (Deficit) before planned resources**	(g) = c+d+e+f	**9,529**	**7,721**	**7,487**	**6,774**	**10,142**	**11,448**	**11,353**	**11,862**	**10,649**	**9,604**	**9,089**	**8,891**	**8,595**	**8,054**	**7,222**	**6,917**	**6,797**	**6,561**	**6,506**	**6,188**
	Contingency Resource Plan																					
	Future Demand-side Measures																					
11	Base Energy Efficiency		161	296	472	649	814	948	1,090	1,224	1,347	1,483	1,558	1,616	1,666	1,706	1,768	1,779	1,788	1,794	1,795	1,795
12	Higher Energy Efficiency		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
13	Time-Varying Rates & Demand Response		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
14	Industrial Load Curtailment		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
15	Electric Vehicle Peak Reduction		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
16	Sub-total	(h)	161	296	472	649	814	948	1,090	1,224	1,347	1,483	1,558	1,616	1,666	1,706	1,768	1,779	1,788	1,794	1,795	1,795
17	**Surplus / (Deficit) after planned DSM**	**(i) = g+h**	**9,690**	**8,017**	**7,959**	**7,424**	**10,957**	**12,395**	**12,443**	**13,086**	**11,996**	**11,087**	**10,647**	**10,506**	**10,261**	**9,760**	**8,990**	**8,696**	**8,586**	**8,354**	**8,302**	**7,983**
18	***Electricity Purchase Agreement Renewals***	(j)	0	59	312	535	816	895	895	895	895	895	895	895	895	895	895	895	895	895	895	895
19	***Future Resources***	(k)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
20	**Surplus / (Deficit) after planned resources**	(l) = i+j+k	**9,691**	**8,076**	**8,271**	**7,958**	**11,772**	**13,291**	**13,338**	**13,981**	**12,892**	**11,982**	**11,542**	**11,402**	**11,156**	**10,655**	**9,885**	**9,591**	**9,481**	**9,250**	**9,197**	**8,879**

Figure 1-19 System capacity Load Resource Balance with Contingency Resource Plan for Low load scenario



* E&C DSM denotes existing and committed demand-side measures.

Table 1-19 System capacity Load Resource Balance with Contingency Resource Plan for Low load scenario

	(MW)		F2022	F2023	F2024	F2025	F2026	F2027	F2028	F2029	F2030	F2031	F2032	F2033	F2034	F2035	F2036	F2037	F2038	F2039	F2040	F2041
	LRB with Existing and Committed Supply																					
1	***Existing and Committed Heritage Resources*** [1]	(a)	11,818	11,818	11,818	11,818	12,965	12,965	12,618	12,618	12,965	12,791	12,791	12,791	12,965	12,965	12,965	12,965	12,965	12,965	12,965	12,965
2	***Existing and Committed Electricity Purchase Agreements***	(b)	1,795	1,512	1,495	1,481	1,400	1,400	1,391	1,362	1,068	974	940	917	885	580	480	480	445	445	437	437
3	***12% Reserves*** [2]	(c)	(1,574)	(1,540)	(1,540)	(1,540)	(1,674)	(1,674)	(1,633)	(1,629)	(1,636)	(1,604)	(1,600)	(1,597)	(1,617)	(1,583)	(1,576)	(1,576)	(1,576)	(1,576)	(1,576)	(1,576)
4	**System Peak Load Carrying Capability (before Planned Resources)**	(d) = a+b+c	12,039	11,789	11,773	11,759	12,691	12,691	12,376	12,350	12,397	12,162	12,131	12,111	12,233	11,962	11,869	11,869	11,834	11,834	11,826	11,826
	Demand - Integrated System Total Gross Requirements																					
5	Dec 2020 Low Load Forecast before DSM	(e)	(10,205)	(10,246)	(10,296)	(10,325)	(10,340)	(10,348)	(10,364)	(10,304)	(10,323)	(10,341)	(10,354)	(10,378)	(10,398)	(10,419)	(10,435)	(10,462)	(10,485)	(10,510)	(10,529)	(10,551)
	Existing and Committed Demand-side Measures																					
6	F21 Energy Conservations Programs Savings		18	18	18	18	16	16	15	15	14	10	9	7	7	7	4	3	3	3	3	3
7	Codes & Standards plus Voltage and VAR Optimization		104	147	187	225	260	292	321	348	374	398	421	442	467	492	517	542	567	592	617	629
8	Energy Conservation Rate Structures		10	14	17	20	13	13	12	12	12	10	7	5	2	-	-	-	-	-	-	-
9	Sub-total	(f)	132	179	222	262	289	321	349	375	400	419	437	455	477	499	521	545	570	595	620	632
10	***Net Metering***	(g)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
11	**Surplus / (Deficit) before planned resources**	(h) = d+e+f+g	**1,965**	**1,723**	**1,699**	**1,697**	**2,639**	**2,663**	**2,361**	**2,422**	**2,474**	**2,239**	**2,215**	**2,187**	**2,312**	**2,042**	**1,956**	**1,952**	**1,919**	**1,919**	**1,917**	**1,907**
	Contingency Resource Plan																					
	Future Demand-side Measures																					
12	Base Energy Efficiency		30	56	85	115	142	164	187	209	229	248	261	272	281	290	299	302	303	304	302	302
13	Higher Energy Efficiency		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
14	Time-Varying Rates & Demand Response		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
15	Industrial Load Curtailment		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
16	Electric Vehicle Peak Reduction		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
17	Sub-total	(i)	30	56	85	115	142	164	187	209	229	248	261	272	281	290	299	302	303	304	302	302
18	**Surplus / (Deficit) after planned DSM**	(j) = h+i	**1,995**	**1,779**	**1,785**	**1,811**	**2,781**	**2,827**	**2,548**	**2,630**	**2,703**	**2,487**	**2,476**	**2,459**	**2,593**	**2,332**	**2,255**	**2,254**	**2,221**	**2,223**	**2,220**	**2,210**
19	***Electricity Purchase Agreement Renewals*** [3]	(k)	0	8	24	38	66	66	66	66	66	66	66	66	66	66	66	66	66	66	66	66
20	***Future Resources*** [3]	(l)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
21	**Surplus / (Deficit) after planned resources**	(m) = j+k+l	**1,995**	**1,787**	**1,809**	**1,849**	**2,847**	**2,893**	**2,615**	**2,696**	**2,769**	**2,554**	**2,542**	**2,525**	**2,659**	**2,398**	**2,321**	**2,320**	**2,288**	**2,289**	**2,286**	**2,276**

Notes:

[1] Includes outages for Mica and Seven Mile

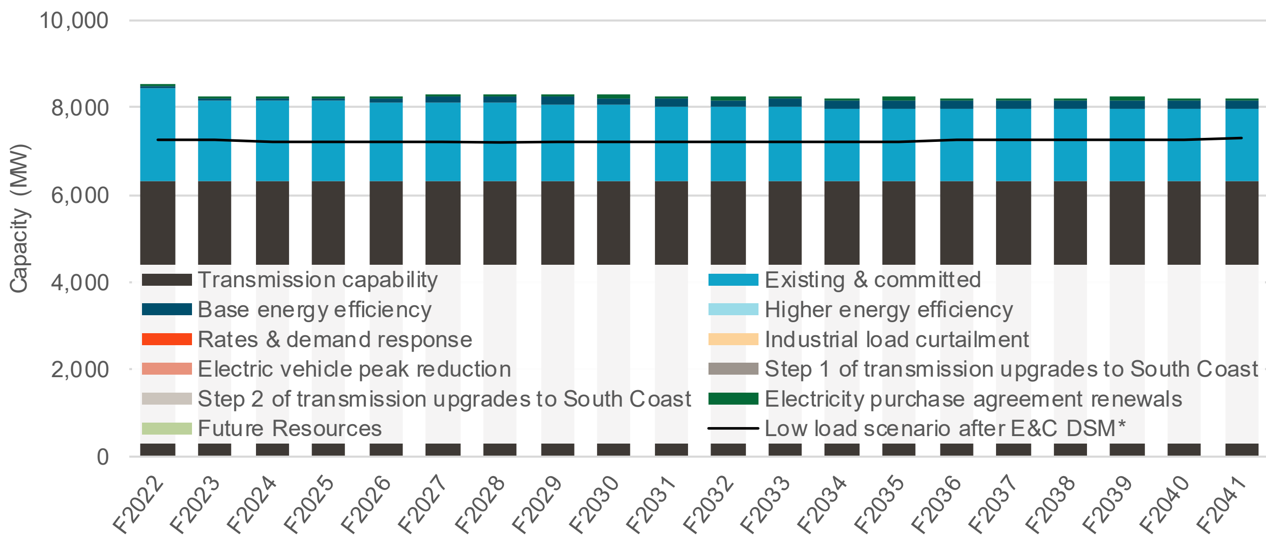
[2] The 12% reserve margin is applied to dependable capacity resources only

[3] The numbers shown include the 12% reserve margin

5.6 Regional capacity Load Resource Balances with Contingency Resource Plan for Low load scenario

Figure 1-20, Table 1-20, Figure 1-21 and Table 1-21 present the South Coast and Vancouver Island capacity Load Resource Balances under the Contingency Resource Plan for the Low load scenario.

Figure 1-20 South Coast capacity Load Resource Balance with Contingency Resource Plan for Low load scenario

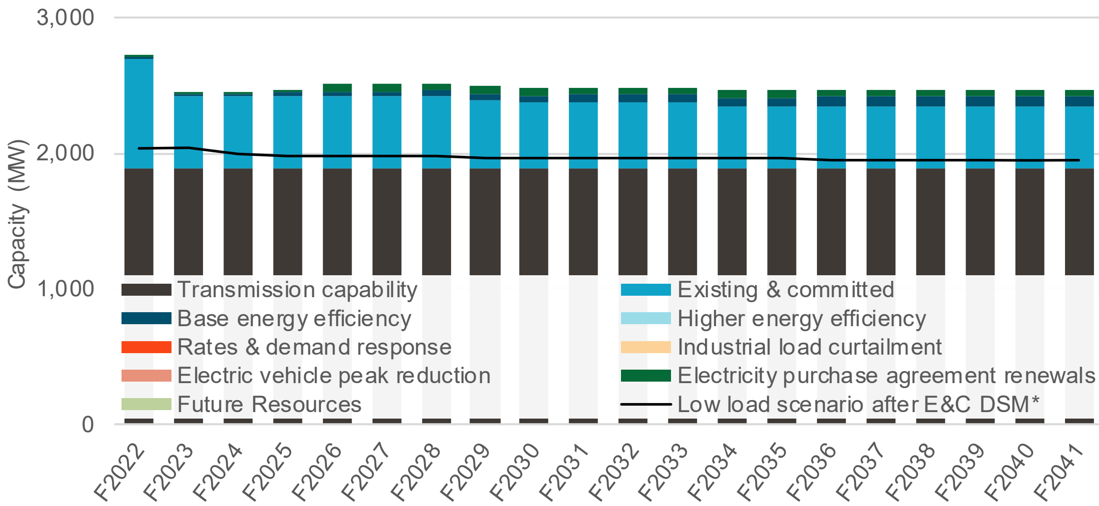


* E&C DSM denotes existing and committed demand-side measures.

Table 1-20 South Coast capacity Load Resource Balance with Contingency Resource Plan for Low load scenario

	(MW)		F2022	F2023	F2024	F2025	F2026	F2027	F2028	F2029	F2030	F2031	F2032	F2033	F2034	F2035	F2036	F2037	F2038	F2039	F2040	F2041
	LRB with Existing and Committed Supply																					
1	***Existing and Committed Heritage Resources***	(a)	1,517	1,517	1,517	1,517	1,519	1,519	1,519	1,519	1,519	1,519	1,519	1,519	1,519	1,519	1,519	1,519	1,519	1,519	1,519	1,519
2	***Existing and Committed Electricity Purchase Agreements***	(b)	635	357	347	336	305	305	296	273	256	214	185	185	161	161	150	150	150	150	142	142
3	**Regional Supply Capacity (before planned resources)**	(c) = a+b	2,152	1,874	1,864	1,853	1,824	1,824	1,815	1,792	1,775	1,733	1,704	1,704	1,680	1,680	1,669	1,669	1,669	1,669	1,661	1,661
4	***Transmission Capability***	(d)	6,300	6,300	6,300	6,300	6,300	6,300	6,300	6,300	6,300	6,300	6,300	6,300	6,300	6,300	6,300	6,300	6,300	6,300	6,300	6,300
	Demand - Regional Gross Requirements																					
5	Dec 2020 Low Load Forecast before DSM	(e)	(7,358)	(7,407)	(7,400)	(7,408)	(7,443)	(7,461)	(7,479)	(7,504)	(7,525)	(7,546)	(7,564)	(7,592)	(7,618)	(7,644)	(7,668)	(7,701)	(7,731)	(7,763)	(7,790)	(7,821)
	Existing and Committed Demand-side Measures																					
6	F21 Programs Savings, Codes & Standards, Rates	(f)	99	135	168	199	225	251	274	296	316	334	351	367	387	407	425	445	465	486	506	515
7	***Net Metering***	(g)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
8	**Regional Surplus / (Deficit) before planned resources**	(h) = c+d+e+f+g	**1,193**	**902**	**932**	**944**	**906**	**913**	**910**	**884**	**867**	**821**	**791**	**778**	**749**	**742**	**726**	**713**	**703**	**692**	**677**	**655**
	Contingency Resource Plan																					
	Future Demand-side Measures																					
9	Base Energy Efficiency		21	39	59	79	98	113	129	143	157	171	181	189	195	202	208	210	211	212	211	211
10	Higher Energy Efficiency		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
11	Time-Varying Rates & Demand Response		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
12	Industrial Load Curtailment		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
13	Electric Vehicle Peak Reduction		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
14	Sub-total	(i)	21	39	59	79	98	113	129	143	157	171	181	189	195	202	208	210	211	212	211	211
15	**Surplus / (Deficit) after planned DSM**	**(j) = h+i**	**1,214**	**941**	**992**	**1,023**	**1,004**	**1,026**	**1,039**	**1,027**	**1,024**	**992**	**972**	**967**	**944**	**944**	**934**	**923**	**914**	**904**	**888**	**865**
	Transmission Upgrades																					
16	Step 1 of transmission upgrades to South Coast		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
17	Step 2 of transmission upgrades to South Coast		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
18	Sub-total	(k)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
19	***Electricity Purchase Agreement Renewals***	(l)	0	3	13	24	55	55	55	55	55	55	55	55	55	55	55	55	55	55	55	55
20	***Future Resources***	(m)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
21	**Regional Surplus / (Deficit) after planned resources**	(n) = j+k+l+m	**1,214**	**943**	**1,005**	**1,047**	**1,059**	**1,082**	**1,094**	**1,083**	**1,079**	**1,048**	**1,027**	**1,022**	**1,000**	**999**	**989**	**978**	**969**	**959**	**943**	**920**

Figure 1-21 Vancouver Island capacity Load Resource Balance with Contingency Resource Plan for Low load scenario



* E&C DSM denotes existing and committed demand-side measures.

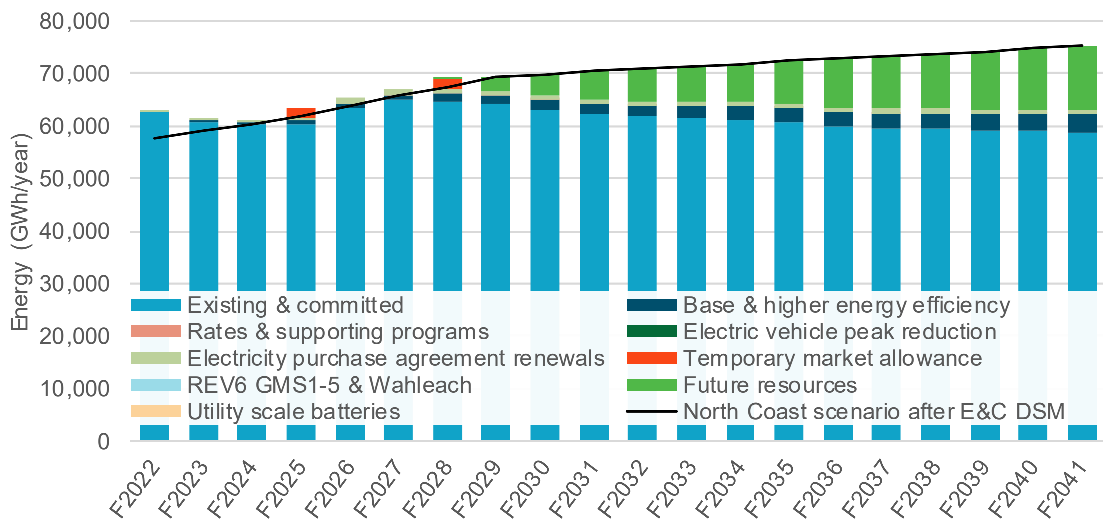
Table 1-21 Vancouver Island capacity Load Resource Balance with Contingency Resource Plan for Low load scenario

	(MW)		F2022	F2023	F2024	F2025	F2026	F2027	F2028	F2029	F2030	F2031	F2032	F2033	F2034	F2035	F2036	F2037	F2038	F2039	F2040	F2041
	LRB with Existing and Committed Supply																					
1	***Existing and Committed Heritage Resources***	(a)	448	448	448	448	448	448	448	448	448	448	448	448	448	448	448	448	448	448	448	448
2	***Existing and Committed Electricity Purchase Agreements***	(b)	361	86	84	83	82	82	82	59	41	41	35	35	11	11	11	11	11	11	11	11
3	**Regional Supply Capacity (before planned resources)**	(c) = a+b	809	534	532	531	530	530	530	507	489	489	483	483	459	459	459	459	459	459	459	459
4	***Transmission Capability***	(d)	1,890	1,890	1,890	1,890	1,890	1,890	1,890	1,890	1,890	1,890	1,890	1,890	1,890	1,890	1,890	1,890	1,890	1,890	1,890	1,890
	Demand - Regional Gross Requirements																					
5	Dec 2020 Low Load Forecast before DSM	(e)	(2,062)	(2,070)	(2,033)	(2,033)	(2,040)	(2,043)	(2,044)	(2,048)	(2,051)	(2,053)	(2,054)	(2,058)	(2,060)	(2,063)	(2,064)	(2,069)	(2,071)	(2,075)	(2,076)	(2,079)
	Existing and Committed Demand-side Measures																					
6	F21 Programs Savings, Codes & Standards, Rates	(f)	28	37	46	54	60	67	73	78	83	88	92	95	100	105	109	114	119	124	130	132
7	***Net Metering***	(g)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
8	**Regional Surplus / (Deficit) before planned resources**	(h) = c+d+e+f+g	**664**	**390**	**435**	**442**	**440**	**444**	**448**	**427**	**412**	**414**	**411**	**411**	**389**	**391**	**394**	**395**	**397**	**399**	**402**	**402**
	Contigency Resource Plan																					
	Future Demand-side Measures																					
9	Base Energy Efficiency		6	12	18	24	29	34	39	44	48	53	56	59	61	63	65	65	65	65	65	65
10	Higher Energy Efficiency		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
11	Time-Varying Rates & Demand Response		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
12	Industrial Load Curtailment		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
13	Electric Vehicle Peak Reduction		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
14	Sub-total	(i)	6	12	18	24	29	34	39	44	48	53	56	59	61	63	65	65	65	65	65	65
15	**Surplus / (Deficit) after planned DSM**	**(j) = h+i**	**670**	**402**	**452**	**466**	**469**	**478**	**487**	**471**	**461**	**467**	**467**	**469**	**450**	**454**	**459**	**460**	**462**	**464**	**467**	**467**
16	***Electricity Purchase Agreement Renewals***	(k)	0	0	2	3	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4
17	***Future Resources***	(l)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
18	**Regional Surplus / (Deficit) after planned resources**	(m) = j+k+l	**670**	**402**	**454**	**468**	**473**	**482**	**492**	**475**	**465**	**471**	**471**	**474**	**454**	**458**	**463**	**464**	**466**	**469**	**472**	**471**

5.7 System Load Resource Balances with Contingency Resource Plan for North Coast scenario

Figure 1-22, Table 1-22, Figure 1-23 and Table 1-23 present the system-wide energy and capacity Load Resource Balances with selected resources in place to "fill" the energy and capacity "gaps" under the Contingency Resource Plan for the North Coast liquified natural gas and mining scenario (North Coast scenario). The figures and tables illustrate the timing of the resources and their energy/capacity contributions.

Figure 1-22 System energy Load Resource Balance with Contingency Resource Plan for North Coast scenario

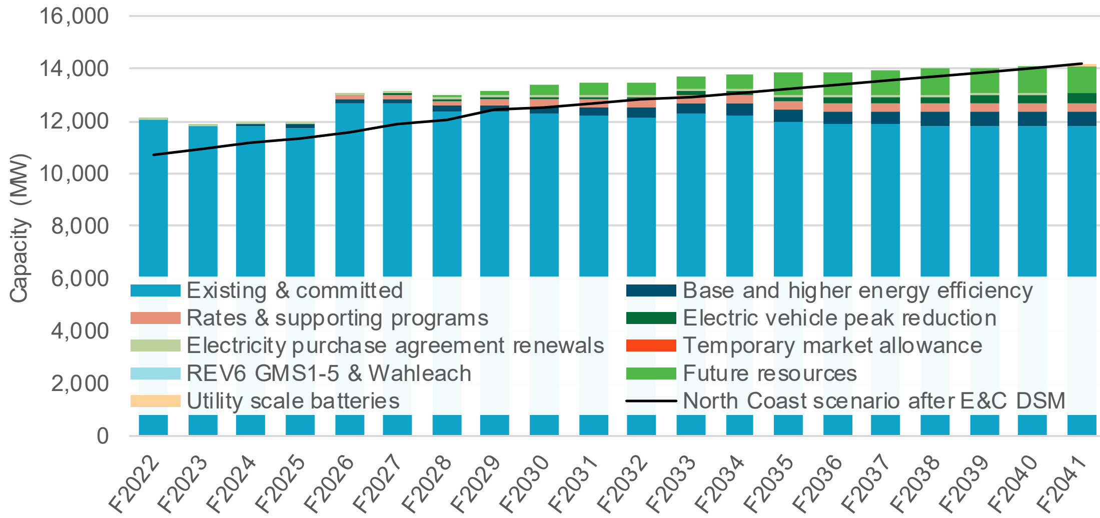


* E&C DSM denotes existing and committed demand-side measures.

Table 1-22 System energy Load Resource Balance with Contingency Resource Plan for North Coast scenario

	(GWh/year)		F2022	F2023	F2024	F2025	F2026	F2027	F2028	F2029	F2030	F2031	F2032	F2033	F2034	F2035	F2036	F2037	F2038	F2039	F2040	F2041
	LRB with Existing and Committed Supply																					
1	***Existing and Committed Heritage Resources***	(a)	46,898	46,898	46,898	47,264	50,790	52,184	52,184	52,184	52,184	52,184	52,184	52,184	52,184	52,184	52,184	52,184	52,184	52,184	52,184	52,184
2	***Existing and Committed Electricity Purchase Agreements***	(b)	15,719	13,717	13,278	13,059	12,807	12,728	12,638	12,210	10,997	9,997	9,501	9,323	9,055	8,541	7,716	7,350	7,212	6,952	6,922	6,736
3	**System Capability (before planned resources)**	(c) = a + b	62,617	60,615	60,176	60,323	63,597	64,912	64,822	64,394	63,181	62,181	61,685	61,507	61,239	60,725	59,900	59,534	59,396	59,136	59,106	58,920
	Demand - Integrated System Total Gross Requirements																					
4	North Coast Scenario	(d)	(58,526)	(60,458)	(61,993)	(63,623)	(65,667)	(67,840)	(69,677)	(71,940)	(72,631)	(73,315)	(74,098)	(74,719)	(75,407)	(76,116)	(76,876)	(77,507)	(78,203)	(78,883)	(79,626)	(80,334)
	Existing and Committed Demand-side Measures																					
5	F21 Energy Conservations Programs Savings		105	117	117	118	112	112	112	109	104	71	60	47	47	43	17	12	12	12	11	10
6	Codes & Standards plus Voltage and VAR Optimization		589	854	1,111	1,355	1,586	1,804	1,996	2,181	2,356	2,523	2,684	2,838	2,992	3,148	3,304	3,459	3,615	3,771	3,927	3,995
7	Energy Conservation Rate Structures		138	177	210	239	156	147	138	139	139	115	86	58	29	-	-	-	-	-	-	-
8	Sub-total	(e)	833	1,148	1,438	1,711	1,853	2,064	2,247	2,429	2,599	2,709	2,830	2,943	3,069	3,191	3,321	3,471	3,627	3,782	3,938	4,005
9	***Net Metering***	(f)	40	50	62	77	95	117	143	174	212	258	311	371	438	510	588	667	749	832	915	998
10	**Surplus / (Deficit) before planned resources**	(g) = c+d+e+f	**4,963**	**1,355**	**(316)**	**(1,512)**	**(121)**	**(747)**	**(2,465)**	**(4,943)**	**(6,639)**	**(8,167)**	**(9,272)**	**(9,898)**	**(10,661)**	**(11,690)**	**(13,068)**	**(13,835)**	**(14,432)**	**(15,134)**	**(15,667)**	**(16,410)**
	Contingency Resource Plan																					
	Future Demand-side Measures																					
11	Base & Higher Energy Efficiency		161	296	472	649	814	983	1,208	1,446	1,674	1,931	2,134	2,324	2,479	2,632	2,794	2,887	2,981	3,049	3,115	3,182
12	Rates & Supporting Programs		-	-	-	-	25	25	26	26	26	26	26	26	27	27	27	27	27	27	27	27
13	Electric Vehicle Peak Reduction		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
14	Sub-total	(h)	161	296	472	649	839	1,008	1,233	1,471	1,700	1,958	2,160	2,351	2,505	2,659	2,820	2,914	3,008	3,076	3,142	3,209
15	***Electricity Purchase Agreement Renewals***	(i)	0	59	312	535	816	895	895	895	895	895	895	895	895	895	895	895	895	895	895	895
16	***Market Allowance***	(j)	-	-	-	2,000	-	-	2,000	-	-	-	-	-	-	-	-	-	-	-	-	-
17	***REV6 GMS1-5 & Wahleach***	(k)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
18	***Future Resources***	(l)	-	-	-	-	-	-	89	2,576	4,043	5,314	6,217	6,651	7,261	8,136	9,352	10,025	10,528	11,162	11,630	12,306
19	***Utility Scale Batteries***	(m)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
20	**Surplus / (Deficit) after planned resources**	(n) = g+h+i+j+k+l+m	**5,125**	**1,711**	**468**	**1,673**	**1,534**	**1,156**	**1,754**	**(0)**	**(0)**	**0**	**0**	**0**	**(0)**	**(0)**	**(0)**	**0**	**(0)**	**0**	**(0)**	**0**

Figure 1-23 System capacity Load Resource Balance with Contingency Resource Plan for North Coast scenario



* E&C DSM denotes existing and committed demand-side measures.

Table 1-23 System capacity Load Resource Balance with Contingency Resource Plan for North Coast scenario

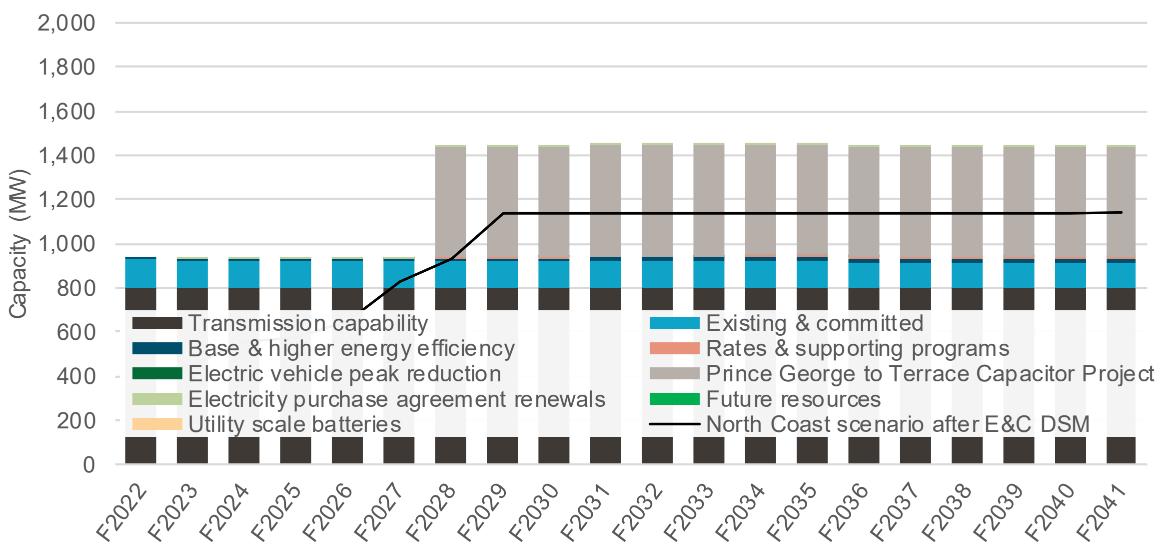
	(MW)		F2022	F2023	F2024	F2025	F2026	F2027	F2028	F2029	F2030	F2031	F2032	F2033	F2034	F2035	F2036	F2037	F2038	F2039	F2040	F2041
	LRB with Existing and Committed Supply																					
1	***Existing and Committed Heritage Resources*** [1]	(a)	11,818	11,818	11,818	11,818	12,965	12,965	12,618	12,618	12,791	12,791	12,791	12,965	12,965	12,965	12,965	12,965	12,965	12,965	12,965	12,965
2	***Existing and Committed Electricity Purchase Agreements***	(b)	1,795	1,512	1,495	1,481	1,400	1,400	1,391	1,362	1,068	974	940	917	885	580	480	480	445	445	437	437
3	***12% Reserves*** [2]	(c)	(1,574)	(1,540)	(1,540)	(1,540)	(1,674)	(1,674)	(1,633)	(1,629)	(1,615)	(1,604)	(1,600)	(1,618)	(1,617)	(1,583)	(1,576)	(1,576)	(1,576)	(1,576)	(1,576)	(1,576)
4	**System Peak Load Carrying Capability (before Planned Resources)**	(d) = a + b + c	12,039	11,789	11,773	11,759	12,691	12,691	12,376	12,350	12,244	12,162	12,131	12,264	12,233	11,962	11,869	11,869	11,834	11,834	11,826	11,826
	Demand - Integrated System Total Gross Requirements																					
5	North Coast Scenario	(e)	(10,862)	(11,180)	(11,420)	(11,635)	(11,892)	(12,208)	(12,467)	(12,819)	(12,971)	(13,121)	(13,290)	(13,453)	(13,624)	(13,802)	(13,991)	(14,176)	(14,360)	(14,542)	(14,721)	(14,889)
	Existing and Committed Demand-side Measures																					
6	F21 Energy Conservations Programs Savings		21	21	21	20	18	18	17	17	16	12	10	8	8	8	4	3	3	3	3	3
7	Codes & Standards plus Voltage and VAR Optimization		118	166	212	254	293	329	361	391	419	445	470	493	520	548	576	604	632	659	687	700
8	Energy Conservation Rate Structures		11	16	19	23	15	14	13	13	13	11	8	5	3	-	-	-	-	-	-	-
9	Sub-total	(f)	150	203	252	297	326	361	392	421	448	468	488	506	531	556	580	607	635	663	690	703
10	***Net Metering***	(g)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
11	**Surplus / (Deficit) before planned resources**	(h) = d+e+f+g	**1,327**	**812**	**605**	**421**	**1,125**	**844**	**302**	**(47)**	**(278)**	**(491)**	**(671)**	**(683)**	**(860)**	**(1,284)**	**(1,542)**	**(1,700)**	**(1,891)**	**(2,045)**	**(2,205)**	**(2,360)**
	Contingency Resource Plan																					
	Future Demand-side Measures																					
12	Base & Higher Energy Efficiency		30	56	85	115	142	175	210	248	285	323	356	387	413	441	467	485	501	517	529	543
13	Rates & Supporting Programs		-	-	-	-	134	151	177	203	314	317	318	320	321	323	324	325	327	328	330	330
14	Electric Vehicle Peak Reduction		-	-	-	24	40	60	73	87	102	119	138	157	178	201	224	247	270	293	315	339
15	Sub-total	(i)	30	56	85	139	316	386	460	537	701	760	812	864	913	964	1,015	1,058	1,099	1,138	1,174	1,212
16	***Electricity Purchase Agreement Renewals*** [3]	(j)	0	8	24	38	66	66	66	66	66	66	66	66	66	66	66	66	66	66	66	66
17	***Temporary Market Allowance***	(k)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
18	***REV6 GMS1-5 & Wahleach*** [3]	(l)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
19	***Future Resources*** [3]	(m)	-	-	-	-	-	-	9	166	344	440	479	505	544	822	925	931	974	981	998	1,009
20	***Utility Scale Batteries***	(n)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	73
21	**Surplus / (Deficit) after planned resources**	(o) = h+i+j+k+l+m+n	**1,357**	**876**	**714**	**598**	**1,506**	**1,296**	**837**	**723**	**833**	**775**	**686**	**753**	**664**	**569**	**464**	**355**	**247**	**140**	**34**	**(0)**

[1] Includes outages at Mica and Seven Mile
[2] The 12% reserve margin is applied to dependable capacity resources only
[3] The numbers shown include the 12% reserve margin

5.8 Regional capacity Load Resource Balance with Contingency Resource Plan for North Coast scenario

Figure 1-24 and Table 1-24 show the North Coast capacity Load Resource Balance with selected resources in place to "fill" the capacity "gap" under the Contingency Resource Plan scenario for North Coast liquified natural gas and mining. The figure and table illustrate the timing of the resources and their energy/capacity contributions. Regional Load Resource Balances for the South Coast and Vancouver Island are not shown as they are not impacted by this scenario.

Figure 1-24 North Coast capacity Load Resource Balance with Contingency Resource Plan for North Coast scenario



* E&C DSM denotes existing and committed demand-side measures.

Table 1-24 North Coast capacity Load Resource Balance with Contingency Resource Plan for North Coast scenario

	(MW)		F2022	F2023	F2024	F2025	F2026	F2027	F2028	F2029	F2030	F2031	F2032	F2033	F2034	F2035	F2036	F2037	F2038	F2039	F2040	F2041
	LRB with Existing and Committed Supply																					
1	***Existing and Committed Heritage Resources***	(a)	7	7	7	7	7	7	7	7	7	7	7	7	7	7	7	7	7	7	7	7
2	***Existing and Committed Electricity Purchase Agreements***	(b)	124	118	118	118	118	118	118	118	118	118	118	118	118	118	107	107	107	107	107	107
3	**Regional Supply Capacity (before planned resources)**	(c) = a + b	131	125	125	125	125	125	125	125	125	125	125	125	125	125	114	114	114	114	114	114
4	***Transmission Capability***	(d)	800	800	800	800	800	800	800	800	800	800	800	800	800	800	800	800	800	800	800	800
	Demand - Regional Gross Requirements																					
5	North Coast Scenario	(e)	(409)	(455)	(560)	(584)	(660)	(832)	(938)	(1,144)	(1,145)	(1,146)	(1,147)	(1,148)	(1,149)	(1,149)	(1,150)	(1,151)	(1,152)	(1,152)	(1,153)	(1,153)
	Existing and Committed Demand-side Measures																					
6	F21 Programs Savings, Codes & Standards, Rates	(f)	4	5	6	7	7	8	8	9	9	9	9	9	9	10	10	10	11	11	12	12
7	***Net Metering***	(g)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
8	**Regional Surplus / (Deficit) before planned resources**	(h) = c+d+e+f+g	**526**	**475**	**371**	**349**	**272**	**101**	**(5)**	**(210)**	**(211)**	**(212)**	**(213)**	**(213)**	**(214)**	**(215)**	**(227)**	**(227)**	**(227)**	**(227)**	**(227)**	**(228)**
	Contingency Resource Plan																					
	Future Demand-side Measures																					
9	Base & Higher Energy Efficiency		1	2	3	4	4	6	7	8	9	11	12	13	14	15	15	16	16	17	17	17
10	Rates & Supporting Programs		-	-	-	-	4	5	5	6	6	7	7	7	7	7	7	7	7	7	7	7
11	Electric Vehicle Peak Reduction		-	-	-	0	0	0	0	0	0	0	0	0	0	0	1	1	1	1	1	1
12	Sub-total	(i)	1	2	3	4	8	10	12	14	16	17	19	20	21	22	23	23	24	24	24	25
	Transmission Upgrades																					
13	Prince George to Terrace Capacitor Project	(j)	-	-	-	-	-	-	500	500	500	500	500	500	500	500	500	500	500	500	500	500
14	***Electricity Purchase Agreement Renewals***	(k)	-	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5
15	***Future Resources***	(l)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
16	***Utility Scale Batteries***	(m)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
17	**Regional Surplus / (Deficit) after planned resources**	(n) = h+i+j+k+l+m	**527**	**482**	**379**	**358**	**286**	**117**	**513**	**310**	**311**	**311**	**311**	**312**	**312**	**313**	**302**	**302**	**302**	**302**	**302**	**303**

A2

Attachment 2: glossary and abbreviations

Words and abbreviations used in the 2021 IRP	Definitions
attribute	A characteristic that describes a resource option or portfolio, used to assess its performance in meeting the planning objectives.
B.C.	British Columbia
Base Resource Plan (BRP)	BC Hydro's plan for meeting its current and future customers' expected electricity needs on a reliable and cost-effective basis.
BC Hydro	British Columbia Hydro and Power Authority
British Columbia Utilities Commission (Commission or BCUC)	An independent regulatory agency of the provincial government operating under and administering the Utilities Commission Act. The BCUC regulates BC Hydro's domestic supply and rates, as well as the safety and reliability of the services BC Hydro provides. The BCUC also assesses concerns from ratepayers regarding BC Hydro's service.
Bulk Transmission System	The major lines or "backbone" of the high voltage transmission system that transfers large amounts of power between regions.
capability	In relation to the integrated electricity system, capability refers to facilities that can be used under specified conditions for a given purpose. Energy capability is the amount of energy that can be generated under specified conditions by a generating unit or by the electric system over a period of time, typically expressed in GWh/year. Transmission capability is the amount of electric power that can be moved or transferred reliably from one area to another on the transmission systems via transmission lines between those areas under specified system conditions.
capacity	The power output of a generator at a given point in time under specified conditions, normally measured in kilowatts (kW) or megawatts (MW). A transmission line's ability to transmit electricity at a given point in time under specified conditions.

capacity factor	The ratio of the average annual power output to the maximum possible output of generating plants.
capacitor station	A capacitor station is a facility where electricity from a high-voltage transmission line is carried through a series of devices call capacitors. This helps to maintain the voltage levels in a transmission line, allowing more electricity to pass through a line over long distances.
carbon dioxide (CO_2) equivalent emissions	Carbon dioxide equivalent" or CO_2e is a term for describing different greenhouse gases in a common unit. For any quantity and type of greenhouse gas, CO2e signifies the amount of CO2 which would have the equivalent climate change impact.
Clean Energy Act (CEA)	The Provincial legislation that sets the foundation for electricity self-sufficiency, energy efficiency, and reduced greenhouse gas emissions for the utility sector. The Act also sets out the consideration of investments in electricity generation from clean or renewable resources across the province.
clean or renewable resource	Defined by the Clean Energy Act as biomass, biogas, geothermal heat, hydro, solar, ocean, wind or other prescribed resources. The Clean or Renewable Resource Regulation prescribes biogenic waste, waste heat and waste hydrogen as additional clean or renewable resources.
Climate Action Plan	A policy document produced by the B.C. Government that describes actions that will be undertaken as government moves to its target of reducing greenhouse gas emissions by 33 per cent below 2007 levels by 2020 and 80 per cent by 2050.
climate change	A change of climate which is attributed directly or indirectly to human activity that alters the composition of the global atmosphere and which is in addition to natural climate variability observed over comparable time periods.
committed resources	Committed resources are those resources that have received necessary internal authorizations to proceed to implementation, as well as any required regulatory approvals, and are expected to begin operating during the planning horizon of the 2021 IRP.
consequence table	Consequence tables are tools that support decision-making by comparing decision alternatives in relation to specific objectives where trade-offs must be made.
Contingency Resource Plan (CRP)	A plan that identifies sources of supply including demand-side measures, storage and transmission components that could be required should the Base Resource Plan not materialize as expected.
December 2020 Load Forecast	BC Hydro's 20-year load forecast finalized in December 2020. It includes reference, high, and low cases for both energy and peak, before and after various adjustments.

demand	Customers' requirements for electric power.
demand response	The shifting of electricity usage out of peak times into periods when supply is more available. Demand Response programs provide utilities the ability to shift electricity usage by directly controlling customers' devices (e.g. water heaters) through voluntary programs.
demand-side measures (DSM)	A rate, measure, action or program undertaken (a)to conserve energy or promote energy efficiency, (b) to reduce the energy demand a public utility must serve, or (c) to shift the use of energy to periods of lower demand. but does not include (d) a rate, measure, action or program the main purpose of which is to encourage a switch from the use of one kind of energy to another such that the switch would increase greenhouse gas emissions in British Columbia.
dependable capacity	The maximum generator output that can be reliably supplied coincident with the system peak load, taking into account the physical state and availability of the equipment, and on water or fuel constraints. Same as dependable generating capacity.
Discount rate	A rate used to determine the present value of cash flows (expenses and revenues) that will occur over a period of time, reflecting the cost of capital.
dispatchable	A resource whose output can be adjusted to meet various conditions including fluctuating demand, weather changes, outages, market price changes and non-power considerations.
electricity grid	An interconnected network for electricity delivery from generators to consumers. Electrical grids vary in size and can cover whole countries or continents. B.C.'s electrical grid is connected to a much larger grid covering B.C., Alberta, portions of 14 western U.S. states, and a small part of Mexico.
electricity purchase agreement (EPA)	A contract that defines the terms and conditions by which BC Hydro purchases electric energy from an independent power producer.
Electricity Self-Sufficiency Regulation	A regulation issued by the Provincial government which prescribes that average water conditions and mid-load forecasts are to be used for the purposes of the "electricity supply obligation" in the Clean Energy Act.
electric vehicle peak reduction	A demand-side measure combining time-varying rates with supporting programs to encourage customers to shift electric vehicle charging outside of system peak periods.

Electrification Plan	BC Hydro's Electrification Plan is a five-year plan to make it easier and more affordable for people to use B.C.'s clean electricity in place of fossil fuels to power their homes, buildings, businesses, and vehicles. The plan proposes new programs and incentives to promote this switch from fossil fuels to clean electricity and attract new industries to B.C. that are looking for clean power.
emissions	Any direct or indirect discharge of solid, liquid or gaseous pollutants into the air.
energy	The amount of electricity produced or used over a period of time, usually measured in kilowatt hours (kWh), megawatt hours (MWh) and gigawatt hours (GWh).
energy efficiency (EE)	A reduction in energy usage while providing the same nature and quality of energy service, such as lighting, cooling or motor torque.
firm energy	Firm energy refers to electricity that is available at all times.
fiscal year (F)	BC Hydro's fiscal year beginning April 1 and ending March 31. Dates marked with an F refer to the year ending March 31 in the year given.
fossil fuel	A fossil fuel is a hydrocarbon-containing material formed underground from the remains of plants and animals that humans extract and burn to release energy for use. The main fossil fuels are coal, petroleum and natural gas, which humans extract through mining and drilling.
FTE	Full-time equivalent
generation	The production of electricity.
gigawatt hour (GWh)	A unit of electrical energy used to describe the total amount of electricity used over time. One GWh is equivalent to one billion watts of energy consumed in one hour.
greenfield site	Land on which no development has previously taken place.
greenhouse gas emissions (GHG emissions)	Any of the atmospheric gases that contribute to climate change such as water vapour, methane, and carbon dioxide.
Greenhouse Gas Reduction Targets Act (GGRTA)	The Greenhouse Gas Reduction Targets Act is Provincial legislation that sets into law B.C.'s greenhouse gas emissions target of at least 33 per cent below 2007 levels by 2020, and at least 80 per cent below 2007 levels by 2050.

GWh/year	Gigawatt hours per year.
independent power producer (IPP)	A non-utility-owned electricity generating facility that produces electricity for sale to utilities or other customers.
Integrated Resource Plan (IRP)	The document describing BC Hydro's long-term plan to meet customers' needs using existing, committed, and new demand-side and supply-side resources.
Intergovernmental Panel on Climate Change (IPCC)	The United Nations body for assessing the science related to climate change.
intermittent resource	A source of energy that has varying output due to natural changes and is not dispatchable. Can also refer to electricity supply that fluctuates or is not available at all times.
liquefied natural gas (LNG)	Natural gas in a liquid form. When natural gas is cooled to minus 259 degrees Fahrenheit (minus 161 degrees Celsius) through liquefaction, it becomes a clear, colorless, odourless liquid.
load	The amount of electricity required by a customer or group of customers.
load centre	An area with a significant number of electricity customers.
load curtailment	A measure that reduces electrical use for a period of time. Load curtailment programs provide customers with an incentive in exchange for agreeing to curtail energy use during specific periods requested by the utility.
Load Forecast	The load requirements that an electricity system will have to meet in future years.
Load-Resource Balance (LRB)	A comparison of the load forecast and existing and committed resources available to meet the load. In this IRP, the Load Resource Balance is such a comparison over a 20-year planning horizon.
megawatt (MW)	A unit of electrical power equal to one million watts.
Near-term Action	The actions that BC Hydro is taking to implement the Base Resource Plan and prepare for contingency scenarios, during the period between the submission of the 2021 IRP and the submission of the next IRP.

net present value (NPV)	The difference between the present value of benefits and the present value of costs (including capital, operating, maintenance and administration costs) for a given discount rate.
net total resource cost	Measures the total costs and benefits of a resource to both the utility and the participants.
net utility cost	Measures the total costs and benefits of a resource to the utility.
North Coast (NC)	Region of the BC Hydro transmission system that is west of Prince George.
off-peak	The time when there is less demand on BC Hydro’s system.
peak demand/load	The highest electrical power demand on a power system in a specified period of time.
planned resource	Resources that BC Hydro is planning to pursue and is taking actions to acquire or develop. Planned resources have not necessarily received regulatory or Board of Director approval.
planning period / planning horizon	Period over which the operation of the various elements of the power system are modelled. For the 2021 Integrated Resource Plan, the planning/period horizon is twenty years.
resource portfolio	A group of individual resource options to be acquired in a sequence over time to meet customers’ future electricity needs.
portfolio analysis	A process of developing and evaluating resource portfolios, each consisting of a combination of supply side, transmission and demand-side resources, which meet customers’ future electricity needs.
present value (PV)	Today’s discounted value of future receipts or expenditures. Refer also to discount rate and net present value.
rate	A utility’s unit price for electricity service provided.
rate impact	The effect on electricity rates.

Reference Load Forecast	The reference forecasts for both energy and peak of the 2020 December Load Forecast, after rate impacts, and without any demand-side measures savings. For the purposes of the 2021 IRP and the time period that it addresses, the Reference Load Forecast reflects further adjustments to the reference forecast of the December 2020 Load Forecast in relation to energy and peak savings attributed to demand-side measures actions and expenditures during fiscal 2021, subsequent to the date of the forecast.
reliability (electric system)	A measure of the adequacy and operating reliability of electric service. Adequacy refers to the existence of sufficient facilities in the system to satisfy the demand and system operational constraints. Operating reliability refers to the system's ability to withstand sudden disturbances in the system.
resource option	A source of electricity or electricity savings that is available to help meet electricity demand, including generation, demand-side measures and transmission facilities.
Resource Options Database (RODAT)	BC Hydro's database of information on a broad range of resources and their attributes that could potentially be used to meet future electricity demand.
Revenue Requirements Application	BC Hydro's application before the British Columbia Utilities Commission expected to determine the revenues BC Hydro will need for its operations, to ensure a safe and reliable supply of electricity to its customers.
Roadmap	The CleanBC: Roadmap to 2030
sequence	The order in which resources should be scheduled or acquired to meet the demand growth.
series compensation	The installation of a series capacitor station in a transmission line to reduce the line's impedance (opposition to electrical flow), permitting higher power transfer.
shunt capacitor	A device that produces reactive power to support the system voltage.
smart-charging technology	Technology that facilitates shifting of residential electric vehicle charging to off-peak times to take advantage of lower time-of-use rates.
South Coast (SC)	The South Coast encompasses the Lower Mainland and Vancouver Island regions of B.C.
Standing Offer Program	A program developed to streamline the process for developers of small and clean energy projects to sell electricity to BC Hydro. The Program applied to proposals for generating projects rated less than 15 MW. The Program has been indefinitely suspended.

static VAR compensator (SVC)	A set of electrical devices that can quickly and reliably control line voltages by providing fast-acting reactive power.
Structured Decision Making	Structured Decision Making is an organized approach to identifying and evaluating creative options and making choices in complex decision situations.
substation	An electrical switching station for terminating transmission lines. It can also be a station at which the system voltage is transformed from a high level to a level suitable for sub-transmission or distribution systems.
supply-side resources	Refers to BC Hydro generation and transmission resources or electricity purchased from independent power producers.
system optimizer (SO)	A computer model used for portfolio modelling in integrated resource planning. For the 2021 IRP, SO was used to select available resources to fill the gap between the forecast load and the available supply in the lowest cost way that meets the planning objectives.
thermal upgrades	A transmission line thermal upgrade involves increasing the current-carrying capability of a transmission line by replacing the conductor with a conductor of a larger size or increasing the ground clearance to allow the line to operate at a higher temperature.
time-of-Use (TOU)	An example of a time-varying rate which generally includes two or more predetermined daily price periods to encourage customers to shift their use of electricity from the system peak period to off-peak periods.
trade-off Analysis	A trade-off analysis is used to inform decisions and to be transparent about the reasons for those decisions by showing explicitly what is gained and what is given up in terms of impacts on decision-objectives when choosing one option over another.
transmission system	Electrical facilities used to transmit electricity over long distances, usually at voltages greater than 69 kV.
unit cost of capacity (UCC)	Present value of the total annual cost of a capacity resource divided by the resource's dependable capacity. It is measured in dollars per kilowatt per year.
unit energy cost (UEC)	Present value of the total annual cost of an energy resource divided by the present value of its annual average energy benefit. It is calculated using either a discounted cash flow method or annualized cost method and is measured in dollars per MWh.

United Nations Declaration on the Rights of Indigenous Peoples (UNDRIP)	A resolution passed by the United Nations in 2007 defining the rights of Indigenous peoples. In 2020, Canada committed to implement UNDRIP into Canadian law.
Utilities Commission Act (UCA)	Provincial legislation setting out the mandate and powers of the British Columbia Utilities Commission, which regulates BC Hydro and other utilities in the province.
volt (V)	The basic unit of measurement of electromotive force, the force required to change the random motion of electrons into an electric current. Refer also to voltage.
voltage	The strength of electromotive force
watt (W)	The basic unit of measurement of electric power, indicating the rate at which electric energy is generated or consumed (1 watt = 1 joule per second).
wholesale electricity trade	The buying and selling for resale of large amounts of electricity at the trading hubs in interconnected electric systems.

BC Hydro Optional Residential Time-of-Use Rate Application

Appendix D

Optional Residential Time-of-Use Rate Customer and Stakeholder Engagement

BC Hydro Optional Residential Time-of-Use Rate Application

Appendix D-1

Rate Design Workshop Slides - May 2021

Webex Session Details

Two Different Ways to Join:

Technical Issues?

Send email to:

bchydroregulatorygroup@bchydro.com

Choice 1: Use your computer's audio and view our speakers

1. Click Join the virtual session link: (embedded here or from your invitation)

   Join the virtual session

2. Select Use Computer Audio:

   Audio: **Use computer audio**

3. Select Start Meeting:

   Start Meeting

4. Please mute and turn off video (**red icons = off**):

   Start video | Unmute

Choice 2: Use cell phone or LAN line to hear audio only

Call in number: 604-449-3026 (can adjust for long-distance)

- Meeting number (access code): 146 629 2460
- Meeting password: 8MqtKKSgE26

4. Please mute audio (**red icons = off**):

   Unmute

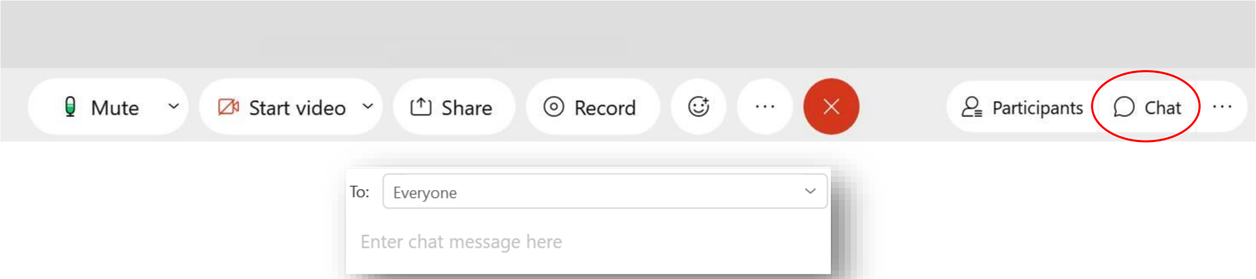
BC Hydro
Power smart

HOW TO PARTICIPATE

Please use the Chat Function to ask Questions and provide feedback

With the large number of registrants, we will not be able to take comments or questions through audio. Please click the **chat box icon shown** below and direct your question or comment to **“Everyone”** to ensure one of the moderators captures it. If you wish to send a question specifically to BC Hydro or one of the presenters that option is available as well. Confidential questions can be forwarded to the email below.

We will endeavor to answer questions in the session as time permits, additional or follow-up questions can be also be sent to bchydroregulatorygroup@bchydro.com. Thank you.

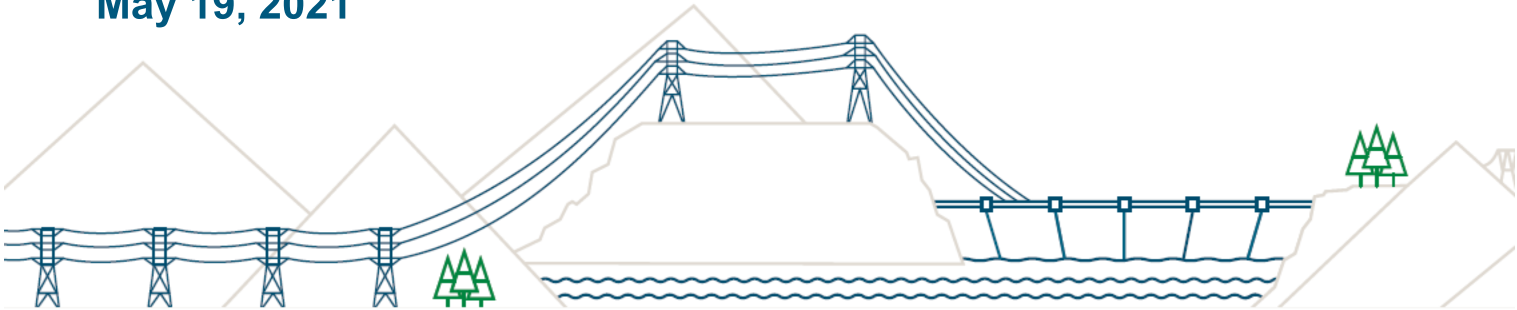


This session will not be recorded and we ask that all recording tools be turned off.

BC Hydro
Power smart

Residential Rate Design Engagement Session

May 19, 2021



BC Hydro
Power smart

Workshop Agenda

Approximate Time	Item	Presenter
1:00 – 1:10pm	Virtual Workshop Procedures	Host
1:10 – 1:20pm	Opening Remarks	Keith Anderson Vice President, Customer Service
1:20 – 1:40pm	Background and Context	Anthea Jubb Senior Regulatory Manager, Tariffs
1:40 – 2:00pm	Jurisdiction Review	Anthea Jubb Senior Regulatory Manager, Tariffs
2:00 – 2:30pm	BC Hydro Residential Customers	Shiau-Ching Chou Rates and Program Manager
2:30 – 2:55 pm	Rate Design Concepts and Pricing	Rob Zeni Senior Regulatory Specialist
2:55 – 3:00 pm	Next Steps and Closing Remarks	Chris Sandve Chief Regulatory Officer

Welcome

Keith Anderson

Vice President, Customer Service

BC Hydro
Power smart

Today's Objectives

- Provide information on the rate concepts we're exploring around residential rate design
- Collect feedback to help shape our future residential rate designs and inform our application to the BC Utilities Commission

BC Hydro’s Mandate

- BC Hydro is a Crown corporation. Our mission is to safely provide our customers with reliable, affordable and clean electricity throughout the province
- BC Hydro supports electrification, including CleanBC goals
- BC Hydro provides its customers with affordable, fair and stable rates
- We strive for economic efficiency in our rate designs to reduce the total overall cost of electricity and maximize the overall benefits of the electricity system

BC Hydro
Power smart

What is Rate Design?

Rate design refers to pricing, charges, terms and conditions of service

Revenue Requirements → **Cost of Service Analysis** → **Rate Design**

Revenue Requirements: How much revenue does BC Hydro need to operate and serve its customers?

Cost of Service Analysis: What are BC Hydro's costs of energy (cents per kWh), cost of demand (dollars per kW) and fixed cost per account (dollars per account) ?

Rate Design: What pricing, charges, terms and conditions should be used to recover costs?

Why are we reviewing rate designs now?

- Changes in customer energy needs and expectations
- Changes in climate policy
- Changes in BC Hydro’s costs, such as a reduction in the cost of new energy supply, and the potential need to invest in transmission and distribution infrastructure.

Engagement Plan for Rate Design

Invite you into the process

Phase I (April-May)
Concepts

- *Online survey*
- *Stakeholder session (May 19)*
- *Telephone townhalls*
- *Additional engagement*

Keep you engaged

Phase II (Aug-Sept)
Options

- *Explore rate options*
- *Measure support*
- *Additional engagement*

Demonstrate we listened

Phase III (Nov-Dec)
Proposal

- *Finalize rate proposals*
- *Additional engagement*

BC Hydro
Power smart

Background and context

Anthea Jubb

Senior Regulatory Manager, Tariffs

BC Hydro
Power smart

Regulatory Context

- Under the Utilities Commission Act, the BC Utilities Commission sets rates
- The current Residential Inclining Block Rate (i.e. residential conservation rate) design is approved by the BC Utilities Commission as part of Order No. G-62-20 until March 31, 2022
- As directed by the BC Utilities Commission, BC Hydro filed a report on March 26, 2021 with our progress and plans on residential rate design
- In that report, BC Hydro committed to filing a residential rate design application by February 2022, that will be informed by customer and stakeholder input

Residential Rate Design History

- BC Hydro has changed our residential rate design only three times:
  - a declining block energy charge from 1958 to 1994, then
  - a flat energy charge from 1995 to 2008, then
  - an inclining block energy charge from 2008 to present.

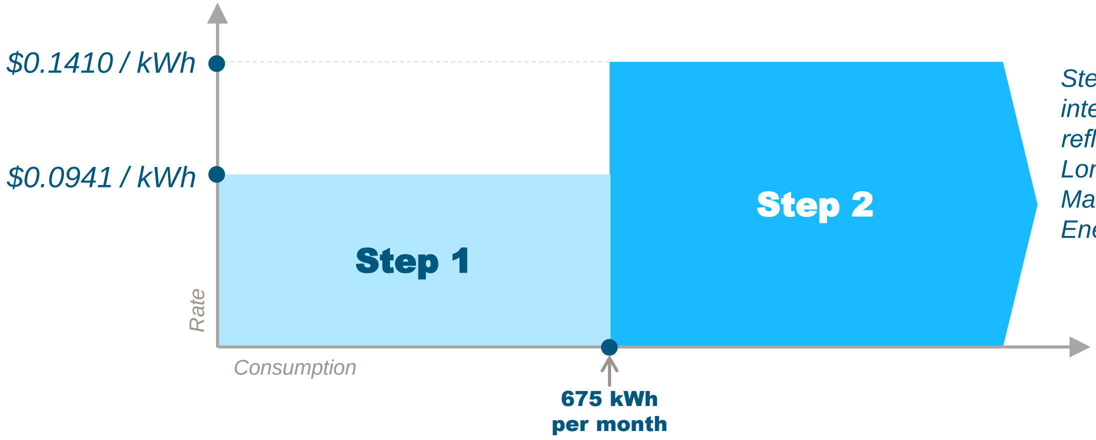
Residential Inclining Block (RIB) Rate Background

- RS1101 Residential Inclining Block Rate, (RIB rate) accounts for 40% of BC Hydro's domestic revenue, 94% of residential sector revenue
- The 2002 Energy Plan provided policy direction for BC Hydro to introduce default rate designs with the overriding objective to promote energy conservation
- At that time, BC Hydro was facing an energy supply deficit, and new sources of energy were expensive
- The RIB Rate was implemented in 2008 to achieve energy conservation, by increasing bills for higher usage customers and decreasing bills for lower usage customers

BC Hydro Power smart

Residential Inclining Block Rate Design

Residential Inclining Block Rate Schedule 1101 = Basic Charge *($0.2080 / day)*
+ Step 1 Energy Charge
+ Step 2 Energy Charge



Step 2 rate was intended to reflect BC Hydro's Long Run Marginal Cost of Energy

BC Hydro Power smart

Residential Inclining Block Rate Performance

- The Residential Inclining Block Rate Design met its objective of achieving energy conservation
- 2013 evaluation verified energy savings from the RIB Rate of up to 200 GWh/year in F2010, equivalent to 1% savings across the Residential Class
- A 2017 evaluation verified that by 2016 the RIB rate was no longer achieving new energy conservation

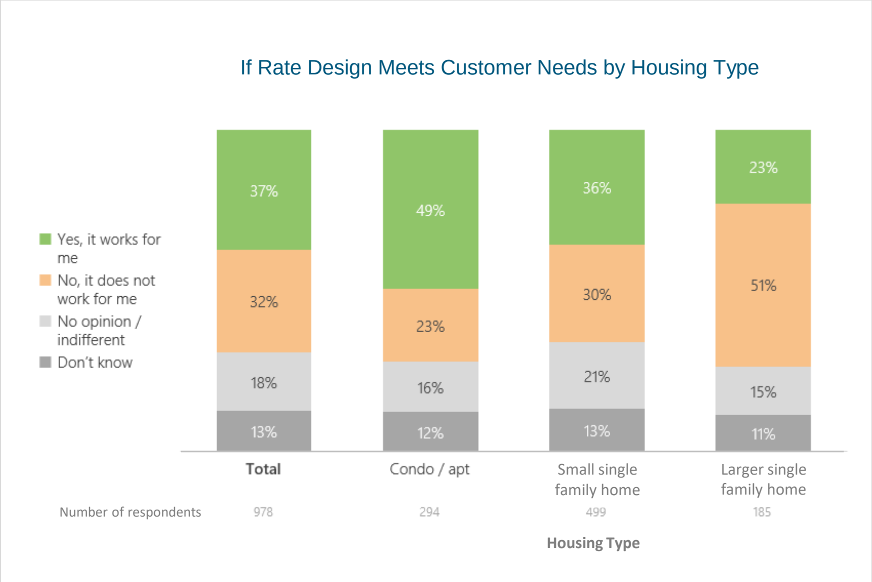
Sources: Appendix C-3B of BC Hydro's 2015 Rate Design Application
Appendix AA of BC Hydro's F2021-F2022 Revenue Requirements Application

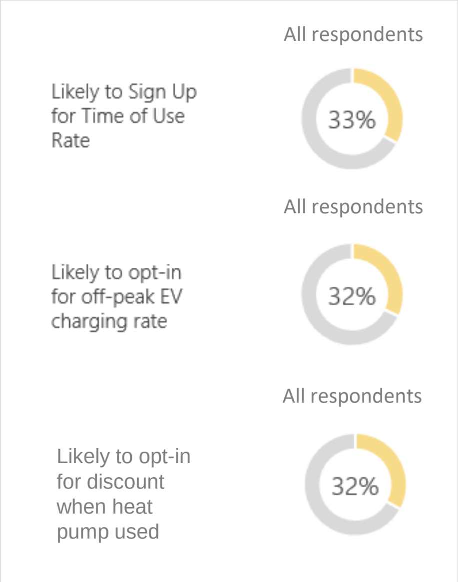
BC Hydro
Power smart

Customer and Stakeholder Feedback

- 2019 Union of BC Municipalities Resolution B73 to change the two-tier pricing due to its impact on home heating costs
- Letters from customers encouraging rate redesign to support electric vehicle charging and reduce the cost of electric home heating

December 2020 Customer Survey





18

This email-to-online survey was sent to a random sample of 8,427 residential customers who previously provided consent to be contacted

BC Hydro
Power smart

Rate Design Costs and Economics

- In addition to customer feedback, cost of service and economics are a foundational input to electric utility rate design
- Rate design applications to the BCUC must be justified on a cost of service and/or economic basis
- Aligning rate design with cost of service and economics is important to BC Hydro because it provides a framework to:
  - Ensure rates are fair to all customers
  - Provide economic benefits to ratepayers
  - Support financial sustainability and recovery of the revenue requirement

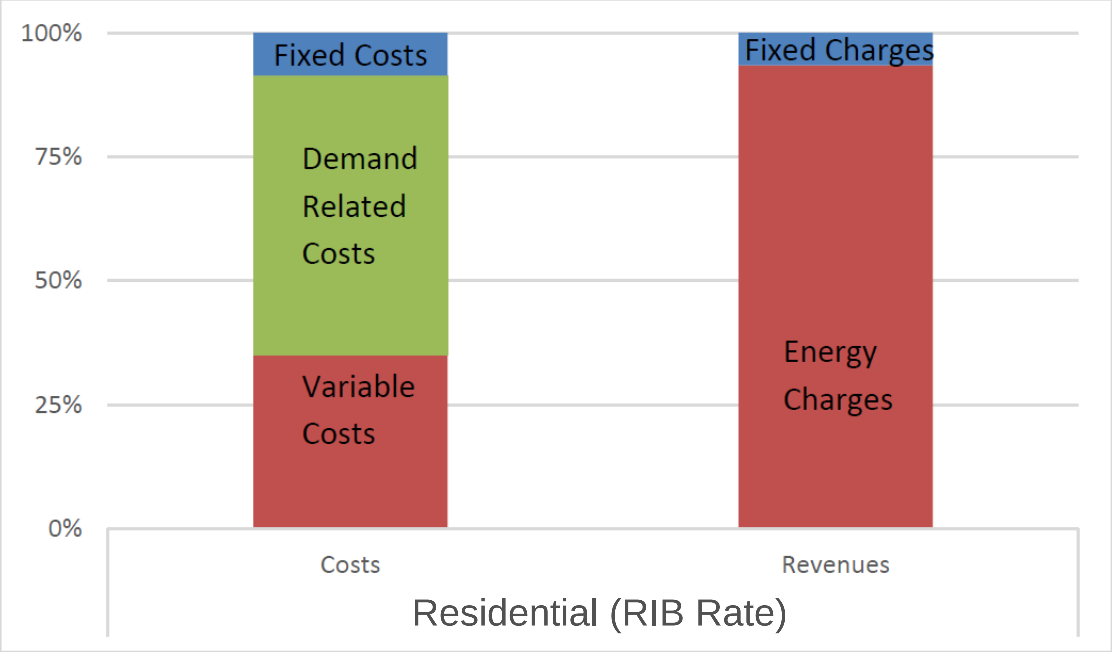
Fully Allocated Cost of Service Study and Rate design

Helps us understand our costs for each customer class

- These studies estimate how much of our total costs are associated with energy, demand and customer care
- In rate design, the concept of fairness relates to how well pricing reflect the utility cost of service
- Fully allocated cost of service studies help us assess fairness

BC Hydro
Power smart

BC Hydro's Costs of Service



F20 cost of energy:
3.9 c/kWh

F20 cost of demand:
219 $/kW-yr

21

BC Hydro
Power smart

BC Hydro's Economic Environment

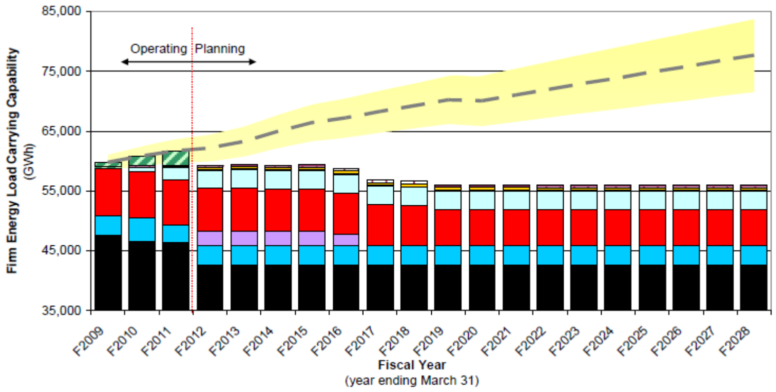
Helps us assess economic efficiency

- Marginal costs provide an estimate of the cost (or savings) of one additional unit of output (energy or capacity)
- Rate design principles of economic efficiency call for the customers marginal price to reflect the utility's marginal costs
- Economically efficient rate design should reduce the overall cost of electricity and maximize the overall benefits of the electricity system

BC Hydro
Power smart

Energy Load Resource Balance in 2008

When the RIB rate was introduced, BC Hydro was in an energy deficit



- Bars represent existing and committed energy supply resources
- Dashed lines represent the load forecast
- Yellow area represents load forecast uncertainty band

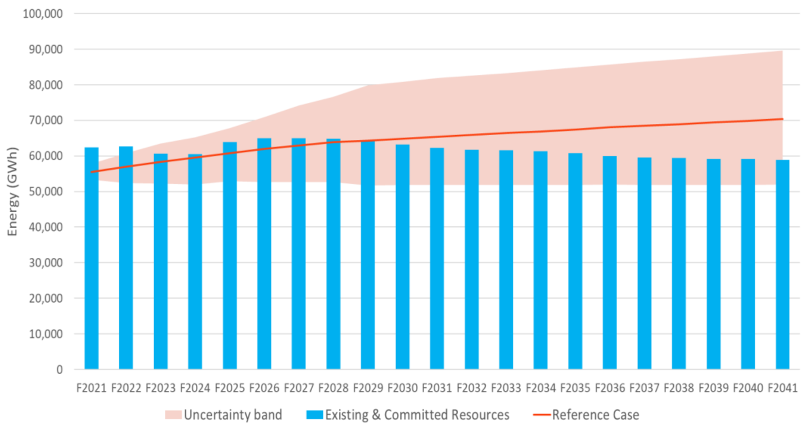
23

Source: BC Hydro's 2008 Long Term Acquisition Plan

BC Hydro
Power smart

BC Hydro's Current Load Resource Balance Energy

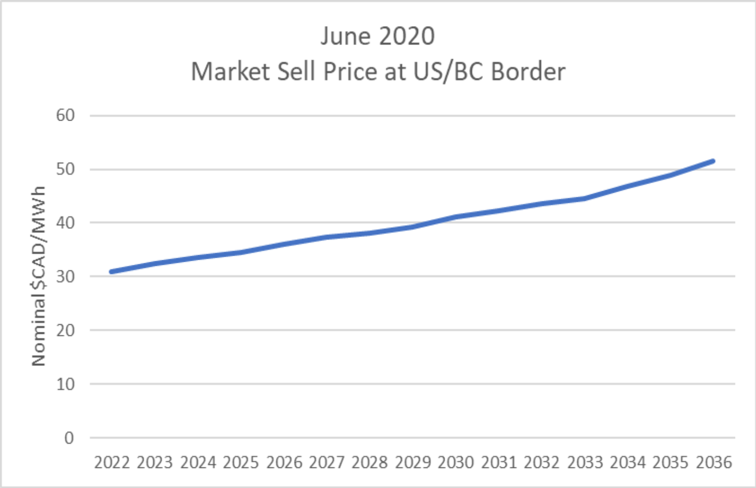
We now expect to be in an energy surplus to about 2030



BC Hydro
Power smart

BC Hydro's Marginal Cost of Energy

Our reference price for energy is 3 to 5 c/kWh



BC Hydro’s Rate Design Objectives

1. Affordability

- Measured by bill impacts associated with a rate design

2. Economic Efficiency

- Measured by how closely the energy charge reflects our marginal cost

3. Decarbonization

- Measured by how much the rate design encourages fuel switching from fossil fuels to clean electricity

4. Flexibility

- Measured by ability to respond to changes in the economic and policy environment and anticipate the need for greater product and service differentiation in rate design.

Feedback form question #1: What measures should we consider in assessing rate designs against our objectives?

BC Hydro
Power smart

Jurisdictional review

Anthea Jubb

Senior Regulatory Manager, Tariffs

BC Hydro
Power smart

Rate Designs and Benefits

Design	Benefits
Flat energy charge plus fixed basic charge • Same energy charge applies for all usage	• Bill, revenue and rate stability • Flexibility to introduce additional voluntary rates
Declining Block Energy Charge • Lower energy charge applies for usage above a threshold	• Economic efficiency during energy surplus • Encourage additional use
Inclining Block Energy Charge • Higher energy charge applies for usage above a threshold	• Economic efficiency during energy deficit • Encourage energy conservation
Time varying energy charges • Energy charge varies over the day	• Economic efficiency during capacity deficit • Shift usage out of peak demand times
Demand charge • Demand charge applies for highest power draw in the month	• Fair allocation of costs • Improves utility fixed cost recovery

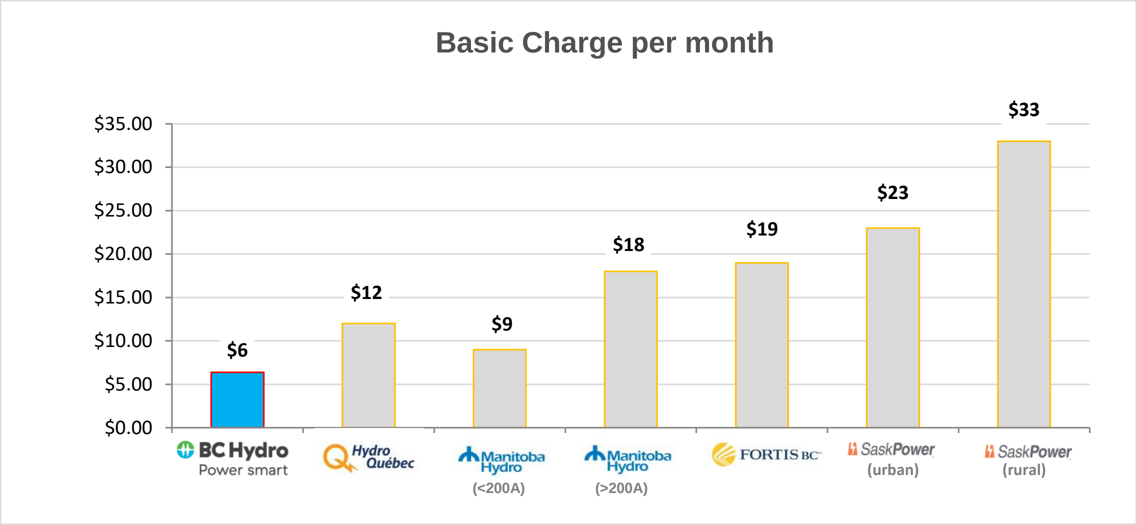
Comparable Canadian Utility Residential Rate Designs

Utility	Default Rate Structure	Energy Charge	Fixed Charge
BC Hydro	Residential Inclining Block Rate (RS 1101/2)	Inclining Block Step 2 threshold is 675kWh/ month	Approx. $6/month
Hydro Quebec	Residential and Farm Rate D	Inclining Block Rate Step 2 threshold is 900 kWh/month	Approx. $12/month
Manitoba Hydro	Residential Standard Rate	Flat rate	Approx. $9/month for service below 200A, and $18/month for service above 200A
Sask Power	Residential Rate	Flat rate	$23/month for urban accounts, $33/month for rural accounts
FortisBC	Residential Rate	Half-way thru 5-year transition from tiered to flat rate. Currently stepped rate with threshold of 800 kWh/month	Approx. $19/month

Information as of April 2021

BC Hydro
Power smart

Comparable Canadian Utility Basic Charge Comparison



30

Information as of April 2021

BC Hydro Power smart

Residential Rate Designs in the US Pacific Northwest

Utility	Default Rate Structure	Energy Charge	Fixed Charge
Pacific Power	Residential	Inclining Block Rate Step 2 threshold is 1000 kWh/month	$9.50/month
Portland General Electric	Basic service for residential and small business customers	Inclining Block Rate Step 2 threshold is 1000 kWh/month	$11/month
Idaho Power Company	Residential Service Standard Plan	Inclining Block Rate Step 2 threshold is 800 kWh/month Step 3 threshold is 2000 kWh/month	$5/month

Information as of April 2021

BC Hydro
Power smart

US Example of Segmentation: Arizona Power Residential Service

Plan	Basic Charge ($/month)	Energy Charge	Demand Charge	Availability
Time of Use choice	13	Seasonal and Daily Time of Use Peak pricing up to 24 c/kWh	N/A	• Higher usage accounts, e.g. larger single family homes (> 999 kWh/month) • Accounts with customer side solar generation
Time of Use Plus	13	Seasonal and Daily Time of Use Peak pricing up to 13 c/kWh	8 $kW	
Time of Use Max	13	Seasonal and Daily Time of Use Peak Pricing up to 9 c/KWh	17 $/kW	
Premier Choice	15	Flat energy Charge of 12.4 c/kWh	N/A	601-999 kWh/month, e.g. smaller single family homes
Lite Choice	10	Flat energy Charge of 11.7 c/kWh	N/A	< 600 kWh per month, e.g. apartments

Information as of April 2021

BC Hydro
Power smart

US Example of Providing Rate Options: Georgia Power Residential Service

Plan	Description	Availability
Flat Bill Rate Schedule Flat-5	Fixed monthly bill = [Expected Monthly kWh * (Energy Charges) * (1+ Risk Adder %)] + Basic Service Charge Risk adder <=10 % No true up at end of years Fixed bill reset annually	Individually metered account with more than 12 months of history and a monthly flat bill > 25 $/month
Plug in EV	Time of use pricing with super off peak price of 1 c/kWh, off peak price of 7 ck/kWh and on-peak price of 20 c/kWh Basic charge of $12/month	Any residential service customer
Pre pay	No deposit, credit check or reconnection fees Basic charge of $18/month Seasonal energy charge: 7.7 c/kWh summer, 5.4 c/kWh winter	Any residential service customer
Residential Service	Winter season: three step declining block energy charge Summer season: three step inclining block energy charge Basic charge of $12/month	Any residential service customer

Information as of April 2021

BC Hydro
Power smart

US Example of End Use Rate: Southern California Edison

Plan	Description	Availability
Time of Use Rate D-Prime	Seasonal and Daily time of use energy charge with lowest price after 9 pm Fixed monthly charge of $12 Offers the lowest energy charges of any of this utility's four residential rate plans Intended to encourage decarbonization through electrification	Exclusively for high usage accounts with one or more: • plug in electric vehicle, • electric heat pump for space conditioning and water heating, • residential battery Requires verification of ownership or lease of the above

Information as of April 2021

BC Hydro
Power smart

Examples of Time Varying Rates

Jurisdiction	Type of Rate	Deployment
Arizona, US (Arizona Public Service)	Time-of-day	Opt-in
Arizona, US (Arizona Public Service)	Three-part rate	Opt-in
California, US (PG&E, SCE, SDG&E)	Time-of-day	Default (2020)
Colorado, US (Fort Collins)	Time-of-day	Mandatory
Illinois, US (ComEd, Ameren Power Illinois)	Real-time pricing	Opt-in
Michigan, US (Consumers Energy)	Time-of-day	Default (2021)

Information as of fall 2020

BC Hydro
Power smart

Examples of Time Varying Rates - Continued

Jurisdiction	Type of Rate	Deployment
Michigan, US (Consumers Energy)	Time-of-day	Default (2021)
Oklahoma, US (OGE)	Variable peak pricing	Opt-in
Ontario, Canada	Time-of-day	Default
Québec, Canada (Hydro-Québec)	Peak-time rebate & Critical peak pricing	Opt-in
France	Time-of-day	Opt-in
Italy	Time-of-day	Default

Information as of fall 2020

BC Hydro
Power smart

Residential Customers

Shiau-Ching Chou
Rates & Program Manager

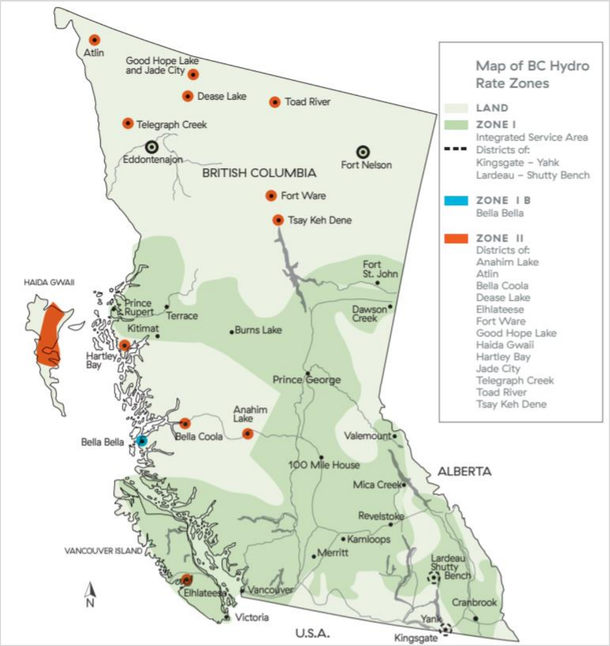
BC Hydro
Power smart

Demographic Analysis

We’ve taken a customer centric view

- **Use our customer data to inform our rate design process**
- **This information is helpful to:**
  - Understand the unique needs of our customers
  - Measure our customer and business objectives
  - Understand how rate options impact customer segments differently

BC Hydro Territory



Rate Zone	# of Customers
Zone I	~1.9M
Zone IB	~500
Zone II	~5,000

BC Hydro Power smart

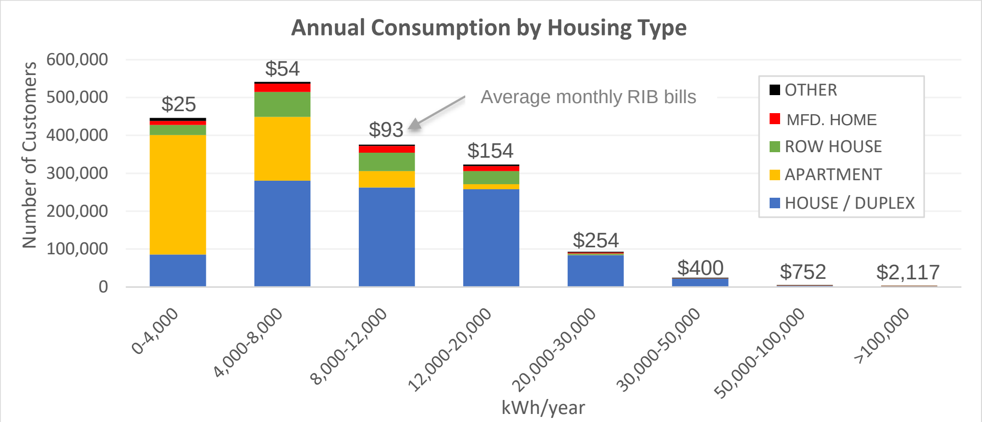
Residential Rates

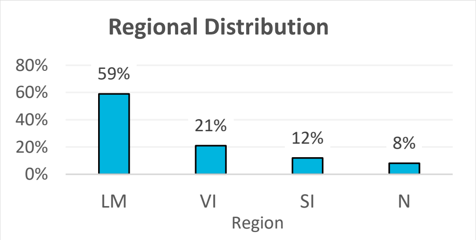
Rate Schedule	Description	Number of Customers	% of Customers	Revenue
1101	**Zone I:** Residential Service	1,856,165	98.56%	$2,132M
1121	**Zone I:** Multiple Residential Service	1,251	0.07%	$10M
1105	**Zone I:** Residential Service – Dual Fuel (closed)	5,646	0.30%	$5M
1151	**Zone I:** Exempt Residential Service	14,581	0.77%	$55M
1161	**Zone I:** Multiple Exempt Residential Service	14	0.00%	$119K
1151	**Zone IB**: Residential Service	472	0.03%	$850K
1107	**Zone II:** Residential Service	5,072	0.27%	$7M
1127	**Zone II:** Multiple Residential Service	4	0.00%	$15K

BC Hydro
Power smart

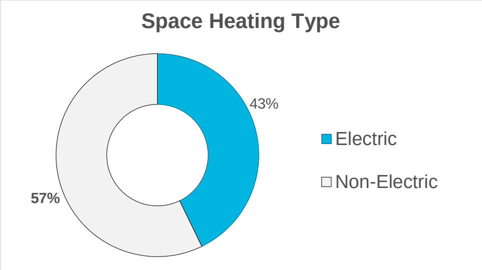
Residential Inclining Block rate customer characteristics

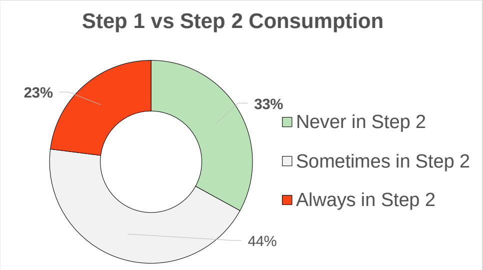
Customer Data	
Number of customers	~1.9M
Avg monthly consumption	836kWh
Avg monthly bill	$99
Total consumption	18,891GWh
Total revenue	$2.25B





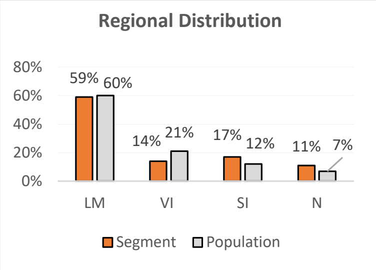
LM: Lower Mainland **VI:** Vancouver Island **SI:** South Interior **N:** North

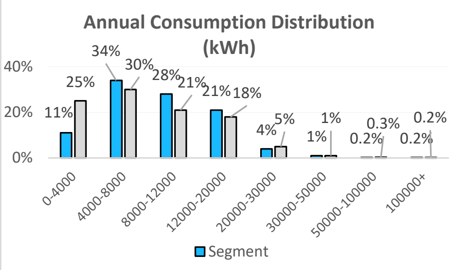


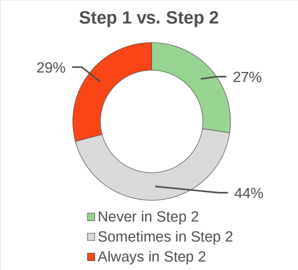


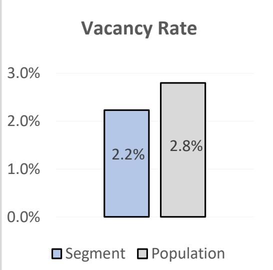
Power smart

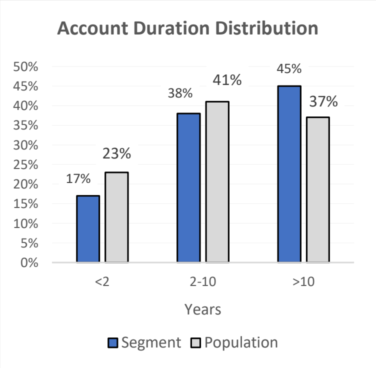
Non-Electrically Heated House/Duplex Customers

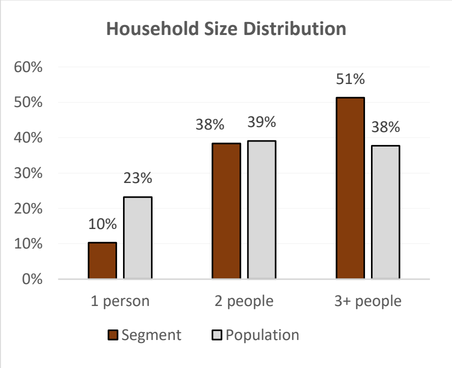


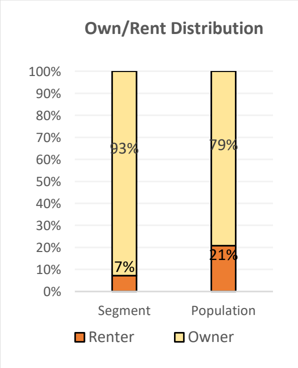












Segment Size

~720k customers
40% of population

Monthly kWh

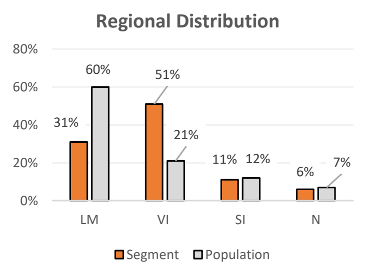
Median: 716
(442 – 1,123)

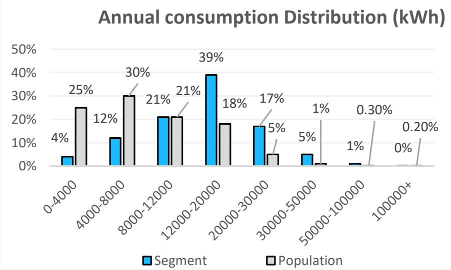
Monthly Bill

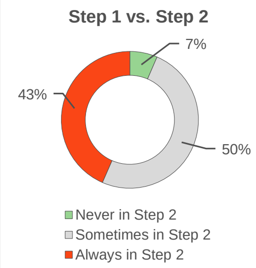
Median: $78
($48 - $134)

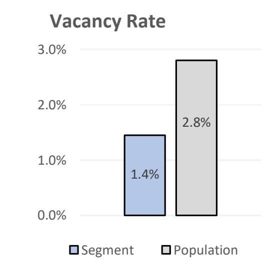
BC Hydro
Power smart

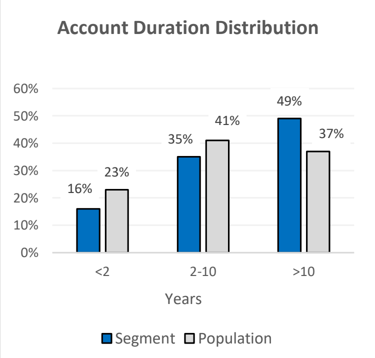
Electrically Heated House/Duplex Customers

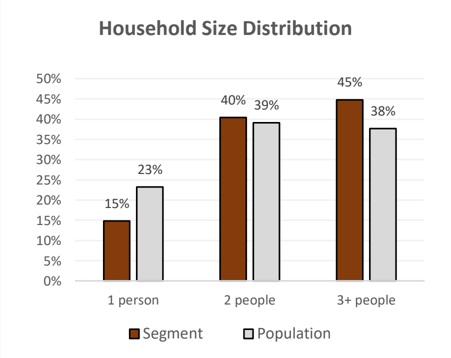


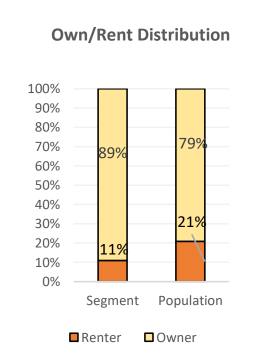












Segment Size

~280k customers
16% of population

Monthly kWh

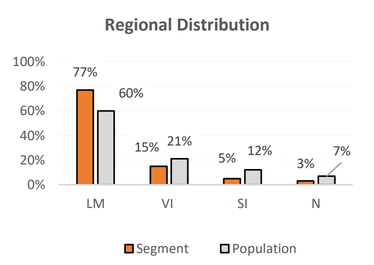
Median: 1,204
(751 - 1,806)

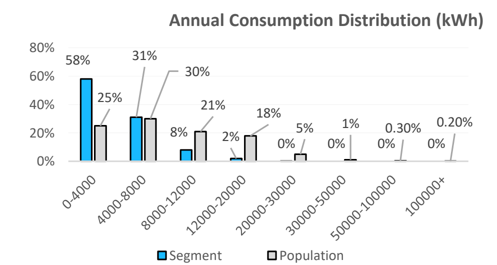
Monthly Bill

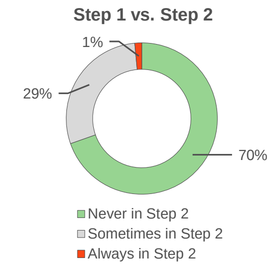
Median: $146
($85 - $231)

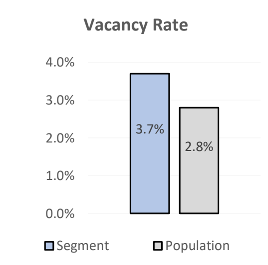
BC Hydro
Power smart

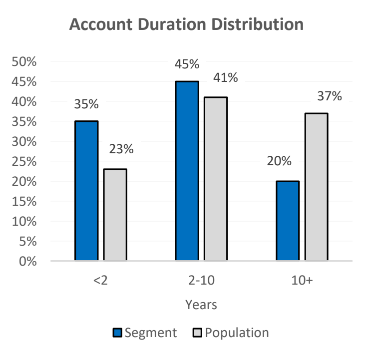
Apartment Customers

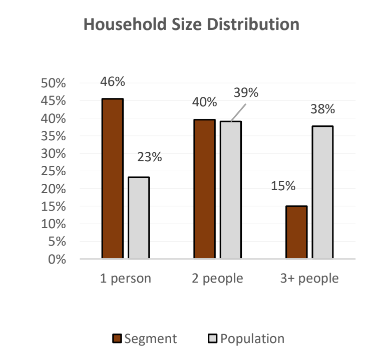


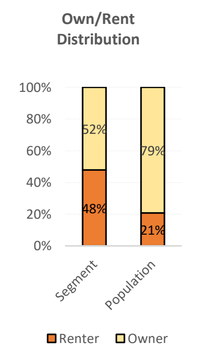


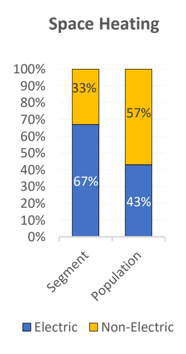












Segment Size

~541k customers
30% of population

Monthly kWh

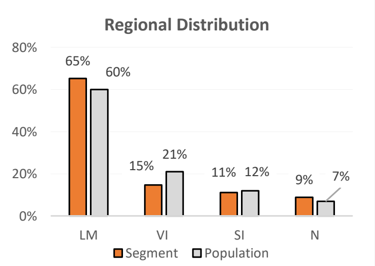
Median: 290
(157 – 555)

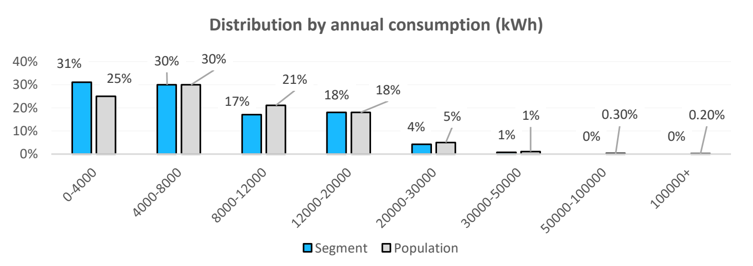
Monthly Bill

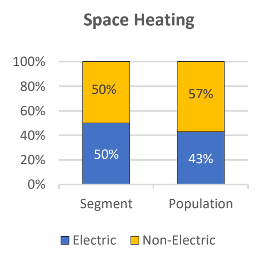
Median: $34
($21 - $57)

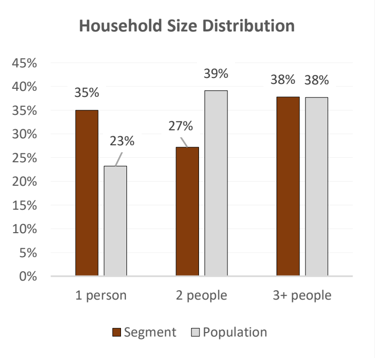
BC Hydro Power smart

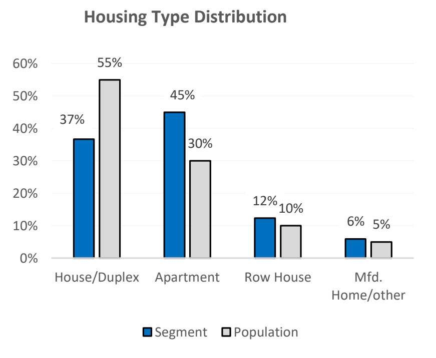
Low Income Customers

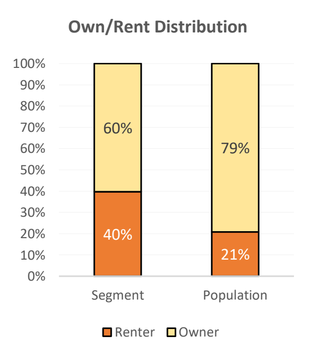












Segment Size

~173k customers
10% of population

Monthly kWh

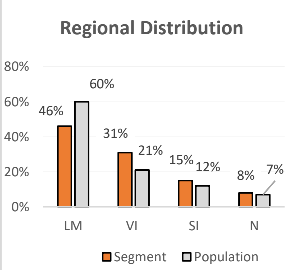
Median: 538
(238 – 1,032)

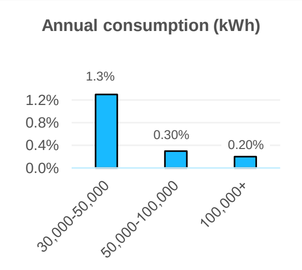
Monthly Bill

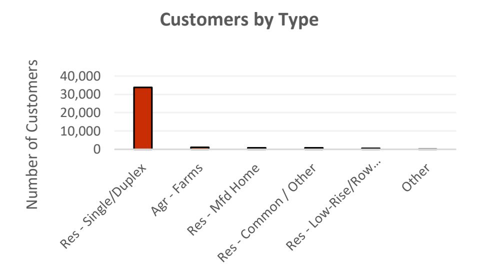
Median: $55
($28 - $126)

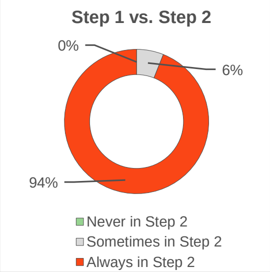
BC Hydro
Power smart

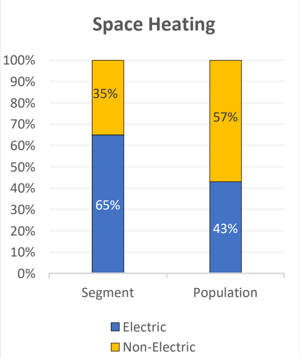
High Consuming Customers (>=30,000kWh/year)

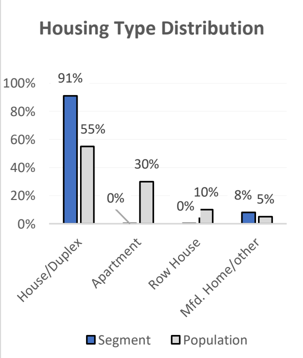


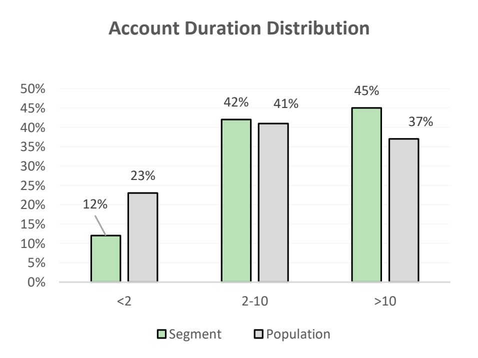












Segment Size

~32k customers
1.8% of population

Monthly kWh

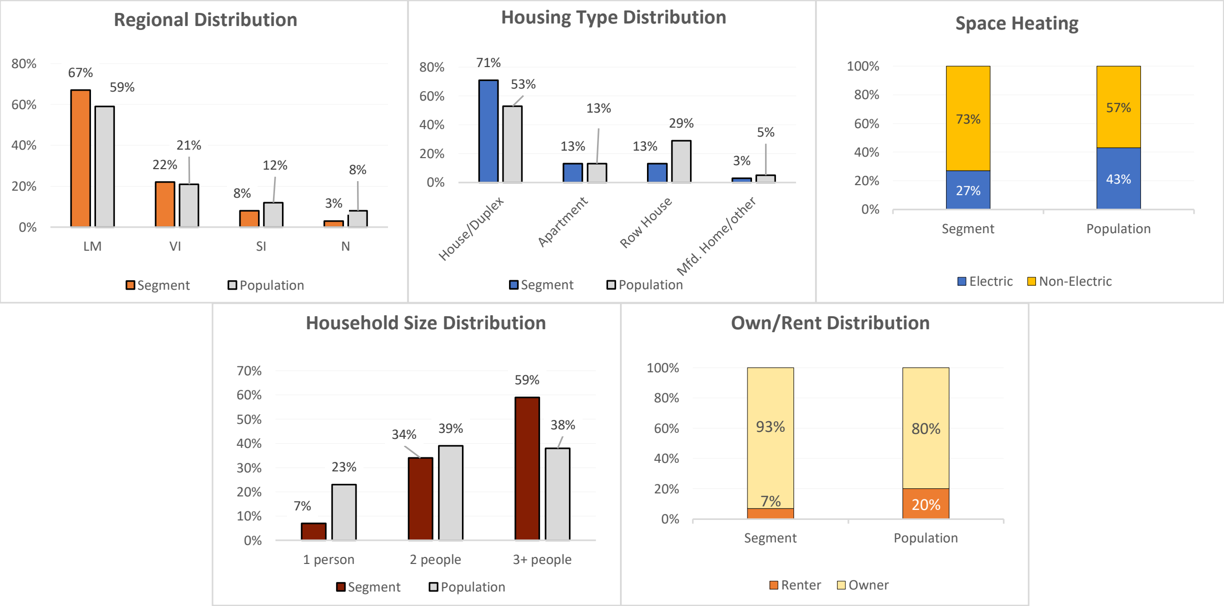
Median: 3,071
(2,648 – 4,550)

Monthly Bill

Median: $410
($350 - $619)

BC Hydro
Power smart

Electric Vehicle Household Customers



Feedback form question #2: What other groups or segments should we look at and why?

BC Hydro
Power smart

Rate design concepts

Rob Zeni

Senior Regulatory Specialist

Rate Design Concepts

We could redesign the default residential rate and introduce voluntary rates

Illustrative default rate design concepts:

- Maintain the inclining block rate
- Eliminate the inclining block rate
- Segment the residential rate class

Illustrative voluntary rate design concepts:

- Introduce voluntary whole home time varying rate
- Introduce voluntary end-use rates, such as electric vehicle charging and heat-pump rates

BC Hydro
Power smart

Preliminary Default Rate Design Concepts

We're seeking feedback on the following default rate design concepts

Default Rate Concepts	Description
Maintain the inclining block rate	Rate concepts may include: • Status quo • Increase of Step1 / Step 2 threshold • Reduced energy charges and increase the basic charge
Eliminate the inclining block rate	Rate concepts may include: • Flat rate and maintain basic charge • Flat rate with increased basic charge • Declining block rate
Residential rates by segment	Rate concepts may include: • Different flat rates based on annual consumption

Forecast Revenue Neutrality is maintained in all pricing scenarios.
This refers to calculating the energy rates and basic charges so that the target revenue from the residential rate class is achieved, resulting in no impact to other rate classes.

BC Hydro
Power smart

Concepts that Maintain the Inclining Block Rate Structure

Illustrative pricing

Default Rate Concepts	Threshold (kWh per month)	Step 1 Rate (¢ / kwh)	Step 2 Rate (¢ / kwh)	Step 3 Surcharge Rate (¢ / kwh)	Basic Charge (¢ / day)
Status quo	675	9.41	14.10	N/A	20.80
Increase of Step1 / Step 2 threshold	900	10	14.5	N/A	20.80
Reduced energy charges and increased the basic charge	675	8.5	11.5	N/A	63

BC Hydro
Power smart

Maintaining the Inclining Block Rate: Considerations

- Depending on the design, a continuation of the inclining block rate design may:
  - Continue to encourage energy conservation
  - Minimize bill impacts of rate redesign
  - Discourage electrification

Feedback form question #3: Do you support BC Hydro advancing rate design concepts that maintain the inclining block rate for further development? Are there additional options related to the inclining block rate you would like to see analyzed?

BC Hydro
Power smart

Concepts that Eliminate the Inclining Block Rate Structure

Illustrative pricing

Default Rate Concepts	Threshold (kWh per month)	Step 1 Rate (¢ / kwh)	Step 2 Rate (¢ / kwh)	Basic Charge (¢ / day)
Status Quo	675	9.41	14.10	20.80

Default Rate Concepts	Threshold (kWh per month)	Step 1 Rate (¢ / kwh)	Step 2 Rate (¢ / kwh)	Step 3 Rate (¢ / kwh)	Basic Charge (¢ / day)
Declining Block Rate	675 / 2500	12	10	9	20.80

Default Rate Concepts	Flat Rate (¢ / kwh)	Basic Charge (¢ / day)
Flat rate and no change to basic charge	11.5	20.80
Flat rate and triple basic charge	10	63

BC Hydro
Power smart

Eliminate the Inclining Block Rate: Considerations

- Depending on the design, eliminating the inclining block design may:
  - Improve bill and revenue stability by reducing high winter heating bills
  - Improve affordability of electric heat
  - Support decarbonization by removing a disincentive to electrify
  - Improve economic efficiency by moving the energy charge closer to marginal costs
  - Increase bills for some customers

Feedback form question #4: Are you interested in BC Hydro further developing rate design concepts that eliminate the inclining block rate? Are there additional options for eliminating the inclining block rate you would like to see analyzed?

BC Hydro
Power smart

Concepts that Segment the Residential Class

Illustrative Pricing

Default Rate Concepts	Threshold (kWh per month)	Step 1 Rate (¢ / kwh)	Step 2 Rate (¢ / kwh)	Basic Charge (¢ / day)
Status Quo	675	9.41	14.10	20.80

Default Rate Concepts	Flat Rate (¢ / kwh)	Basic Charge (¢ / day)
Flat rate for Customers < 8,000 kWh per year	9.5	20.80
Flat rate for Customers 8,000 to 20,000 kWh per year	11.5	20.80
Flat rate for Customers > 20,000 kWh per year	12.5	20.80

BC Hydro
Power smart

Segment the rate class: Considerations

- Depending on the design, segmenting the rate class may:
  - Improve flexibility by allowing for greater service differentiation across the rate class bill
  - Improve affordability for lower usage accounts
  - Be considered unfair to customers in segments that that have a higher rate

Feedback form question #5: Are you interested in BC Hydro further developing rate design concepts that segment the rate class? Are there additional options for segmenting the rate class you would like to see analyzed?

BC Hydro Power smart

Preliminary Voluntary Rate Design Concepts

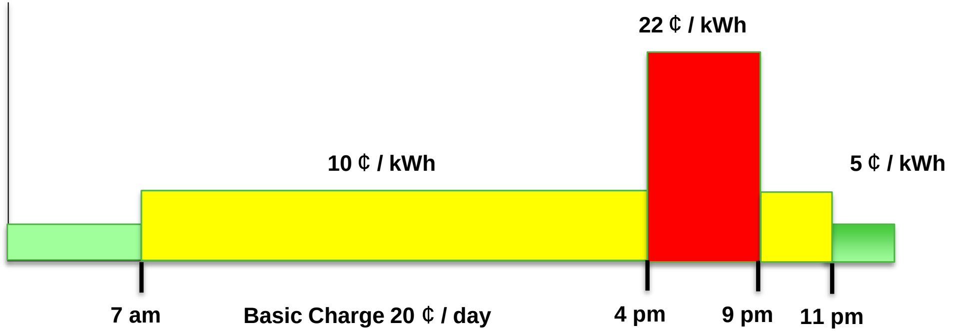
We're seeking feedback on the following voluntary rate design concepts

Voluntary Rate Concepts	Description
Whole-home time varying rates	Rate concepts may include: • Seasonal time varying rates • Weekday / weekend time varying rates • Traditional (peak, off-peak, super off-peak) time varying rates or simple day / night rates • Critical peak period pricing
End-use rates, such as electric vehicle charging and heat-pump rates	Rate concepts may include: • Seasonal time varying rates • Weekday / weekend time varying rates • Traditional (peak, off-peak, super off-peak) time varying rates or simple day / night rates • Discounted rate based on end use

BC Hydro
Power smart

Voluntary Whole Home Time Varying Rate

Traditional time varying rate with peak, off-peak and super off-peak illustrative pricing



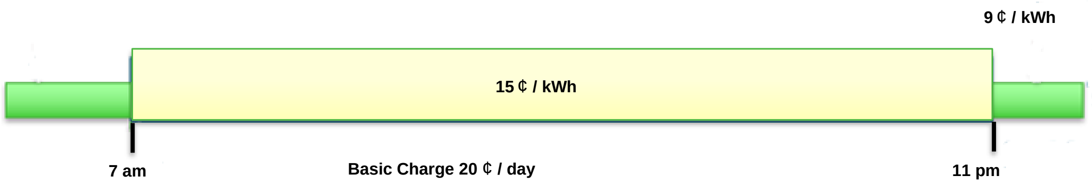
Voluntary time varying rates: Considerations

- Depending on the design, voluntary time varying rates may:
  - Improve flexibility by allowing for greater service differentiation across the rate class
  - Improve affordability by reducing bills for customers who can shift when they use electricity
  - Improve economic efficiency by sending a price signal to shift demand from peak periods to minimize required transmission and distribution investments
  - Reduce utility revenue, which can be offset by utility savings on transmission and distribution

Feedback form question #6: Are you interested in BC Hydro further developing rate design concepts for time varying rates? Are there additional options for time varying rates you would like to see analyzed?

Voluntary End Use Time Varying Rate

Example of day / night-time pricing for end uses such as electric vehicle charging



60

BC Hydro
Power smart

Voluntary end use rates: considerations

- Depending on the design, voluntary end use rates may:
  - Improve economic efficiency by sending a price signal to reduce peak demand and minimize required transmission and distribution investments
  - Support decarbonization by encouraging electric vehicle adoption and heat pump adoption
  - Be perceived as unfair by customers who cannot participate as they do not have the end use technology

Feedback form question #7: Are you interested in BC Hydro further developing end use rates? Are there additional options for end use rates you would like to see analyzed?

Other considerations

Feedback form question #8: Are there any other rate design concepts we didn't mention today that you would like us to explore?

Feedback form question #9: Are there any rate concepts that you feel may require program support (marketing and outreach, educational materials, financial incentives, technology incentives) in order to be effective?

Closing remarks

Chris Sandve

Chief Regulatory Officer

BC Hydro
Power smart

Engagement Plan for Rate Design

Demonstrate we listened

Phase III
(Nov-Dec)
Proposal

- Finalize rate proposals
- Additional engagement

Keep you engaged

Phase II
(Aug-Sept)
Options

- Explore rate options
- Measure support
- Additional engagement

Invite you into the process

Phase I
(April-May)
Concepts

- Online survey
- Stakeholder session (May 19)
- Telephone townhalls
- Additional engagement

We'd love to hear more from you.

- Complete the online Feedback Form this week
- Join us for additional engagement

BC Hydro
Power smart

Closing Remarks:
Key Contacts and Process

- BC Hydro values your participation and feedback on our rate designs
- Please contact BC Hydro Regulatory Group with any questions about the regulatory or engagement process: bchydroregulatory@bchydro.com
- Remember to submit your feedback by June 02, 2021
- The link to the online feedback form is: https://bchydro.ca1.qualtrics.com/jfe/form/SV_8kqmM9K9t03OeLc

BC Hydro
Power smart

BC Hydro
Power smart

BC Hydro
Power smart

BC Hydro Optional Residential Time-of-Use Rate Application

Appendix D-2

Rate Design Workshop Feedback Summary
May 2021

Residential Rates Stakeholder Workshop #1

Feedback Summary Report – May 19 2021

A. SESSION OBJECTIVES

The objectives of the workshop were to:

- Provide information about the rate concepts being explored around residential rate design;
- Collect feedback to help shape future residential rate designs; and
- Inform a Rate Design application to the BC Utilities Commission.

B. METHODOLOGY

Feedback was collected using an online feedback form available to participants. A link was provided within a chat box to participants, highlighted in the presentation material, and posted online at bchydro.com with a request to complete by June 2, 2021.

C. PARTICIPATION

Twenty-three (28%) of the 83 non-BC Hydro participants completed the feedback form.

D. KEY THEMES

A review of the quantitative and qualitative responses indicate that stakeholders are interested in the following topics that include, but are not limited to:

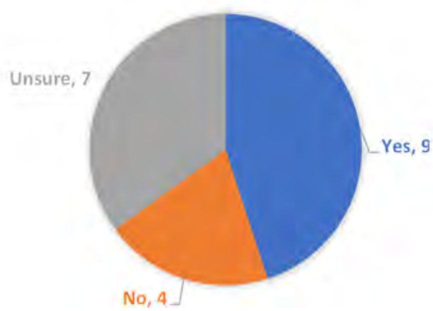
- Affordability for low income
- Challenges for rural locations
- Electric vehicles
- Environment, particularly de-carbonization
- Experience with, or knowledge of, other jurisdictions
- Exports
- Fuel switching barriers and opportunities
- Simplified billing/communications
- Solar, incentives, and net metering
- Tenants and limitations on capital expenditures to support change
- Unique circumstances of Indigenous Nations

E. FEEDBACK FORM RESULTS

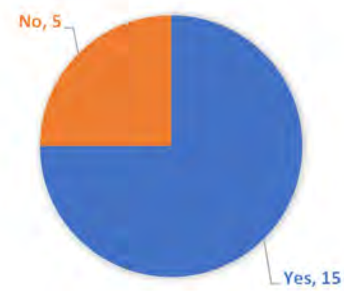
The feedback form was comprised of several open and closed ended questions that participants had the option to respond to with the following results and verbatims.

Participants were asked if they support BC Hydro advancing the further development of certain rate design concepts along with session satisfaction and themes from verbatim comments. It is important to note that the sample size in all cases is too small for the results to be statistically significant.

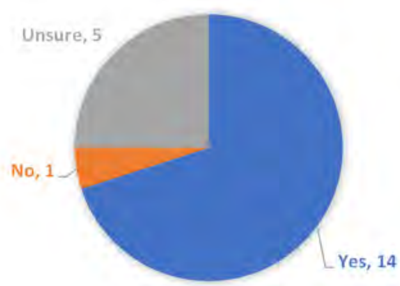
Maintain Inclining Block



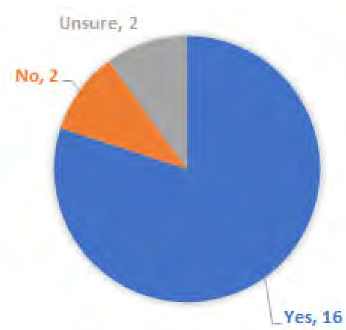
Eliminate Inclining Block



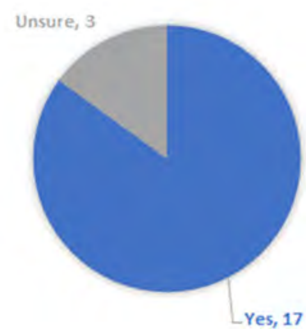
Segment the Class



Time Varying Rates



End Use Rates



Q1: The following verbatim comments represent a selection of viewpoints that were provided when respondents were asked to think back to the discussion about BC Hydro's rate design objectives and then identify measures that should be considered in assessing rate designs against our objectives:

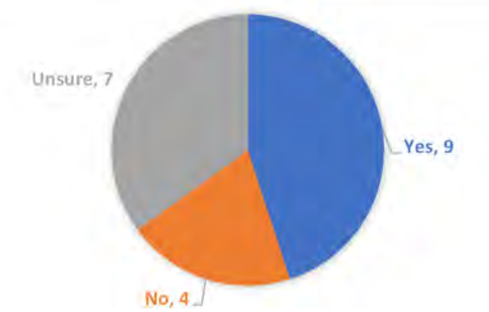
1. The decarbonization measure should be directly related to the ability to meet our provincial and sectoral climate targets and provide government with the information it needs to report on progress in its annual climate accountability report.
2. The City of Vancouver supports the above objectives. We view objectives #2 and #4 as being secondary considerations relative to objectives #1 and #3; decarbonization is imperative for meeting Vancouver's and BC's climate targets. Regarding affordability, the emphasis should be on lower income households where affordability challenges are most significant.

3. # 3 Decarbonization should be the top priority
4. Utilities must encourage/incentivize deep energy retrofits, especially on the building envelope and air-tightness improvements, to downsize the new mechanical equipment (heat pumps). This could help reduce the impact of electrification on the grid, which could help building users' electricity consumption. The next is to help to decarbonize by discounted rates for customers pursuing electrification. Finally, introduce time-of-use rates to help with DSM + DR. In addition, net-metering should be included. (crediting based on the kWh fed to the grid, not buying kWh)
5. Affordability and Decarbonization should be prioritized as this directly impacts the customers. Since Decarbonization is one of the National priorities and it is clear by now that electrification is clearly the solution in BC, costing based on decarbonization and encouraging consumers to use electricity over gas would be ideal.

Q2: During the session we provided detailed analysis about six specific household types within the residential customer segments. A select group of participants suggested that the following other groups or segments should be considered:

1. If possible, look at renters who pay energy bills and also those in energy poverty (see CUSP's energy poverty tool at https://energypoverty.ca/). We'd also be interested in a comparison of single family homes who use heat pumps vs. electric baseboard vs. fossil fuel heating. Any insight into homes that use wood would also be interesting.
2. Self-generating households such as those with solar net metering.
3. BC Hydro should include information on urban versus rural customers and on-reserve versus off-reserve customers to help better understand energy usage differences between those types of customers. Information on non-integrated area customer usage compared to integrated area customers would also be helpful. BC Hydro should work with Indigenous Nations to do an analysis of electricity usage by Indigenous customers. BC Hydro should provide information on the proportion of customers with electric heat who do not have access to natural gas.
4. Within the high-consuming customer category, we want to confirm that the analysis will take into account differences in household size – as a large multi-generational family with many occupants would be different from a wealthy couple or single homeowner in the same consumption category. We also recommend exploring income as a cross-cutting factor for all of the above categories.
5. Rural customers vs urban customers
6. Customers who meet the definition of energy poverty (those spending more than twice the national median on energy) need to be considered as well. Energy poverty is not always experienced by low-income customers exclusively. For example, many BC Hydro customers living in older, less efficient single family homes, in rural areas without natural gas access, have very high bills. These customers are often middle income, yet they meet the definition of experiencing energy poverty. Such customers often cannot afford the switch to a heat pump, even with incentives, and so continue to rely on baseboard.

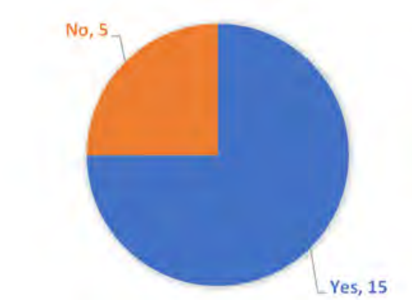
Q3: Nine (45%) of the 20 respondents support BC Hydro advancing the development of rate design concepts that maintain the inclining block rate as compared to four (20%) that do not, while seven (35%) are unsure. Below is a selection of feedback from respondents that would like to see BC Hydro analyze the following additional options related to maintaining the inclining block rate:



Sample size is too small to be significantly significant.

1. Increasing the daily basic charge should be considered as a separate issue from the inclining versus flat energy charge. There may be merit in increasing the daily basic charge regardless of which energy rate option is chosen and that question should be considered separately, in addition to modelling the energy rate bill impacts with and without changes to the basic charge.
2. We do not support maintaining the inclining block rate as it can have the effect of discouraging electrification. Increasing the Step 1/Step 2 threshold may also negatively impact large multi-generational families who fall into the 'high consuming customer' category.
3. demand based rates time of day

Q4: 15 (75%) of the twenty respondents support BC Hydro advancing the development of rate design concepts that eliminate the inclining block rate as compared to 5 (25%) that do not, while none (0%) are unsure. Below is a selection of feedback from respondents that would like to see BC Hydro analyze the following additional options related to eliminating the inclining block rate:

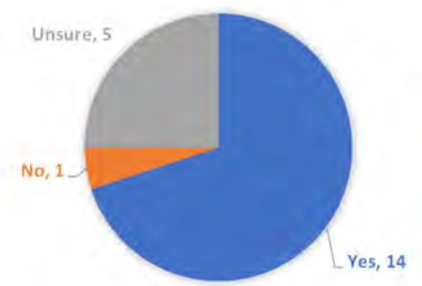


Sample size is too small to be significantly significant.

1. Both flat rate and declining block rates should be analyzed for ways that they could effectively incentivize decarbonization. Eliminating or modifying the inclining block rate will be necessary to support decarbonization by removing the current cost disincentive to electrify, but at this time we think that more analysis is required before determining which rate structure to implement or modify. The analysis of different options should be forward-looking and consider changing climate and electricity use patterns such as the increased use of air-conditioning in summer.
2. BC Hydro should continue to consider options to eliminate the tiered rate given its current energy surplus and the impact of the current rate on electric heat customers. BC Hydro should work with Indigenous nations to maximize access to federal green energy programs.

3. Yes, the inclining block rate has the potential to penalize those who fuel-switch, purchase an EV, or are low income and cannot afford energy efficiency upgrades.
4. While we support rate designs that enable decarbonization and improve the overall affordability of electricity, it is important that the design accompanies provisions to ensure that an increase in billing does not negatively impact low-income households. The rate design need not directly address this, but needs to consider what supports can mitigate its impact (such as an increased BC low income tax credit, etc.).
5. if its replaced by TOU

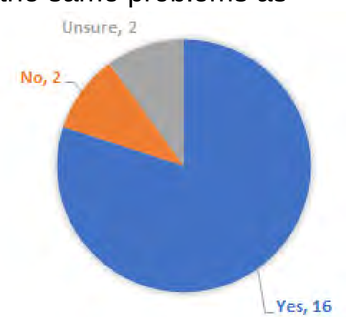
Q5: Fourteen (70%) of the twenty respondents support BC Hydro advancing the development of rate design concepts that segment the rate class as compared to one (5%) that does not, while five (25%) are unsure. Below is a selection of comments from respondents that would like to see BC Hydro analyze the following additional options related to segmenting the rate class:



Sample size is too small to be significantly significant.

1. Greater granularity on existing segmentation to better understand use and loads: temporal – hourly, daily, weekly(?) and seasonal; Locational – climate and heating loads; as previously described.
2. It is not clear how segmenting the class into higher and lower users would contribute to BC Hydro's rate objectives. It may also prove difficult to implement if customers install their own generation that offsets a portion of their load.
3. No. The segmented options presented in the slides seem to have the same problems as inclining block, i.e. they discourage decarbonization.

Q6: Sixteen (80%) of the twenty respondents support BC Hydro advancing the development of rate design concepts for time varying rates as compared to two (10%) that do not, while two (10%) are unsure. Below is a selection of comments from respondents that would like to see BC Hydro analyze the following additional options related to time varying rates:



Sample size is too small to be significantly significant.

1. Time-varying rates should be analyzed on both an opt-in and opt-out basis. Analyzing them on a voluntary basis only may limit understanding of the potential scale of their impact on BC Hydro's rate design objectives.
2. Time varying rate designs as a voluntary option are worth exploring. In addition to time of day differences it would be worth considering whether there should be seasonal components to the time periods as well. There should be a campaign designed to ensure that First Nations are aware of these varying rates and opportunities for rate savings at different times of the day. Each First Nation community should have a full-time energy specialist.

3. Consider implementing time of day rate tiers to support lowering demand peaks and making better use of existing electrical infrastructure as electrification expands load. Also potentially an equity measure to support reduced rates for home heating using low cost thermal storage heating units.
4. Time of use rates could further support electrification and minimize peak loads. We support seasonal, weekday/weekend, peak/off-peak and critical peak time varying options.
5. It is unclear given current evidence that TOU rates would provide a significant impact on demand, and run the risk of increasing costs for lower-income customers that have less ability to change their consumption timing patterns.

Q7: Seventeen (85%) of the twenty respondents support BC Hydro advancing the development of rate design concepts for end use rates as compared to none (0%) that do not, while three (15%) are unsure. Below is a selection of comments from respondents that would like to see BC Hydro analyze the following additional options related to end use rates:

Sample size is too small to be significantly significant.

1. There may be more benefits to pursuing time varying rates than complicating the rate design by adding end-use rates. The voluntary time varying rates could also provide incentive for customers with electric vehicles to charge their vehicles over night rather than during the day.
2. We support discounted end use rates for EV charging and heat pumps.
3. especially, end-uses that otherwise would use fossil fuels
4. End use rates are the most efficient way to incentivize decarbonization, and promote the uptake of technologies like electric heat pumps and electric vehicles. Would like to see a willingness to explore this as a serious option.

Q8: Other rate design concepts that a selection of respondents would like BC Hydro to explore include:

1. Consider enhancing net metering rates to support wider deployment of solar both as renewable energy source and a grid resiliency measure, i.e. local power generation available during brown outs/black outs.
2. We would like BC Hydro to consider demand charge structures that don't disproportionately impact DC fast charging stations. Additionally, rates based on estimated energy loads will support curbside electrification opportunities, such as public e-bike share stations and connections to food trucks etc. Concerning service connection timelines and costs, customers in certain residential building categories face significant costs and delays to electrify. We would like to see BC Hydro address these varied costs and timelines across building categories.
3. Real-time rate structure enticing demand response

Q9: The following rate concepts were felt to require program support (marketing and outreach, educational materials, financial incentives, technology incentives) in order to be effective:

1. Any change to rates will require some level of marketing to educate and empower the public. It will be especially important to build a sense of "why" for rate payers based around the opportunity to mitigate climate change through B.C.'s renewable electricity system, while maintaining efficient use of electricity. Rates which increase the options available to customers – e.g. time-varying rates, end use rates – would need additional outreach so that customers can optimize their rate for their electricity usage and the rates achieve the intended electricity usage changes. To achieve the GHG reduction levels needed to meet our provincial climate targets, particular publicity and financial/technology incentives may be required for rate options that encourage electrification, as has been proven successful with incentives for electric vehicle uptake.
2. Voluntary time of use programs would likely require information for individuals and communities to understand the advantages. For example, providing information about what their bill in a month would have been if they were on the voluntary program. Energy specialists funded by BC Hydro and coordinated with FNEMC could help build community capacity for this role and improve understanding and uptake of voluntary rate options.
3. Any changes would require additional program support that is accessible to multiple demographics. It is also a great opportunity to promote existing incentives for retrofits, energy saving tips, etc. Upfront engagement with low income groups before any decisions are made is also critical to ensure that all of the barriers and potential unintended consequences are considered.
4. Per above, all rate designs require supports and/or financial provisions to protect low-income households as they transition to electrification. All rate designs would benefit from communication to residents on how changes will help achieve Provincial decarbonization objectives. Additionally, segmenting the residential class in particular would require marketing and education to address fairness concerns.
5. Financial and technical support for smart panels and other smart devices would allow users to more directly control their consumption from either a time of use or end use perspective

Q10: Eighteen (75%) of twenty-four respondents were fully satisfied (7) or somewhat satisfied (11) with the engagement session overall while two (8%) of respondents were somewhat dissatisfied (2) or strongly dissatisfied (0) leaving four (16%) neutral about how they felt.

Q11: A selection of other verbatim comments shared include:

1. In rural areas where there is no natural gas often it's also hard to get fuel oil or propane. When the temperature gets cold (-15c) or colder the heavy use of electricity is unavoidable. Therefore the two tier rate should be eliminated from november to march.
2. It's great to see that BC Hydro is considering new rate structures. As a townhome owner with electric heat and hot water who wants to purchase an electric vehicle soon, I feel penalized by the current structure even through I am trying to live a low-carbon lifestyle.

Appendix A: Rates Stakeholder Session Feedback Form

Intro Thank you for joining our residential rate engagement session on May 19. We'd like to get your feedback about what you heard as we continue to explore concepts for what our residential rates could look like in the future. This feedback form should take about 5-10 minutes to complete, and your responses will be anonymous.

The answers provided are collected and protected in accordance with Section 26(c) of the Freedom of Information and Protection of Privacy Act. All responses are submitted in confidence and treated accordingly. If you have any questions please contact bchydroregulatorygroup@bchydro.com.

BC Hydro's Rate Design Objectives

1. Affordability

- Measured by bill impacts associated with a rate design

2. Economic Efficiency

- Measured by how closely the energy charge reflects our marginal cost

3. Decarbonization

- Measured by how much the rate design encourages fuel switching from fossil fuels to clean electricity

4. Flexibility

- Measured by ability to respond to changes in the economic and policy environment and anticipate the need for greater product and service differentiation in rate design.

Q1 Thinking back to the discussion about BC Hydro's rate design objectives, what measures should we consider in assessing rate designs against our objectives?

Q2 During the session we provided detailed analysis about specific household types within the residential customer segment including:

- Non-electrically heated houses/duplexes
- Electrically heated houses/duplexes
- Apartments
- Low-income customers
- High consuming customers
- Electric Vehicle households

What other groups or segments should we look at?

Q3A Do you support BC Hydro advancing rate design concepts that maintain the inclining block rate for further development?

O Yes

O No

O Unsure

Q3B Are there additional options related to the inclining block rate that you would like to see analyzed?

Q4A Do you support BC Hydro advancing rate design concepts that eliminate the inclining block rate for further development?

O Yes

O No

O Unsure

Q4B Are there additional options for eliminating the inclining block rate that you would like to see analyzed?

Do you support BC Hydro advancing rate design concepts that segment the rate class for **Q5A** further development?

O Yes

O No

O Unsure

Q5B Are there additional options for segmenting the rate class you would like to see analyzed?

Q6A Do you support BC Hydro advancing rate design concepts for time varying rates for further development?

O Yes

O No

O Unsure

Q6B Are there additional options for time varying rates you would like to see analyzed?

Q7A Do you support BC Hydro advancing end use rates for further development?

O Yes

O No

O Unsure

Q7B Are there additional options for end use rates you would like to see analyzed?

Q8 Thinking back to the session, were there any rate design concepts that weren't mentioned that you would like us to explore?

Q9 Are there any particular rate concepts that you feel may require program support (marketing and outreach, educational materials, financial incentives, technology incentives) in order to be effective? If so, why?

Q10 Now, we'd like to shift from getting your feedback about the content of the engagement session to the session itself. Please tell us how satisfied you are with the residential rates engagement session overall.

- O Fully satisfied
- O Somewhat satisfied
- O Neutral
- O Somewhat dissatisfied
- O Strongly dissatisfied

Strongly Disagree / Somewhat Disagree conditional questions

Display This Question:

If Now, we'd like to shift from getting your feedback about the content of the engagement session to... = Somewhat dissatisfied

Or Now, we'd like to shift from getting your feedback about the content of the engagement session to... = Strongly dissatisfied

Q11 Please elaborate and tell us why you are not satisfied with the session.

Q12 To end, please share any other comments.

Q13 Thank you for your feedback.

Appendix B: Feedback provided via Email from Roger Bryenton

Subject: Participation in BC Hydro Rate Redesign Process

Body of Email:

Dear Ms. Jubb and Mr. Zeni,

I have reviewed much of the publicly available information regarding rate design and BC Hydro's Rate Redesign process. I have put together what I hope to be an informative and useful document examining present use, disaggregation and segmentation for BC (as presented), factors relevant to rate structure, and proposed two major improvements to be assessed:

1. A "Proportional" rate structure, revenue neutral as described in the attached document, and

2. An "Optimized" rate structure, which would include the the proportional structure above, including many segmentation factors and "Adders" or "Subtractors" to facilitate program integration within rate structures, using smart meters, and incorporating Artificial Intelligence and Machine Learning. This would automatically optimize a customer's use and rates for a minimum bill.

I would be pleased to have your feedback on the proposed evolution of rates, and how rates can be effectively used to facilitate our dramatic transformation to a much lower carbon society over the next 20 to 30 years.

I would also be pleased to be considered as a resource consultant to the rate design process and group, should you wish to consider this option.

Again thank you for the opportunity to participate in the process and I look forward to further communication with you.

Sincerely,
Roger Bryenton
BASc Mechanical Engineering, (former registered P.Eng. from 1998 to 2007), MBA
Energy Systems Consultant.
778 232-1326

Attachment Contents:

It is essential to develop progressive rates that incorporate various relevant factors affecting rates that can now be facilitated by the use of the smart meters, and real-time data, with real-time calculation capabilities. Such factors would be: location, electric heat, income, time value (so if we save when export prices are high and power can be exported, everyone benefits), and type of heat source – oil or gas, to enable decarbonization. In this type of rate design about 12 factors, plus 4 options - EV's, Retrofitting, Heat pumps, and Solar Panels all get considered.

The purpose is to minimize electricity bills, fairly, and are based upon smart meters and load modification or Demand Side Management (if customers desire).

Information from BC Hydro from the workshop, with comments:

1. **Slide 21** - 2/3 of the cost of supplying power is "demand" related. This includes the costs not directly related to the amount of energy sold. It is an estimate or de-facto proxy for the number of kW supplied. Without a further disaggregation of actual kW vs other related costs, it is difficult to determine how closely it relates to actual “kW demand”. Because this portion is not directly tied to rates, it does not directly encourage or discourage use. In order to better allocate costs, and hence rates, it is important to have rates related to energy and actual demand. At this time, because 400 amp service costs just a little more than 200 amp service there is little reason not to over-service new homes.

   If the “demand” component does reflect the cost of service, then increased service, 400 amp vs 200 amp requires a revised cost structure, so that 400 amp service is much closer to double the cost of 200 amp service.

2. **Slide 43** - 5% of the customers use 15% of the power, yet pay the same per kWh rate as frugal users.

3. Very modest users pay the highest rates per kWh, because of the monthly charges.

4. **Slide 15** - The Tier 2 rate (step 2) begins at 675 kWh/mo, with the cost increasing from 9.4 cents/kWh to 14.1 cents/kWh. A “**Revenue Neutral**” line can be developed by taking the average use of 836kWh/mo (Slide 41) at $99/mo = 11.84 Cents per kWh.

   New “Proportional” Rate Structure.
   Revising Slide 15 so that the cost (vertical) axis is accurately shown will enable an accurate line to be drawn from the axes interception at “0” use and “0” cost through the 836 and 11.84 point to create the **revenue neutral line**. This revenue neutral line includes all customers including the large users, beyond the average “836” use, including the “high consuming customers” above the “12,000 – 20,000 Kwh/yr” or 1333 kWh / mo. and beyond.

   This chart of a “Proportional” rate is presented below:

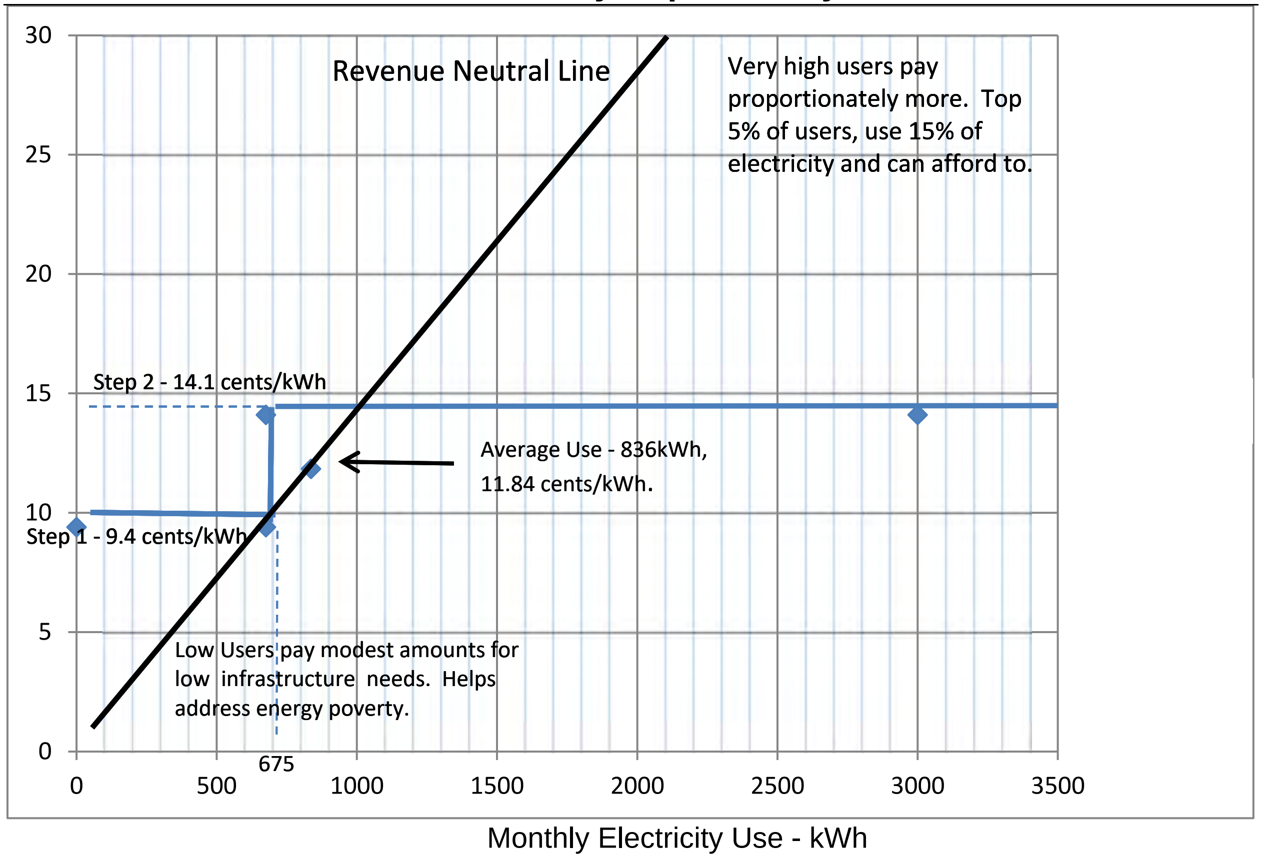


Illustration of "**Proportional Rate Structure**", where the **rate is proportional to use**. Example – at 500 kWh per month the rate would be about 7.5 cents/kWh while at 1000 kWh/mo would be about 14 cents/kWh.

5. **Segmentation** - An innovative and versatile rate calculation algorithm is proposed, which takes into account about 12 factors, and calculates the lowest rate for each customer and is revenue neutral. It segments electricity use into many categories, then determines the least cost to customers.

   Slides 41 through 47 - In order to better understand how customers use electricity, BC Hydro has segregated use by amount of use, (although the segments are not all equal in size), by Electrically Heated Homes, Non-electrically Heated Homes, by House and Apartment, by Low Income, and by Large Users.

   a. In order to better understand use, it is proposed to perform additional analysis to use finer segments, especially for lower users: increments of 2000 kWh, or possibly 1000 may be instructive.
   b. Segmentation by geographical location will allow a better understanding of electricity use, and the effect of rate changes on those customers.
   c. Segmentation by temporal factors: time of day (hourly), day of week, week of year, and seasonally will provide a better understanding of how supply and

demand matching can be optimized, for cost, value for export and peak management. It will also inform congestion avoidance or solutions.

d. Finer segmentation by income will allow evaluation of the proposed "proportional" rate.
e. Additional segmentation by size of dwelling and all electric will enable a better understanding and applicability of rates and programs to reduce electricity use. An electricity or energy intensity number, kWh/sq m may identify customers who are using particularly high amounts when compared to cohorts, and opportunities for rates and programs to provide savings.
f. Segmentation by renter vs owner will enable assessment of rates or programs to address the split-incentive whereby owners do not pay for electricity thus there is no reason to save.
g. Segmentation by location of existing congestion will enable factors to be applied to rates in those locations, facilitating postponement or avoidance of upgrades, particularly distribution. This may be very useful over the next 20 to 30 years as rapid decarbonisation is implemented, and the likelihood of congestion and shortages evolve with massive anticipated load increases.

   An example is what will happen on Vancouver Island with rapid decarbonisation, anticipated increasing electricity use and probable need for additional generation and/or transmission. Can innovative rates defer or avoid such capital expenditures, by alternative "investments" into deep retrofits of all-electric homes, and possibly heat pumps?

This proposed rate structure is termed "Optimized", due to the inclusion of various relevant factors determined from the segmentation plus additional factors described below as part of the response to Question 1. Objective 6, termed **Transformative Adaptability.**

Appendix C: Feedback provided via Email from the First Nations Energy and Mining Council

Subject: First Nations Energy and Mining Council submission on residential rate design feedback questions

Body of Email:

Attached is the completed questionnaire for the residential rate design feedback questions from FNEMC.

Thank you,

Paul

Attachment Contents:

Submission from the First Nations Energy and Mining Council

May 31, 2021

Feedback question #1

BC Hydro's rate objectives include:

1.Affordability

- Measured by bill impacts associated with a rate design

2. Economic Efficiency

- Measured by how closely the energy charge reflects our marginal cost

3. Decarbonization

- Measured by how much the rate design encourages fuel switching from fossil fuels to clean electricity

4. Flexibility

- Measured by ability to respond to changes in the economic and policy environment and anticipate the need for greater product and service differentiation in rate design.

Feedback form question #1: What measures should we consider in assessing rate designs against our objectives?

> *BC Hydro's rate design objectives should include implementing recognition and reconciliation and its obligations under the BC Declaration on the Rights of Indigenous Peoples Act as an objective. This would include an understanding of how proposed changes to rate design will affect Indigenous customers, including Indigenous customers who live in non-integrated areas.*

Feedback form question #2:

BC Hydro examined electricity usage for different types of residential customers:

- Non-electric heat
- Electric heat
- Apartment
- Low income
- High consumption customers
- Electric vehicle

Feedback form question #2: What other types of customer segments should we look at and why?

BC Hydro should include information on urban versus rural customers and on-reserve versus off-reserve customers to help better understand energy usage differences between those types of customers. Information on non-integrated area customer usage compared to integrated area customers would also be helpful.

BC Hydro should work with Indigenous Nations to do an analysis of electricity usage by Indigenous customers.

BC Hydro should provide information on the proportion of customers with electric heat who do not have access to natural gas.

Feedback question #3

Do you support BC Hydro advancing rate design concepts that maintain the inclining block rate for further development? Are there additional options related to the inclining block rate you would like to see analyzed?

Increasing the daily basic charge should be considered as a separate issue from the inclining versus flat energy charge. There may be merit in increasing the daily basic charge regardless of which energy rate option is chosen and that question should be considered separately, in addition to modelling the energy rate bill impacts with and without changes to the basic charge.

Feedback form question #4:

Are you interested in BC Hydro further developing rate design concepts that eliminate the inclining block rate? Are there additional options for eliminating the inclining block rate you would like to see analyzed?

BC Hydro should continue to consider options to eliminate the tiered rate given its current energy surplus and the impact of the current rate on electric heat customers. BC Hydro should work with Indigenous nations to maximize access to federal green energy programs.

Feedback form question #5:

Are you interested in BC Hydro further developing rate design concepts that segment the rate class? Are there additional options for segmenting the rate class you would like to see analyzed?

It is not clear how segmenting the class into higher and lower users would contribute to BC Hydro's rate objectives. It may also prove difficult to implement if customers install their own generation that offsets a portion of their load.

Feedback form question #6:

Are you interested in BC Hydro further developing rate design concepts for time varying rates? Are there additional options for time varying rates you would like to see analyzed?

Time varying rate designs as a voluntary option are worth exploring. In addition to time of day differences it would be worth considering whether there should be seasonal components to the time periods as well.

There should be a campaign designed to ensure that First Nations are aware of these varying rates and opportunities for rate savings at different times of the day. Each First Nation community should have a full-time energy specialist.

Feedback form question #7:

Are you interested in BC Hydro further developing end use rates? Are there additional options for end use rates you would like to see analyzed?

There may be more benefits to pursuing time varying rates than complicating the rate design by adding end-use rates. The voluntary time varying rates could also provide incentive for customers with electric vehicles to charge their vehicles over night rather than during the day.

Feedback form question #8:

Are there any other rate design concepts we didn't mention today that you would like us to explore?

BC Hydro should explore how advancing reconciliation and addressing the requirements of the United Nations Declaration on the Rights of Indigenous Peoples Act could be integrated into rate options. This should include considering if and how rates classes might be developed specific for Indigenous customers and communities to recognize the impacts of electricity systems on Indigenous people. Options could include exemptions from the basic customer charge or other rate discounts for Indigenous customers to acknowledge the legacy impacts of hydroelectric development on Indigenous people.

Feedback form question #9:

Are there any rate concepts that you feel may require program support (marketing and outreach, educational materials, financial incentives, technology incentives) in order to be effective?

Voluntary time of use programs would likely require information for individuals and communities to understand the advantages. For example, providing information about what their bill in a month would have been if they were on the voluntary program.

Energy specialists funded by BC Hydro and coordinated with FNEMC could help build community capacity for this role and improve understanding and uptake of voluntary rate options.

BC Hydro Optional Residential Time-of-Use Rate Application

Appendix D-3

Rate Design Workshop Slides - November 2021

Residential Rate Design Engagement Session

November 18, 2021

BC Hydro
Power smart

Logistics

A few items before we begin …

- If you’re having trouble connecting: https://stream.allwestbc.com/
- Presentation location: Other regulatory matters (bchydro.com)
- If you have questions, please use “Chat”
- If you have specific feedback and opinions, please provide them in the feedback form

Poll Feedback Form

- Other questions, feedback or technical issues? BCHydroRegulatoryGroup@bchydro.com

Agenda

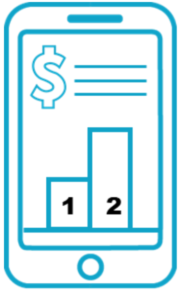
Time	Topic	Presenter
10:00 am – 10:15 am	Welcome and Overview	Keith Anderson Vice President, Customer Service
10:15 am – 10:45 am	Engagement Summary	Kari Baker, Customer Experience Manager
10:45 am – 11:30 pm	Default Residential Rate Design Options	Shiau-Ching Chou, Rates & Program Manager
11:30 am - noon	Default Rate Design Assessment, Implementation and F2023 Pricing Principles	Chris Sandve, Chief Regulatory Officer
12:00 pm – 12:30 pm	**Lunch Break**	
12:30 pm – 1:00 pm	Optional Residential Rates, our Integrated Resource Plan, and Engagement results	Anthea Jubb, Senior Regulatory Manager
1:00 pm – 1:30 pm	Optional Rates Context and Jurisdiction Review	Mike Wenzlaff, Senior Program Manager
1:30 pm – 2:20 pm	Optional Rate Designs	Rob Zeni, Senior Regulatory Specialist
2:20 pm –2:30 pm	Next Steps and Closing Remarks	Chris Sandve, Chief Regulatory Officer

An overview of rates

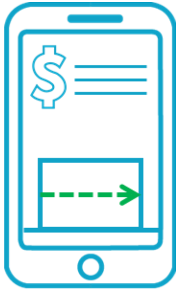
Here are the rates we'll be talking about today

1. Default rates

Option 1
Maintain Residential
Inclining Block Rate



Option 2
Transition to a
Flat Energy Charge Rate



2. Optional rates

Electric Vehicle
Peak Reduction Rate

Residential
Time of Use Rate

Welcome and Overview

Keith Anderson

Vice President, Customer Service

BC Hydro
Power smart

Today's objectives

- Provide a summary of engagement
- Provide an update on Residential Rate Design:
  - Default Residential Rate
  - Optional Residential Rates
- Collect feedback to help shape our future residential rate designs and inform future rate design applications to the BC Utilities Commission

What is rate design?

Rate design refers to pricing, charges, and terms & conditions of service

The process

Revenue Requirements	Cost of Service Analysis	Rate Design

What it means

Revenue Requirements: How much revenue we need:
- to be able to operate
- to serve our customers

Cost of Service Analysis:
- Cost of energy (cents per kWh)
- Cost of demand (dollars per kW)
- Fixed cost per account (dollars per account)

Rate Design: Identify the following in order to recover our costs:
- pricing
- charges
- terms & conditions

BC Hydro's rate design objectives

Affordability

Measured by bill impacts associated with a rate design

Economic efficiency

Measured by how closely the energy charge reflects our marginal cost

Decarbonization

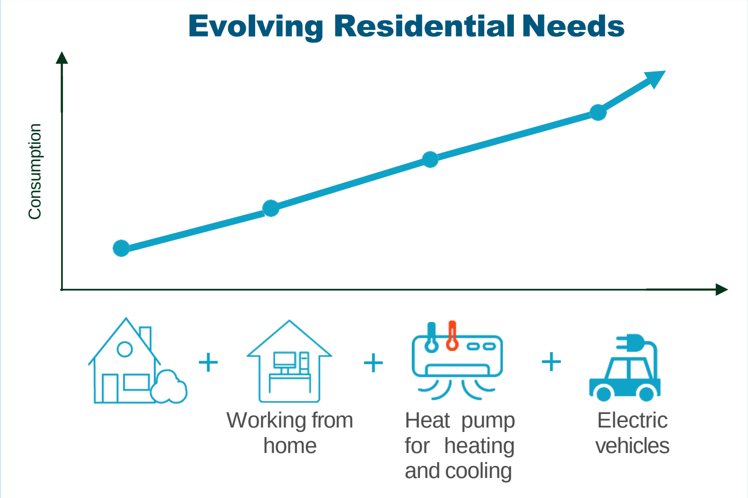
Measured by how much the rate design encourages switching from fossil fuels to clean electricity

Flexibility

Measured by the ability to respond to changes in the economic and policy environments and anticipate the need for greater product and service differentiation in rate design

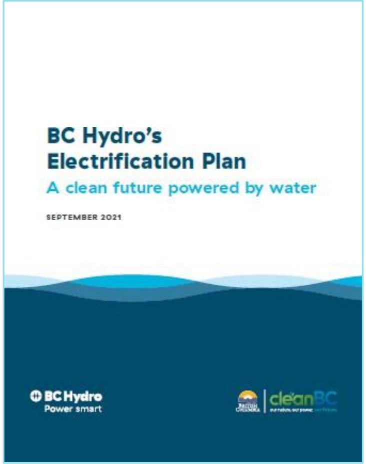
Why we are reviewing rate designs now

- Changes in customer energy needs and expectations
- Changes in climate policy
- Changes in BC Hydro's costs, such as a reduction in the cost of new energy supply, and the potential need to invest in transmission and distribution infrastructure



Electrification

- BC Hydro supports the Province's CleanBC climate plan and generates and delivers clean, renewable power to our customers.
- The Province announced BC Hydro's Electrification Plan in September 2021 to encourage and incentivize residents and businesses to switch from fossil fuels to clean electricity.
- Rate design is an important tool to encourage decarbonization.



Engagement Summary

Kari Baker

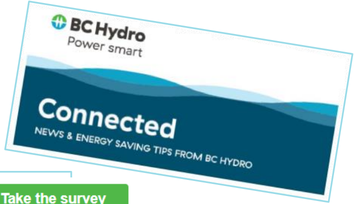
Customer Experience Manager, Customer Service

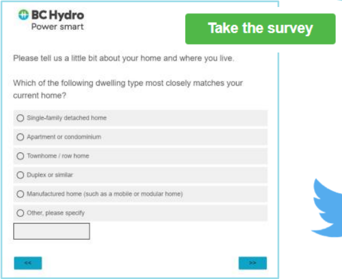
BC Hydro
Power smart

Engagement activities

We heard from more than 25,000 people

What we did	How many participated
Customer survey I	978
Customer panel	1,931
Customer survey II	792
Public poll	22,680
In-depth interviews	15
Telephone townhalls	395
Stakeholder workshops	109
Meetings	~
Digital dialogue	35





What we heard

- Affordability and keeping bills low are important to customers
- Those who often have higher bills due to the current residential inclining block rate (RIB) rate seek change, while those who do not, prefer the status quo
- Climate change is important to many customers
- Familiarity with and interest in rates varies significantly
- Of the potential rate options presented, optional Time-of-Use (TOU) rates drew the most interest

Customer feedback

There is tension between several views

Diverse customer sentiment

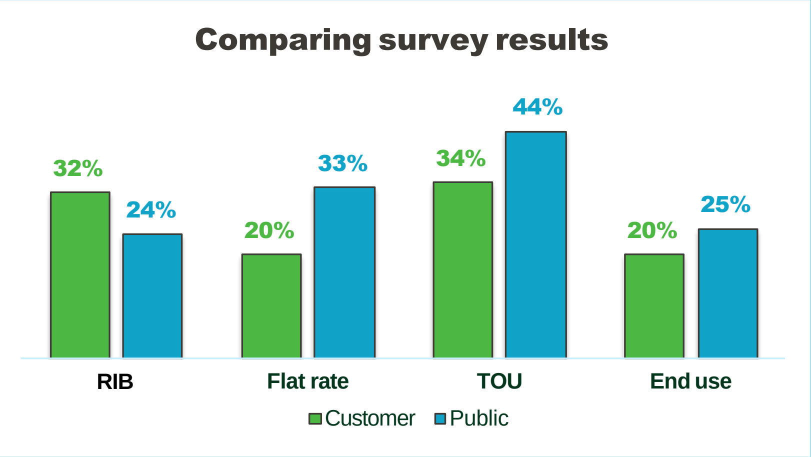
"Everyone should pay the exact same rate."	vs	"People should pay different rates depending on their income, location, heating type, etc."
"Thank you for keeping my bill and rates low."	vs	"The bill from BC Hydro is the biggest one I have. "
"Conservation is good for the environment."	vs	"Electrification is good for the environment. "
"People need to take personal responsibility for their usage."	vs	"I'd be willing to help those that are struggling to pay their bill."

There are differences between BC Hydro customers and the public

	Customer survey	Public survey
	n = 792	n = 22,680
Familiarity with the bill		
• Very familiar	22.2%	36.7%
• Familiar	47.3%	46.5%
• Somewhat familiar	25.4%	14.3%
• Not very familiar	5.2%	2.5%
Frequency in Step 2 (self reported)		
• Every bill	21.2%	32.6%
• Most of the bills	15.0%	17.0%
• Some of the bills	21.9%	20.9%
• Never	13.0%	14.0%
• Unsure	28.9%	15.5%

- The representative Customer survey collected feedback from a random sample drawn from the Residential account holder database.
- The Public survey acted as a broader public engagement activity, enabling the collection of larger volumes of comments across various customer profiles, including non-account holders.

Rate preferences



Customer survey

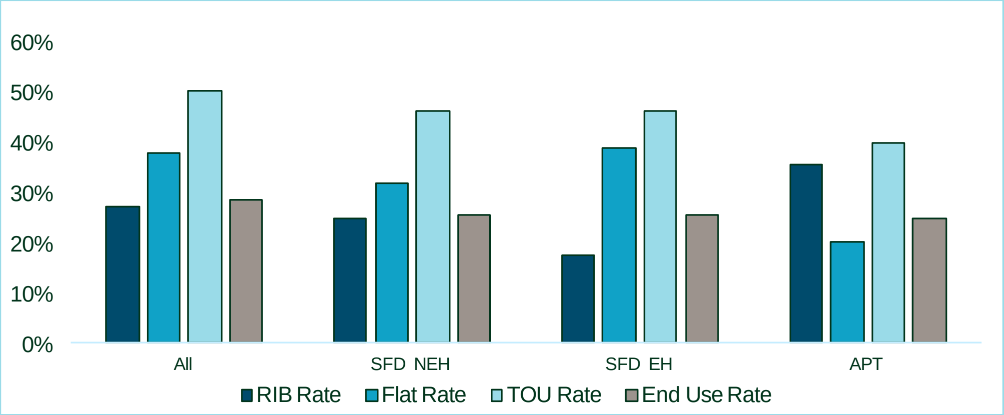
- Representative
- N= 749

Public survey

- Not weighted due to respondent self-selection and inability to confirm customer status
- N=16,552

Rate preference depends on several factors

Time Of Use (TOU) is most preferred overall
Electrically heated single-family dwellings preferring a Flat Rate
Apartments prefer Residential Inclining Block (RIB)

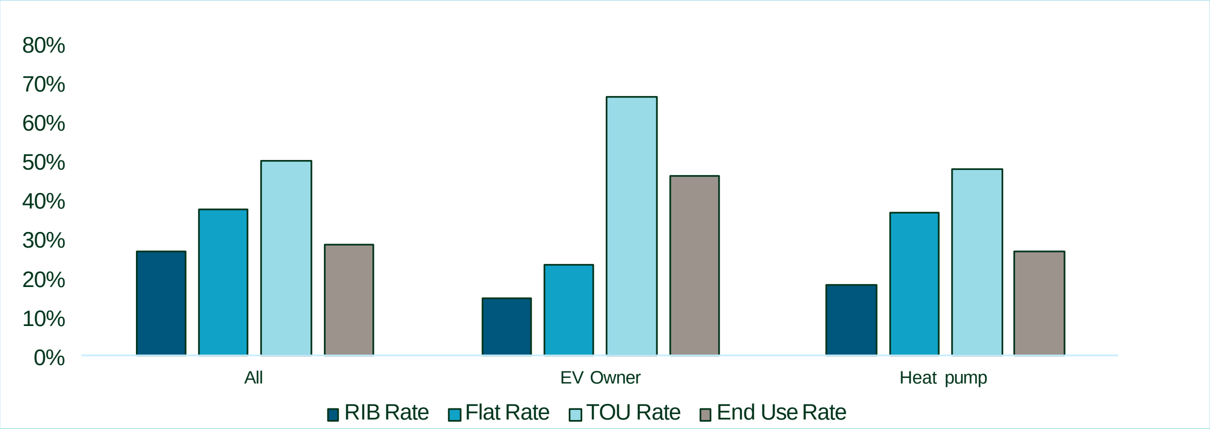


Legend

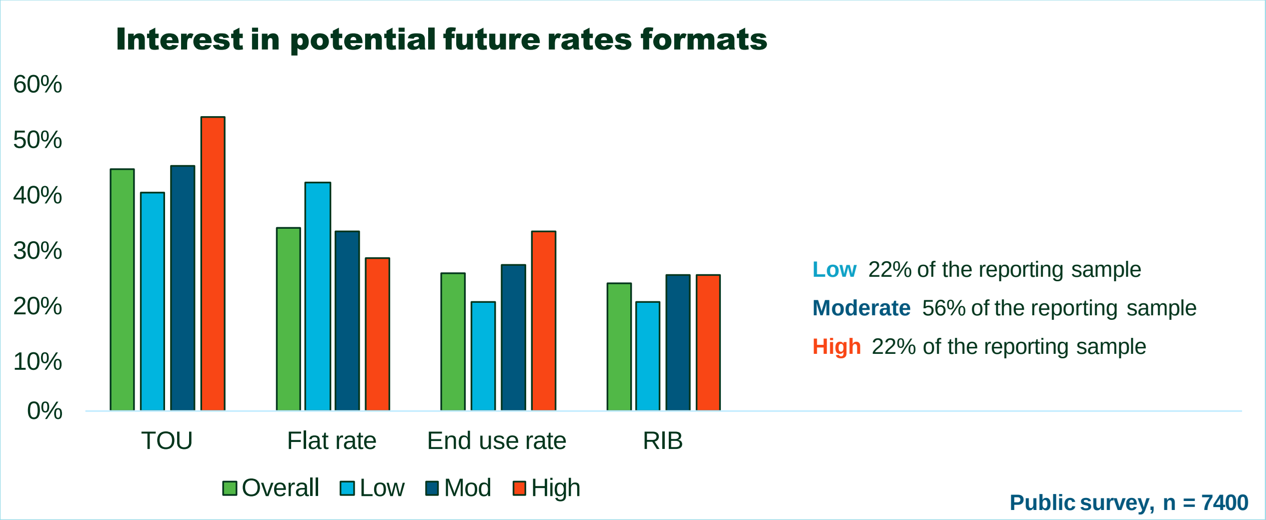
- SFD NEH: Single family dw elling w ith non-electric heat
- SFD EH: Single family dw elling w ith electric heat
- APT: Apartment

Rate options preference – special segments

Electric Vehicle owners prefer Time of Use and End Use
Heat pump owners prefer Time Of Use and Flat



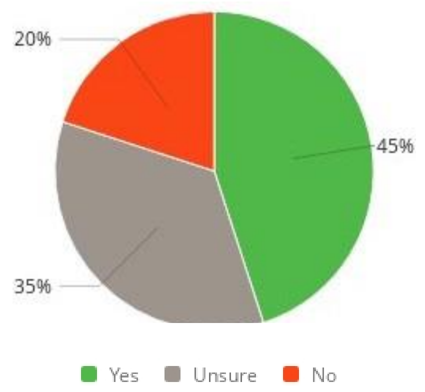
Preferences by income



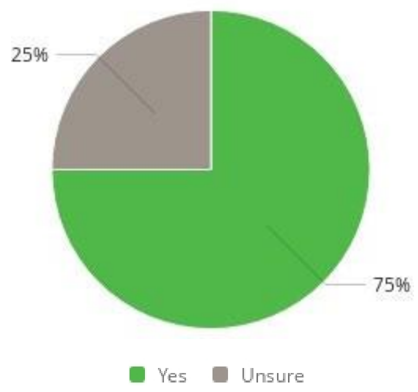
Stakeholder workshop feedback

Do you support BC Hydro advancing rate concepts that ...

Maintain RIB



Eliminate RIB



Telephone townhall

A new methodology to be more inclusive

- Support those who may not have internet access or prefer to interact in voice channels
- Provide information on the rate concepts being explored around residential rate design
- Mixed support to keep residential inclining bloc (RIB) or change the rate
- Lots of feedback and questions not related to rate design

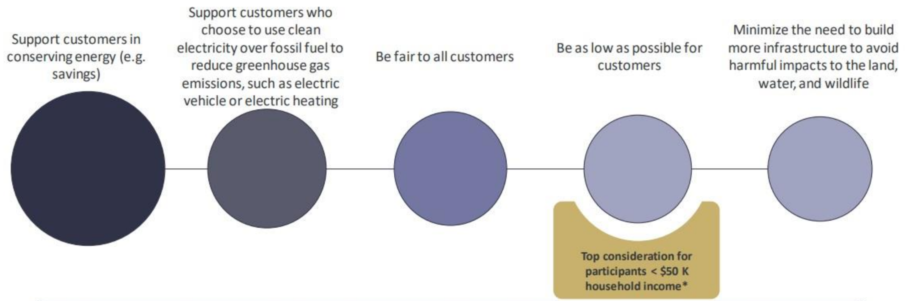
Digital dialogue

QUALITATIVE RESEARCH

Exploring attitudes more deeply

Supporting conservation, clean energy use and fairness were the top 'stated' considerations; lower income participants were mainly interested in having a low bill

Q: Which, if any of these factors, do you think BC Hydro should consider when developing its electricity rates?



After seeing hypothetical bill impacts, nearly all chose the option that provided them personally with the lowest bill and/or encouraged conservation.

Final thoughts

We're continuing to listen

- There is no "one size fits all" rate design
- The current engagement underway explores options and bill impacts

Default Residential Rate Design Options

Shiau-Ching Chou

Rates & Program Manager, Customer Service

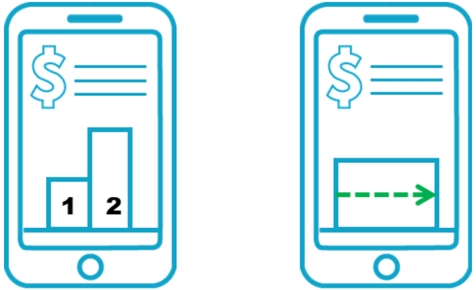
BC Hydro
Power smart

Default residential rate options

1. Default rates

Option 1
Maintain Residential
Inclining Block Rate

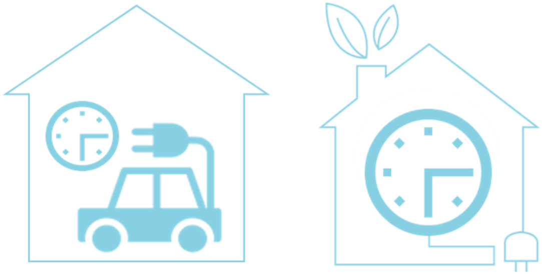
Option 2
Transition to a
Flat Energy Charge Rate

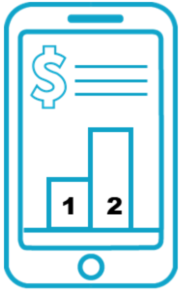


2. Optional rates

Electric Vehicle
Peak Reduction Rate

Residential
Time of Use Rate





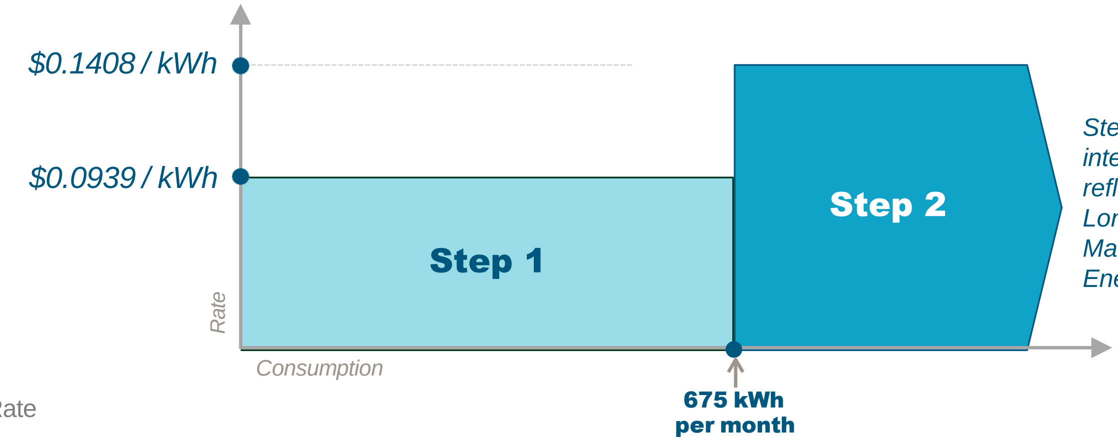
Option 1

Maintain Residential Inclining Block (RIB) Rate

BC Hydro
Power smart

Residential Inclining Block Rate

Residential Inclining Block Rate Schedule 1101 = Basic Charge ($0.2077 / day)
+ Step 1 Energy Charge
+ Step 2 Energy Charge



Step 2 rate was intended to reflect BC Hydro's Long Run Marginal Cost of Energy

F2022 Rate

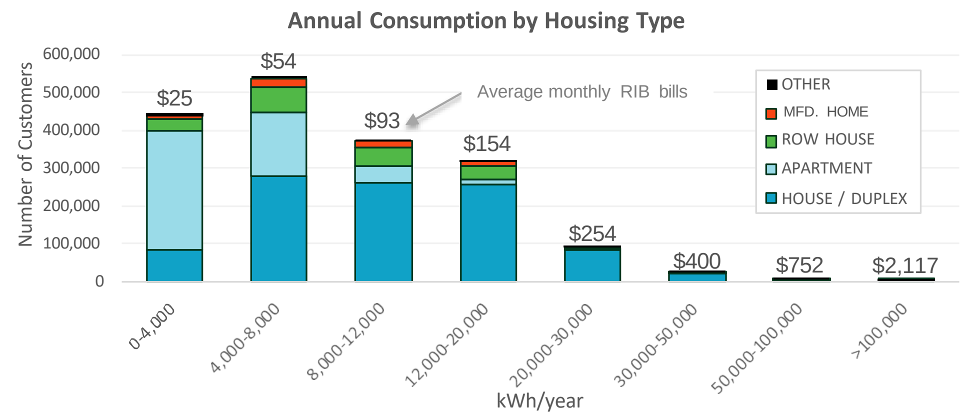
Residential Inclining Block (RIB) Rate background

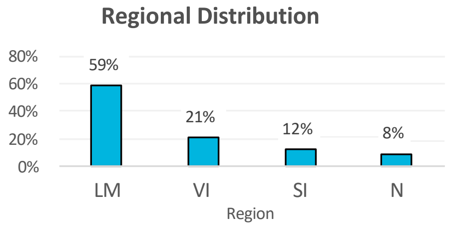
- About 1.9 million customers take service under RS 1101 Residential Inclining Block Rate ("RIB" rate). It accounts for 94% of residential sector revenue and 40% of BC Hydro's domestic revenue.
- The RIB Rate was implemented in 2008 to achieve energy conservation, by increasing bills for higher usage customers and decreasing bills for lower usage customers.
- The current RIB Rate pricing principles will expire in March 2022. BC Hydro has committed to file a residential rate application in February 2022.

RIB Rate customer characteristics

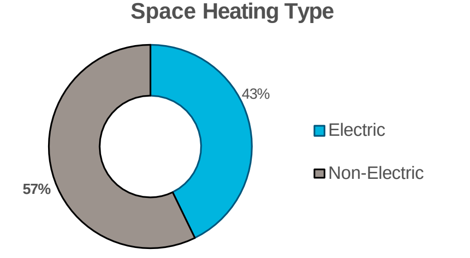
Fiscal 2020 Customer Data

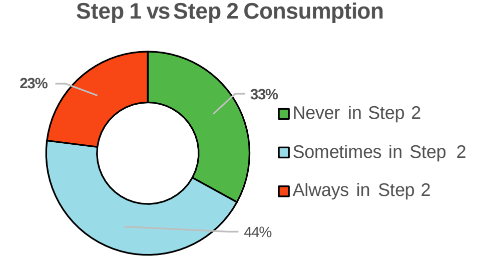
Customer Data	
Number of customers	~1.9M
Avg monthly consumption	836kWh
Avg monthly bill	$99
Total consumption	18,891GWh
Total revenue	$2.25B





LM: Lower Mainland VI: Vancouver Island SI: South Interior N: North





RIB achieved its objectives

- The RIB Rate met its objective of achieving energy conservation.
- Since its implementation in 2008, many customers have developed a good awareness and understanding of the RIB Rate, and how its stepped structure incents conservation.

RIB Evaluation Report F2009 to F2012*

Year	Energy Savings (GWh)	Peak Demand Savings (MW)
F2009	57 - 94	12 - 20
F2010	94 - 202	20 - 43
F2011	11 - 41	2 - 9
F2012	33 - 86	7 - 18

*Available in Appendix C-3B of BC Hydro's 2015 Rate Design Application: https://docs.bcuc.com/Documents/Proceedings/2015/DOC_44664_B-1-BCH-2015-Rate-Design-Appl.pdf

RIB is no longer achieving new conservation

- Customer response to the Step 2 price diminished over time.
- Some customer report they did all they could to respond to the higher step 2 price.
- By 2016, the RIB rate was no longer achieving new energy conservation.

RIB Evaluation Report F2013 to F2017*

Year	Energy Savings (GWh)	Peak Demand Savings (MW)
F2013	23	5
F2014	3	1
F2015	13	3
F2016	0 - 11	0 - 2
F2017	0 - 6	0 - 1

*Available in Appendix AA Attachment 2 of BC Hydro's F2020-F2021 Revenue Requirements Application: https://docs.bcuc.com/Documents/Proceedings/2019/DOC_53488_B-1-BCH-F20-F21-RR-Application.pdf

RIB no longer aligns with cost of service

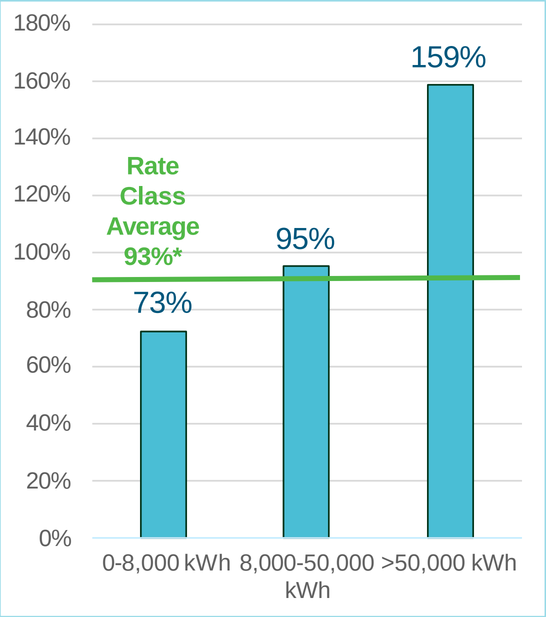
Marginal Cost of Energy

- RIB Step 2 energy charge was initially benchmarked to BC Hydro's long run marginal cost of energy.
- BC Hydro's updated long run marginal cost of energy will be released in December 2021 and is expected to be substantially lower than the current Step 2 rate of $0.1408/kWh.

Cost of Service

- Revenue to Cost Ratio (R/C Ratio) = Total revenue divided by full allocated cost of service
- Compared to the residential class, lower consumption customers are paying lower than their cost of service while high consumption customers are paying more.

Illustrative RIB Rate R/C Ratio by Annual Consumption



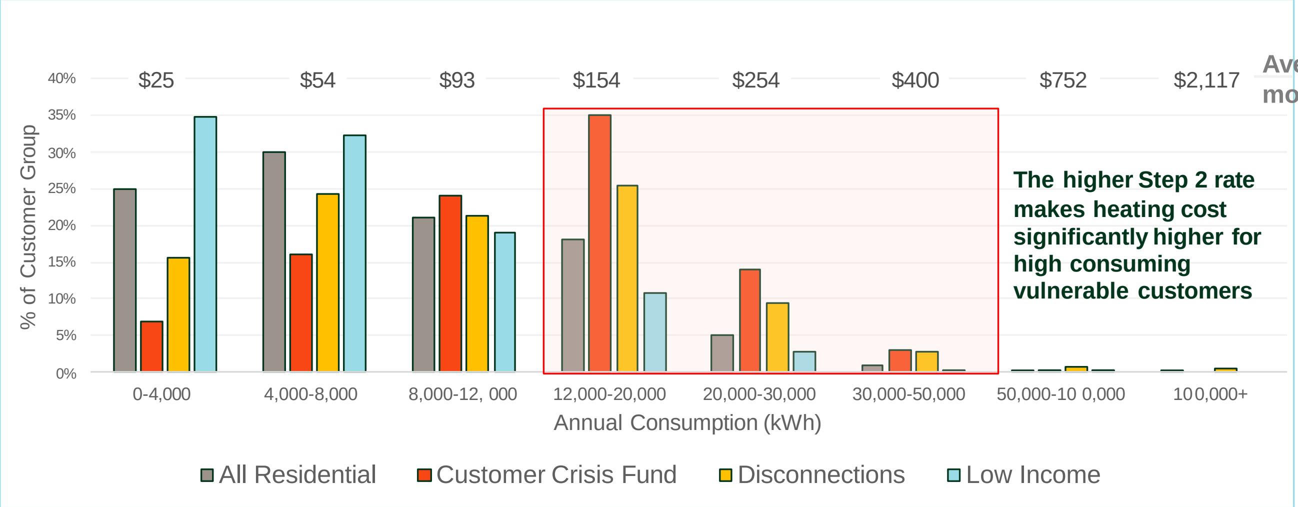
*F2020 Fully Allocated Cost of Service Study

Customer complaints and escalations

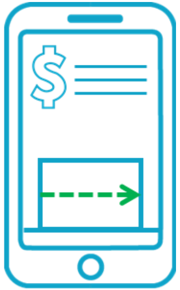
BC Hydro frequently receives complaints about the residential inclining block rate design from:

- Customers with no access to natural gas
- Customers with large families and large homes
- Customers who live in colder or rural areas
- Customers who purchased electric vehicles
- Customers who installed heat pumps

Higher consuming vulnerable customers have more challenges paying bills



F2019 Customer data (all residential)
2018-06 to 2020-05 Customer Crisis Fund Participants
F2020 Disconnection data
F2017 Residential End Use Survey (low income)

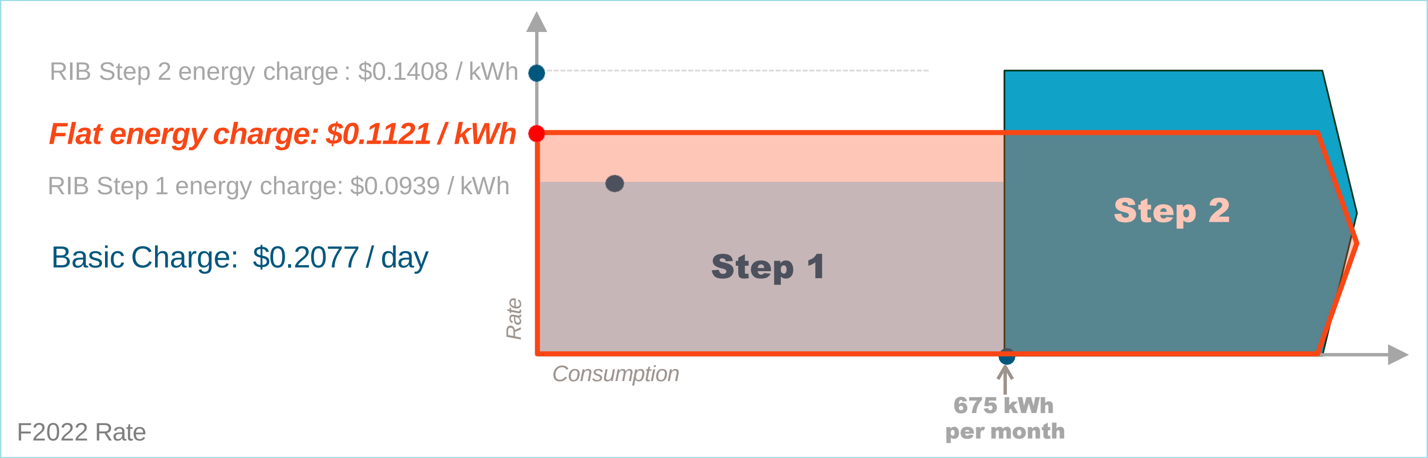


Option 2

Transition to a Flat Energy Charge Rate

BC Hydro
Power smart

Preliminary Flat Rate (no change to basic charge)



	Step 1	Step 2
Energy Sales (% of kWh per year)	62%	38%
Revenue (% of $ per year)	52%	48%

Flat Rate better aligns with Cost of Service

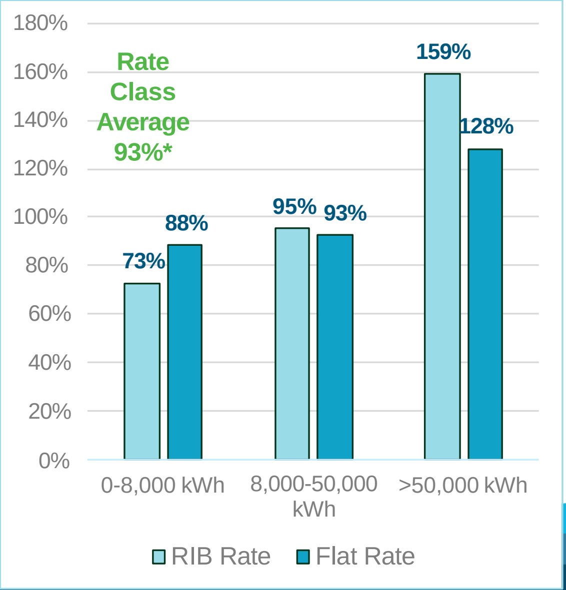
Marginal cost of energy

- Flat rate reduces the marginal cost of energy. Customers do not pay a higher price per kWh for consuming more electricity.

Cost of Service

- The R/C ratios are more even under the Flat rate.
- The R/C ratio for lower consumption customers increased to be closer to the rate class average and high consumption customers reduced significantly.

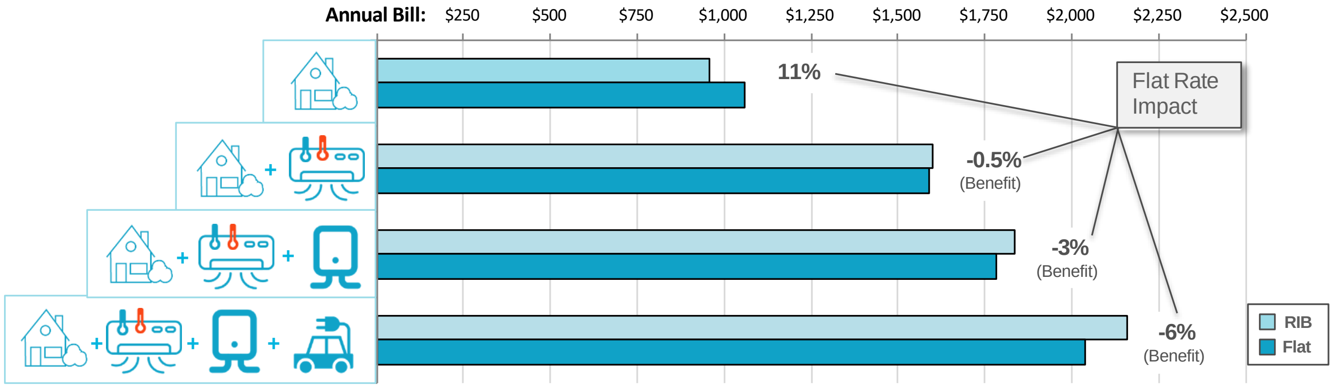
Illustrative R/C ratio by annual consumption



*F2020 Fully Allocated Cost of Service Study

Flat Rate Removes an Electrification Barrier

Single Family Home	Heat Pump	Water Heater	EV
~8,700 kWh/year	~4,750 kWh/year	~1,700 kWh/year	~2,300 kWh/year
Median non-electrically heated	(ASHP with COP 2.55)	(ASHP water heater COP 2.0)	

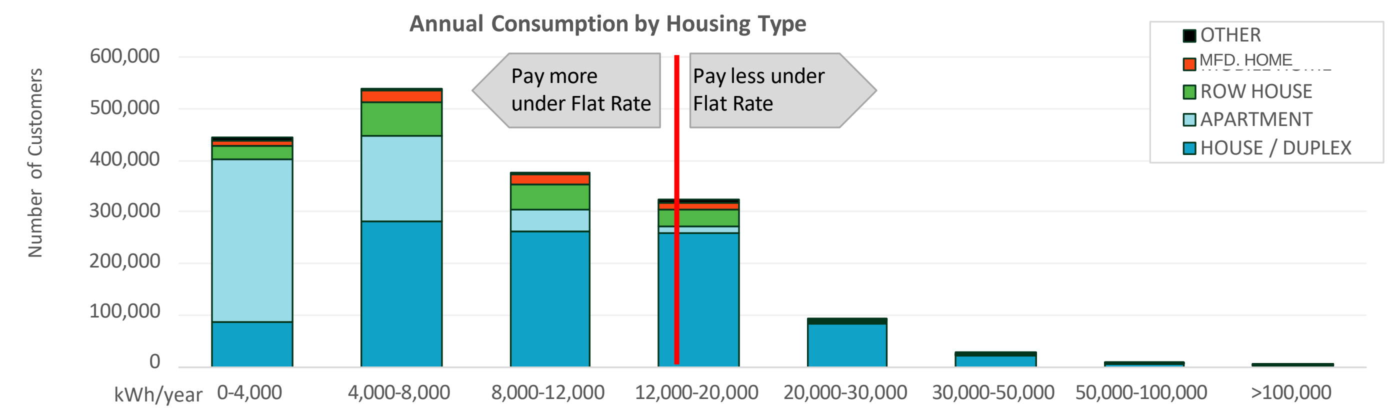


F2022 Rate: Flat rate based on $0.2077/day Basic Charge & $0.1121/kWh Energy Charge

*Based on efficiency of 20kWh/100km

Flat Rate would have bill impacts

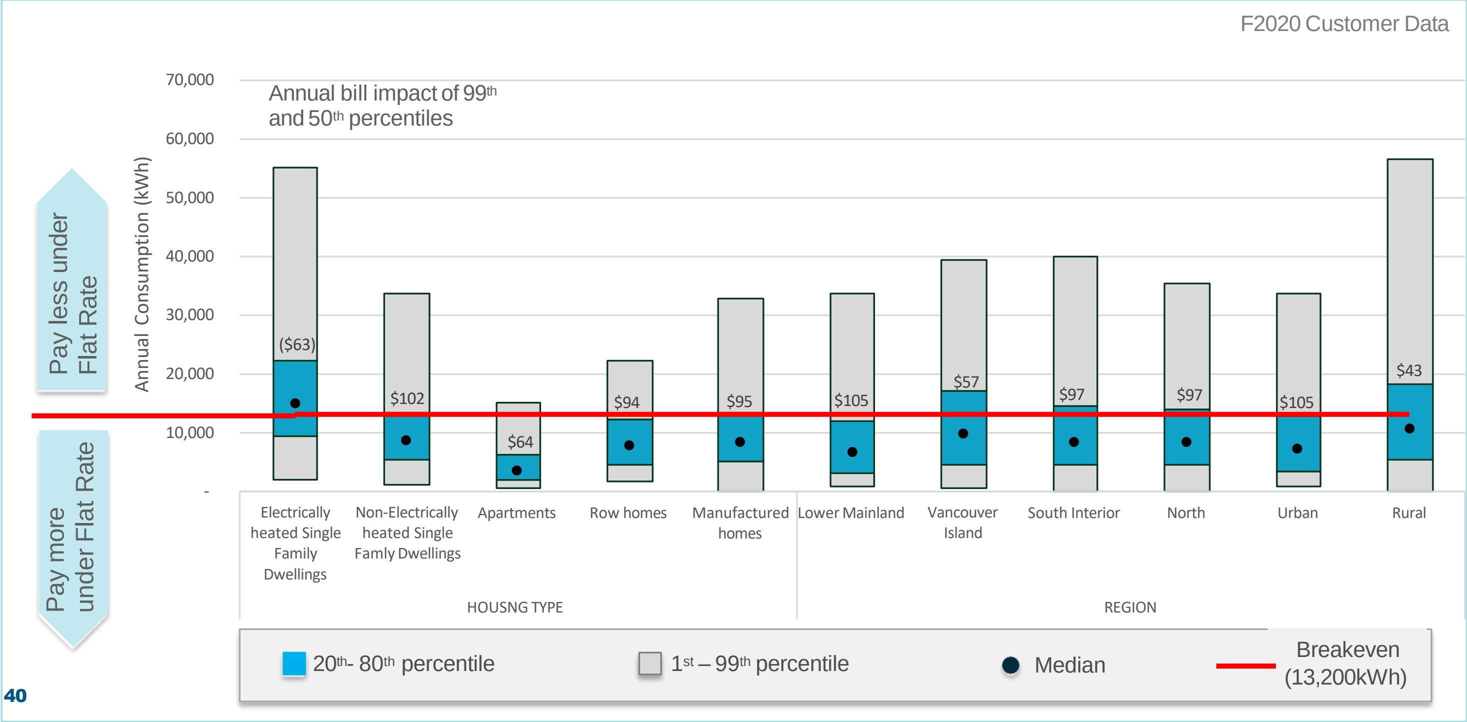
F2020 Customer data
F2022 Rate



Annual consumption (kWh)	0-4,000	4,000-8,000	8,000-12,000	12,000-20,000	20,000-30,000	30,000-50,000	>50,000
% of all customers	25%	30%	21%	18%	5%	1%	0.5%
Avg. RIB Bill ($/year)	$306	$651	$1,106	$1,838	$3,026	$4,791	$13,995
Avg. Flat Bill ($/year)	$352	$750	$1,184	$1,785	$2,741	$4,155	$11,529
Med. Bill Impact $	$46	$99	$78	($52)	($284)	($635)	($2,466)
Med. Bill Impact %	15%	15%	7%	(3%)	(9%)	(13%)	(18%)

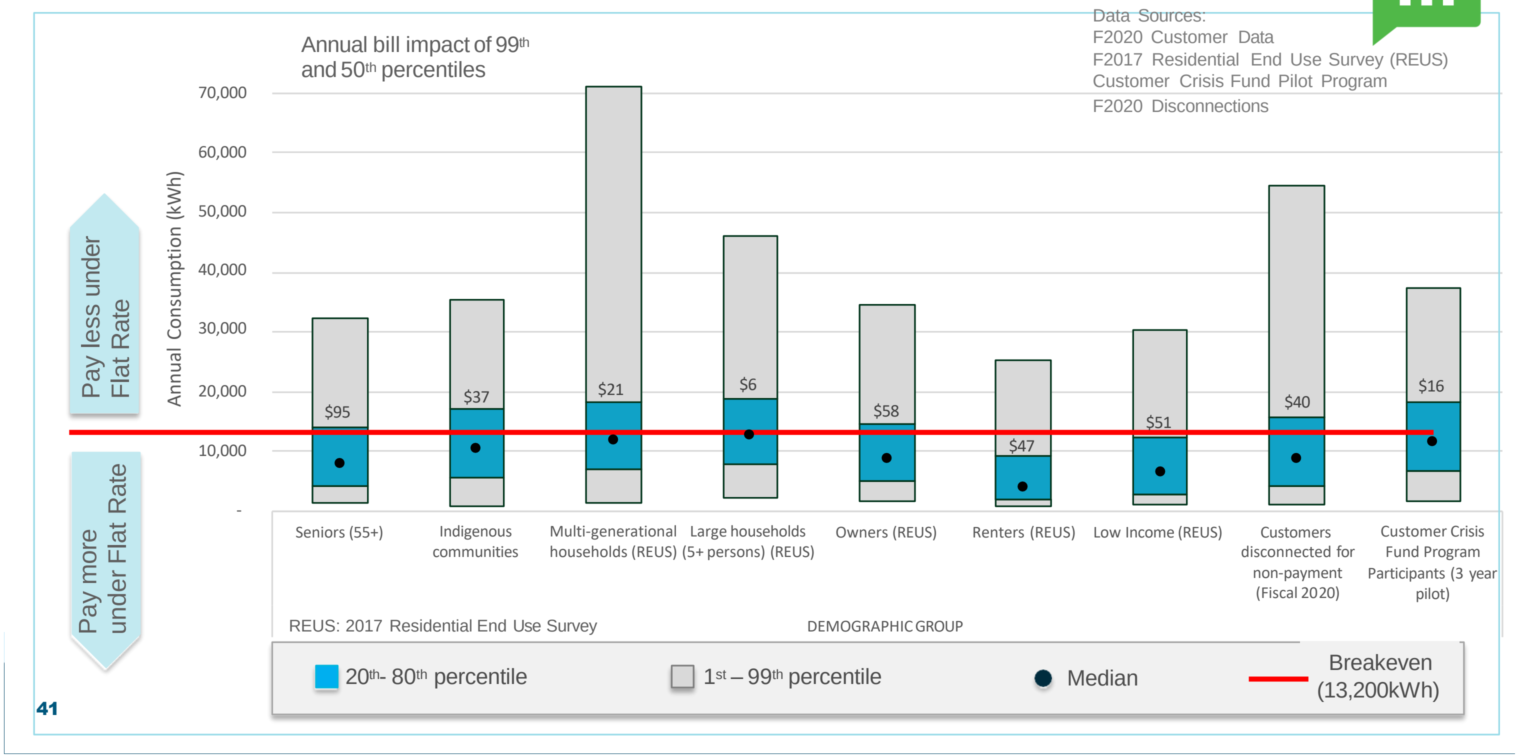
39

Illustrative annual Flat Rate bill impact



40

Illustrative annual Flat Rate bill impact



Default Rate Design Assessment

Chris Sandve, Chief Regulatory Officer

BC Hydro
Power smart

A closer look at the Basic Charge

- The Residential basic charge was introduced in March 1977 and has since been increased by the amount of any general rate increase as approved by the Commission.
- The basic charge is intended to recover a portion of BC Hydro's customer-related costs, which do not vary with usage.
- The current RIB Basic Charge recovers ~60% of the fixed customer related costs, increasing it would reflect BC Hydro's fixed customer related costs.
- BC Hydro's basic charge is among the lowest of any Canadian Electric Utilities.

Illustrative bill impacts of increasing Basic Charge

- BC Hydro consulted extensively on the concept of increasing the basic charge as part of our 2015 Rate Design Application
- At that time, some parties opposed increases to the basic charge because the current level is accepted by customers and increasing it would increase bills for low consuming customers, including apartments and some low-income customers

Annual Consumption (kWh)	No Change to Basic Charge	Increase Basic Charge to 1.5X
Basic charge (per day)	$0.2077	$0.3116
Energy charge (per kWh)	$0.1121	$0.1082
0-4000	15%	24%
4001-8000	15%	17%
8001-12000	7%	6%
12001-20000	-3%	-5%
20001-30000	-9%	-12%
30001-50000	-13%	-16%
>50000	-18%	-21%

Default Rate Design Bonbright Assessment

Bonbright Principle	Maintain RIB Rate Design	Flat Energy Charge no change to Basic Charge	Lower Flat Energy Charge Increased Basic Charge
Economic Efficiency Price signals to encourage efficient use and discourage inefficient use	**Poor** Step 2 energy charge does not reflect marginal cost	**Good** Energy charge better reflects marginal cost	**Good** Energy charge better reflects marginal cost
Fairness Fair Appointment of costs among customers; avoid undue discrimination	**Poor** High consuming customers pay more than their cost of service while low consuming customers pay less	**Good** High and low consuming customers pay closer to their cost of service	**Very Good** Closest design to cost of service
Practicality Customer understanding and acceptance, practical and cost effective to implement; freedom from controversies as to proper interpretation	**Moderate** Customer complaints and engagement indicate mixed support for status quo	**Moderate** Bill impacts arise but can be moderated with a gradual transition	**Poor** Bill increases to low consuming customers may be unacceptably high
Stability Recovery of the revenue requirement; revenue and rate stability	**Moderate** High step 2 price may discourage customers from using electricity. Stepped rate design leads to bill volatility.	**Good** Elimination of stepped rate design stabilizes bills and rates. Lower energy charge reduces barrier to using electricity.	**Very Good** Higher fixed charges stabilize revenue, lower energy charge and encourage customers to use electricity.

Other rate design options considered

Concepts	Rate Designs	Considerations
Modifying the inclining block rate	• Lowering Step 2 rate • Increase Step 1 threshold • Add an additional tier	✓ Reflects feedback from customers X Bill impacts to low consumption customers X Does not address RIB rate challenges
Eliminating the inclining block rate	• Declining block rate • Seasonal rate	✓ Lower customers' marginal cost to replace fossil fuels with clean electricity X Worse bill impacts to low consumption customers than Flat rate X Seasonal rates add complexity without reducing annual electricity costs
Segmenting residential customers	• Segment by consumption • Segment by dwelling type • Varying energy charge • Varying basic charge	✓ Minimize bill impact for certain customer groups X Benefits to certain customers limited unless very targeted X Shifts bill impacts to other customer groups X No cost of service basis X Challenging to implement and administer

Implementation Options

Rate change implementation options

Implementation option	Description	Example
1. Immediate	Implement the new rate design shortly after Commission approval.	BC Hydro's Large General Service and Medium General Service rate change in 2017.
2. Delayed	Provide a period (e.g., 3 years) under existing rate before implementing the new rate design. Allows customers time to prepare for the new rate.	BC Hydro's General Service E-Plus rate phase out.
3. Gradual	Adjust prices over a transition period (e.g., 5 to 10 years) until they reach the new rate design. This spreads the annual bill impact from the transition to a new rate over a longer period.	FortisBC's Residential Conservation Rate transition to a flat rate over 5 years. BC Hydro's Residential E-Plus Rate phase out over 10 years.

BC Hydro believes gradual implementation is the best option to transition the default residential rate to a Flat Rate.

Illustrative bill impact mitigation – transition

Transitioning from RIB rate to flat rate over several years can mitigate some bill impacts

Annual Consumption (kWh)	Avg Annual RIB Bill	Flat Rate Total Bill Impact $	Flat Rate Total Bill Impact %	3-Year Transition Annual Impact	5-Year Transition Annual Impact	7-Year Transition Annual Impact	10-Year Transition Annual Impact
0-4000	$306	$46	15%	5.0%	3.0%	2.2%	1.5%
4001-8000	$651	$100	15%	5.1%	3.1%	2.2%	1.5%
8001-12000	$1,106	$78	7%	2.4%	1.4%	1.0%	0.7%
12001-20000	$1,838	($52)	(3%)	(0.9%)	(0.6%)	(0.4%)	(0.3%)
20001-30000	$3,026	($284)	(9%)	(3.1%)	(1.9%)	(1.3%)	(0.9%)
30001-50000	$4,791	($635)	(13%)	(4.4%)	(2.7%)	(1.9%)	(1.3%)
>50000	$13,995	($2,466)	(18%)	(5.9%)	(3.5%)	(2.5%)	(1.8%)

Combined bill impact – 5 year transition

Illustrative annual bill impact of transitioning from RIB rate to flat rate over 5 years with no change to basic charge inclusive of general bill increases or decreases

Annual Consumption (kWh)	Y0 F2023	Y1 F2024	Y2 F2025	Annual Consumption (kWh)	Y0 F2023	Y1 F2024	Y2 F2025
General Rate Increase	(1.4%)	2.0%	2.7%	General Rate Increase	(1.4%)	2.0%	2.7%
0-4000	(1.4%)	4.9%	5.6%	0-4000	($4)	$15	$18
4001-8000	(1.4%)	5.0%	5.6%	4001-8000	($9)	$32	$38
8001-12000	(1.4%)	3.3%	4.0%	8001-12000	($15)	$36	$45
12001-20000	(1.4%)	1.3%	2.0%	12001-20000	($26)	$24	$36
20001-30000	(1.4%)	0%	0.6%	20001-30000	($42)	($1)	$18
30001-50000	(1.4%)	(0.8%)	(0.2%)	30001-50000	($67)	($38)	($10)
>50000	(1.4%)	(1.7%)	(1.2%)	>50000	($195)	($234)	($158)

Combined bill impact – 10 year transition

Illustrative annual bill impact of transitioning from RIB rate to flat rate over 10 years with no change to basic charge inclusive of general bill increases or decreases

Annual Consumption (kWh)	Y0 F2023	Y1 F2024	Y2 F2025	Annual Consumption (kWh)	Y0 F2023	Y1 F2024	Y2 F2025
General Rate Increase	(1.4%)	2.0%	2.7%	General Rate Increase	(1.4%)	2.0%	2.7%
0-4000	(1.4%)	3.5%	4.2%	0-4000	($4)	$10	$13
4001-8000	(1.4%)	3.5%	4.2%	4001-8000	($9)	$22	$28
8001-12000	(1.4%)	2.7%	3.4%	8001-12000	($15)	$29	$38
12001-20000	(1.4%)	1.7%	2.3%	12001-20000	($26)	$30	$43
20001-30000	(1.4%)	1.0%	1.7%	20001-30000	($42)	$29	$50
30001-50000	(1.4%)	0.6%	1.3%	30001-50000	($67)	$28	$60
>50000	(1.4%)	0.2%	0.8%	>50000	($195)	$21	$111

F2023 Pricing Principles

BC Hydro
Power smart

RIB pricing principles

RIB Pricing Principles

How the annual general rate increase / decrease is applied to the three elements of the RIB rate:

- Basic Charge
- Step 1 Energy Charge
- Step 2 Energy Charge

The current pricing principles will expire in March 2022

Fiscal Year	BCUC Order No.	
F2009 – F2010	G-124-08	Approval of RIB Rate.
F2011	G-180-10	Apply RRA % equally
F2012 – F2014	G-45-11	Increase Step 2 to the higher of RRA % or up to 10% bill impact
F2015 – F2016	G-13-14	Apply RRA % equally
F2017 – F2019	G-5-17	Apply RRA % equally
F2020	G-214-18	Apply RRA % equally
F2021 – F2022	G-62-20	Apply RRA % equally

Preliminary F2023 RIB pricing principles

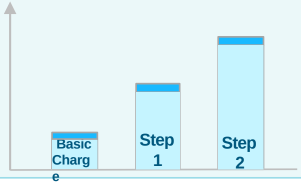
(interim and refundable)

F2023 RRA – net impact of 1.4% decrease

- +0.62% increase
- -2% Deferral Account Rate Rider (DARR)

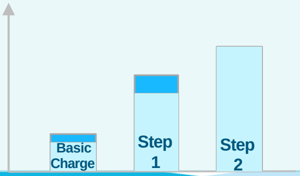
Option 1

Basic charge: increase by 0.62%
Step 1: increase by 0.62%
Step 2: increase by 0.62%
(-2% DARR applies to the total bill)
All customers see a ~1.4% bill decrease



Option 2

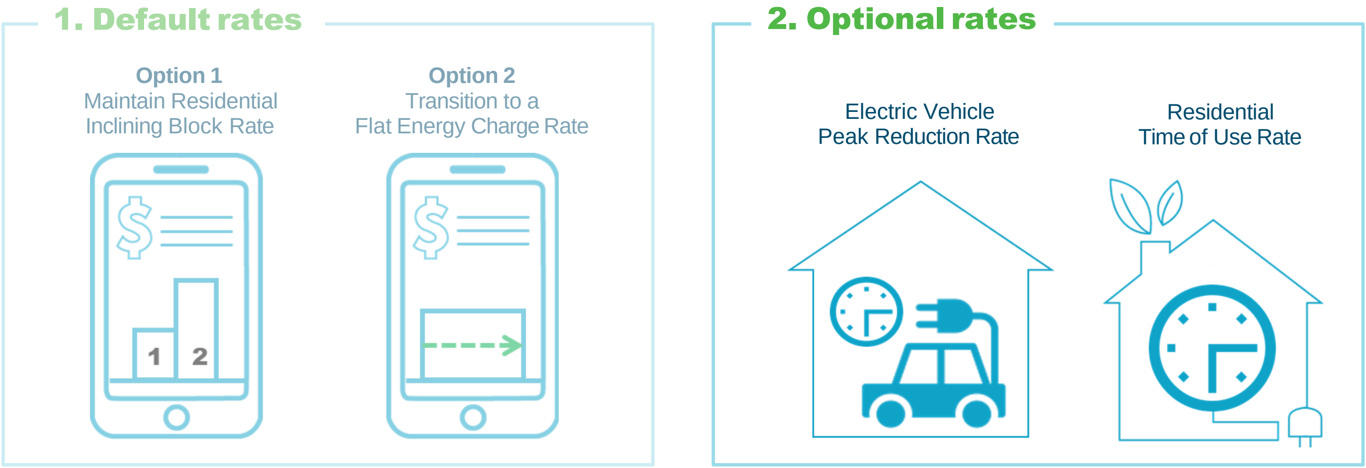
Basic charge: increase by 0.62%
Step 1: increase by 1.17%
Step 2: no change
(-2% DARR applies to the total bill)
Customers see various bill decreases



Illustrative option 2 bill impact

Annual Energy Usage (kWh)	Average Bill Impact ($)	Average Bill Impact (%)
0-4000	($3)	(1.0%)
4001-8000	($6)	(1.0%)
8001-12000	($14)	(1.2%)
12001-20000	($28)	(1.5%)
20001-30000	($51)	(1.7%)
30001-50000	($87)	(1.8%)
>50000	($271)	(1.9%)

Optional residential rates



Agenda

Time	Topic	Presenter
12:30 pm – 12:50 pm	Time-of-use Rates and our Integrated Resource Plan	Anthea Jubb, Snr. Regulatory Manager
12:50 pm – 1:10 pm	Customer and stakeholder feedback	Anthea Jubb
1:10 pm – 1:20 pm	Electric vehicles in BC	Mike Wenzlaff, Snr. Program Manager
1:20 pm – 1:30 pm	Jurisdictional review	Mike Wenzlaff
1:30 pm – 2:20 pm	Optional time-of-use rate designs	Rob Zeni, Snr. Regulatory Specialist
02:20 pm – 02:30 pm	Next steps and closing Remarks	Chris Sandve, Chief Regulatory Officer

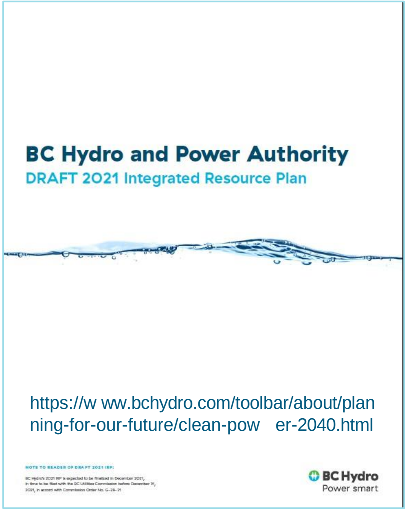
Time-of-use rates and our Integrated Resource Plan

Anthea Jubb

Senior Manager Tariffs and Rate Design

BC Hydro’s Integrated Resource Plan

- An integrated resource plan is a guidebook for what, when, and how to meet customers’ evolving electricity needs
- BC Hydro’s 2021 Integrated Resource Plan looks at a 20-year time frame and will guide decisions on how to meet future customer needs for electricity
- We released our draft Integrated Resource Plan in July 2021 and will file our final plan with the BC Utilities Commission December 2021



https://w ww.bchydro.com/toolbar/about/planning-for-our-future/clean-pow er-2040.html

The need for capacity

- Capacity is needed as early as Fiscal 2027 in the Lower Mainland and Vancouver Island regions

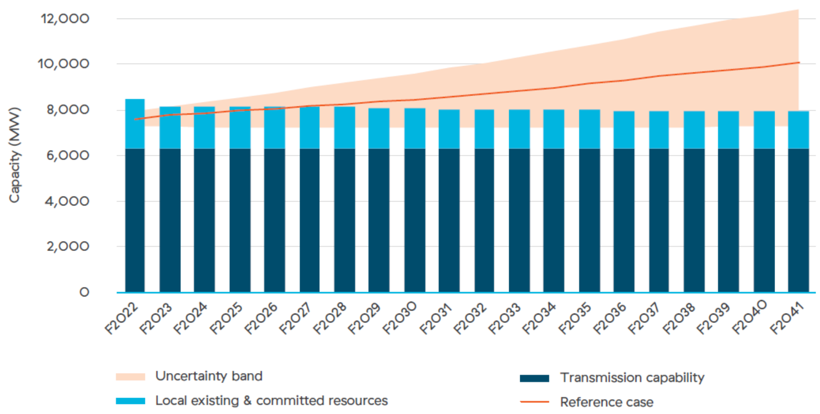
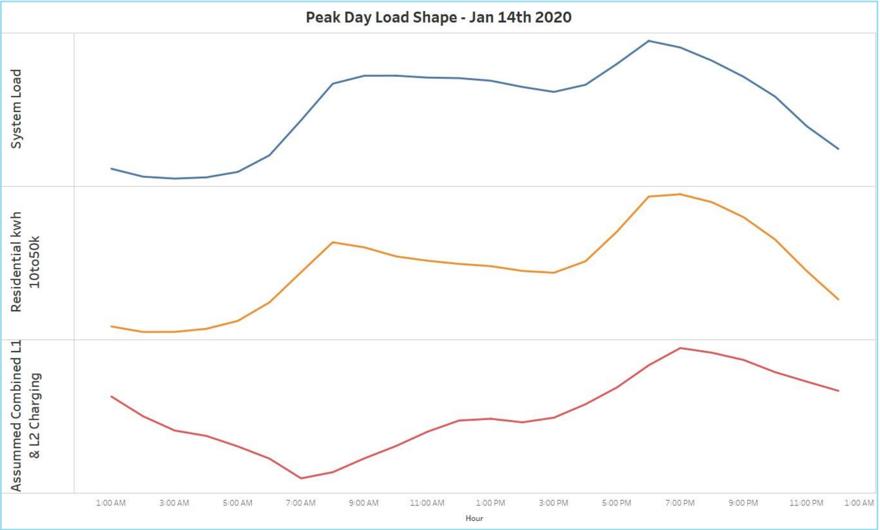


Figure 3. South Coast capacity Load Resource Balance: December 2020 Load Forecast vs. existing & committed resources (w/ transmission) – before planned resources

Time-varying rates can be a capacity resource

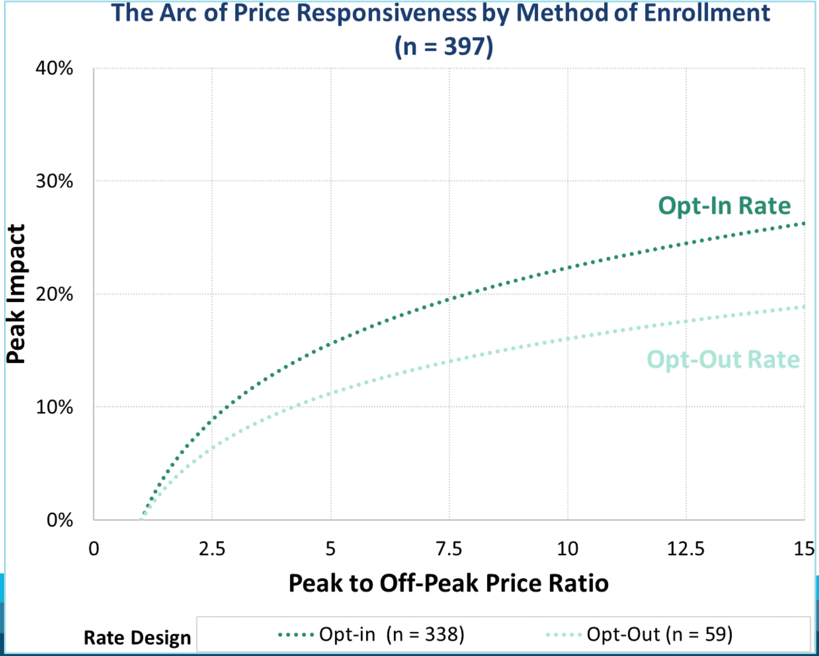
- BC Hydro’s demand related costs arise because of the need to serve load during our peak demand times
- If customers can move when they use electricity to time outside our peak demand periods, this can provide a resource alternative to investing in distribution, transmission and generation capacity



Support for opt-in time-varying rates

- Consultation completed for the integrated resource plan showed an overall openness and support for time-varying rates
- Concern for customers who cannot take advantage of time-varying rates to lower their bills
- Opt-in design emphasizes customer choice and mitigates the potential for negative bill impacts for customers who could be defaulted into a rate that is not well suited for them

Opt-in time varying rates reliably reduce peak demand



Source: The Brattle Group

Time-varying rates in the Integrated Resource Plan

BC Hydro’s draft integrated resource plan includes the following elements:

- Pursue voluntary time-varying rates supported by demand response programs to achieve 220 MW of capacity savings at the system level by fiscal 2030
- Pursue a combination of education and marketing efforts as well as incentives for smart-charging technology for customers to support a new or existing (as applicable) voluntary residential time of-use rate to shift home charging by 50 per cent of residential electric vehicle drivers to off-peak demand periods to achieve 100 MW of capacity savings at the system level by fiscal 2030.

Optional residential time-of-use rate

We are advancing two of the time varying rates in the Integrated Resource Plan now:

- Opt-in residential time of use rate that applies to the entire residential account
- Opt-in electric vehicle peak reduction time of use rate that applies to home charging of electric vehicles only

Help manage the impact of home charging of electric vehicles on BC Hydro’s system, and provide capacity in the South Coast where it is needed earliest

BC Hydro
Power smart

Engagement Results

Anthea Jubb
Senior Regulatory Manager Tariffs and Rate Design

BC Hydro
Power smart

2020 Rates Perception Survey

Approach

A random sample of residential customers with an email address on file who have given consent to be contacted

15-minute email-to-online survey

Survey Responses

Year	Date	Invitations	Completed Surveys	Participation Rate
2020	December 11 - 30	8,427	978	12%

Total results accurate to ±3% (19 times out of 20)

The survey results have not been weighted

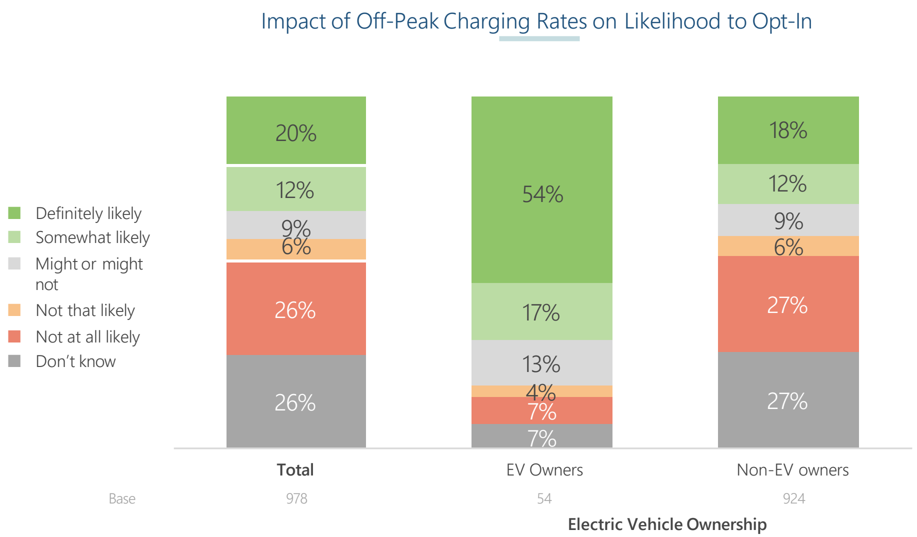
6
6

sentis

ELECTRIC VEHICLE RATE LIKELIHOOD TO OPT-IN

Overall, just under one-third of customers indicate that they are likely to opt in to receive a lower electricity rate in exchange for charging an EV during off-peak times.

Current EV owners are very likely to opt in – over half (54%) indicate that they are 'definitely likely' to opt in.



Base: Total
E2. For many customers with electric vehicles, "plugging in" while parked at home is the most convenient way to charge the battery. An off-peak electric vehicle home charging rate would allow customers to charge their vehicles at home at a lower cost. If an off-peak rate for electric vehicle charging became available, what is the likelihood that you will sign up (opt in)?

sentis

ABILITY TO CHANGE TIMING OF ELECTRICITY USE

Overall, just under half of customers indicate that they could adjust the timing of the use of their washer, dryer or dishwasher to take advantage of lower off-peak electricity rates. Those living in condos/apts are less likely to indicate that they can adjust the timing of their use of these appliances.

Much smaller percentages of customers indicate that they would be able to adjust a space heating or cooling appliance to take advantage of lower-off peak electricity rates.

Proportion That Could Adjust Their Timing of Use

	Total	Condo / Apt	Small, detached home	Larger family home
Base	(978)	(294)	(499)	(185)
Washer	47%	39%	51%	52%
Dryer	47%	39%	51%	50%
Dishwasher	48%	41%	50%	54%
Space (room) heating	17%	17%	17%	18%
Space (room) cooling	12%	10%	13%	14%

■/■ % yes

■ Lower than other household profiles

Base: Total (978)

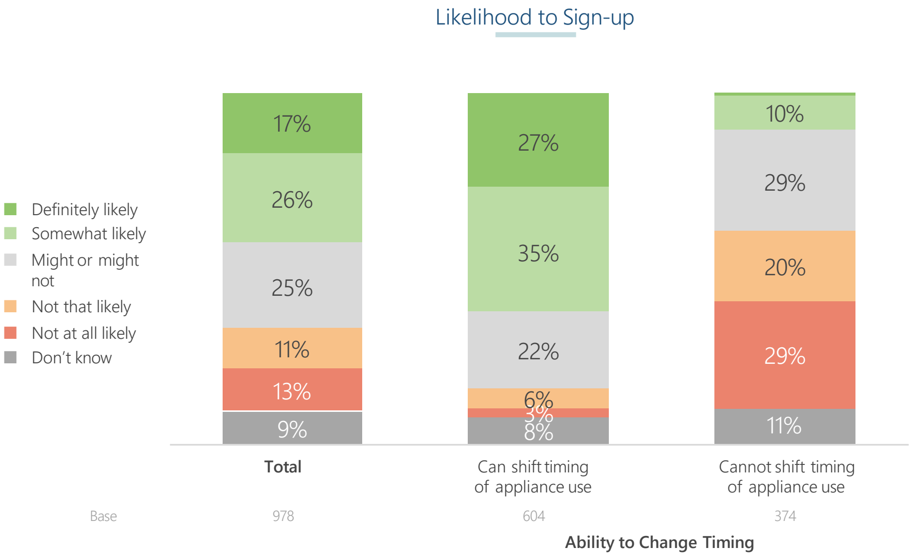
D1. BC Hydro is also exploring other optional rates. Customers would be able to choose to stay on the standard rate or they could sign up for an option that meets their needs. A time of use rate is one option. This rate helps shift electricity use away from peak demand times (i.e. 4 p.m. to 8 p.m.) by offering a lower rate for using power during off-peak times (i.e. 11 p.m. to 7 a.m. or weekends) and a higher rate for electricity used during peak times. If time of use rates became available, could you change the timing of the use of any of the following electrical appliances to take advantage of a lower off-peak charge?

LIKELIHOOD OF SIGNING UP FOR TME OF USE OPTION

Overall, 43% of customers indicate that they are likely to sign up for a time of use option, while just under one-quarter (24%) are not likely.

However, 62% of customers who indicated that they could operate at least one of their appliances during off-peak times indicate that they are likely to sign up for a time of use option.

Consistent with their lower stated ability shift appliance use to off-peak times, those living in condos/apts are less likely to sign up for a time of use option (35%), compared to those living in small detached homes (45%) or larger family homes (48%).



Base: Total (978)
D2. Based on this time of use rate concept, what is the likelihood that you will sign up if it became available to you?

REASONS FOR LIKELIHOOD OF SIGNING UP

sentis

The most common reason that customers are likely to sign up for a time of use option is the prospect of lower electricity bills.

Most of those who indicate that they might sign up want more information or say it depends on the cost savings that could be achieved.

The most common reasons that customers are not likely to sign up for a time of use option are that they simply don't want to change their usage to off-peak times or unable to do so.

	Total	Condo	Smaller Detached Home	Larger Family Home
Likely to sign-up	368	87	196	85
Reduces cost / more economical / cheaper	28%	28%	27%	31%
I can change my time of use / can take advantage of program	16%	14%	16%	18%
Need more information / details	14%	9%	13%	19%
More off-peak use better for the system environment / already do this	10%	11%	12%	6%
Depends on the cost difference / cost savings	8%	3%	9%	12%
Like being able to control my use to access lower rates	8%	9%	8%	6%
Good idea / It is used elsewhere	8%	10%	7%	7%
Might or might not sign-up	219	65	116	38
Need more information / details	30%	23%	36%	24%
Depends on the cost difference/ cost savings	23%	15%	26%	29%
Don't want to change my time of use / not interested / hassle	8%	6%	9%	5%
Don't know if I'll be able to change my time of use	8%	12%	5%	8%
Depends on what time periods would qualify	7%	6%	7%	11%
Not likely to sign-up	223	79	103	41
Don't want to change my time of use / not interested / hassle	36%	33%	38%	37%
Can't change time of use on some or all things / can't take advantage of program	25%	28%	21%	29%
Current bill already low/ not relevant for my situation	13%	20%	12%	5%

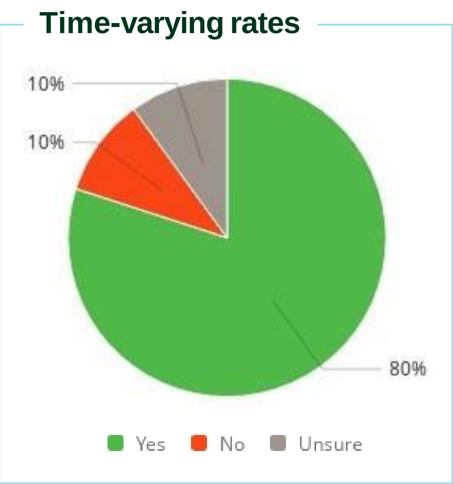
D3. Why are you [definitely / somewhat likely / unlikely to sign up?] / Why do you say you might or might not sign up? Only main mentions are shown.

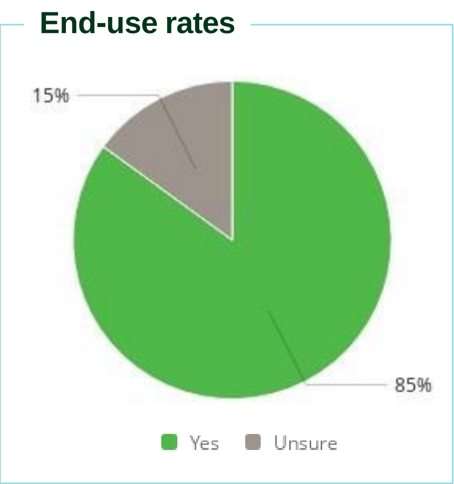
2021 customer and public survey

	Customer survey	Public survey
Fielding method	Online & phone May 10 to 31, 2021	Online via BCH website starting April 28, 2021
Respondents	Randomized representative sample drawn from the account holder database	Open to anyone
Sample size	821 (includes 72 phone interviews)	21,000+
Final preferences on future rate design: Top 3 choices	**Time-of-use** Keep RIB	**Time-of-use** Flat rate Plan with options

2021 public workshop

- Public rate design workshop on May 19, 2021
- 109 participants made up of organizations that represent BC Hydro residential customers
- Participants were asked if they support BC Hydro advancing the development of time-varying rates and end-use rates





Electric vehicle market and policy context

Mike Wenzlaff – Senior Program Manager, Electric Vehicles

BC Hydro
Power smart

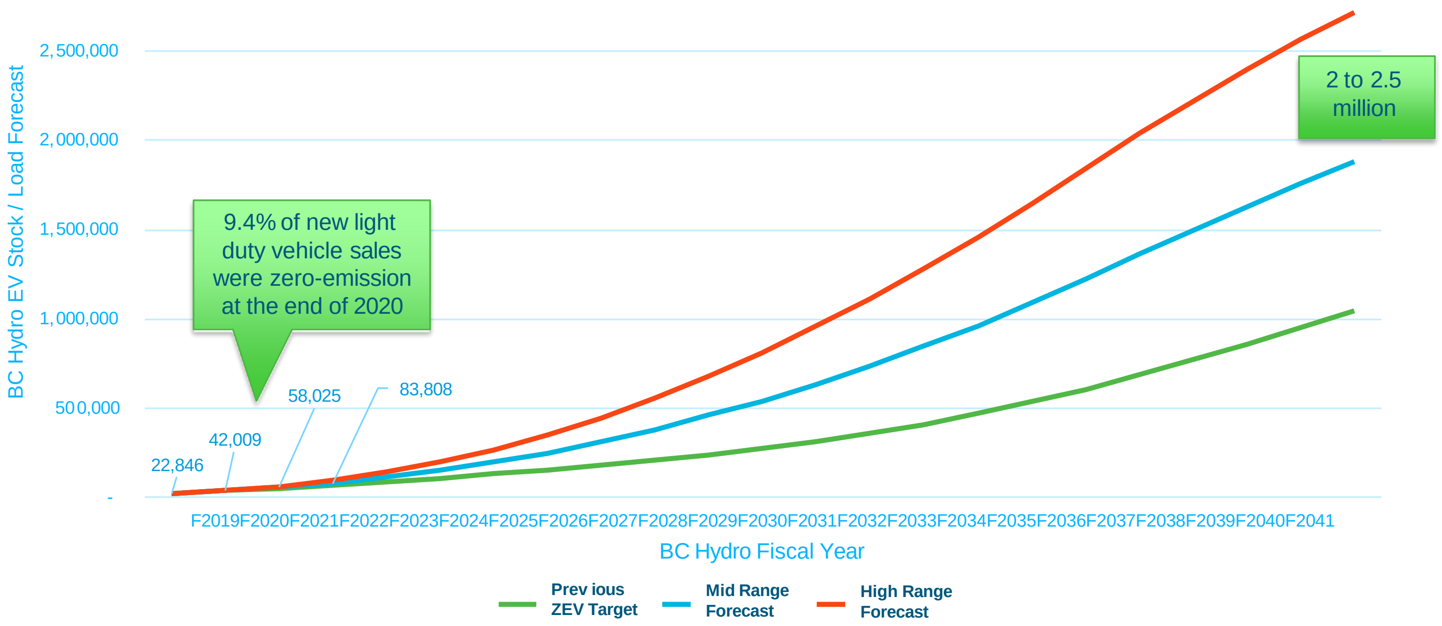
CleanBC Policy Context

- B.C. Government's CleanBC Roadmap to 2030 launched in October 2021
- More ambitious goals than the 2018 version to respond to the climate crisis
- Key focus is accelerating electrification of transportation and buildings
- Five years ahead of original zero-emission vehicle sales target (10% by 2025) as 9.4% of new car sales reached at end of 2020

Updated B.C. Zero Emission Vehicles Sales Targets	
2026	26%
2030	90%
2035	100%

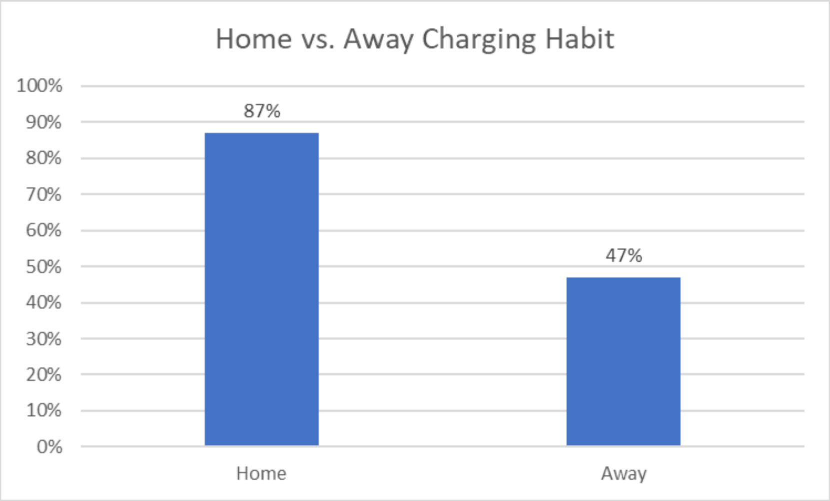
cleanBC
our nature. our power. **our future.**

Forecast EVs on the Road in B.C.



75

EV Charging – Home and/or Away



Source: BC Hydro Residential End-Use Survey 2020

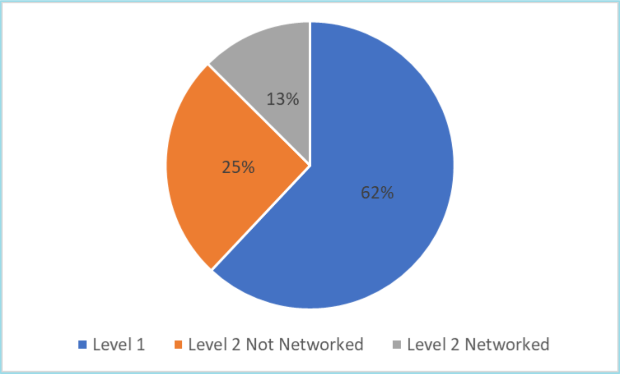
EV charging – at home

Home Charging Levels

Level 1
Regular wall socket (120 volt)

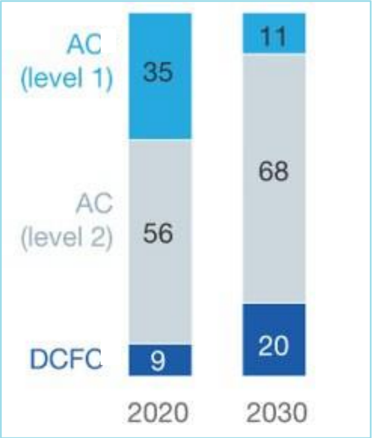
Level 2
Networked or non-networked EV charger (240 volt)

Today: More than half of home charging is Level 1



Source: BC Hydro Residential End-Use Survey 2020

Future: Level 2 charging will be the majority



DCFC: Direct Current Fast Charge

Source: United States Market Forecast; McKinsey & Company

Charging EV’s at home – metering

EV charging can either be metered as part of whole-home consumption or separately metered

	Standard Metering	Separate Metering	
Metering Configuration	**Current** 	**Initial Option: Second BC Hydro meter** 	**Potential Future Option: Metering via networked EV charger** 
Rates Supported	• **Current**: Standard default rate (Residential Inclining Block) • **Proposed**: Optional Whole-Home Time-Of-Use rate	• **Proposed**: EV Peak Reduction end-use rate	
Charging Speed	• Level 1 or Level 2	• Level 1 or Level 2	• Level 2 only
Considerations	✓ Simpler to administer and easier for customer to sign up for optional rate as no additional metering required × EV consumption cannot be separated for billing purposes from rest of the home usage	✓ Full recognition of EV load shift to off-peak periods ✓ Supports some newer apartments that have separate meters for EV × Customer will need to install separate metering at their cost	✓ Full recognition of EV load shift to off-peak periods ✓ Customer can take advantage of supported networked EV charger with no further electrical work required × Not currently approved by Measurement Canada

Jurisdictional review

Mike Wenzlaff – Senior Program Manager, EV's

BC Hydro
Power smart

Time-of-use rates jurisdictional review

- Residential time-of-use rates have been around for many years in some jurisdictions
- Some time of use rate are available only to those with electric vehicles
- More recently, utilities are offering specific electric vehicle time-of-use rates requiring a second utility meter
    - Two utilities are using the Level 2 networked charger and/or vehicle telemetry to bill EV charging separately

Examples of time-varying rates

Utility	Default	Whole Home	Electric Vehicle (end-use)
Pacific Gas & Electric	Time-of-use (peak and off-peak periods) *Customers can opt-out for another plan including tiered rate structure	Three plans offered • 4-9 pm everyday (baseline allowance) • 5-8 pm weekdays • EV ownership required	Time-of-use plan • Peak, off-peak and super off-peak rates • Requires second meter
Salt River Project	Basic plan – flat with seasonal 2 tier (summer and summer peak months)	Four plans offered • 3-6 pm or 4-7 pm weekdays • Shift 6-8 hours of use on weekdays • EV overnight	N/A
Consumers Energy	2-tier step rate	Three plans offered • Default with summer peak Seasonal and off-peak pricing • Low overnight	N/A
Sacramento Municipal Utilities District (SMUD)	Time-of-use *Customers can opt-out for a seasonal flat rate structure	Two plans offered • Seasonal, peak and off-peak • EV option to receive a lower overnight rate – must register the EV	N/A

Examples of time-varying rates

Utility	Default	Whole Home	Electric Vehicle (end-use)
Georgia Power	Starting 2021 – Smart Usage Time-of-Use	Three plans offered • On and off-peak • Plug in EV rate (super off-peak) • Smart usage	N/A
Green Mountain Power	Variety of rate options including: • Single flat rate • Critical Peak Pricing • Seasonal Time-of-Use • EV Off-Peak and Time-of-u	One plan offered • Seasonal, May – Oct and Nov - April	Two plans offered • Off-peak period, customer managed • Utility managed charging
San Diego Gas & Electric	Time-of-Use	Three plans offered • 2 pricing periods • 3 pricing periods • 3 pricing periods + demand response • EV specific – 2 plans, seasonal	One plan offered • Seasonal • Requires installation of second meter

Nova Scotia Power time-of-use rate

Rate	Time of Use	Standard
Monthly Charge	$10.83	$10.83
Winter Season & On-Peak Pricing (per kWh)	NOV 1 – MAR 31 (151 DAYS) 7 AM - 11 AM: $0.32 11 AM - 4 PM: $0.16 5 PM - 9 PM: $0.32 9 PM - 7 AM: $0.16	$0.16
Non-Winter Season & Off-Peak Pricing (per kWh)	APR 1 – OCT 31 (214 DAYS) $0.10 ANYTIME IN NON-WINTER ~34.7% savings of standard rate	
Holidays & Weekends	ALL HOLIDAYS & WEEKENDS IN WINTER ARE OFF PEAK $0.16	
Estimated Savings	~20%	

Implemented 2021 as a capacity resource in support of Nova Scotia Power's 2020 Integrated Resource Plan

Optional Residential Rate Designs

Robert Zeni

Senior Regulatory Specialist, Regulatory

BC Hydro
Power smart

Rate design framework

- Pricing is revenue neutral to the otherwise applicable rate, assuming no load shifting
- Rates are opt-in
- Designs are assessed for potential economic and cost of service justification
- Designs are assessed for attractiveness to participants, and for potential free ridership

Preliminary rate design assessment: impacts on ratepayers

Ratepayer economic Assessment:

- Analyzes revenue loss and load shifting relative to the marginal value of capacity, allowing for uncertainty. The value of capacity which can be assessed from our capacity reference prices (to be included in our 2021 integrated resource plan) as well as our distribution extension costs

Evaluation:

- Benefit cost ratio of 1 or more is good
- Between 0.80 and 1 is moderate
- Less than 0.80

Cost of Service Assessment:

- Compares the revenue to cost ratio of participants after load shifting to the revenue to cost ratio of other residential customers, allowing for the standard uncertainty range of +/- 5%, based on our fully allocated cost of service study
- Average residential revenue to cost ratio is 93%

Evaluation:

- Greater than 93% good
- Between 88% is 93% is moderate
- Less than 88% is poor

Preliminary rate design assessment: enrollment & load shifting

Bill Savings with Load Shifting:

- Potential bill savings for the target customer after load shifting should be high enough to attract participation
- Preliminary assessment:
  - Greater than 100 $/yr is good
  - Between 50 and 100 $/yr moderate
  - Less than 50 $/yr is poor

Bill Savings without Load Shifting:

- Potential bill savings for customers without load shifting provides an indicator of the risk of attracting free riders.
- While some free ridership is expected, ideally most customers will have limited bill savings if they do not shift load.
- Preliminary assessment
  - Less than 50 $/yr is good
  - Between 50 and 100 $/yr is moderate
  - Greater than 100 $/yr is poor

Electric Vehicle Peak Reduction Rate Designs

Robert Zeni
Senior Regulatory Specialist, Regulatory

Electric vehicle peak reduction rates

Option 1: Three Price Periods, Year-Round Pricing, Energy Charges Only, Electric Vehicle Load Only

Preliminary Rates		
Energy Charge	7:00 AM – 4:00 PM	11.25 ¢/kWh
Energy Charge	4:00 PM – 11:00PM	18.39 ¢/kWh
Energy Charge	11:00 PM – 7:00 AM	4.54 ¢/kwh
Basic Charge	0 ¢/day	

Preliminary Assessment

- Capacity benefit cost ratio: 1
- Revenue to cost ratio: 75% to 130%
- Illustrative customer bill savings with load shifting: $120 / yr
- Illustrative customer bill savings without load shifting: $0 / yr

Electric vehicle peak reduction rates

Option 2: Two Price Periods, Year-Round Pricing, Energy Charge and Basic Charge, Electric Vehicle Load Only

Preliminary Rates		
Energy Charge	7:00 AM – 11:00 PM	10.78 ¢/kWh
Energy Charge	11:00 PM – 7:00AM	4.54 ¢/kWh
Basic Charge	20.8 ¢/day	

Preliminary Assessment

- Capacity benefit cost ratio: 1.4
- Revenue to Cost Ratio: 104% to 183%
- Illustrative customer bill savings with load shifting: $87 / yr
- Illustrative customer bill savings without load shifting: $35 / yr

Electric vehicle peak reduction Bonbright assessment

Bonbright Principle	Option 1 Three price periods, year-round pricing, energy charges only	Option 2 Two price periods, year-round pricing, energy charge and basic charge
Economic Efficiency: Price signals to encourage efficient use and discourage inefficient use	**Very Good** Three price periods reflects marginal costs	**Good** Two price periods somewhat reflects marginal costs
Fairness: Fair Appointment of costs among customers; avoid undue discrimination	**Good** Capacity benefit cost ratio is good Revenue to cost ratio is good	**Very Good** Capacity benefit cost ratio is very good Revenue to cost ratio is good
Practicality: Customer understanding and acceptance, practical and cost effective to implement; freedom from controversies as to proper interpretation	**Very Good** Bill savings with load shifting are high enough to attract participation Bill savings without load shifting are low enough to discourage free ridership	**Moderate** Bill savings with load may be too low to attract participation Bill savings without load shifting may attract some free riders
Stability: Recovery of the revenue requirement; revenue and rate stability	**Good** The rates are predictable and revenue neutral	**Good** The rates are predictable and revenue neutral

Residential Time-of-Use Rate Designs

Robert Zeni
Senior Regulatory Specialist, Regulatory

92

Available for accounts with annual consumption up to 50,000 kW/year

- Residential service accounts with consumption > 50,000 kWh/yr are primarily business operations
- Their high load factor and majority exposure to Step 2 means they would get substantial bill savings under a residential time of use rate, **without load shifting**
- As they use electricity differently than households, we have little confidence that they would shift load in response to a residential time of use rate

BC Hydro
Power smart

Annual Consumption (kWh)	Number of Customers	Average Energy Usage (kWh)	Average Annual Bill Under RIB	Average Annual Bill Under TOU w/o Load Shifting	Average Annual Bill Savings
50k – 100k	3,425	65,500	$8,900	$7,350	$1,550 / 17%
> 100k	1,641	172,000	$24,000	$19,100	$4,900 / 20%

93

Time-of-use pricing in winter only

- The economics of offering year-round time of use pricing that applies to an entire residential account are not supportable
- The value to BC Hydro of time of use rates comes from the capacity savings that occur in our winter peak demand period
- Discounted overnight pricing outside of winter reduces customer bills and erodes BC Hydro revenue without a corresponding benefit to BC Hydro
- The approach aligns with industry standards: a survey of > 150 residential time of use rates found that 78% offer time of use pricing in the utility's peak demand season only[1]

Note 1: The Electricity Journal 30 (2017) 64–72; A. Faruqui et al; Arcturus 2.0: A meta-analysis of time-varying rates for electricity.

BC Hydro
Power smart

Optional residential time-of-use rates

Option 1: Three Price Periods, Winter Weekday, <50,000kWh/yr Accounts only

Preliminary Rates			
Energy Charge	7:00 AM – 4:00 PM 9:00 PM – 11:00 PM	10.33 ¢/kWh	Weekdays November 1 to February 28 Daily
Energy Charge	4:00 PM – 9:00PM	26.37 ¢/kWh	
Energy Charge	11:00 PM – 7:00 AM	4.54 ¢/kwh	
Energy Charge	All hours	11.44 ¢/kWh	All day not listed above
Basic Charge	20.8 ¢/day		Daily

Preliminary Assessment			Illustrative Customer	
	Benefit / Cost Ratio	Revenue / Cost Ratio	Bill Savings with Load Shifting	Bill Savings without Load Shifting
Household load only	0.3*	94%	$67	$44
Household with EV	0.8	97%	$146	$101

* Can improve by marketing Time Of Use to “high load shifting potential” households

Optional residential time-of-use rates

Option 2: Three Price Periods, Winter Daily, <50,000kWh/yr Accounts only

Preliminary Rates			
Energy Charge	7:00 AM – 4:00 PM 9:00 PM – 11:00 PM	10.33 ¢/kWh	Weekdays November 1 to February 28 Daily
Energy Charge	4:00 PM – 9:00PM	26.37 ¢/kWh	
Energy Charge	11:00 PM – 7:00 AM	4.54 ¢/kwh	
Energy Charge	All hours	11.44 ¢/kWh	All day not listed above
Basic Charge	20.8 ¢/day		Daily

Preliminary Assessment			Illustrative Customer	
	Benefit / Cost Ratio	Revenue / Cost Ratio	Bill Savings with Load Shifting	Bill Savings without Load Shifting
Household load only	0.3*	94%	$83	$62
Household with EV	0.7	95%	$145	$93

* Can improve by marketing Time Of Use to “high load shifting potential” households

Residential time-of-use Bonbright assessment

Bonbright Principle	Option 1 Three price periods, winter weekday	Option 2 Three price periods, winter daily
Economic Efficiency: Price signals to encourage efficient use and discourage inefficient use	**Very Good** Pricing reflects marginal costs	**Good** Pricing reflects marginal costs
Fairness: Fair Appointment of costs among customers; avoid undue discrimination	**Moderate** Capacity benefit cost ratio is poor but can be improved if high load shift potential customers are targeted Revenue to cost ratio is good	**Moderate** Capacity benefit cost ratio is poor but can be improved if high load shift potential customers are targeted Revenue to cost ratio is good
Practicality: Customer understanding and acceptance, practical and cost effective to implement; freedom from controversies as to proper interpretation	**Good** Bill savings with load shifting are high enough to attract participation Weekday only pricing may attract participants Bill savings without load shifting are low enough to discourage free ridership	**Good** Bill savings with load shifting are high enough to attract participation Bill savings without load shifting are low enough to discourage free ridership
Stability: Recovery of the revenue requirement; revenue and rate stability	**Good** The rates are predictable and revenue neutral	**Good** The rates are predictable and revenue neutral

97

Special conditions

Electric vehicle peak reduction

- Enrollment is on an opt-in basis
- Available for service primarily for home charging of electric vehicle(s)
- Electric vehicle load must have a separate meter and be associated with a primary residence
- If a customer chooses to opt-out, the electric vehicle meter consumption will be aggregated to the primary residence meter consumption and be billed under the selected whole home rate.
- Must be billed monthly on paperless billing
- Equal Payment Plan, Net Metering and Meter Choices Program customers are not eligible
- Minimum enrollment is one billing period, if a customer opts out of the time-of-use rate they cannot re-enroll in the rate for one year

Residential time-of-use

- Enrollment is on an opt-in basis
- Must have a BC Hydro smart meter
- Must be billed monthly
- Must be paperless billing
- Equal Payment Plan, Net Metering and Meter Choices Program customers are not eligible
- Minimum enrollment is one billing period, if a customer opts out of the time-of-use rate they cannot re-enroll in the time-of-use rate for one year

Monitoring and evaluation

- Annual Monitoring
  - Participation
  - Customer satisfaction / complaints
- Three Year Evaluation
  - Analyze the economic impact on all rate payers
  - Analyze the fully allocated cost of service
  - Assess the extent of any free-ridership
  - Customer and stakeholder feedback
- Three-year evaluation report to be filed with the British Columbia Utilities Commission and potentially inform re-pricing

Closing Remarks

Chris Sandve
Chief Regulatory Officer

BC Hydro
Power smart

100

Thank you

Please complete the online Feedback Form by Friday Nov 26

BC Hydro
Power smart

BC Hydro Optional Residential Time-of-Use Rate Application

Appendix D-4

Rate Design Workshop Feedback Summary – November 2021

Residential Rates Stakeholder Workshop #2

Feedback Summary Report – November 18 2021

A. SESSION OBJECTIVES

The objectives of the workshop were to:

- Provide information about the rate design options being considered for the standard residential rate and new optional time-based rates planned to be introduced to residential customers;
- Collect feedback to help shape future residential rate designs; and
- Inform a Rate Design application to the BC Utilities Commission.

B. METHODOLOGY

Feedback was collected using an online feedback form available to participants. A link was provided at the end of the session and delivered via email on November 23 with a request to complete by November 26, 2021.

C. PARTICIPATION

Fourteen (21%) of the 66 participants accessed the feedback form including one that partially completed the questions and two that abandoned with no responses, resulting in 11 (79%) completes.

D. KEY THEMES

Although no definitive positions were expressed to support or oppose the default and optional rates, several verbatim responses leaned more positively towards a shift towards a flat rate.

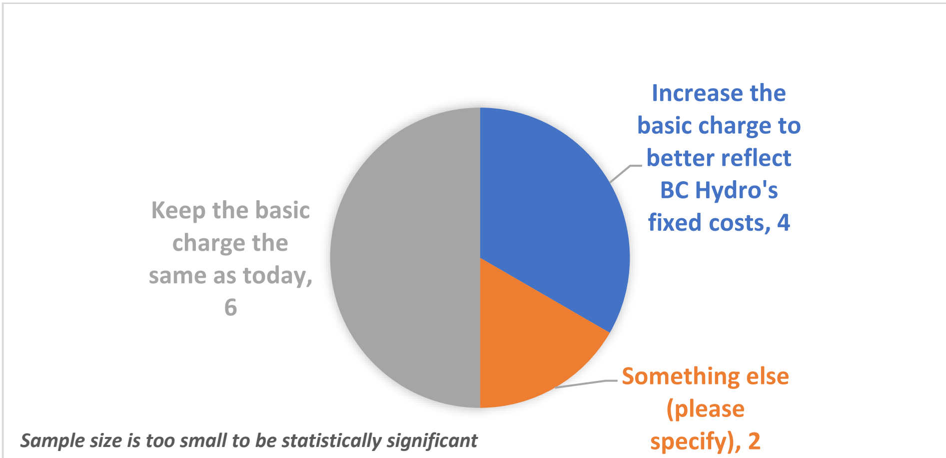
When asked for additional comments, responses were varied with no strong theme and included sentiments that relate to the following general concepts:

- Concern for potential impacts to the low-income customers.
- Separately metered TOU implementation is impractical and too expensive.
- Suggestions to use incentive programs to drive electrification.
- Too much change for customers to tolerate if basic charge and default rate adjusted at the same time or too quickly.
- Opposition to any concepts that may limit participation such as restricting access based on paperless, billing cycle, or enrollment in existing BC Hydro programs.

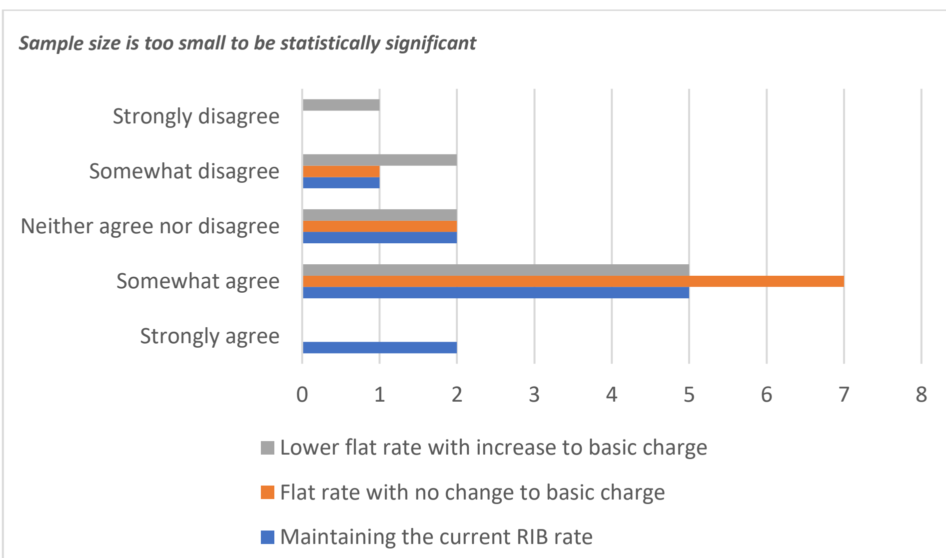
E. FEEDBACK FORM RESULTS

The feedback form was comprised of several open and closed ended questions that participants had the option to respond to with the following results and verbatims.

Q7: The basic charge is a fixed daily charge that partially recovers BC Hydro's fixed customer related costs. These costs don't vary much based on the amount of electricity a customer uses. The current basic charge for residential customers recovers about 60% of those fixed customer-related costs. **Thinking about the people you represent, which option would they prefer if BC Hydro advances a flat rate in its February 2022 application?**



Q9: Do you agree with BC Hydro's preliminary assessment of the default rate designs against the Bonbright rate design principles?

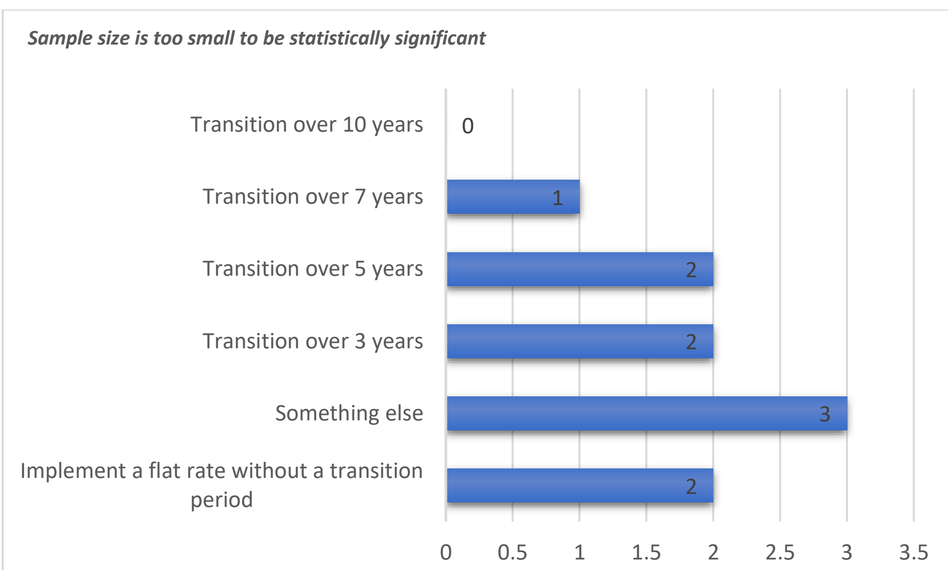


Additional verbatim comments on the Bonbright assessment.

- Bonbright principles are insufficient, colonial and outdated; they do not address equity or environmental outcomes.

- I'm concerned that the changes BC Hydro is making will be punitive for low-income customers. I think more focus needs to be paid to customer groups, house sizes, and income levels to ensure that "fair" doesn't mean punitive to low-income households, who are already struggling with costs (such as rent, heat, food, insurance, etc). Increasing costs will lead to cutting heat, food, insurance resulting in potentially catastrophic issues.
- Will the rate structure change consumer behavior that Bonbright impact.
- We do not agree with the 'poor' practicality assessment of lower/ cost-based energy rate. See attached comments [Appendix B].
- With future risk such as distributed generation (e.g. solar panels on roofs), it would be good to increase the basic charge to better reflect the costs of connecting to the grid (and getting the benefits of grid connections such as frequency stability, suck & blow energy, capacity on demand etc.). Bills need to change to ensure that those that partially defect from the grid pay their fair share, otherwise those that cannot defect (e.g. low/fixed income) will cross subsidize those that can (e.g. solar panel installers).
- BC Hydro's current low marginal cost and surplus of energy will not last. In the longer term, the marginal cost will be for renewable energy, and with electrification, Hydro will be in increasing deficit. This should be reflected somehow in current calculations.
- I would question Flat rate with Same Basic for Practicality. 1.4 customers with higher bills over the duration of the transition is material.

Q11: Thinking about the individuals you represent, if BC Hydro were to move to a flat rate, over how many years should the transition take place?

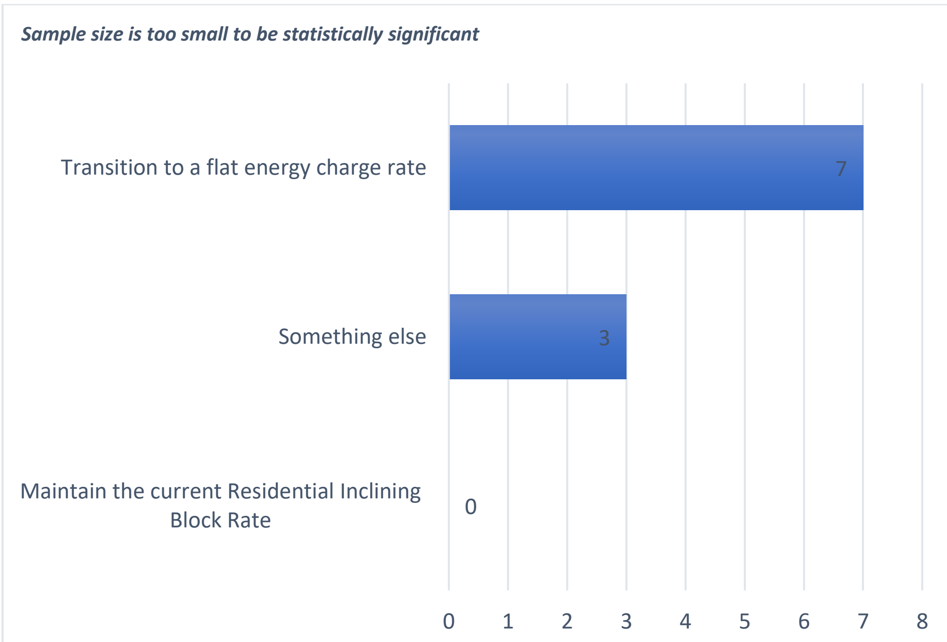


Additional verbatim comments from those who responded “Something else”:

- Never, based on BC Hydro's slides the transition to a flat rate will increase utility costs by $51 per month [sic – is per year], which is not acceptable.

- Transition should not be so long and should be to more comprehensive change. See attached comments. [Appendix B]
- 0 - 3 years seems reasonable

Q12: Again, thinking about the individuals you represent; which option do you think they'd most like BC Hydro to apply for with the BCUC?



Additional verbatim comments from those who responded "Something else":

- These are people who don't have money and can't afford increasing costs. BC Hydro needs to incorporate ability to pay into the calculations
- Transition to more comprehensive change. See attached comments. [Appendix B]
- While BCSEA supports the energy conservation signal of the RIB, we recognize that it may not support all aspects of a sustainable energy transition.

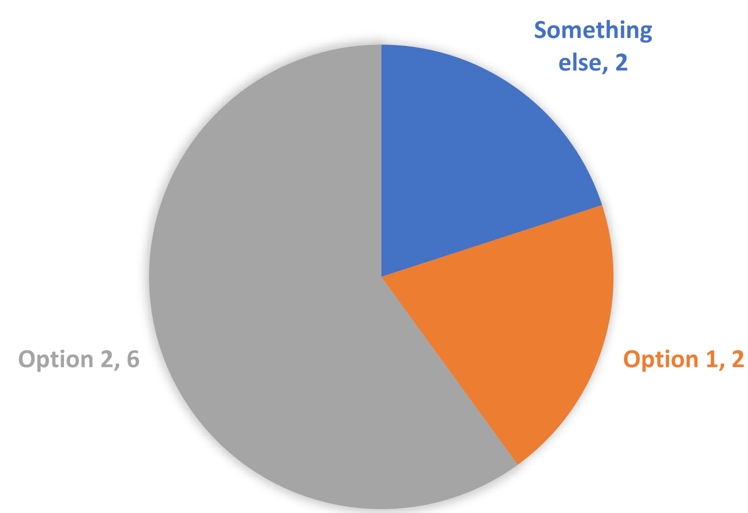
Q13: Please provide any other feedback on the default residential rates.

- From an electrification and climate mitigation and resilience perspective (to protect against overheating), we should remove barriers to heat pumps as much as possible.
- "As originally implemented, the RIB was an energy conservation measure. In retrospect it didn't work out that way. It encouraged high energy residential users to use natural gas instead of renewable electricity. Over a decade ago the Clean Energy Act came into effect and one of the stated objectives is: "to encourage the switching from one kind of energy source or use to another that decreases greenhouse gas emissions in British Columbia".
- If it wasn't urgent to reduce GHGs over a decade ago it certainly is now. But there is a problem with eliminating RIB. Residential Customers who don't use much electricity have

gotten used to paying the Tier 1 rate. It is unlikely they will be able to benefit from a flat rate or time of use rate for electric vehicles or heat pumps. As an aside separately metered time of use rates are not practicable. Too expensive to implement and administer.

- The solution to the problem is to unwind RIB and mover to a flat rate at roughly the same rate the carbon tax is increasing with complete elimination by 2030. With a larger unwind initially to reflect the current carbon tax of $45 per tonne.
- Transitioning to a flat rate is a good step towards alleviating the highest bill impacts for rural households in energy poverty. However, it will increase bills for the majority of customers. Therefore this transition should be complimented with a bill protection program for low-income customers that will see bill increases. This could be a ratepayer or a taxpayer program.
- I think that BC Hydro needs to improve their support for low income households, by incorporation a low income rate, increase capital incentives, and increase study incentives. This support will help low income households to have healthier homes, reduce costs, and increase their quality of life!
- The change to the flat rate charge is needed if you are going to expand EV charging and electrification in buildings
- Mandated electrification is most likely to hit seniors, low/moderate income and social housing the worst. Rates need to reflect that fact. Subsidized localized power generation (e.g. rooftop solar) is being used heavily in other jurisdictions to both offset these increased costs, and reduce the need for expensive Hydro generation and transmission investments.
- Please consider and explain the future risk more completely with regards to the selected rate design. For example, the impact of high-income customers partially defecting (e.g. energy but not capacity defection) via installing solar panels. Also, provide discussion about which options better align with the value of capacity (e.g. fixed costs that are installed to address connection capacity even if energy is low). The discussion to date has not included enough about the alignment with the increasing value of capacity (and decreasing value of energy) that comes with intermittent generation, EV charging etc.
- BCSEA is concerned that flattening the RIB would increase bills for the majority of low-consuming customers and reduce bills for the highest consuming customers. This goes in the wrong direction for encouraging DSM. It also goes mostly in the wrong direction for mitigating energy poverty. BCSEA recognizes that BC Hydro wants to encourage more use of electricity, but that should be aimed at switching users from fossil fuels onto electricity, i.e. rather than encouraging the wasteful use of electricity by residential customers who are already large consumers.
- I expressed support for no change to Basic because the bill impacts would exacerbate the bill impacts of a RIB to Flat transition.
- See attached comments [Appendix B]

Q15: Thinking about the individuals you represent, which pricing principles option do you think BC Hydro should propose for Fiscal 2023 (i.e. effective April 1, 2022)?

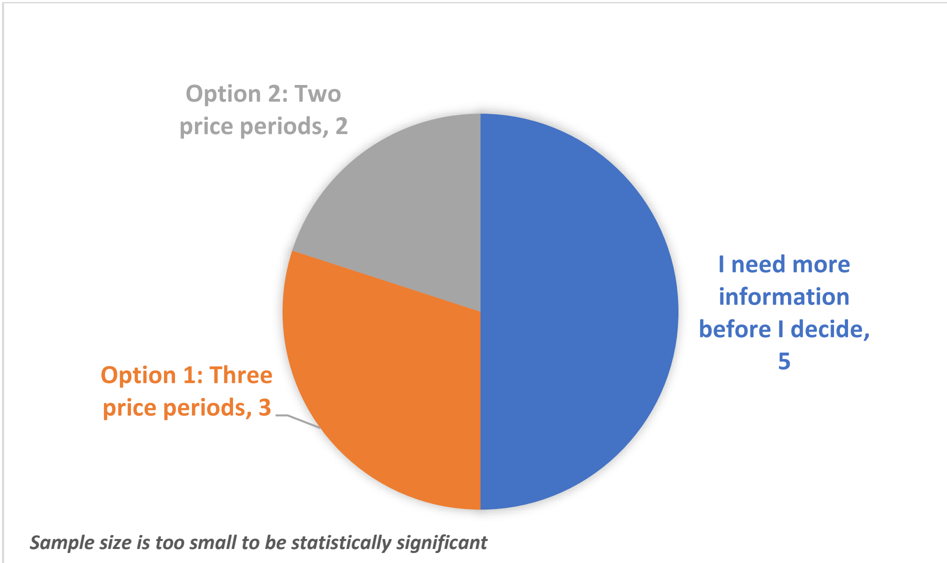


Sample size is too small to be statistically significant

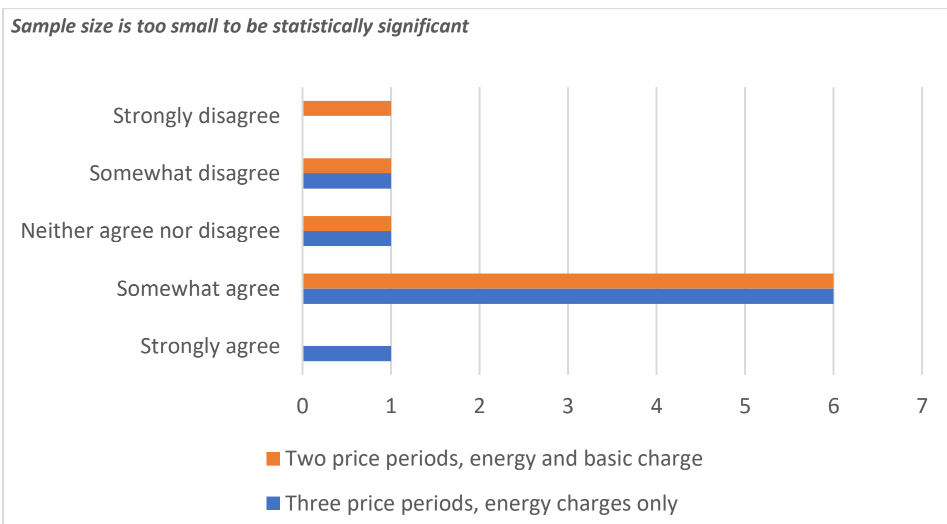
Additional verbatim comments from those who responded "Something else":

- Option 2 is the minimum that should be done to move to better rate

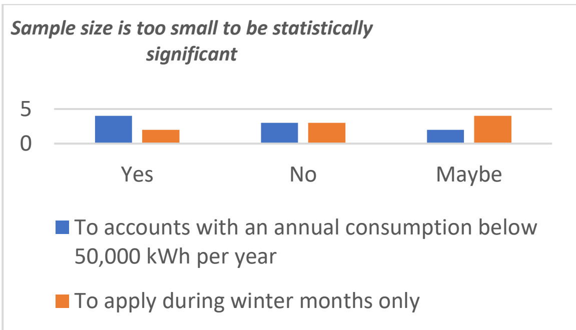
Q17: Which option do you prefer for the opt-in electric vehicle peak reduction rates?



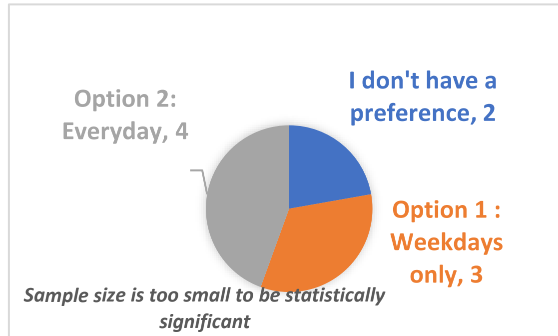
Q18: Do you agree with our preliminary assessment of the of the electric vehicle reduction rates against the Bonbright rate design principles?



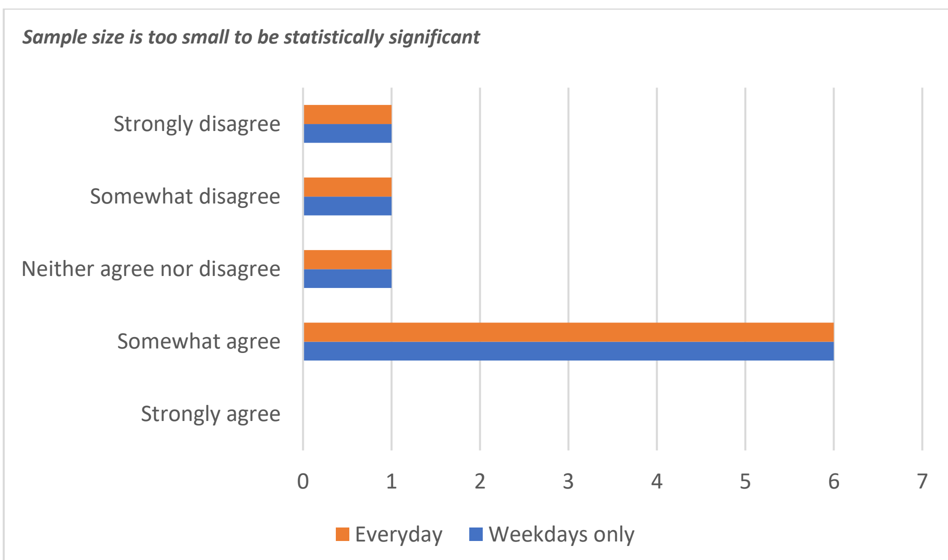
Q20: Do you support limiting availability of the opt-in whole home time of use rate?



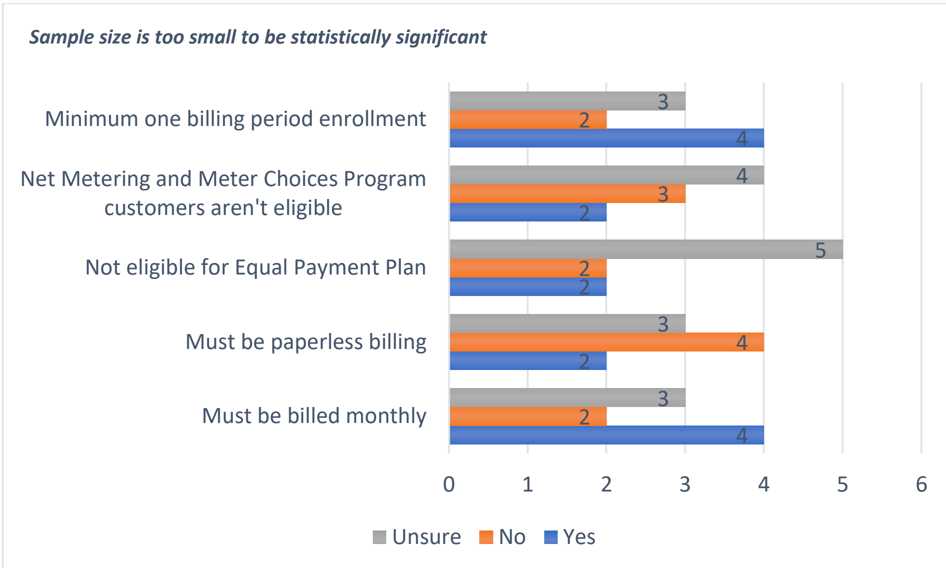
Q22: Which option do you prefer for an opt-in whole-home time-of-use-rate that applies in winter months (November, December, January, February)?



Q23: Do you agree with our preliminary assessment of the of the optional residential time-of-use rate against the Bonbright rate design principles?



Q24: Special conditions - Do you support the following proposed terms and conditions?



Q27: Can you tell us more about why you don't support the special condition(s)?

- I don't understand why paperless billing is necessary. I mean, it's good to be paperless but why is it a program condition? As for re-enrollment - having to wait a whole year to re-enroll is a long time and you might penalize those whose circumstances change and by then time one year rolls around they would have lost interest or motivation to re-enrol. I think a shorter timeframe (6 months?) to re-enrollment would discourage people from signing on and then cancelling (and creating administrative burden for Hydro) but also provide some flexibility for people whose circumstances change.
- It is not clear why a one-month billing period is required for the program to succeed. If this "pilot" in extended to all customers, BC Hydro is suggesting that all bills will change to monthly billing and it is not clear that BC Hydro is suggesting this change to all customers (if so, state so clearly and the reasons why and I may change the position at that time).
- People interested in net metering will be interested in renewable energy and likely also to be interested in EVs. They should not be forced to choose between a rate that supports NM and a rate that supports EV charging -- bad optics.

Q25: Do you have any other feedback on optional rates that you'd like to share?

- I would explore technologies that make it easy for consumers to reduce their peak power consumption - building batteries and phone apps.
- How will this work for strata corporations and tenants in rental/commercial/industrial buildings?

- Paper billing should be maintained for those that are less computer savy (e.g. older people, marginalized groups). Paper billing ensures equitable access to programs that should not be reserved exclusively for the more affluent or tech savy customers. Select "one wheel" for billing and apply it to all customers consistently.
- I put maybe for the special condition Must be paperless billing. I don't know enough about the benefits. The downside is that it may attract opposition to the entire rate design option based on a concern (for people without internet access even though) that isn't essential for the rate design to be successful.
- See attached file [Appendix B]

Appendix A: Rates Stakeholder Session Feedback Form

Q1 Thank you for attending our stakeholder engagement session on November 18. We invite you to provide your feedback, on what you heard during the session, including any concerns you might have with the rate options we're exploring. To help with completing the feedback form, you can refer to the slides we shared during the session. Your feedback is important and will be considered as part of our application to the BC Utilities Commission (BCUC) that we plan to submit early next year.

It's important to note that your feedback, including the organization you're representing, will be used by BC Hydro and included in the application and will become part of the public records resulting from the regulatory proceeding. Please don't identify third-party individuals or account specific information in your comments. Comments bearing references to identifiable individuals will not be included as part of the public records due to privacy concerns.

Any personal information you provide to BC Hydro in this form is collected and protected in accordance with the Freedom of Information and Protection of Privacy Act. BC Hydro is collecting information for the purpose of rate design in accordance with BC Hydro's mandate under the Hydro and Power Authority Act, the BC Hydro Electric Tariff, the Utilities Commission Act and related Regulations and Directions. If you have any questions about the collection or use of the personal information collected on this form please contact the BC Hydro Regulatory Group via email at: bchydroregulatorygroup@bchydro.com.

Q2 Your contact information: Name

Q3 Title:

Q4 Community or organization:

Q5 Representing (if different from community or organization)

Q6 Contact e-mail:

Q7 Basic charge (slides 43 - 44)
The basic charge is a fixed daily charge that partially recovers BC Hydro's fixed customer related costs. These costs don't vary much based on the amount of electricity a customer uses. The current basic charge for residential customers recovers about 60% of those fixed customer-related costs.

Thinking about the individuals you represent, which option would they prefer, if BC Hydro applies for a flat rate in its February 2022 application?

O Keep the basic charge the same as today

O Increase the basic charge to better reflect BC Hydro's fixed costs

O Something else (please specify)

Q8 Default rates - Bonbright Principles (slide 45)

Q9 Do you agree with BC Hydro's preliminary assessment of the default rate designs against the Bonbright rate design principles?

	Strongly disagree	Somewhat disagree	Neither agree nor disagree	Somewhat agree	Strongly agree
Maintaining the current RIB rate	O	O	O	O	O
Flat rate with no change to basic charge	O	O	O	O	O
Lower flat rate with increase to basic charge	O	O	O	O	O

Q10 Please add any additional comments on the Bonbright assessment.
Please don't include any names or personal information in your response.

Q11 Implementation Options (slides 48 - 51)Thinking about the individuals you represent, if BC Hydro were to move to a flat rate, over how many years should the transition take place?

- O Transition over 3 years
- O Transition over 5 years
- O Transition over 7 years
- O Transition over 10 years
- O Implement a flat rate without a transition period
- O Something else ____

Q12 Again, thinking about the individuals you represent; which option do you think they'd most like BC Hydro to apply for with the BCUC?

- O Maintain the current Residential Inclining Block Rate
- O Transition to a flat energy charge rate
- O Something else ____

Q13 Please provide any other feedback on the **default** residential rates.
Please don't include any names or personal information in your response.

Q14 Preliminary F2023 RIB pricing principles (slides 53 - 54)
RIB Pricing Principles refer to how general rate increases are applied to the three elements of the RIB rate – basic charge, Step 1 and Step 2 energy charges. The current RIB pricing principles will expire on March 31, 2022. BC Hydro needs to apply for new RIB pricing principles to be effective April 1, 2022 prior to the completion of the Residential Rate Design Application proceeding. BC Hydro typically applies general rate increases or decreases equally to the three RIB rate elements. We are exploring different pricing principles options for April 1, 2022.

Option 1: Apply the general rate increase of 0.62% equally to the three RIB rate elements. Combined with a 2% credit from the Deferral Account Rate Rider, this results in all customers' bills reducing by around 1.4%.

Option 2: Reduce the price gap between Step 1 and Step 2 by freezing the Step 2 price and increasing the basic charge by 0.62% and the Step 1 price by 1.17%. Combined with a 2% credit from the Deferral Account Rate Rider this results in customers with low consumption experiencing a bill reduction of about 1% and customers with high consumption experiencing a bill reduction of almost 2%.

Q15 Thinking about the individuals you represent, which pricing principles option do you think BC Hydro should propose for Fiscal 2023 (i.e. effective April 1, 2022)?

O Option 1

O Option 2

O Something else ____

Q17 Optional Rates

Slides 89 - 90
Which option do you prefer for the opt-in electric vehicle peak reduction rate?

O Option 1: Three price periods

O Option 2: Two price periods

O I need more information before I decide

Electric vehicle peak reduction: Bonbright Criteria (slide 91)

Q18 Do you agree with our preliminary assessment of the of the electric vehicle reduction rates against the Bonbright rate design principles?

	Strongly disagree	Somewhat disagree	Neither agree nor disagree	Somewhat agree	Strongly agree
Option 1: Three price periods, energy charges only	O	O	O	O	O
Option 2: Two price periods, energy and basic charge	O	O	O	O	O

Q20 Slide 93 – 94 Do you support limiting availability of the opt-in whole home time of use rate :

	Yes	Maybe	No
To accounts with an annual consumption below 50,000 kWh per year	O	O	O
To apply during winter months only	O	O	O

Q22 Slides 95 - 96 Which option do you prefer for an opt-in whole-home time-of-use rate that applies in winter months (November, December, January, February)

O Option 1 : Weekdays only

O Option 2: Everyday

O I don't have a preference

Q21 Residential time-of-Use Bonbright Criteria (slide 97)

Q23 Do you agree with our preliminary assessment of the of the optional residential time-of-use rate against the Bonbright rate design principles?

	Strongly disagree	Somewhat disagree	Neither agree nor disagree	Somewhat agree	Strongly agree
Option 1: Weekdays only	O	O	O	O	O
Option 2: Everyday	O	O	O	O	O

Q24 Special conditions (slide 98)
Do you support the following proposed terms and conditions?

	Yes	No	Unsure
• Must be billed monthly	O	O	O
• Must be paperless billing	O	O	O

• Not eligible for Equal Payment Plan	O	O	O
• Net Metering and Meter Choices Program customers aren't eligible	O	O	O
• Minimum one billing period enrollment,(i.e. if a customer opts out of the time-of use-rate they cannot re-enroll in the rate for one year)	O	O	O

Can you tell us more about why you don't support the special condition(s)?

Q25 Do you have any other feedback on **optional** rates that you'd like to share?
Please don't include any names or personal information in your response.

Appendix B: Feedback provided via Email from Marvin Shaffer and Jim Quail and referenced in Feedback Form responses

Subject: Comments on BC Hydro November 18 Residential Rate Design Workshop

Body of Email:

The answers to the feedback form refer to an attached file. It provides a more detailed explanation of our thoughts on the workshop presentation. It is attached below since there was no opportunity to attach it to the feedback form.

Marvin Shaffer and Jim Quail

Attachment Contents:

In its workshop on residential rate design, BC Hydro presented an alternative to its current residential inclining block (RIB) rate structure as well as two 'opt-in' optional rates. Driving BC Hydro's pursuit of alternatives to RIB is its desire to better align residential rates with key rate design objectives of economic efficiency, affordability, flexibility and the effective promotion of government decarbonization policy.

RIB does not serve these rate design objectives well. The current rate structure is not economically efficient; it does not signal customers the cost consequences to BC Hydro of more or less electricity use. The second-tier rate in particular, which was originally intended to reflect the long run marginal cost of energy (and which in itself is problematic because it is the short not long run marginal cost that determines the incremental costs or value to BC Hydro of more or less energy use) is far too high. Long run marginal costs of energy have fallen well below the current second-tier rate and short run marginal costs are much lower still.

The current rate structure does not support the government's decarbonization policy. Customers who shift from fossil fuel to electric heating and vehicles will likely have to pay the high second-tier rate for their incremental electricity use. Rather than support decarbonization, the current rate structure in fact works against it.

With respect to affordability, the current rate structure does generate lower average rates for lower use customers, but the correlation between electricity use and income is far from perfect. Whether one benefits or not from RIB depends largely on size and type of dwelling and on fuel use for heating and other applications. Arguably RIB unfairly discriminates against larger, often multi-generational families living in larger homes and customers who have electric heating and appliances for environmental or other reasons, including limited access to natural gas.

As for flexibility, there is none – there is only one residential rate option.

To its credit, BC Hydro was clear that continuation of the RIB rate is not desirable. However, it is unfortunate that BC Hydro presented only one 'default' rate alternative to RIB – flattening the energy rate to the revenue-neutral equivalent of the current two-tier structure.

The problem with RIB is not just the two tiers. As BC Hydro itself indicated, the energy rate is too high – well above energy costs – and the fixed customer charge is too low – far less than capacity and other fixed costs. Given the growing importance of fixed relative to energy costs in BC Hydro's overall cost structure and the critical need to lower energy rates in accordance with low energy costs to maximize efficient use of the BC Hydro system, it would be appropriate and timely to develop and evaluate other alternatives to RIB, in particular alternatives that address not only the two-tier rate structure but also the very problematic imbalance between energy and fixed charges.

The time-of-use (TOU) and electric vehicle (EV) 'opt-in' optional rates BC Hydro presented would appear to be the principal way BC Hydro proposes to address the limitations of simply flattening the energy charge. But like the optional rates BC Hydro has put forward for other customer classes, this approach is inherently limited, bureaucratic and unnecessarily costly.

The 'opt-in' nature of the TOU rate will almost certainly result in limited participation. And whatever participation there is, the TOU rates that BC Hydro has proposed will limit the opportunities and benefits customers and BC Hydro can realize. The varying rates would only address peak capacity concerns; they would not signal the varying cost or value of energy by time of day and season. Participation and benefit from the EV rate would also be limited because of the costs of the separate metering and monitoring for unintended use it would require.

A different approach that comprehensively addresses the problems with the current RIB rate should be considered.

The starting point for a rate structure alternative that better aligns with BC Hydro's key objectives of efficiency, support for decarbonization and flexibility would be to separate the recovery of energy costs from capacity and other fixed costs. It is the use of the energy rate to recover a significant amount of fixed costs that underlies the inefficiencies and discouragement of electrification in the current and to a lesser degree flattened rate alternative BC Hydro has proposed.

With energy rates designed to recover energy costs, BC Hydro could offer customers a wide range of choice – fixed energy rates, different TOU rate packages or other options, like the critical peak pricing BC Hydro referenced in the workshop – all without the need to monitor and constrain what options customers chose. There would be no free rider or unintended use concerns because in all cases the energy rates would reflect the estimated costs of energy the customers would consume and fixed costs would be recovered separately. The resources and costs BC Hydro would have to incur to deal with these concerns under its proposals could instead be devoted to more productive customer service, helping customers make the best choice to suit their specific interests and needs.

The recovery of fixed costs is challenging, but that is something BC Hydro needs to directly address given the growing importance of these costs. Ideally the fixed cost charge that customers face should reflect in a simple and practical manner their contribution to capacity and other fixed system requirements. Some measure of service level or capacity requirement would have to be used. Further work is needed to develop the best way to do that, but the answer is not to pretend the problem doesn't exist by burying ever-increasing fixed charges in the energy rate.

While separating energy from fixed cost recovery will encourage more efficient energy use and decarbonization, as well as enable much greater customer choice and flexibility, it will result in higher overall bills for low use customers. Low use customers have benefitted from a rate structure that discriminated in their favour since RIB was introduced and change will raise concerns. But the fact is, with growing capacity and other fixed system costs, it is expensive serving low use customers, not all of whom are low-income households deserving of what in effect is a rate subsidy. And it is inefficient and counter to decarbonization objectives to continue to recover fixed costs in the energy rate.

Phasing in changes in the rate structure can mitigate concerns about rate shock, though consideration of the magnitude of the bill impact, not just percentage change is important to determine what length of phase-in is warranted. As for affordability, a much more targeted approach is needed than simply protecting all low use customers from the costs of the low use service they demand.

For example, working with the provincial government and as authorized by government directive, BC Hydro could develop a schedule of fixed charge discounts tied to household income or other indicator of affordability. Other low-income support programs could also be considered.

In summary, while the case for moving away from the current RIB rate structure is clear, the alternative BC Hydro has put forward does not adequately address the problems with the current rate. Alternatives which more comprehensively address the problems with the current rate need to be developed and evaluated, providing a principle-based, more efficient and equitable path forward.

BC Hydro Optional Residential Time-of-Use Rate Application

Appendix D-5

Optional Residential TOU Rate Workshop Slides and Information Booklet - November 2022

Log-in Instructions

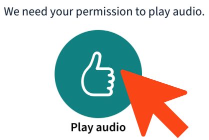
Technical Issues?
Send email to:
bchydroregulatorygroup@bchydro.com

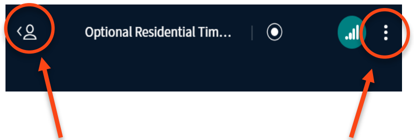
Step 1: Copy link into your browser (on desktop or mobile device):
https://bbb.allwestbc.com/b/bch-loq-ymr-zvk

Device	Recommended Browser
Laptop/desktop	Google Chrome, Mozilla Firefox or Microsoft Edge
iPhone/iPad	Safari
Android phone or tablet	Google Chrome

Step 2: Enter your full name (first and last name) and click "Join"

Step 3: If prompted, select "Play audio".





Click on this icon to access the chat

Click on this icon to make the presentation fullscreen

How to participate:

- Please keep your microphone and video off to help with connectivity issues and limit distractions.
- For those joining virtually, please use the **Chat** feature to ask questions.
- **TIP:** Use the three dots in the upper right corner to maximize the presentation by selecting "Make fullscreen".

BC Hydro
Power smart

Optional Residential Time-of-Use Rate Workshop

November 29, 2022

BC Hydro
Power smart

Workshop Agenda

Time	Agenda Item	Presenter
9:00 – 9:05	Welcome	Cynthia Curll, Moderator
9:05 – 9:15	Opening Remarks	Keith Anderson, Vice President, Customer Service
9:15 – 9:35	Background and Context	Chris Sandve, Chief Regulatory Officer
9:35 – 9:55	Summary of engagement to date	Mario Laszczak, Customer Policy and Engagement Manager
9:55 – 10:45	Proposed Optional Time-of-Use Rate	Shiau-Ching Chou, Senior Regulatory Manager
10:45 – 11:00	Break	
11:00 – 11:30	Demand Side Management	Pat Mathot, Residential Marketing Manager
11:30 – 11:45	RIB Pricing Principles	Chris Sandve, Chief Regulatory Officer
11:45 – 12:00	Wrap Up and Next Steps	Chris Sandve, Chief Regulatory Officer

Objectives for today's session

- **Provide context and updates since we last met**
- **Provide a summary of engagement to date and insights**
- **Review new proposed optional residential TOU rate design**
  - Respond to questions and gather your feedback
- **Review Residential Demand Side Management programs**
  - These programs complement an optional time-of-use rate
- **Review our Residential Inclining Block (RIB) pricing principles proposal**
- **Review next steps**

BC Hydro
Power smart

Opening Remarks

Keith Anderson, Vice President

Customer Service

BC Hydro
Power smart

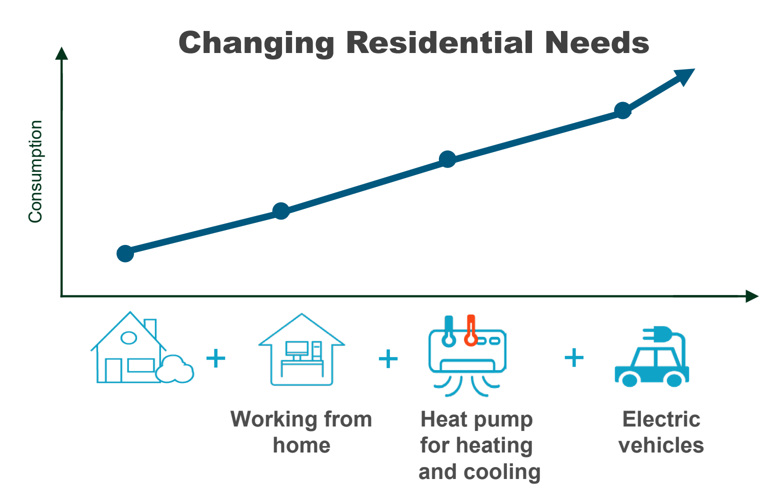
What is rate design?

Rate design refers to pricing, charges, and terms & conditions of service

	Revenue Requirements	Cost of Service Analysis	Rate Design
Process:	Revenue Requirements	Cost of Service Analysis	Rate Design
What it means:	How much revenue we need: ▪ to be able to operate ▪ to serve our customers	▪ Cost of energy (cents per kWh) ▪ Cost of demand (dollars per kW) ▪ Fixed cost per account (dollars per account)	Identify the following in order to recover our costs: ▪ pricing ▪ charges ▪ terms & conditions

Customers' energy needs are evolving

- Changes in customer energy needs and expectations
- Increased focus on climate change and environmental impacts
- Changes in BC Hydro's costs, such as a reduction in the cost of new energy supply, and the potential need to invest in transmission and distribution infrastructure



Background and Context

Chris Sandve

Chief Regulatory Officer

BC Hydro
Power smart

BC Hydro's rate design objectives

Affordability

Measured by bill impacts associated with a rate design

Economic efficiency

Measured by how closely the energy charge reflects our marginal cost

Decarbonization

Measured by how much the rate design encourages switching from fossil fuels to clean electricity

Flexibility

Measured by the ability to respond to changes in the economic and policy environments and anticipate the need for greater product and service differentiation in rate design

BC Hydro
Power smart

Why is BC Hydro Proposing An Optional Residential Time-of-Use Rate?

- Customer Choice
- Electric Vehicles
- 2021 Integrated Resource Plan

1. Pursue voluntary time-varying rates supported by demand response programs to achieve approximately 220 MW of capacity savings at the system level by fiscal 2030
2. Pursue a combination of education and marketing efforts as well as incentives for smart-charging technology for customers to support a voluntary residential time-of-use rate to shift home charging by 50 per cent of residential electric vehicle drivers to off-peak demand periods to achieve approximately 100 MW of capacity savings at the system level by fiscal 2030

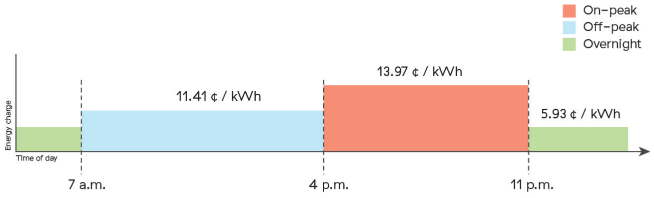
Last November....

We showed you these leading optional residential time-of-use rate design concepts.

EV Only Time-of-Use Rate

Available for separately metered EV Charging

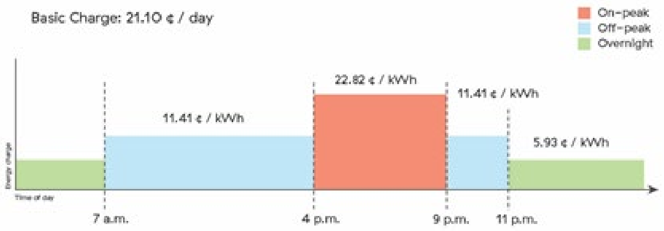
Year Round



Whole Home Time-of-Use Rate

Winter

Basic Charge: 21.10 ¢ / day



Non-Winter

Basic Charge: 21.10 ¢ / day

Pricing structure applies from March through October.

Challenges with These Rate Designs

- With time-of-use rate, amount that a customer pays should depend on their **load shape**
- However, when the default rate is an inclining block rate, the amount that a customer pays depends on both their **load shape** and **overall consumption**

This creates two problems

- **Low Participation:** Customers with low overall consumption can't save because the **time-based charges are too high**
- **Structural Winners:** Customers with high overall consumption save without reducing their peak demand because the **time-based charges are too low**

Concept Question

Is there a way to avoid charging customers more/less based on overall consumption?

BC Hydro
Power smart

Engagement Summary

Mario Laszczak, Manager

Customer Policy and Engagement

BC Hydro
Power smart

Engagement | Consultation Process

- In December 2020, BC Hydro began a process to engage with residential customers and stakeholders as it explored opportunities to update residential rates.
- 2 phases of engagement over 14 months:

- Quantitative and qualitative feedback and inputs collected through various channels and methods from ~35,000 participants on a range of rate options:
  - keeping existing rates
  - optional time-of-use and end-use rates
  - flattening the two-tiered rate

Stakeholder Engagement | Summary of Activities

Stakeholder Engagement Efforts	Number of Participants	Representation
BC Hydro Workshops & Special Interest Group Meetings	~200	▪ Residential customers ▪ Aboriginal housing ▪ Housing development ▪ Electric vehicles ▪ Indigenous Nations ▪ Environment & sustainability ▪ Local government ▪ Low income ▪ Seniors ▪ Union employees ▪ Commercial customers ▪ Builders

Customer Engagement | Summary of Activities

Customer Engagement Efforts	Number of Participants	Purpose of engagement
Quantitative Consultation Efforts		
Poll	1,931	▪ Testing of engagement objectives and questions
6 Surveys	32,821	▪ Understand customer needs & perceptions about rates ▪ Learn about rate preferences, energy use, values, priorities and bill perceptions ▪ Explore rate concepts and understanding
Qualitative Consultation Efforts		
In-depth interviews	15	▪ Individual engagement to assess perceptions and values related to rates
Telephone Townhalls	395	▪ Explore rate concepts
Digital dialogue	35	▪ In-depth discussion about bill impacts
Focus Groups	32	▪ Explore time-of-day concepts with Electric Vehicle and non-Electric Vehicle owners

Stakeholder Engagement | What we heard

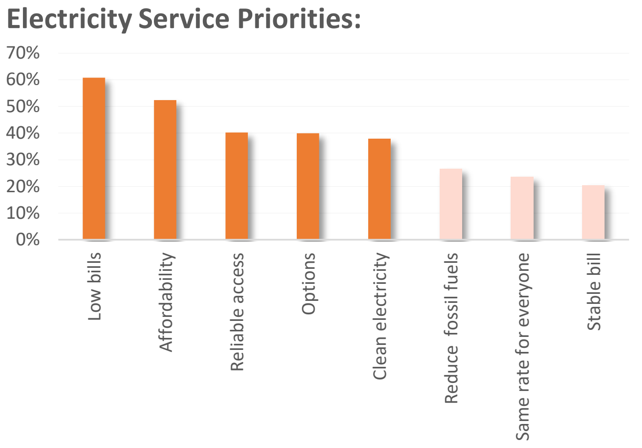
Input and feedback from the workshops generally fell into the following key topics:

- Environment, particularly decarbonization, heat pumps, and Electric Vehicles
- Affordability and fairness
- Fuel switching
- Eliminating RIB or transitioning to a flat rate
- Time-of-use (TOU) rate designs

Support electrification through voluntary time-of-use rates to reduce Electric Vehicle charging costs and incent customers to shift usage from BC Hydro's system peak period.

Customer Engagement | What we heard

Along with desire for service that's low cost, affordable and reliable, customers want rates that encourage clean electrification and offer choices to meet a variety of needs and circumstances.



Rate Design Preferences:

Customer Survey (N=749)	Public Survey (N=22,680)
Time-Of-Use	Time-Of-Use
RIB	Flat
Bill Stability	Plan with options

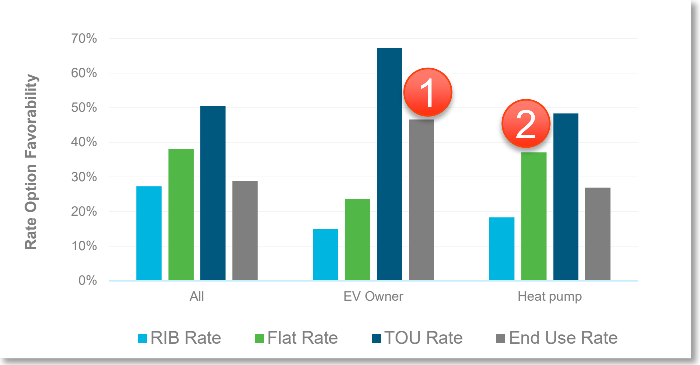
Engagement | Rate Preferences

1. Optional Time-Of-Use rate is most preferred overall & in non-electrically heated Single Family Detached homes
2. Electrically heated Single Family Detached homes showed preference for the optional Flat and TOU rates
3. Apartments showed preference for the Residential Inclining Block (RIB) and optional TOU rates

Participants were asked to select up to 3 rates

Engagement | Rate Preferences

1. Electric Vehicle owners tend to prefer the optional Time-Of-Use and End-Use rates
2. Heat pump owners prefer optional Time-Of-Use and Flat rates



Participants were asked to select up to 3 rates

Of the potential rate options presented, optional Time-Of-Use rates drew the most interest.

Customer Engagement | Feedback Summary

Rate preference trends:

- Customers with higher bills due to the current stepped rate, and those looking to electrify, seek opportunities to save through other voluntary rate options.
- Customers with lower bills and those supporting conservation prefer the current stepped rate (RIB).
- Electric Vehicle owners favour optional Time-Of-Use and End-Use rates, but the potential requirement for separate metering for an EV charging Time-Of-Use rate is seen as impractical and too expensive.
- Time-Of-Use rate should be offered daily, year-round with a peak price no higher than $0.25/kWh
- Those with limited or no ability to shift when they use electricity, view Time-Of-Use rates as unfair.

BC Hydro
Power smart

Engagement | Support for Concepts & Principles

Based on personal circumstances and preferences, customers and stakeholders expressed interest in and support for:

- Rates that remove barriers and encourage environmentally friendly and sustainable electrification.
- Time-Of-Use rates that reduce electric vehicle charging costs and incent a shift of usage to make better use of existing electrical infrastructure.
- Voluntary rate choices and options to meet the range of individual customer needs and circumstances.

BC Hydro
Power smart

Customer Quotes

"I would definitely subscribe to a time of use charge from my EV. Such a rate structure would encourage me to sell my wife's car and buy another EV. It would certainly encourage further purchases of EV's."

"I am happy to see that BC Hydro is considering an improved rate structure to account for the implementation of electric vehicles, heat pumps and electric furnaces, all of which we are going to need to transition to very soon to fight climate change."

"No one size fits all but it would be good to find the one method which would help meet the needs of keeping hydro as a clean energy fuel while maintaining a reasonable cost to homeowners. Giving homeowners a choice as to when they could access electricity at a lower rate by choices they personally make as to how and when they use electricity is a good model."

BC Hydro
Power smart

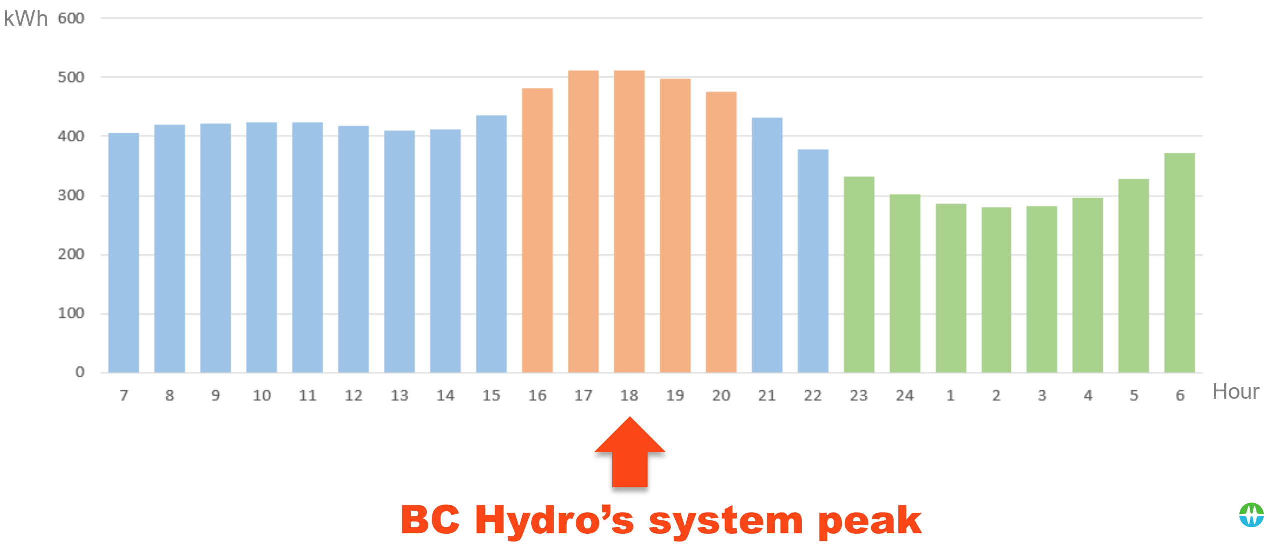
Optional Residential Time-of-Use Rate

Shiau-Ching Chou, Senior Regulatory Manager

Tariffs and Rate Design

BC Hydro
Power smart

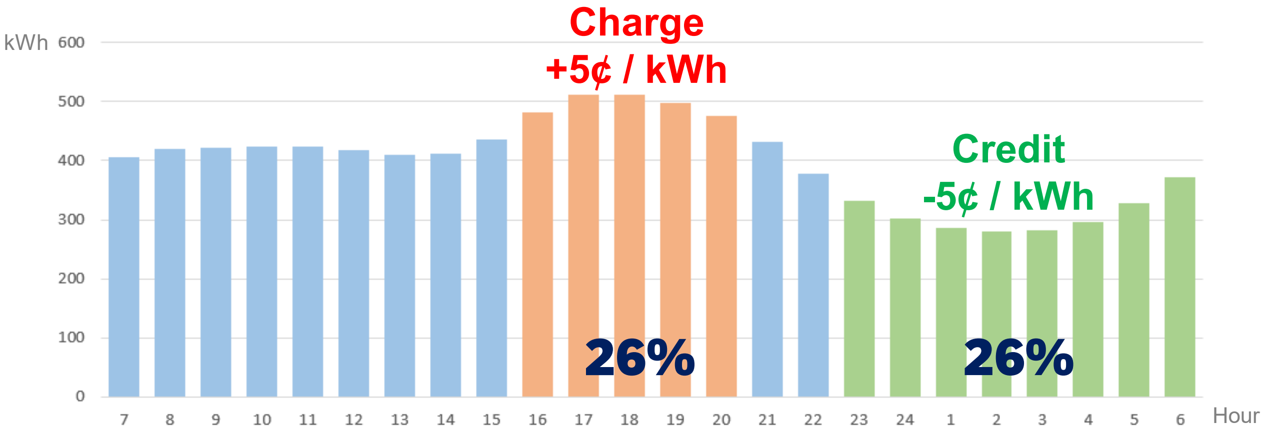
Average Residential Customer Load Shape



BC Hydro
Power smart

New Credit/Charge Rate

First: two-step rate	Customer's energy charges are calculated by the two-step rate.
Second: time-of-use rate	Customer receives a 5-cent credit for every kWh consumed during the Overnight period and a 5-cent charge for every kWh consumed during the Peak period.
Third: two step + time-of-use	Customer’s monthly energy charge includes the two-step rate + time-of-use charges.



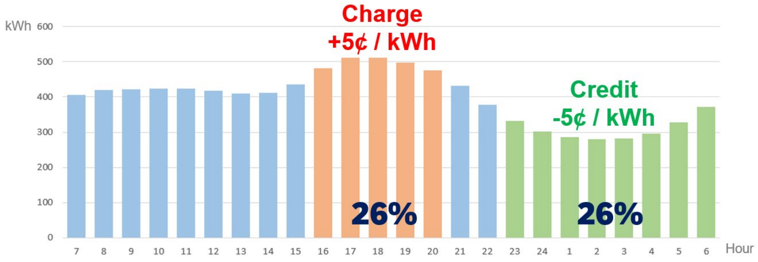
New Credit/Charge Rate

Illustrative Energy Charge calculation ***before*** load shifting for a 1,000 kWh bill

First

Step 1 Energy Charge	675 kWh X $0.0950 =	$64.13
Step 2 Energy Charge	325 kWh X $0.1408 =	$46.09
Total RIB Energy Charge		$110.22

Second



Overnight Period Credit	260 kWh X ($0.05) =	($13.00)
Peak Period Charge	260 kWh X $0.05 =	$13.00
Total TOU Energy Charge		$0.00

Third Total Energy Charges = $110.22

Feedback Questions

- Do you understand how the optional credit / charge time-of-use rate concept works?
- Do you think this rate is easy for customers to understand?

BC Hydro
Power smart

Load Profiles by Customer Group

All Residential Customers

Peak Load 4PM – 9PM	Overnight Load 11PM – 7AM	Average Annual Bill Difference per Customer with No Load Shifting
26%	26%	(12 cents)

Electrically Heated			% of Customers	Housing Type	% of Customers	Non-Electrically Heated		
Peak Load	Overnight Load	Average Annual Bill Difference				Peak Load	Overnight Load	Average Annual Bill Difference
25.7%	25.8%	(10 cents)	19%	Apartment	9%	27.4%	24.3%	$5
24.4%	27.1%	($23)	16%	Single House	41%	26.5%	25.4%	$6
25.6%	25.3%	$2	6%	Townhouse	4%	27.4%	24.0%	$11
24.0%	27.5%	($22)	1%	Mobile Home	3%	25.8%	25.5%	$1
23.5%	28.6%	($32)	1%	Other (~1%)	1%	23.3%	28.8%	($19)

*Based on F2022 full year customer consumption with no load shifting

Load Profiles by Consumption

Annual Consumption (kWh)	% of Customers	Peak Load 4PM – 9PM	Overnight Load 11PM – 7AM	Average Annual Bill Difference
0 - 4,000	21%	27.2%	24.4%	$3
4,001 - 8,000	29%	26.9%	24.5%	$7
8,001 - 12,000	22%	26.5%	25.0%	$8
12,001 - 16,000	13%	25.9%	25.7%	$1
16,001 - 2,0000	7%	25.2%	26.5%	$(11)
20,001 - 30,000	6%	24.4%	27.5%	$(37)
30,001 - 50,000	2%	23.3%	29.3%	$(107)

*Based on F2022 full year customer consumption with no load shifting

Potential for structural winners and losers due to overall consumption is largely mitigated

Load Shape of Customers with an Electric Vehicle

Consumption	Average Annual Consumption (kWh)	Peak Load 4PM – 9PM	Overnight Load 11PM – 7AM	Off-Peak Load All other hours	Energy Charge Difference
Household	9,537	2,477	2,480	4,579	($0.12)
EV	2,433	718	892	823	($8.66)
Total	11,970	3,196	3,371	5,403	($8.78)
Total %	100%	27%	28%	45%	

BC Hydro
Power smart

Credit/Charge Rate Assumptions

Input	Assumption
Non-EV Participation	15% with 6-year “S-curve” ramp up
EV Participation	50% with 6-year “S-curve” ramp up
Non-EV Peak Demand Reduction (50% to Off-Peak / 50% to Overnight)	5%
EV Peak Demand Reduction (20% to Off-Peak / 80% to Overnight)	75%

BC Hydro
Power smart

Participation Assumptions

15%
Non-EV

"I developed BC Hydro's enrollment assumptions for time-varying rates, with assistance from my Brattle colleagues. The base case enrollment assumptions are 15% for opt-in deployment…I developed these estimates through analysis of U.S. Energy Information Administration data on existing utility time-of-use rate offerings and a review of utility evaluation reports on time-varying rate offerings.

The enrollment assumptions for time-varying rates that I provided to BC Hydro are consistent with the best available industry data and literature on the topic, and supported by my extensive experience designing and evaluating the rate offerings for utilities across North America and internationally."

- Dr. Ahmad Faruqui, Capacity Savings Estimates in BC Hydro's 2021 IRP: An Independent Review, Section 5 (Exhibit B-3, 2021 IRP Proceeding)

BC Hydro
Power smart

Participation Assumptions – Electric Vehicles

50%
EV

"BC Hydro's assumption of 50% driver participation in EV charging DR programs and rates is ambitious, but I believe it is achievable based on a review of early experience with EV TOU rates in other jurisdictions…BC Hydro's participation estimate is near the upper end of the range of enrollment rates that have been achieved, but is not outside that range."

- Dr. Ahmad Faruqui, Capacity Savings Estimates in BC Hydro's 2021 IRP: An Independent Review, Section 10 (Exhibit B-3, 2021 IRP Proceeding)

75%
Shifting

An evaluation prepared for San Diego Gas & Electric found that EV owners shifted 73% to 84% of their charging to the overnight period in response to price ratios in the range of 2:1 to 4:1.

BC Hydro
Power smart

Price Ratios & Peak Demand Reduction Response

Price ratios of BC Hydro's credit / charge time-of-use rate proposal

Energy Charge	Peak Period +5¢	Off Peak Period	Overnight Period -5¢	Peak/ Overnight Ratio	Peak/ Off Peak Ratio
Step 1 Energy Charge	14.50	9.50	4.50	3.1 : 1	1.5 : 1
Step 2 Energy Charge	19.08	14.08	9.08	2.1 : 1	1.4 : 1

Blended price ratios

Consumption	Price Ratio
Household Consumption	2.1
EV Consumption	2.5

Peak demand reduction response monitored by the industry

Price Ratio	Peak Demand Reduction
1.4	2.9%
1.5	3.5%
2.1	6.4%
3.1	10.0%

BC Hydro
Power smart

Feedback Question

- Do you understand how BC Hydro came up with the participation and peak demand reduction assumptions for the proposed optional residential time-of-use rate?

- Do you think these assumptions are reasonable?

BC Hydro
Power smart

Estimated Bill Savings by Customer Group

Cost of EV charging

2,433 kWh

Step 1 rate	$239 / year
Step 2 rate	$343 / year
Flat rate	$278 / year

Electrically Heated			% of Customers	Housing Type	% of Customers	Non-Electrically Heated		
Home Only	EV Only	Home + EV				Home Only	EV Only	Home + EV
($5)	($57)	($62)	19%	Apartment	9%	$2	($57)	($55)
($38)	($57)	($95)	16%	Single House	41%	($5)	($57)	($62)
($9)	($57)	($66)	6%	Townhouse	4%	$4	($57)	($53)
($33)	($57)	($90)	1%	Mobile Home	3%	($8)	($57)	($65)
($43)	($57)	($100)	1%	Other (~1%)	1%	($26)	($57)	($83)

In F2024 dollars based on F2022 RS 1101 customer consumption data.

BC Hydro
Power smart

Estimated Bill Savings by Consumption

Under this new concept, almost all customers have the potential to save.

Annual Consumption (kWh)	% of Customers	Old Rate No EV	Old Rate with EV	New Rate Home Only	New Rate EV Only	New Rate Home & EV
0 - 4,000	21%	$33	$23	$1	($57)	($56)
4,001 - 8,000	29%	$75	$39	$1	($57)	($56)
8,001 - 12,000	22%	$69	$13	($2)	($57)	($59)
12,001 - 16,000	13%	$30	($27)	($12)	($57)	($69)
16,001 - 2,0000	7%	($14)	($71)	($28)	($57)	($85)
20,001 - 30,000	6%	($80)	($136)	($58)	($57)	($115)
30,001 - 50,000	2%	($204)	($260)	($138)	($57)	($195)

In F2024 dollars based on F2022 RS 1101 customer consumption data.

Estimated Bill Saving for customers with an Electric Vehicle

Consumption	Average Annual Consumption (kWh)	Peak Load 4PM – 9PM	Overnight Load 11PM – 7AM	Off-Peak Load All other hours	Energy Charge Difference
Household	9,537	2,354	2,542	4,641	($9.41)
EV	2,433	180	1,323	931	($57.15)
Total	11,970	2,533	3,864	5,572	($66.56)
Total %	100%	21%	32%	47%	

BC Hydro
Power smart

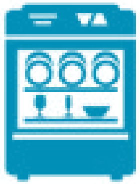
Illustrative Consumption Shifting Scenarios

Charge EV after work at 5 p.m.

↓

Charge EV after 11 p.m.

Up to $240 saving per year

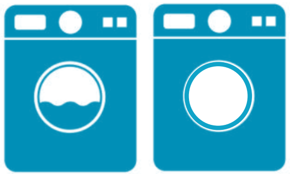


Once a day at 7 p.m.

↓

Once a day after 11 p.m.

Up to $25 saving per year



2 times a week at 7 p.m.

↓

2 times a week at 9 p.m.

Up to $25 saving per year

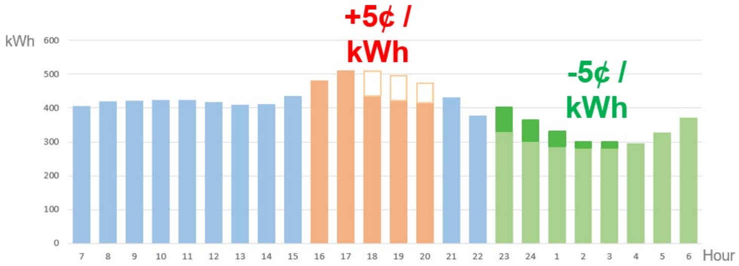
New Credit/Charge Rate

Illustrative Energy Charge calculation ***after*** load shifting for a 1,000 kWh bill

First

Step 1 Energy Charge	675 kWh X $0.0950 =	$64.13
Step 2 Energy Charge	325 kWh X $0.1408 =	$46.09
Total RIB Energy Charge		$110.22

Second



Overnight Period Credit	300 kWh X ($0.05) =	($15.00)
Peak Period Charge	220 kWh X $0.05 =	$11.00
Total TOU Energy Charge		($4.00)

Third Total Energy Charges = $106.22

Feedback Questions

- Compared to the old TOU rate design, do you agree that this concept does a better job mitigating the potential for people to save without reducing peak demand?
- Do you think this rate provides enough savings potential to encourage people to shift their consumption?

BC Hydro
Power smart

Forecast Participation and Capacity Savings

Metric	F2030	F2038
Capacity Savings	166 MW	477 MW
Non-EV Participants	132,000	83,000
EV Participants	130,000	415,000

BC Hydro
Power smart

Credit/Charge Rate Assessments

Cost of Service Justification

Target Revenue:Cost Ratio **93%**

Total Participant Revenue
/
Implementation cost + Total Participant Cost

Year 5	Year 10	Year 12	Year 15
88%	92%	93%	95%

Economic Justification

Target Benefit:Cost Ratio **1**

Capacity Savings
/
Implementation Cost + Revenue Loss

5 Year	10 Year	15 Year
0.50	1.10	1.75

Concept passes both tests

Assessment on Rate Design Principles

Grouping	Principle	BC Hydro assessment
Economic Efficiency	Price signals to encourage efficient use and discourage inefficient use	The rate provides a clear price signal to encourage customers to reduce consumption during BC Hydro's system peak period and incents customers to use more during the overnight period when more system capacity is available.
Fairness	Fair apportionment of costs among customers	The rate has an additional charge for each kWh during BC Hydro's system peak period when the cost to provide service is higher and a discount for each kWh during the overnight period when the cost to provide service is lower.
	Avoid undue discrimination	All customers are provided the same credit/charge if they choose to take service under the rate.
Practicality	Customer understanding and acceptance, practical and cost effective to implement	The simple "-5 / +5 per kWh" concept means it is easy for customers to understand and estimate bill savings. It's also easier to implement, administer and communicate to customers. The rate is flexible and can be layered on top of any rate structure.
	Freedom from controversies as to proper interpretation	Since the rate is voluntary and provides mutual benefits, freedom from controversy is not an issue.
Stability	Recovery of the revenue requirement	The rate is designed to be revenue neutral on a class average basis to recover forecast revenue requirements.
	Revenue stability	The rate largely eliminates structural revenue loss by overall consumption. This means that revenue loss will generally only occur from customers' shifting their consumption out of the peak period, which will have corresponding cost reductions for all ratepayers.
	Rate stability	The rate is stable as the charge/credit is fixed.

Feedback Question

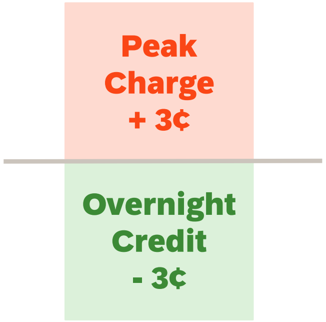
Do you agree with BC Hydro's Bonbright Assessment of this proposed optional time-of-use rate design?

BC Hydro
Power smart

Alternatives to Be Explored through Customer Consultation

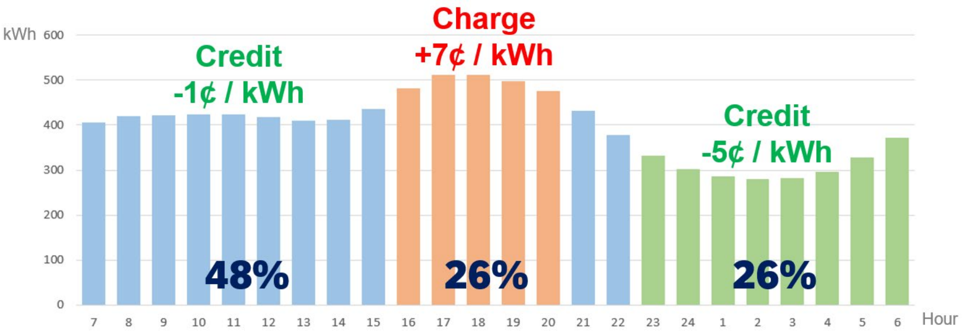
Alternative Option 1

A lower price signal



Alternative Option 2

Higher peak charge + moderate discount for all other hours



Feedback Question

Compared to the proposed rate design (+5/-5), would you be interested in these slightly different alternatives?

BC Hydro
Power smart

Benefits of the Credit/Charge Rate

- ✓ All customers have the potential to save
- ✓ Eliminates most structural winners due to overall consumption
- ✓ Can be layered on to the two-step rate or other rate structures
- ✓ Can be applied to the whole home load or EV load only
- ✓ Incorporated customer feedback:
  - The rate is ***optional***
  - The rate is ***year-round***
  - The rate applies ***everyday*** during a week
  - Energy Charge during peak period does not exceed 25¢/kWh
  - No need to install a second meter to achieve savings from EV charging

BC Hydro
Power smart

Feedback Questions

- Do you support BC Hydro advancing the proposed optional credit / charge residential time-of-use rate?
- Please provide any further comments you have about this optional time-of-use rate.

BC Hydro
Power smart

BREAK

BC Hydro
Power smart

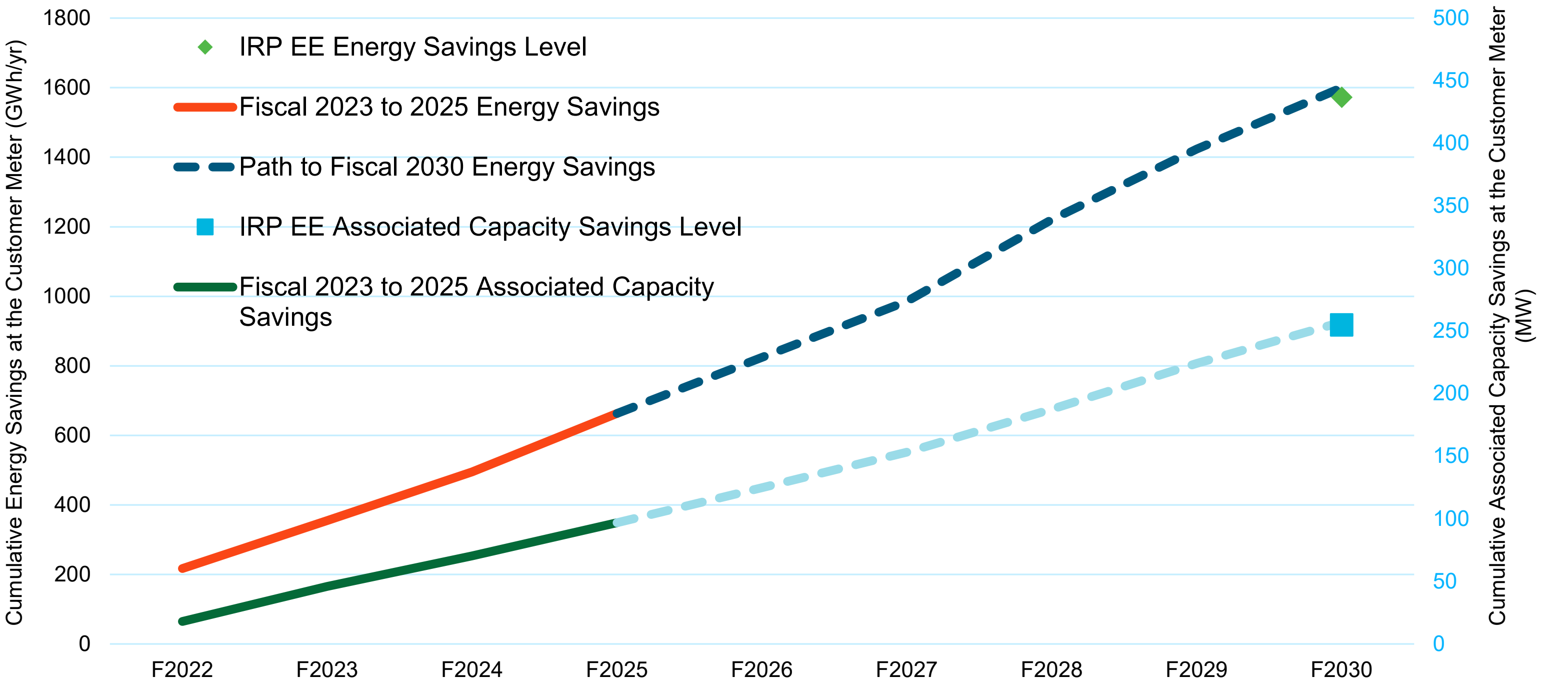
Demand Side Management Programs

Pat Mathot

Manager, Residential Marketing

BC Hydro
Power smart

Increasing support for DSM



Existing Energy Efficiency Program Refresher

BC Hydro
Power smart

Energy efficiency support for lowering bills

- Program support for all residential customers, regardless of rate choice
- Energy efficiency drives down overall consumption and peak-time usage
- Programs include:
  - **Home Renovation Rebates** – Insulation, windows, heat pumps
  - **Retail rebates -** Smart thermostats, lighting, appliances
  - **Team Power Smart** – Energy reduction challenges and rewards

BC Hydro
Power smart

Income Qualified and First Nations

- **Energy Saving Kit (ESK)** - Free, easy to install measures

- **Energy Conservation Assistance Program (ECAP)** - free upgrades for individuals and non-profit housing providers
  - Examples of measures that may qualify:
    - LED light bulbs
    - Water-efficient showerheads & faucet aerators
    - ENERGY STAR appliances
    - Insulation in walls, attic, or crawl space
    - Heat pumps for mobile homes

- **Non-Integrated Area and Indigenous Offers**
  - Higher value incentives
  - Community level planning and workforce capability building

BC Hydro
Power smart

Enabling activities

- Industry support to provide customers with access to trained and qualified trade allies/supply-chain partners
  - Creating and driving trades training
  - Connecting customers with qualified trades/installers
  - Educating customers on efficient products and connecting them with partners that sell those products

BC Hydro
Power smart

New Offers to Shift and Save

Newer programs for shifting energy use

- **HydroHome** - Real-time energy data & insights
- **Peak Saver** - Behavioural peak day rewards
- **Peak Rewards** - Technology enabled demand response
- Customers on RIB and optional TOU rate are eligible

BC Hydro
Power smart

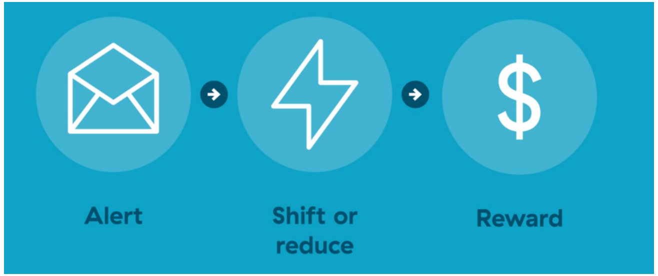
HydroHome

Advanced Energy Management App

- Live Energy Usage Feedback
- Energy Consumption Analysis
- Personalized suggestions and recommendations
- Smart Home Control

Peak Saver

- Low-barrier, no-cost, no penalties
- Accessible to all residential customers
- Reduce your use by 20% during a peak event, earn $3
- Participants choose what actions to take in their home



BC Hydro
Power smart

Peak Rewards

- Connected devices that can be triggered remotely by BC Hydro to adjust their operation – set it and forget it
- Customer may opt-out any time and remains in control
- Receive $35 per device category each year
- New device types will be added as technology progresses

BC Hydro
Power smart

Peak Rewards

- Devices include select:
  - Baseboard thermostats
  - Electric vehicle chargers
  - Water heater load controllers
  - Continually exploring other device categories

- Some devices support customer preference settings

BC Hydro
Power smart

F2024 – F2025 Residential Inclining Block (RIB) Rate Pricing Principles

Chris Sandve

Chief Regulatory Officer

BC Hydro
Power smart

RIB Rate Pricing Principles

How revenue requirements application (RRA) rate increases / decreases are applied to the three elements of the RIB rate:

- Basic Charge
- Step 1 Energy Charge
- Step 2 Energy Charge

The current approved pricing principles will expire March 2023.

Fiscal Year	BCUC Order	Pricing Principle
F2009 - F2010	G-124-08	Approval of RIB Rate
F2011	G-180-10	Apply RRA % equally
F2012 - F2014	G-45-11	Step 2 increased to higher of RRA % or up to 10% bill impact
F2015 – F2016	G-13-14	Apply RRA % equally
F2017 – F2019	G-5-17	Apply RRA % equally
F2020	G-214-18	Apply RRA % equally
F2021 – F2022	G-62-20	Apply RRA % equally
F2023	G-210-22	Apply RRA % to Basic Charge, maintain Step 2, apply rate increase to Step 1 to earn F2023 forecasted revenue had RRA % been applied equally

F2024 RIB Pricing Principle

F2024 RRA – net impact of 2% increase

- 1% general increase
- (1%) Deferral Account Rate Rider, currently at (2%)

Option 1

Basic charge: increase by 1%
Step 1: increase by 1%
Step 2: increase by 1%
(1%) DARR applies to the total bill
All customers see a 2% bill increase

Option 2

Basic charge: increase by 1%
Step 1: increase by 1.89%
Step 2: no change
(1%) DARR applies to the total bill
Customers see various bill increases (see Table)

Option 2 Bill impact

Annual Energy Usage (kWh)	Average Bill Impact ($)	Average Bill Impact (%)	Bill Difference from Option 1
0-4000	$8	2.7%	$2
4001-8000	$17	2.7%	$4
8001-12000	$25	2.3%	$3
12001-16000	$31	1.9%	($2)
16001-20000	$37	1.7%	($7)
20001-30000	$45	1.5%	($15)
30001-50000	$62	1.3%	($32)
>50000	$142	1.1%	($110)

The BCUC approved Option 2 for F2023

F2025 RIB Pricing Principle

F2025 RRA – net impact of 2.7% increase

- 2.2% general increase
- (0.5%) Deferral Account Rate Rider, F2024 at (1%)

Option 1

Basic charge: increase by 2.2%
Step 1: increase by 2.2%
Step 2: increase by 2.2%
(0.5%) DARR applies to the total bill
All customers see a 2.7% bill increase

Option 2

Basic charge: increase by 2.2%
Step 1: increase by 4.3%
Step 2: no change
(0.5%) DARR applies to the total bill
Customers see various bill increases (see Table)

Option 2 Bill impact

Annual Energy Usage (kWh)	Average Bill Impact ($)	Average Bill Impact (%)	Bill Difference from Option 1
0-4000	$14	4.3%	$6
4001-8000	$28	4.3%	$10
8001-12000	$38	3.4%	$8
12001-16000	$43	2.6%	$(2)
16001-20000	$46	2.1%	$(14)
20001-30000	$51	1.7%	$(32)
30001-50000	$59	1.3%	$(70)
>50000	$98	0.8%	$(238)

The BCUC approved Option 2 for F2023

BC Hydro Proposes Option 2

- There is no justification to increase Step 2 Energy Charge beyond 14.08¢ / kWh.
- The RIB rate is no longer achieving incremental energy conservation.
- BC Hydro’s long-run marginal cost of energy is 6.5¢ / kWh.
- Option 2 improves the fairness of revenue recovery of the RIB rate.
- The bill impact differences between Option 1 and Option 2 are moderate.
- A two-year Pricing Principles application improves regulatory efficiency.

BC Hydro
Power smart

Feedback Question

- Which RIB Pricing Principles option do you think BC Hydro should propose?
- Do you support a one-year (F2024) or a two-year (F2025) pricing principles application?

BC Hydro
Power smart

Wrap Up and Next Steps

Chris Sandve

Chief Regulatory Officer

BC Hydro
Power smart

Next Steps

2022-11 **Stakeholder consultation (now)**

2022-12 **Customer consultation**

2023-02 **Applications**
- Optional residential time-of-use rate
- RIB Pricing Principles

2023 **Consultation on next steps on the default rate**

BC Hydro
Power smart

Closing Remarks

- BC Hydro values your participation and feedback on our rate designs.
- Please contact BC Hydro Regulatory Group with any questions about the regulatory or engagement process: bchydroregulatorygroup@bchydro.com
- Remember to submit your feedback by December 15, 2022.
- The link to the online feedback form is: https://bchydro.ca1.qualtrics.com/jfe/form/SV_2lAa8hMHcxjPqjY

BC Hydro
Power smart

BC Hydro
Power smart

Optional Residential Time-of-Use Rate

NOVEMBER 2022

BC Hydro
Power smart

Table of contents

1. Background

1.1 Overview of BC Hydro's residential customers

The Residential Service rate class is BC Hydro's largest rate class accounting for about 89% of BC Hydro's customers, 36% of domestic energy sales and 43% of revenue.[1]

There are approximately 1.88 million residential customers taking service under a few different residential rates. Table 1 below summarizes BC Hydro's residential customers by Rate Schedule (RS).

Table 1 BC Hydro's Residential Service Offerings

Rate Schedule	Applies to[2]	Number of Customers	% of Customers	Revenue ($M)
RS 1101, 1121 – Default Residential Inclining Block (RIB) Rate	Zone I	1,857,416	98.6%	2,091
RS 1105 E Plus Service (closed)	Zone I	5,646	0.3%	5
RS 1107, 1127 Residential Service – Zone II	Zone II	5,076	0.3%	7
RS 1148 Residential Service – Zone II (closed)[3]	Zone II	2	0.0%	0.00278
RS 1151, 1161 – Exempt Residential Service	Zone I, IB	15,067	0.8%	56
Total		**1,883,207**	**100.00%**	**2,159**

As shown in Table 1 above, the vast majority of BC Hydro's residential customers are taking service under RS 1101 and 1121 – the Residential Inclining Block (RIB) rate. RS 1101 is for Premises with separately metered Dwellings, and RS 1121 is for Premises with more than two Dwellings under one meter.

Currently, the RIB rate applies on a default basis to all residential customers in our integrated service area. There are limited options available to a small number of qualifying customers under other rate schedules:

- Qualifying residential farms may take service under RS 1151, which has a flat energy charge instead of inclining block energy charges like the RIB rate;
- Customers in Zone 1B (Bella Bella) also take service under RS 1151.
- Customers in Zone II take service under RS 1107 which has the same charges as RS 1151, except for a higher energy charge applied for any consumption over 1,500 kWh per month.
- Qualifying customers with back-up heating systems take interruptible service under RS 1105 Residential E-Plus Rate. RS 1105 is a closed rate and is being phased out by March 31, 2028;
- Common areas of residential multi-occupancy buildings have options to select the applicable General Service rate; and
- Qualifying residential customers taking service under the RIB rate may also participate in RS 1289 Net Metering Service.

1.2 Overview of the Residential Inclining Block rate

The RIB rate has a fixed daily basic charge and per kWh inclining block energy charges. The lower step 1 energy charge applies to consumption below a threshold of 1,350 kWh per two-month billing period (675 kWh per one-month billing period). The higher step 2 energy charge applies to consumption above that threshold. The 675 kWh threshold was intended to be near 90% of the median consumption of BC Hydro's residential customers. The fiscal 2022 charges for the RIB rate are provided in Table 2 and illustrated in Figure 2 below.

1 Based on fiscal 2020 actuals.

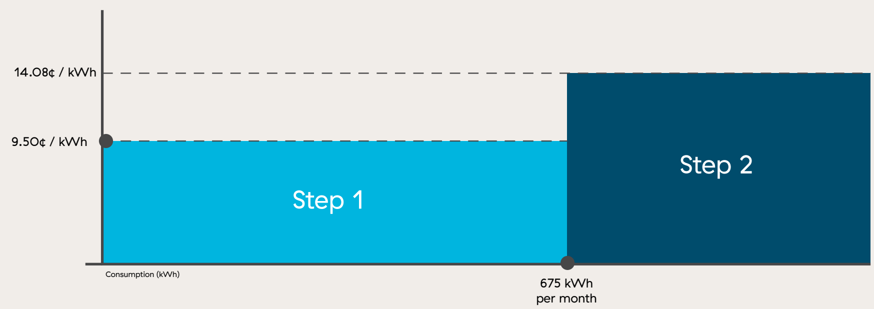
2 Zone I refers to BC Hydro's integrated system. Zone II are Non-Integrated Area communities that are served by stand-alone generation systems. Zone 1B is the community of Bella Bella.

3 RS 1148 has the same charges as RS 1151.

Table 2 Rate Summary for Rate Schedule 1101

RS 1101	Rates Effective April 1, 2022
Basic Charge	20.90¢ per day
Step 1 Energy Charge	9.50¢ per kWh
Step 2 Energy Charge	14.08¢ per kWh
Step 1 / Step 2 Threshold	1,350 kWh per two-month billing period (675 kWh per one-month billing period)

Figure 1 Residential Inclining Block Rate Charges



Step 1 Energy Charge (9.50¢/kWh) +

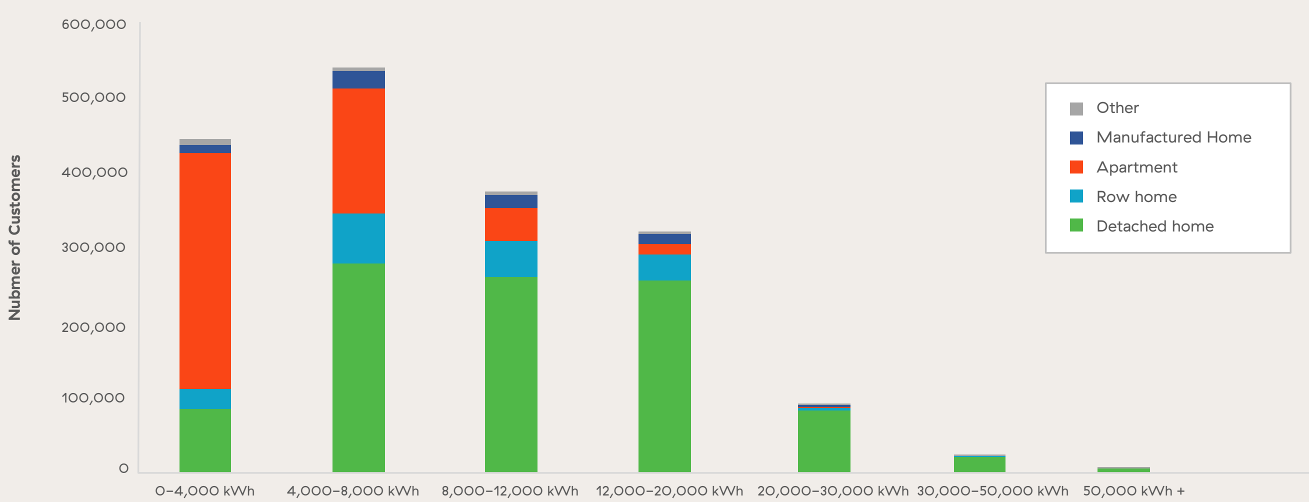
Step 2 Energy Charge (14.08¢/kWh) +

Basic Charge (20.90¢/day)

The average monthly consumption of all RIB customers in fiscal 2020 was 836 kWh, which is about 10,000 kWh a year, with an average monthly bill of approximately $100.

Figure 2 below shows the consumption and housing type distribution of customers on the RIB rate.

Figure 2 Annual Electricity Consumption by Housing Type



As shown in Figure 2 above, most customers on the RIB rate consume less than 20,000 kWh a year and most live in single detached homes or duplexes (55%) or apartments (30%).[4] In B.C., about 43% of RIB customers have primary electric fuel space heating and the rest are mostly primary natural gas fuel heated.

4 BC Hydro uses the term "apartments" to refer to separately metered, individual Dwellings in multi-occupancy buildings, and may include either owned or rented Dwellings.

1.3 Key drivers for developing an optional residential time-of-use rate

As discussed in section 1.1 above, the RIB rate applies on a default basis to all residential customers in our integrated service area with limited other options available to a small number of qualifying customers.

BC Hydro is exploring opportunities to provide customers with choices for the rate they pay for electricity service. A key area of focus has been optional time-varying rate structures which can provide bills savings by encouraging customers to shift their electricity use to periods when system capacity is more available.

The Government of B.C. released its CleanBC Plan on December 5, 2018, to increase the use of cleaner energy, especially renewable hydroelectricity, in key sectors of the economy, shifting away from reliance on fossil fuels. Among other things, the CleanBC Plan included a proposed timeline for new zero emission vehicle sales targets.

The CleanBC Roadmap to 2030, released October 25, 2021 is an elaboration and continuation of the CleanBC Plan.[5] It sets out the following interim targets for zero-emission vehicle sales and leases in British Columbia:[6]

- 26% by 2026; and,
- 100% by 2035.

In addition, the federal government has also now set a target for light-duty zero emission vehicle sales of 100% by 2035. [7]

Electric Vehicles (EVs) are forecast to be a significant source of BC Hydro's peak demand, if not managed. BC Hydro's 2021 Integrated Resource Plan, filed with the Commission in December 2021, looks at a 20-year time frame and guides decisions on our integrated system to meet the future electricity needs of our customers. To meet future increased electricity demand due to increased EV charging load, BC Hydro's 2021 IRP includes introducing more customer-based electricity management options to support energy-efficiency and capacity savings during peak electricity demand periods. This includes new optional time-varying rate structures to encourage customers to shift their electricity use to periods when system capacity is more available.

Optional residential time-of-use rates are identified as a Near-term Action of the 2021 IRP. BC Hydro's optional residential time-of-use rate proposal below is the first large-scale optional time-varying rate we plan to introduce to deliver the capacity savings called for in the 2021 IRP.

1.4 Purpose of this information booklet

This information booklet is intended to:

- Provide background information on BC Hydro's recent residential rate design efforts;
- Recap various engagement activities conducted since December 2020 to learn what's important to customers when it comes to the cost of electricity, including feedback on potential rate options;
- Summarize feedback we received and explain how we have responded to this feedback.
- Explain key factors that have informed our thinking on the current rate design since our last public workshop on November 18, 2021; and
- Inform customers and stakeholders on our optional residential time-of-use rate proposal.

The next public workshop on our optional residential time-of-use rate proposal is scheduled for November 29, 2022. It will include a more detailed discussion on the rate design presented in this booklet. Feedback from customers and stakeholders received during this workshop will inform our optional residential rate design application, which is planned to be filed with the British Columbia Utilities Commission (BCUC) in early 2023. We hope you will join us at the next workshop, and we look forward to hearing your feedback.

5 CleanBC Roadmap to 2030.

6 Ibid.

7 In June 2021, the Government of Canada set a mandatory target for all new light-duty cars and passenger trucks sales to be zero-emission by 2035, accelerating Canada's previous goal of 100% sales by 2040.

1.5 Structure of this information booklet

The remainder of this information booklet is structured as follows:

- **Section 2** provides background on key stakeholder and customer engagement activities that informed our rate design proposal, including a recap of the engagement activities and a summary of stakeholder and customer feedback.
- **Section 3** describes our optional residential time–of–use rate proposal, including potential customer savings under the proposed time–of–use rate.
- **Section 4** summarizes the ratepayer economic, cost of service and Bonbright assessments of the optional time–of–use rate proposal.
- **Section 5** outlines the ways you can provide feedback.

2. Key engagement activities informing our rate design proposal

2.1 Summary of stakeholder and customer engagement activities

In 2020 and 2021, we undertook research and analyses to better understand our residential customers, their individual situations and their views on rates and energy consumption habits. This consultation process engaged over 35,000 customers and stakeholders to review the current RIB rate and customers' interests in optional rates.

Table 3 below summarizes the stakeholder engagement activities and Table 4 below summarizes the customer consultation activities.

Table 3 Summary of stakeholder engagement

Stakeholder Engagement Efforts	Timing	Number of Participants	Representation
BC Hydro Workshops	May 19, 2021 and November 18, 2021	109 (May 2021) 74 (November 2021)	○ Residential customers ○ Aboriginal housing ○ Housing development ○ Electric vehicles ○ Environment & sustainability ○ Local government ○ Low income ○ Seniors ○ Union employees ○ Commercial customers
Four Meetings	May to December 2021	Three to 15 for each	○ Builders ○ Indigenous Nations ○ Local Government ○ Low Income
	Total	**200+**	

Table 4 Summary of Customer Consultation:

Customer Engagement Efforts	Timing	Number of Participants[8]	Purpose
Consultation Efforts with Quantitative Results			
Perception Survey by Sentis	December 2020	934	Understanding the needs of customers and perceptions about rates.
Your Power Poll by BC Hydro	April 2021	1,931	Testing survey questions for understanding with registrants of an ongoing panel.
Concepts Survey by Sentis	May 2021	821	Learning about rate preferences, energy use, values, and priorities as well as bill perceptions.
Public Survey No. 1 by BC Hydro	April to June 2021	22,680	Exploring rate concepts with customers and the public.
Time-of-use survey by Leger	October 2021	1,009	Exploring voluntary time-of-use rate concepts with EV and non-EV owners.
Public Survey No. 2 by BC Hydro	November 2021	6,031	Exploring rate options with customers and the public.
Options Survey by Sentis	November to December 2021	1,346	Learning more about electricity rate priorities, rate perceptions, and exploring whether customers intend to fuel switch to electricity.

8 The total includes individuals who may have participated in multiple consultation sessions.

Customer Engagement Efforts	Timing	Number of Participants[8]	Purpose
Consultation Efforts with Qualitative Results			
Telephone Interviews by BC Hydro	April 2021	15	Individual calls to learn about customer perceptions and values related to rates, including those from Indigenous Nations.
Telephone Town Halls by Stratcom	May 2021	395	Two sessions to explore rate concepts.
Digital Dialogue by UPWORDS	August 2021	35	In-depth discussion about bill impacts.
Focus Groups by Leger	January 2022	32	Four sessions to explore time-of-use rate concepts with EV and non-EV owners.
	Total	**35,200+**	

2.2 Summary of stakeholder and customer engagement feedback

Stakeholder feedback

Stakeholders' feedback during the last two public engagement workshops on optional residential rates generally covered the following key topics:

- Environment, particularly decarbonization, heat pumps, and EVs;
- Affordability and fairness;
- Fuel switching; and
- Time-of-use rate designs.

In general, stakeholders support optional time-of-use rates that could help EV drivers reduce their EV charging costs and reduce demand-related costs for all ratepayers by incenting customers to shift usage out of BC Hydro's system peak demand period to periods when system capacity is more available to make better use of existing electrical infrastructure.

Customer feedback

We learned that most customers think about their electricity bill first, and not the rate under which they are charged. As a result, a customer's preferred rate structure tends to reflect their personal circumstances. Some customers, especially EV owners, expressed an interest in time-of-use rates. However, there was a strong view against default time-of-use rates on the basis that it would be difficult for many customers to change when they use electricity.

Key themes expressed include:

- Affordability, keeping bills low and decarbonization are important to customers;
- Familiarity with and interest in rates varies significantly; and
- Of the potential optional rates presented, optional time-of-use rates drew the most interest.

Of all the potential optional rates options we explored, optional time-of-use rates drew the most interest from participants. Many customers were familiar with the concept of time-of-use rates, either because they once lived in jurisdictions where time-of-use rates were an option, or through family and friends who have personal experience with these rates.

8 The total includes individuals who may have participated in multiple consultation sessions.

Most customers prefer optional time–of–use rates, and some customers are concerned that if time–of–use rates are introduced, they will become the default rate. EV owners are especially supportive of a rate that would allow them to charge their vehicles overnight at a lower rate.

In terms of specific design elements of time–of–use rates, key comments expressed include:

- Time–of–use energy charges should be offered year–round as opposed to during winter months only to offer customers more savings;
- Time–of–use energy charges should be offered daily as opposed to weekdays only to help build routine behaviours;
- The energy charge during the peak period should be under 25 cents per kWh so it is not prohibitive to customers who need to use electricity during peak hours; and
- Customers are not enthusiastic about investing in rewiring and installing a second meter to participate in a time–of–use rate that would only apply to EV charging load.

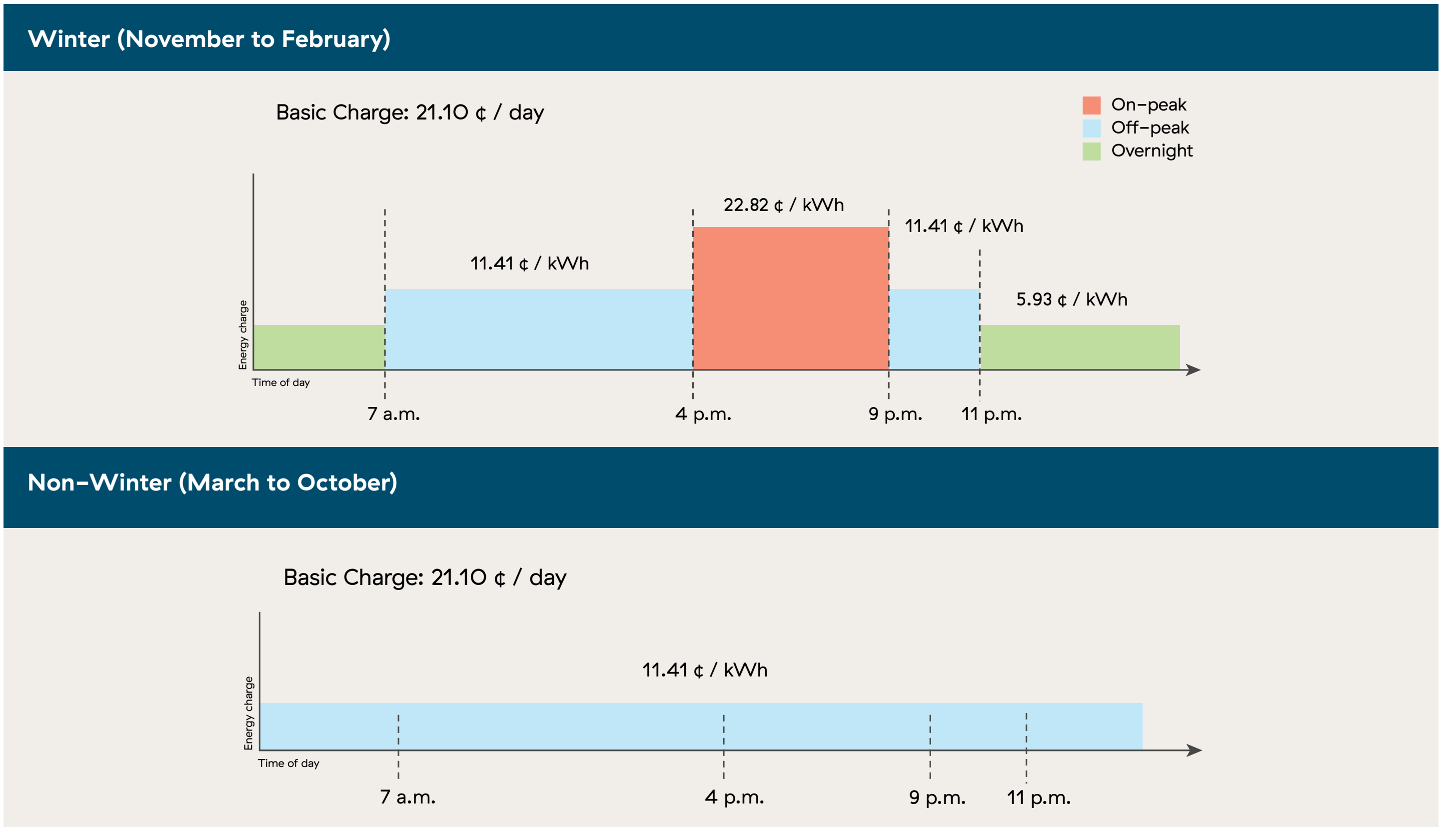
3. BC Hydro's optional residential time-of-use rate proposal

3.1 Traditional time-of-use rate design

The most common time-of-use rate design among North American utilities is one that has fixed energy charges per kWh for specific time periods during a day. Most utilities also have time-of-use energy charges that apply only during their peak season (i.e., summer months only for utilities in warmer climates or winter months for utilities in colder climates). This is the residential time-of-use rate design we presented in our previous two workshops and it is illustrated in Figure 3 below.

The on-peak, off-peak and overnight energy charges in this design were modelled based on the average consumption and load shape of all RIB customers. This was done so that, on average, if customers who participated in an optional time-of-use rate did not change when they use electricity, the overall revenue collected by BC Hydro would remain the same.

Figure 3 Previous fixed energy charge residential time-of-use design



3.2 Challenges with the traditional time-of-use rates

As mentioned in section 1.1 above, most of BC Hydro's residential customers take service under the RIB rate. With a time-of-use rate, the amount that a customer saves should depend on their load shape (i.e., how much they consume in each time period at different time-based energy charges). However, when customers' default rate is an inclining block rate, like the RIB rate with its higher energy charge for consumption over a certain consumption threshold, the amount that a customer could save by opting into a time-of-use rate with fixed time-based energy charges depends on both their load shape and their overall consumption.

This creates two problems:

Low Participation: Customers with lower overall consumption currently pay most of their consumption at the lower step 1 energy charge of 9.50 cents per kWh. They can't save because the time-based and non-winter charges under the above time-of-use rate are too high.

Structural Winners: Customers with high overall consumption currently pay for a significant portion of their consumption at the higher step 2 energy charge of 14.08 cents per kWh. They can save without reducing their peak demand because the time-based charges are too low.

As shown in Figure 3 above, under BC Hydro's original proposal, during the non-winter months, customers would be charged a flat energy charge of 11.41 cents per kWh, which is the blended average of the step 1 (9.50 cents) and step 2 (14.08 cents) energy charges under the RIB rate. This increases the low participation and structural winners challenges described above because customers with low consumption would pay more during the non-winter months and customers with high consumption would pay less during the non-winter months.

BC Hydro explored a design modification where customers on an optional time-of use would be charged the RIB rate during the non-winter months. This partly addresses the two challenges described above but it doesn't solve them. During the winter period, there are still a significant number of customers who can't save and there are still a significant number of customers who can save without reducing their peak demand.

3.3 New credit / charge time-of-use rate proposal

To overcome these challenges, BC Hydro developed a new time-of-use rate design that largely eliminates structural winners and provides all customers with an opportunity to save.

Under this new time-of-use rate design, customers would still have their total electricity usage during the billing period billed under the existing default RIB rate. Then customers would receive a 5-cent per kWh discount for all kWh consumed during the overnight period (11 p.m. to 7 a.m.) and a 5-cent per kWh additional charge for all kWh consumed during the peak period (4 p.m. to 9 p.m.). For kWh consumed during the off-peak period (9 p.m. to 11 p.m. and 7 a.m. to 4 p.m.), no discount or additional charge would be applied.

The 5-cent credit was selected because based on BC Hydro's Fiscal 2021 Fully Allocated Cost of Service Study, the average embedded energy cost is approximately 4 cents per kWh. With a 5-cent credit, the minimum overnight energy charge is 4.5 cents per kWh (step 1 energy charge of 9.50 cents per kWh minus 5 cents). The 5-cent credit provides meaningful bill savings to customers while ensuring the minimum overnight energy charge still recovers the average embedded energy cost. To stay revenue neutral, a corresponding 5-cent charge is added to the peak period consumption.

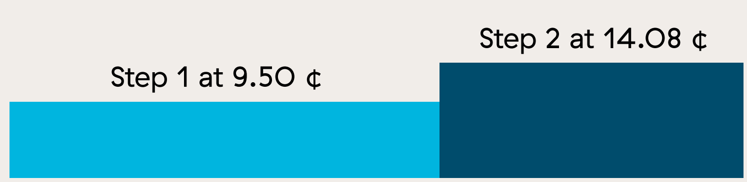
The reason this concept works is that, on average, customer electricity usage during the peak period is almost identical to customer electricity usage during the overnight period at around 26% each. This means if customers participating in the optional time-of-use rate don't shift any of their electricity use out of the peak period, they would pay the same as they would under the RIB rate. Figure 4 below illustrates the monthly energy charge for 1,000 kWh under this new design:

Figure 4 Illustrative monthly energy charge of the proposed time-of-use rate

FIRST:

A customer's energy charges are calculated by the two-step rate. This example illustrates a typical residential customer who has used 1,000 kWh in an average month.

Two-step energy charges for an average month.



Two-step energy charges

Step 1

675 kWh X $0.0950 = $64.13

Step 2

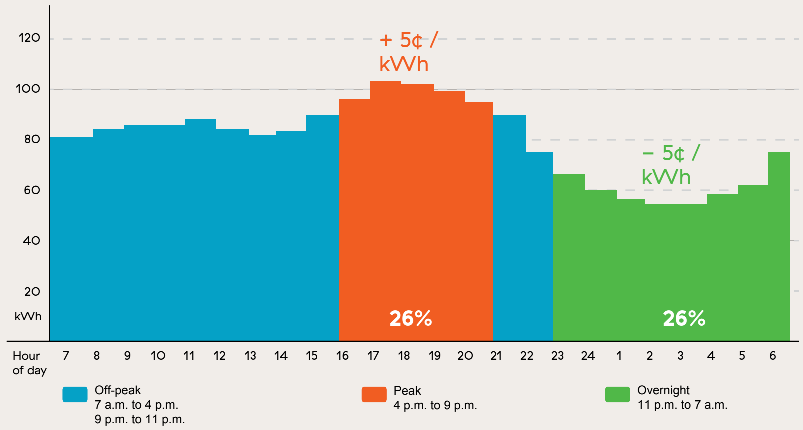
325 kWh X $0.1408 = $46.09

Total two-step energy charges: $110.22

SECOND:

This same customer's 1,000 kWh of usage is shown below in terms of energy use by time period. In this example, over a month period, they used as much energy (26%) between 4 p.m. and 9 p.m. as they did in the 11 p.m. to 7 a.m. period. Time-of-use energy charges are calculated by adding up electricity usage (kWh) during the Overnight (credit) and Peak (charges) periods.

Electricity for an average month, by each hour of the day. No shift in electricity use.



Time-of-use energy charges

Overnight Period Credit

260 kWh X ($0.05) = ($13.00)

Peak Period Charge

260 kWh X $0.05 = $13.00

Off-Peak: No credit or charge

480 kWh

Total time-of-use energy charges: $0.00

THIRD:

The customer's monthly bill includes the RIB rate + time-of-use energy charges

$110.22 + $0.00 = $110.22

While the information above shows this concept can work on average, every customer is different and whether the concept works overall, or for an individual customer, depends on the consumption patterns of the customers that decide to participate.

For this reason, BC Hydro also analyzed the consumption patterns of customers with different characteristics to understand how well this concept would work across a range of potential participation scenarios.

Table 5 below shows the peak period and overnight peak consumption ratios for customers with different housing and heating types. It also shows how much lower or higher bills would be for those customers, if they don't shift any of their electricity use out of the peak period.

Table 5 Load shape and energy charge comparisons by housing and heating type

Customer Group	Number of Customers	Average Annual Bill ($)	Peak Period Load %	Overnight Period Load %	Bill Difference ($)
Electrically heated					
Apartment	293,149	$648	25.7%	25.8%	$(0)
Single detached Home	249,207	$2,085	24.4%	27.1%	$(23)
Townhouse	88,214	$1,352	25.6%	25.3%	$2
Manufactured Home	13,139	$1,548	24.0%	27.5%	$(22)
Other	11,824	$1,563	23.5%	28.6%	$(32)
Non-electrically heated					
Apartment	141,259	$385	27.4%	24.3%	$5
Single detached Home	641,843	$1,270	26.5%	25.4%	$6
Townhouse	69,097	$784	27.4%	24.0%	$11
Manufactured Home	46,215	$1,094	25.8%	25.5%	$1
Other	8,935	$891	23.3%	28.8%	$(19)

As shown in the table above, customers from all different housing and heating types have very similar overall consumption ratios between the peak period and overnight period.

Table 6 below shows the same comparison for customers with different overall annual consumption levels. As with different housing and heating types, the data shows that overall consumption ratios between the peak period and overnight period are similar across different annual consumption segments.

Table 6 Time-of-use rate bill comparison by annual consumption

Customer Group	Number of Customers	Average Annual Bill ($)	Peak Period Load %	Overnight Period Load %	Bill Difference ($)
0 – 4,000 kWh	321,746	318	27.2%	24.4%	$3
4,001 – 8,000 kWh	451,005	673	26.9%	24.5%	$7
8,001 – 12,000 kWh	340,199	1,142	26.5%	25.0%	$8
12,001 – 16,000 kWh	211,107	1,681	25.9%	25.7%	$1
16,001 – 20,000 kWh	115,875	2,237	25.2%	26.5%	$(11)
20,001 – 30,000 kWh	104,908	3,073	24.4%	27.5%	$(37)
30,001 – 50,000 kWh	29,035	4,807	23.3%	29.3%	$(107)

As shown, customers with very high annual consumption tend to have more consumption during the overnight period which means they can benefit from this time-of-use rate design without shifting any of their electricity use out of the peak period.

However, unlike BC Hydro's previous proposal, these estimated bill savings reflect differences in consumption patterns rather than the structural savings from opting out of the RIB rate and avoiding its higher step 2 energy charge.

This analysis validated that the new time-of-use rate proposal largely mitigates the structural winner and low participation challenges with our previous proposal. Even though some customers may be charged more under the optional time-of-use rate than the RIB rate if their initial consumption patterns are unchanged, these estimated bill increases can be more than offset by shifting consumption out of the peak period, providing all customers with an opportunity to save.

3.4 Estimated customer bill savings

Under this new rate design, if a customer can shift some of their electricity usage such as EV charging, dishwashing, or clothes washing and drying out of the peak period, they can save 5 cents for each kWh shifted to the off-peak period and 10 cents for each kWh shifted to the overnight period. Table 7 below provides some illustrative saving estimates for a few consumption shifting scenarios:

Table 7 Illustrative consumption shifting scenarios

Example	Annual Saving
A customer typically plugs in their EV when they get home from work at 4:30 p.m. and keeps it plugged in until their commute to work the next morning. By plugging in or scheduling the charging to begin after 11 p.m., this customer could save	Up to $240 per year
A customer typically runs their ENERGY STAR® dishwasher once a day around 6 p.m. after dinner. By starting the dishwasher around 8 a.m., after breakfast, this customer could save	Up to $15 per year
A customer typically runs their ENERGY STAR® dishwasher once a day around 6 p.m. after dinner. By starting the dishwasher at 11 p.m., before they go to bed, this customer could save	Up to $25 per year
A customer typically does two loads of laundry per week around 7 p.m. By starting those two loads between 9 p.m. and 11 p.m. this customer could save	Up to $25 per year

Customers' bill savings will depend on their individual consumption behaviours. For rate design modelling purposes, BC Hydro used the following assumptions to estimate bill savings for different customer groups. These assumptions align with the assumptions used in BC Hydro's 2021 IRP and have been validated by The Brattle Group.

- Among customers with no EV, 15% of those who can save under the proposed time–of–use rate will participate.
- On average, participating customers with no EV will reduce their peak period consumption by 5%. Of the consumption shifted, 50% will be shifted to the overnight period and 50% will be shifted to the off–peak period.
- Among customers with an EV, 50% of those who can save under the proposed time–of–use rate will participate.
- On average, participating customers with an EV will reduce their peak period EV charging load by approximately 75%. Of the consumption shifted, 80% will be shifted to the overnight period and 20% will be shifted to the off–peak period.

The assumption of an average 5% reduction in non–EV peak period consumption is based on the price ratios of the proposed optional time–of–use rate design.

Table 8 below summarizes the price ratios of our optional time–of–use rate proposal after adding the 5–cent charge and 5–cent credit to the existing RIB rate step 1 and step 2 energy charges.

Table 8 Price ratios of proposed optional time–of–use rate design

Energy Charge	Peak Period	Off Peak Period	Overnight Period	Peak/ Overnight Ratio	Peak/ Off Peak Ratio
Step 1	14.50	9.50	4.50	3.2 : 1	1.5 : 1
Step 2	19.08	14.08	9.08	2.1 : 1	1.4 : 1

The Brattle Group maintains a database of time–varying pricing deployments and pilots from around the globe called Arcturus. Based on the results from opt–in, time–of–use rates in Arcturus, The Brattle Group estimated peak demand reduction impacts for each of these price ratios. These estimates are set out in Table 9 below.

Table 9 Peak demand reduction by price ratio

Price Ratio	Peak Demand Reduction
1.4	2.9%
1.5	3.5%
2.1	6.4%
3.1	10.0%

The average split between step 1 and step 2 consumption for all RIB customers is approximately 61% / 39%.

Using this split and the 50% to off–peak and 50% to overnight shifting assumption mentioned above, the average reduction in non–EV peak period consumption can be calculated as follows:

(3.5 X 50% + 10.0 X 50%) X 61% + (2.9 X 50% + 6.4 X 50%) X 39% = 5.9%

The overall blended average price ratio for the non–EV consumption can be calculated as follows:

(1.5 X 50% + 3.1 X 50%) X 61% + (1.4 X 50% + 2.1 X 50%) X 39% = 2.1

Using the 20% to off–peak and 80% to overnight shifting assumption mentioned above, the EV Charging load blended average price ratio can be calculated as follows:

(1.5 X 20% + 3.1 X 80%) X 61% + (1.4 X 20% + 2.1 X 80%) X 39% = 2.5

The assumed reduction in EV peak load is 75%. An evaluation prepared for San Diego Gas & Electric found that EV owners shifted 73% to 84% of their charging to the overnight period in response to price ratios in the range of 2:1 to 4:1.[9]

9 Refer to: **https://www.sdge.com/sites/default/files/SDGE%20EV%20%20Pricing%20%26%20Tech%20Study.pdf.**

Table 10 below shows the estimated household load and EV load shifting savings by housing and heating type using the above assumptions. Table 11 below shows the same bill saving estimates by annual consumption segments.

Table 10 Estimated bill savings by housing and heating type

Customer Group	Number of Customers	Average Annual Consumption (kWh)	Average Annual Bill ($)	Estimated Annual Household Load Saving ($)	Estimated Annual 2,433 kWh EV Load Saving ($)
Electrically heated					
Apartment	293,149	5,457	$648	$(5)	$(57)
Single detached Home	249,207	16,488	$2,085	$(38)	$(57)
Townhouse	88,214	11,165	$1,352	$(9)	$(57)
Manufactured Home	13,139	12,531	$1,548	$(33)	$(57)
Other	11,824	12,528	$1,563	$(43)	$(57)
Non-electrically heated					
Apartment	141,259	3,112	$385	$2	$(57)
Single detached Home	641,843	10,566	$1,270	$(5)	$(57)
Townhouse	69,097	6,780	$784	$4	$(57)
Manufactured Home	46,215	9,165	$1,094	$(8)	$(57)
Other	8,935	7,051	$891	$(26)	$(57)

Table 11 Estimated bill savings by annual consumption

Customer Group	Number of Customers	Average Annual Consumption (kWh)	Average Annual Bill ($)	Estimated Annual Household Load Saving ($)	Estimated Annual 2,433 kWh EV Load Saving ($)
0 – 4,000 kWh	321,746	2,442	$318	$1	$(57)
4,001 – 8,000 kWh	451,005	5,962	$673	$1	$(57)
8,001 – 12,000 kWh	340,199	9,869	$1,142	$(2)	$(57)
12,001 – 16,000 kWh	211,107	13,814	$1,681	$(12)	$(57)
16,001 – 20,000 kWh	115,875	17,791	$2,237	$(28)	$(57)
20,001 – 30,000 kWh	104,908	23,749	$3,073	$(58)	$(57)
30,001 – 50,000 kWh	29,035	6,039	$4,807	$(138)	$ (57)

As shown, savings for customers living in apartments and townhouses or with low annual consumption are minimal. However, the 5% peak period consumption reduction assumption is an average and individual customers can save more than shown above if they can reduce their peak period consumption by more than 5%. In addition, all customers can achieve meaningful savings if they own an EV and shift the EV charging load out of the peak period.

3.5 Our time-of-use rate proposal incorporated customer feedback

BC Hydro's new optional residential time-of-use rate proposal incorporates the following design elements that reflect customers' feedback:

The proposed time-of-use rate is optional.
Customers who cannot or do not want to shift their electricity usage behaviours can stay on the current RIB rate.

The proposed time-of-use rate is year-round.
This provides more opportunities for customers to save and allows customers to "set it and forget it" when it comes to behavioural or technology changes they may make to achieve savings.

The proposed time–of–use rate applies everyday during a week.

This helps customers easily build their daily electricity consumption routines.

Energy charge during peak hours does not exceed 25 cents per kWh.

Even if a customer has a lot of consumption at the step 2 energy charge, the peak period energy charge including the additional 5 cent additional charge will be 14.08 cents + 5 cents = 19.08 cents per kWh, which is significantly lower than 25 cents per kWh.

Customers with an EV do not need to install a second meter to achieve savings from EV charging.

The proposed time–of–use rate is largely bill neutral to most customers if they do not reduce their peak period consumption. This means that customers with EVs can achieve bill savings if they charge their EV during the overnight period even if their other electricity consumption habits remain unchanged.

Customers who already have a separate meter for EV charging or plan to install one at a marginal incremental cost while undertaking service upgrades to install new Level 2 charging at their home, can choose to have both their home and EV consumption billed under the optional time–of–use rate or to have the time–of–use credits and charges apply to their EV charging load only. In the future, if advancements in measurement standards and technology allow, the option to have the time–of–use credits and charges apply to EV charging load only could be offered to more customers, without the need for a separate meter.

4. Assessment of the optional residential time-of-use rate proposal

4.1 Ratepayer economic assessment

BC Hydro assessed the forecast economic impacts on ratepayers from the new time-of-use rate. BC Hydro calculated the benefit-cost ratio of the rate using the following formula:

$$\frac{\textit{Forecast Capacity Savings}}{\textit{(Estimated Implementation Cost + Forecast Revenue Loss)}}$$

A benefit-cost ratio greater than one indicates that forecast benefits from the proposed rate exceed the forecast revenue loss when compared with forecast RIB rate revenue and the estimated implementation costs, resulting in benefits to all BC Hydro customers over time. A benefit-cost ratio of one indicates no impact on ratepayers. A benefit-cost ratio less than one indicates a negative impact on non participating ratepayers.

Table 12 below shows that the proposed optional time-of-use rate has a benefit-cost ratio over 1 greater than a 10-year period and a 15-year period, indicating the rate is forecast to achieve benefits for all ratepayers over the long term. While costs exceed benefits over the shorter-term, this is common for optional rate structures given lower initial participation and higher up-front implementation costs.

Table 12 Benefit-cost ratio of the optional time-of-use rate proposal

Year after rate launch	Year 5	Year 10	Year 15
Benefit-cost ratio	0.5	1.10	1.75

4.2 Cost of service assessment

BC Hydro also assessed the forecast cost recovery of the proposed optional time-of-use rate. A revenue-cost (R/C) ratio of 1 indicates the cost to provide service to a group of customers is recovered from the revenue received from these customers. Based on BC Hydro's Fiscal 2021 Fully Allocated Cost of Service Study (FACOS), the R/C ratio for the residential rate class was 93%. Therefore, BC Hydro considers a R/C ratio that is close to 93% to be an appropriate level of cost recovery for the optional residential time-of-use.

Table 13 below shows that the proposed optional time-of-use rate has a R/C ratio above 90% by year 8 and above 93% by year 12, indicating that the rate is forecast to appropriately recover its costs over the long term. As with the benefit-cost ratio, a lower R/C ratio is to be expected in the shorter term due to lower initial participation and higher up-front implementation costs.

Table 13 Revenue-cost ratio of the optional time-of-use rate proposal

Year after rate launch	Year 5	Year 8	Year 10	Year 12	Year 15
Benefit-cost ratio	88.0%	90.6%	92.0%	93.2%	94.7%

4.3 Bonbright assessment

The British Columbia Utilities Commission has previously determined that the eight rate design criteria, set out by Dr. James Bonbright in Principles of Public Utility Rates, are consistent with the Utilities Commission Act test of fair, just, and not unduly discriminatory and form an appropriate foundation for rate structures. BC Hydro assessed the proposed optional time-of-use rate against the eight Bonbright criteria. Table 14 below provides a summary of BC Hydro's Bonbright assessment.

Table 14 Bonbright assessment of the optional time-of-use rate proposal

Bonbright Criteria	Remarks
Economic Efficiency	
1. Price signals that encourage efficient use and discourage inefficient use	The rate provides a clear price signal to encourage customers to reduce consumption during BC Hydro's system peak period and incents customers to use more during the overnight period when more system capacity is available.
Fairness	
2. Fair appointment of costs among customers	The rate has an additional charge for each kWh during BC Hydro's system peak period when the cost to provide service is higher and a discount for each kWh during the overnight period when the cost to provide service is lower.
3. Avoid Undue Discrimination	All customers are provided the same charge/credit if they choose to take service under the rate.
Practicality	
4. Customer understanding and acceptance; practical and cost-effective to implement	The optional rate reflects customers' feedback, as summarized in section 3.5 above. The simple "–5 / +5 per kWh" concept means it is easy for customers to understand and estimate bill savings. It's also easier to implement, administer and communicate to customers. The rate is flexible and can be layered on top of any rate structure.
5. Freedom from controversies as to proper interpretation	Since the rate is voluntary and provides mutual benefits, freedom from controversy is not an issue.
Stability	
6. Recovery of the Revenue Requirements	The rate is designed to be revenue neutral on a class average basis to recover forecast revenue requirements.
7. Revenue stability	The rate largely eliminates structural revenue loss. This means that revenue loss will generally only occur from customers' shifting their consumption out of the peak period, which will have corresponding cost reductions for all ratepayers.
8. Rate stability	The rate is stable as the charge/credit is fixed.

5. Ways to provide feedback

BC Hydro is hosting a workshop on November 29, 2022 with interveners and stakeholders to review and discuss this new optional residential time-of-use rate proposal. At this meeting, we will be providing a feedback form to seek your feedback on this proposal. You can also contact us at **bchydroregulatorygroup@bchydro.com** with any additional comments or questions. For information on BC Hydro's residential rate designs, please visit **bchydro.com/yourrates**.

CS-2768

BC Hydro
Power smart

BC Hydro Optional Residential Time-of-Use Rate Application

Appendix D-6

Optional Residential TOU Stakeholder Workshop Feedback Summary from November 29, 2022

Residential Rates Stakeholder Workshop #3 Feedback Form
Summary Report – Nov 29 2022

A. SESSION OBJECTIVES

The objectives of the workshop were to:

- Provide context and updates since we last met;
- Provide a summary of engagement to date and insights;
- Review new proposed optional residential time-of-use rate design;
- Review Residential Demand Side Management programs;
- Review our Residential Inclining Block (RIB) pricing principles proposal;
- Collect feedback to help shape future residential rate designs; and
- Inform a Rate Design application to the BC Utilities Commission.

B. METHODOLOGY

Feedback was collected using an online feedback form available to participants and invitees. A link was provided at the end of the session. Two follow-up emails were sent with a request to submit feedback by December 15, 2022. The first was sent to all registered attendees on December 1 with a request to complete by December 15, 2022. The second was sent to all invitees (less the registered attendees) to invite them to submit their feedback based on the workshop presentation and booklet.

C. PARTICIPATION

Twenty-six (26) parties completed the feedback form, 13 of which are confirmed attendees, of the remaining 13, five (5) indicated they didn't attend the workshop, but they read the presentation materials. There was a total of 44 confirmed workshop attendees (37 virtual, 7 in-person). The result is 13 completes from workshop attendees, 31% completion rate, and the additional 13 completes from a combination of potential workshop and non-workshop attendees.

D. KEY THEMES

Overall, the respondents indicated support for this proposed optional residential time-of-use rate design. It was favoured for the following reasons:

- Fairly simple to understand.
- Stands alone regardless of default rate.
- Minimizes bill impacts to most residential ratepayers if they opt-in and don't shift at all.
- Mitigates structural winners over the previous design.

Feedback was mixed in terms of whether there is a strong enough incentive to shift to save.

- There's a general sense that there is enough incentive to shift energy consumption from the peak period, for those who can.
- Some expressed that $25/year in savings for whole home shifting (no EV) likely isn't enough incentive to enroll and shift load from the peak period.
- The rate design sends the right signal to encourage EV load shift.

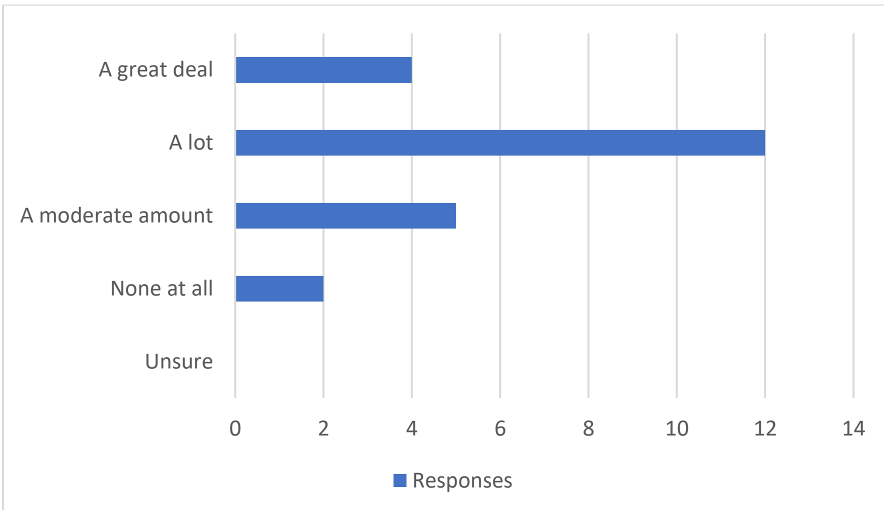
There wasn't strong support for alternative rate designs presented.

E. FEEDBACK FORM RESULTS

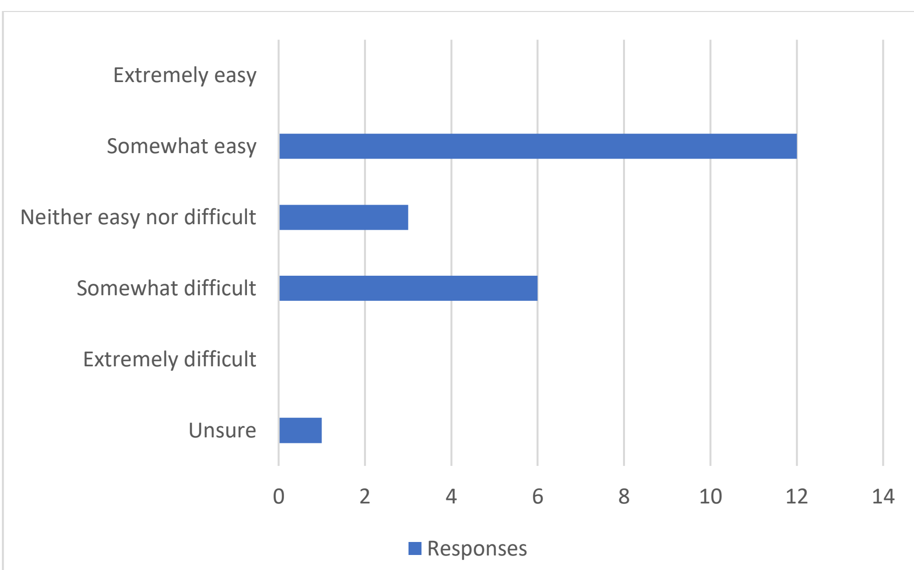
The feedback form was comprised of several open and closed ended questions that participants had the option to respond to with the following results and verbatims.

Start of Block: Feedback Form Results

Q5: To what degree do you understand how the optional credit/charge time-of-use rate concept works?



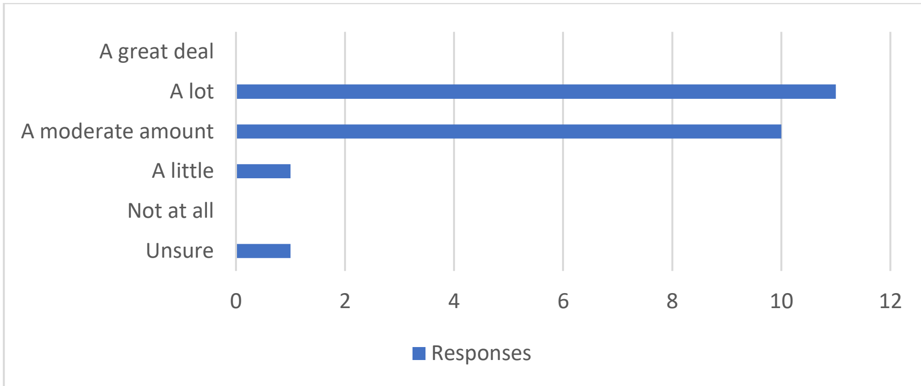
Q6: Do you think this rate design is easy for customers to understand?



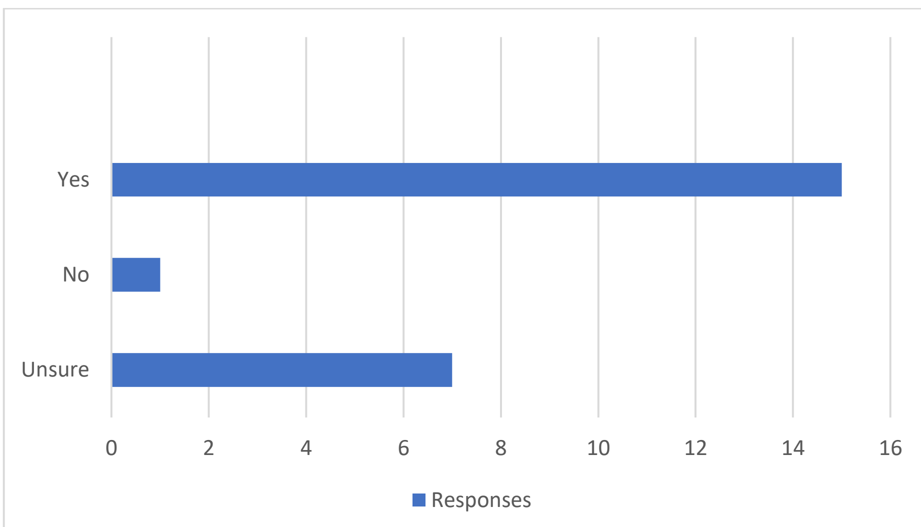
Residential Rates Stakeholder Workshop #3 Feedback Form

Summary Report – Nov 29 2022

Q7: To what degree do you understand how BC Hydro came up with the participation and peak demand reduction assumptions for the proposed optional residential time-of-use rate?



Q8: Do you think these assumptions are reasonable?



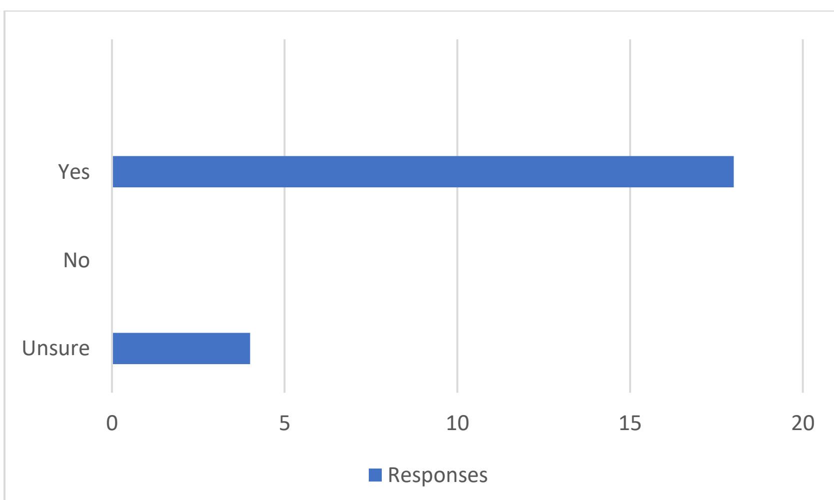
Q9: Comments related to Q8.

- You may have to try some pilots in different parts of the province to test the accuracy of the modelling. San Diego is a very different jurisdiction from B.C. where we have low energy costs.
- While I do understand how BC Hydro derived those assumptions and estimates, it does appear complex for the lay person to understand.

- We have some questions regarding the assumptions: Regarding the opt-in percentage assumptions, what happens if more people opt into this savings than expected? Will this place [BC] Hydro at a deficit and what will be the contingency? How will the increase in active cooling systems in buildings affect the assumptions and the cost savings, noting that cooling demand peaks around 3-6 pm which overlaps with the first half of the peak period?
- To what extent do you believe the customers will be able to install timers for such things as washing machines/dryers, EV charging?
- Think it will take some focused education and outreach to help customers understand how the rate can help them save money. Expect uptake will be slow initially. Specific materials and processes for Indigenous customers and communities will likely be needed.
- There are concerns for people who have electric heat in NE B.C. Heat pumps are not an option so electric heat is typically from an electric forced air furnace. Load shifting is not an option due to the cold winter climate.
- The one element I'm not sure about is why there is such a difference between the electrically heated vs. non-electrically heated homes. Is it because electrically heated homes have a higher overnight load? Its great that the benefits accrue to the electrically heated homes, as an added incentive to get off fossil fuels, I just don't understand the details of why they save more on average.
- The main problem I see with the proposed option is its applicability during the weekends. The proposal is for 7 days a week (so it is always the same to provide consistent behavioural incentives). However, given that weekends are different from a cost causation perspective, necessity, and typical residential routine perspective, I recommend re-assessing this approach. Let weekends be different because the underlying drivers (and need) are different on those days (e.g., Catching up on chores during weekends means that dryers, washing machines, etc. will be run more during the days – and this is ok from a cost causation perspective).
- The best laid plans and assumptions are often way off the mark.
- The assumptions are reasonable, given the current difficulties to get better data.
- Seems to me that you'll get the 15% for opt in through the EV customers who want the lower pricing for their EV and don't have or want to pay for a second meter. Getting to 50% of EVs will be a bit of a challenge, but with strong communications it's pretty easy for EV owners to schedule their charging so it will be more a customer capacity to program their cars. Some are easier than others.
- Like the time rate. Present step rate is bad, real bad.
- It is unclear if the averaged load shape across all customer types and seasons is sufficient evidence that the rate is "bill-neutral" without load shifting. I would expect that some customers would see bill increases under this rate, without changing behaviour.
- I think for most people that do not get to Step 2 that they may not be interested at all. For those that go over or well over on Step 2 that they would like a visual presentation with commentary to learn the reasons why. This also would go for current EV users or ones that are contemplating it.

- BCPIAC's staff felt that a more accurate description of our assessment of the ease of understanding for a fluent English-speaker would fall between "somewhat easy" and "extremely easy". However, since 17.1% of the province's residents speak something other than French or English in the home, it is conceivable that there is a significant number of people[…] who would not find an explanation provided in only Canada's two official languages understandable whatsoever. BCPIAC's staff lawyers strongly recommend that [BC] Hydro generate materials explaining any optional rate designs in any languages identified as the most popularly used by B.C. residents (aside from English). Some we have identified are: Mandarin, Cantonese, Punjabi, German, Tagalog, French, Korean, Spanish, and Farsi but we would recommend BC Hydro refer to the most recent Census data to inform its decision-making. We believe the non-EV participation assumption is likely reasonable given Dr. Faruqui's assessment on slide 33. However, we have doubts about whether the EV participation assumption is reasonable. Figure 3 in Exhibit B-3 of the 2021 IRP Proceeding shows an average enrolment in EV time-varying rates of 21%. While we appreciate that some utilities achieved rates higher than BC Hydro's selected 50%, we are still not necessarily convinced about this assumption. There may have been other factors that resulted in higher uptake amongst EV users by utilities in other jurisdictions (ex: existing familiarity and adoption of time of use rates) that do not apply in our current context. Without further information we cannot agree with BC Hydro's assumption at this time. At this time, we do not have concerns regarding B.C. peak demand reduction assumptions. However, as a procedural point, we think it would have been helpful for the slideshow presentation to include a slide explaining the calculations behind the information on slide 35, similar to the explanations contained on page 12 of the Option Residential Time of Use Booklet.

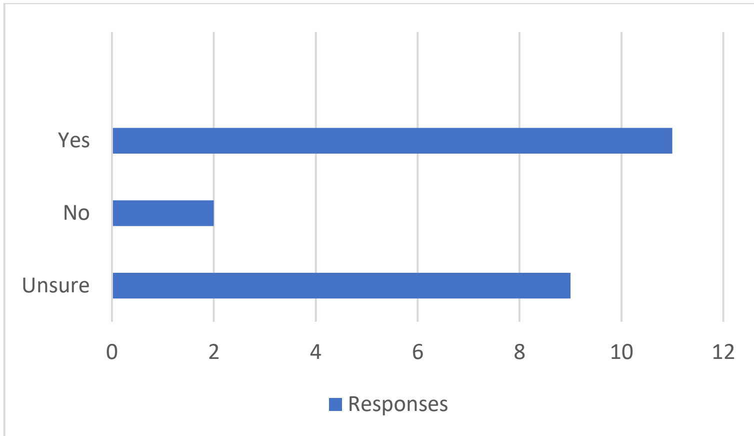
Q10: Compared to the old time-of-use rate design, do you agree that this concept does a better job mitigating the potential for people to save without reducing peak demand?



Q11: Comments related to Q10.

- Yes, layering the credit over top of the existing rate structure likely helps here and makes it clearer as an option on top of the existing rate.
- Yes, based on what was provided, this design appears to better mitigate the potential for structural winners.
- We had a BC Hydro staff member clarify that "the old rate design" refers to the TOU rate design BC Hydro presented last November, but did not file an application for. We do not think that the presentation provided enough information about "the old rate design" in order to allow for such an assessment of their comparative merits, particularly in regards to the issue of free-ridership.
- This looks like a better proposal.
- This is completely understandable. By the way, this has been going on in most European countries for decades, not completely new concept.
- The new design is an improvement from the perspective of low participation and free ridership.
- The credit system does really address some of the key challenges noted with the first iteration of the optional time-of-use demand rate.
- See previous comment regarding electric heating type and inability to load shift in the northeast. It would be good to see a scenario based on actual usage figures. Can BC Hydro's smart meters provide data that would demonstrate/compare costs based on the different rate structures?
- Rationale: This new approach works with both inclining block and flat use rate structures. Rationale: It is fairer to lower consuming customers (e.g., correlated to lower income and more vulnerable customers). Cross subsidizing EV usage (i.e., high income customers) on the backs of low income customers (i.e., low consumption customers) was a problem with the old proposal. Rationale: Cost causation is better with this new proposal.
- It is not a lot of savings if peak demand is not reduced.

Q12: Do you think this rate provides enough savings potential to encourage people to shift their consumption?



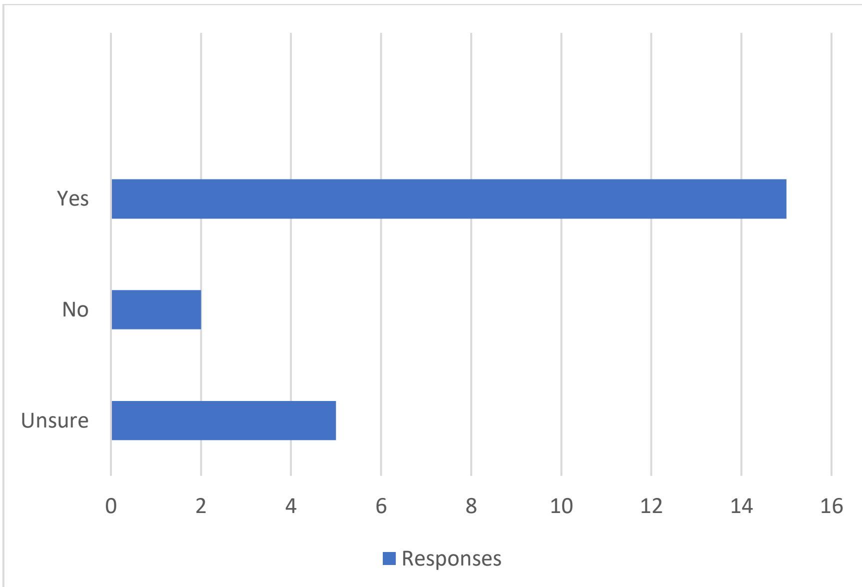
Q13: Comments related to Q12.

- Yes, particularly with a massive shift to EVs in the coming years have this rate structure in place will be attractive for households to opt in and shift their energy use patterns.
- With experience, it may need a little tweaking.
- The challenge on the household level will be communicating what options people have. Beyond the dishwasher example given. For instance, direct promotions to participants for smart thermostats for baseboards, switching the most used baseboards to in-wall fan heaters and space and other energy use management technique education will be key to realizing savings.
- Some EV owners may be enticed to switch their consumption – however, the TOU rate is not likely to encourage EV adoption or grow the wider customer base. We'd like to see additional measures in place not just to mitigate structural winners but to actively encourage decarbonization. The savings potential of +5/-5 may not be enough to prompt a meaningful shift in consumption.
- Smaller consumers probably won't find it saves them enough – will probably be more attractive to larger users and EV owners.
- Slide 38 shows that 85% of customers will save, in the best scenario (New Rate Home & EV), between $4.67 and $5.75 per month. This is very minimal and probably not enough to incentivize customers to change their behaviors. When BC Hydro looked at other jurisdictions to select its participation assumptions for non-EV and EV participants, were the savings higher or similar to what BC Hydro's proposed TOU rate design. If they were higher (because perhaps the other utilities had not fixed the structural problems with optional TOU rates), maybe BC Hydro should not expect as high a participation rate with its own proposal.

- Rationale: Cost causation is what the current levels are set by. If cost causation is not enough to change behaviours, then that is okay. Incentive levels should not be set artificially high because that will create other distortions that will negatively affect ratepayers. Let price signal desired behaviour, and people will respond according to their willingness/ability to pay and change.
- People need enough of a reason/push to change their habits.
- Only if there was confidence in the numbers that were provided. Again, I'm speaking on behalf of users that cannot load shift (electric heat users). I think the rate provides an incentive for those who can shift their load.
- Just right (not too much or too little).
- It will depend on how this is communicated to customers and how easy it is for them to shift their energy use through technology devices. There will be a communication challenge because their bills will be based on two-moving parts - the Tier 2 rates and the TOU rates. I think they can understand the concept, but it will be harder for them to understand what that means for their bills. Again, maybe pilots would help test the modelling.
- It seems to; but I would have like to see a sensitivity analysis based on highest rates of load shifting to overnight, from nominal to maximum.
- For low energy users unless they get into EV charging not so much as the higher energy users.
- EV owners would likely be enticed by this rate. For others, there is not enough schedulable load to result in significant savings under this rate (savings of $25/yr are unlikely to encourage participation in what is a relatively complex rate to understand)
- At this point, we cannot offer any informed opinion on this, but at first blush, given the low anticipated cost-savings, it does not appear that it would. BCPIAC's staff lawyers suggest that, if [BC] Hydro decides to proceed with the +5/-5 Optional TOU rate, that it also tout the collective good that would result. For example: 1. environmental (less upgrades needed in the short term so less damage to our physical environment and climate); 2. lower costs and less energy poverty in both the short and longer term when capacity expansions are not needed all at once; 3. technological improvements during the intervening time can help modify and improve upgrade plans; 4. greater opportunity to plan in ways that avoid, reduce or offset impacts to Indigenous Peoples and private landowners when upgrades are deferred, etc. Whether the rate provides sufficient economic incentive to encourage people to shift their consumption will depend on the economic situations and vulnerabilities of the ratepayers who participate as well as an understanding of the potential costs of facilitating the shift of energy use to off peak (i.e., are any devices needed or any other costs associated with this shift).
- As an apartment dweller with electric heating and only a dishwasher in suite (no washer/dryer), a savings of 25$ per year for switching dishwasher use to after 11pm isn't a big reduction, personally. However, I think $240 savings per year for townhomes/single family homes that charge an EV in their garage could be enough incentive to switch to non-peak times.

- Although the amounts of projected savings are not great, if BC Hydro promotes the programs effectively, BCSEA thinks significant numbers of customers will participate, particularly for EV charging.

Q14: Do you agree with BC Hydro's Bonbright Assessment of this proposed optional time-of-use rate design?



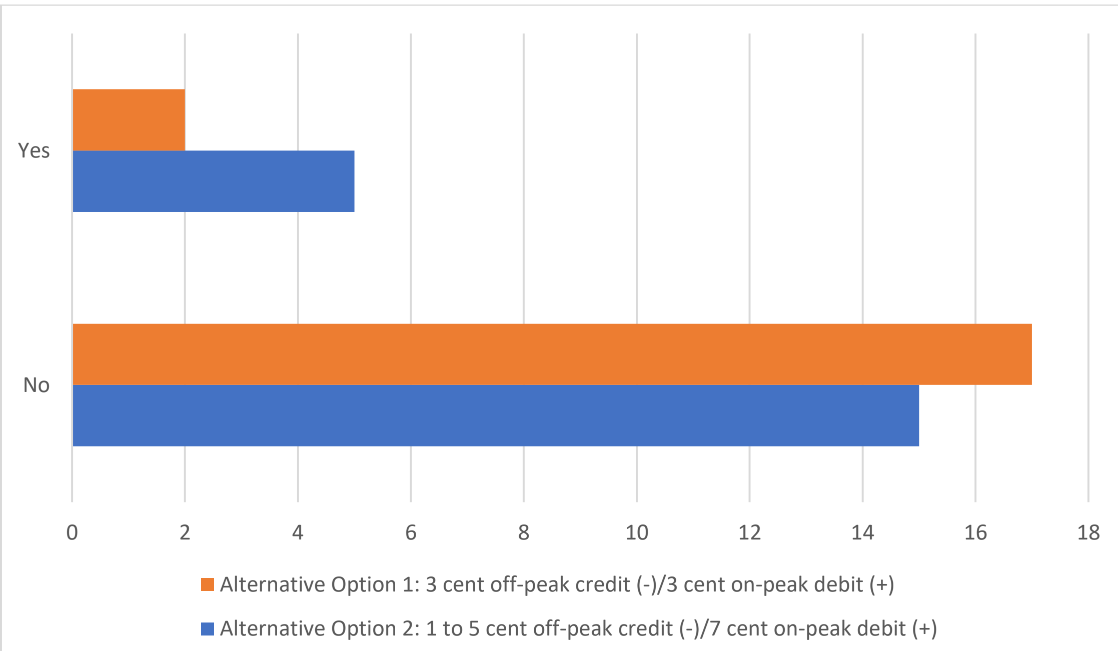
Q15: Comments related to Q14.

- Unsure as to why you would forecast for fewer non-EV participants in 2038. Or perhaps I'm just unsure if the EV participants only have their EV on this program with a separate meter, or if they have their whole house in the program, or both. [Assume related to Q8]
- In this case, there are two ways in which to answer your question: one that takes a siloed view (i.e., does this accord with the Bonbright Assessment within the confines of its program and those who will likely participate and only within that narrow scope) versus one that makes the assessment in the greater ecosystem of [BC] Hydro's entire operation. In an assessment using only the first narrow lens, we agree that the optional rate satisfies the second, third, and fourth of Bonbright's principles listed. As noted in the responses to the previous questions, it is not clear to us that the +5/-5 rate design will provide adequate economic signals or incentivize enough participation to achieve [BC] Hydro's capacity reduction goals so we cannot offer a definitive opinion on whether it satisfies the first principle listed: economic efficiency. In the second assessment format we cited above, one we strongly urge BC Hydro to use in addition to the narrower scope of the first, BCPIAC's staff lawyers do not feel this rate passes the assessment.

- I disagree with the Bonbright Assessment in general. These principles are the product of an antiquated era marked by systems of colonialism and white supremacy. Much of what was once considered “discriminatory” or “unduly preferential” is now known as “equity”, “climate justice” and “reconciliation”, and is entirely appropriate to mandate of modern-day utilities. We encourage BC Hydro to request a review and modernization of these Principles.
- I agree with all the statements but just wonder if the low energy users would opt in.
- I agree that over time, the TOU will pay for itself. I also think there are still issues with the Tier 2 rates, which undermine the assessment of the overall design of BC Hydro rates - beyond just the TOU rates. One question: beyond the changes in rates, are there any other Participant Costs that customers will have to pay (e.g., upgraded meters and the technology devices I mentioned earlier)?
- Generally, the propose[d] option is better than the old proposal. However, the proposal is predicated on increased EV uptake over time. In the regulatory filing, please discuss the issues/problems if EV uptake does not increase as fast as forecast and discuss the implications of economic justification ratios less than 1 (i.e., it is only after EV usage picks up that the proposal makes economic sense, what is the sensitivity to EV uptake and what are the breakeven points).
- Generally, agree with the assessment against the rate design principles.
- BC Hydro's assessment is reasonable.
- A qualified yes. As far as practicality is concerned and the ease to understand, I think this new TOU rate, which combines the RIB and the TOU aspect is probably more complex to understand than anything I've seen before. However, after reading the slides and listening to the presentation, I understand the rate and the problems BC Hydro was trying to fix with it but I don't think the lay person will have the same ease to understand it.
- We agree with the principle of economic efficiency – this is an improvement over the RIB. – Regarding avoiding undue discrimination: only offering a separate option for people with an EV-only meter feels discriminatory if not also offered to MURBs. Bonbright defines undue discrimination as the dissimilar treatment of similar services, or similar treatment of dissimilar services. Allowing one- and two-family homes with separate EV metering to opt in, but not allowing the same for multi-family buildings with metering of common elements (like parking / EV charging / laundry rooms) appears discriminatory. We encourage this TOU rate be expanded for MURBs so they can also benefit from savings - open it to stratas and rental buildings who have EV charging running off their common property meter(s). Overnight charging periods appear long enough that they would have minimal impact on energy management systems, should Hydro include MURBs in the program. - A significant proportion of residents receive service through General Service (non-residential) accounts. These are centralized heating systems for MURBs. TOU rates for General Service will also help to optimize service connection sizing and utilization for MURBs, for example to balance/shift EV charging versus thermal loads. Thermal networks (building-scale and neighbourhood-scale) serving heating/cooling/hot water loads can go a long way to help alleviate electricity grid constraints, particularly in denser urban neighbourhoods. - Regarding fair appointment of costs among customers: While TOU rates would reduce demand-related

costs for all ratepayers, are non-EV owners (including those who sacrifice certain benefits to live in walkable communities) effectively cross-subsidizing EV-owners? Is it deemed to be fair if EV-owners can save up to several hundred dollars per year while non-EV owners can save up to $50 per year ($25 dishwashing + $25 clothes washing/drying). Further, savings would be less for residents who are unable to effectively shift their loads and/or do not own or use dishwashing or clothes washing machines.

Q10#1: Compared to the proposed rate design (+5/-5), would you be interested in the following slightly different rate designs?



Q10#2: Comments related to Q10#1_Option 1.

- The bigger the delta between high and low the more attractive it is.
- The +5 and -5 is easy to understand as stated in the presentation.
- While it's less punitive to those who don't load shift, it's also less of an incentive to do so.
- Think the higher credit is more likely to result in the desired load shifting than this option.
- The incentive-disincentive difference in Option 1 is less, than in BC Hydro’s base proposal, which would tend to weaken the response.
- Not enough of an incentive.
- Not enough incentive to switch to off-peak electricity use.
- It depends.
- Insufficient differential to be enticing.

- If 5 cents is representative of cost causation, go with those levels.
- I don't think that it will be enough incentive to shift

Q10#2: Comments related to Q10#1_Option 2.

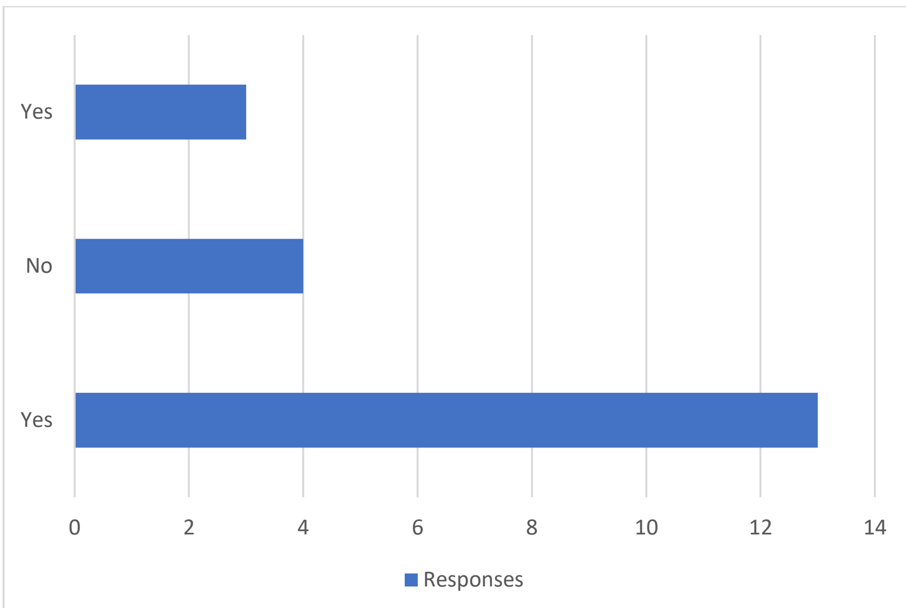
- More incentive to move to off-peak electricity use seems better.
- Greater incentives.
- Think this is too complicated – prefer the simpler two period credit/charge option.
- The incentives and disincentives in Option 2 are more complicated to understand than in BC Hydro's base proposal.
- The imbalance means some people will lose out and may not be enough incentive to switch.
- Maybe implement the more aggressive option after you see what happens with your current proposal.
- Keep life simple. I don't object, but it is more complicated.
- Keep it simple.
- It depends.
- I find this confusing; the symmetry of the credits/debits keeps what is potentially a confusing rate structure simpler for people to understand and hopefully be motivated by.
- Higher peak costs would seem to penalize users that cannot load shift.
- Gets confusing with different credits/debits.
- Could potentially be a stronger signal to shift demand.
- +7/-5 provides a stronger incentive to encourage a behaviour change, reduce peak electricity distribution constraints, and further accounts for increased demand from the operation of active cooling systems which will usually peak in the mid-late afternoon. If this were under still an option under consideration, we propose pairing with stronger educational campaigns to make the rate easier to understand.

Q11: I am interested in something else. Comments related to Q10#1.

- We are open to other models with a stronger price signal that also won't penalize those who are unable to shift their consumption (to provide suggestions, we would need a better grasp on the cost impacts to customers).
- The sole goal appears to be avoiding peak hours (4-9PM). Stay focused on that and ensure that it is economically, rather than politically, or environmentally driven. If the economics are sound, then reasonable environmental and other outcomes will follow over the long term.
- Really like the simplicity of 5 + and –.
- I chose to have a 100% electrically heated home (without a heat pump) and own an EV for environmental reasons. Even though my house is new (2017) and considered energy efficient (EnerGuide Rating of 82), my annual consumption was 32,762 kWh in 2021. So I would be looking for the option that could provide me with the greatest opportunity for savings.

- Consider adding an hour or two from 2pm-4pm of "off-peak" time to move peak time load to earlier in the day. It's easier to see how a household might shift cooking, clothes washing, and heating load to before peak time rather than after.
- Comments on 3/3 – given our doubts about the impact of 5+/5- noted above, we believe 3+/3- would likely not provide adequate incentive for adoption. Comments on 5/7 - We would need to see a modelling of this iteration in order to make sure that it yields sufficient benefit to Hydro's capacity demands in order to justify that level of incentive.
- Additional opt-in rate for customers with heat pumps, to encourage efficient electrification.

Q18: Do you support BC Hydro advancing the proposed optional credit/charge residential time-of-use rate?



Q19: Please provide any further comments you have about the optional residential time-of-use rate:

- We suggest modelling the alternatives first and also bringing forward a program that addresses the barriers to participation that may be experienced by low and fixed income as well as indigenous communities, for example through DSM. That way, the TOU proposal will be more in the spirit of the proposed regulatory amendments that we understand are to come.
- This could be an effective demand response tool. However, it is insufficient as a response to current criticisms of the RIB rate. More needs to be done.
- The old rate proposal would be providing me with the greatest savings opportunity. While I understand the rationale for BC Hydro to advance the new TOU rate design, I cannot say that I prefer it to the old one.

- NO to Alternative Option 1 YES to Alternative Option 2, but prefer the proposed option.
- Keen to see this move ahead as soon as possible. It will significantly bolster electrification efforts.
- It is good that it is optional. Education/outreach will be necessary to get the desired uptake. Might also be something that could be communicated at the time of purchase of an EV or a major appliance (e.g., if dishwasher or dryer has timer that can be set to come on over night). May also be opportunity for engagement through Indigenous community energy planning – will need to develop and share materials specifically for Indigenous communities.
- Is there a possibility to provide data using actual usage numbers with the existing smart meters?
- I think the proposed rate structure is very good - it supports/encourages electrification while still encouraging conservation behaviours with a tiered structure, is equitable in that small homes or low energy users still have an opportunity to save and is reasonably easy to understand with the +/- 5 cents idea. Since its optional it won't put anyone in the position of paying more or having a system they don't understand.
- Great work on finding innovative solutions to address the feedback received through first iteration of engagement/review.
- But I still think there needs to be a discussion regarding the Tier 2 rates. I understand the concern at BC Hydro about bills increasing if you get rid of the second-tier rate. However, the approach of slowly eliminating them over time by not applying rate increases to Tier 2 will take too long. Many new and upgraded buildings are being penalized because of EVs and electrification. The time to eliminate the Tier 2 rates should be linked to the ambition of building electrification and EV policies at the Provincial and local levels. Maybe BC Hydro, could review increasing the threshold for the Tier 2 rates, so new apartments or even townhouses do not get caught with the higher rates. I also liked the idea about having special rates for heat pumps. Could new fully electrified buildings be exempted from the Tier 2 rates?
- BCSEA commends BC Hydro for working out this proposal, which looks as though it could be effective, and which minimizes free riders.
- Generally, we support the proposed TOU rate which helps address the bill impacts associated with the former design. However, to encourage EV adoption and attract more people to electrify, more work is needed. We understand the TOU rate, but we think it may be more challenging for customers to grasp than the two-tier system. Customers who are generally conscious about their energy consumption and energy cost will likely take the time and effort to understand the new TOU rate concept. Conversely, customers who are less conscious and/or non-EV owners who ostensibly have relatively little control over their electricity usage are unlikely to pay attention without simple illustrative examples that demonstrate cost impacts. It would be good to provide illustrative examples/ profiles to help customers understand how the TOU rate will impact the different types. Where possible, rely on visuals to communicate this or consider translated materials so that the new rate can be more comprehendible to non fluent English-speaking customers. We encourage the development of the tool on My Hydro to help customers understand how much they will pay under TOU rate/ what habits they can change to adjust their bill. – Additionally, we recommend: 1) This TOU

rate be expanded for MURBs so they can also benefit from savings. 2) Considering an equivalent TOU rate structure with a stronger price signal to motivate greater behaviour change. 3) Introducing additional rates specific to heating and cooling. Customers are limited in how much they [are] adjusting their heating and cooling so this TOU rate has limited impact in that regard.

End of Block: Feedback Form Results

Appendix A: Feedback Form

Optional Residential Time-of-Use Rate Workshop Feedback Form

Start of Block: Optional Time-of-Use Feedback Form

Q1 As we prepare to submit an application to the BC Utilities Commission to propose a new optional time-of-use rate for residential customers, we're asking for your feedback, including any concerns or issues you might have with our proposal. Please refer to the optional time-of-use rate presentation slide deck for more information when completing this survey.

Please be aware that your feedback, including the organization you're representing, will be included in the application and be part of the public record for the regulatory proceeding. Due to privacy concerns, we ask that you do not identify third -party individuals or account specific information in your comments. Comments that reference identifiable individuals will not be included as part of the public record.

Any personal information you provide to BC Hydro on this form is collected and protected in accordance with the Freedom of Information and Protection of Privacy Act, Section 26(c). BC Hydro is collecting information with this for the purpose of rate design in accordance with BC Hydro's mandate under the Hydro and Power Authority Act, the BC Hydro Electric Tariff, the Utilities Commission Act and related Regulations and Directions. If you have any questions about the collection or use of the personal information collected on this form please contact the BC Hydro Regulatory Group
at bchydroregulatorygroup@bchydro.com

Please submit your feedback by December 15th, 2022.

Page Break

Q2 Your contact information:

Name:

Q3 Title:
Q4 Organization:

A great deal	A lot	A moderate amount	A little	None at all	Unsure

Q5 E-mail address:

____

Page Break

Q6 General Feedback
Please provide your general comments and feedback about the workshop:

____

Page Break

Q7 Optional Time-of-Use Rates

Now we are going to ask you about the proposed optional time-of-use rate. Please answer based on the individuals you represent.

o To what degree do you understand how the optional credit/charge time-of-use rate concept works? Please refer to slides 25-27 for more information.

A great deal	A lot	A moderate amount	A little	None at all	Unsure

○ Do you think this rate design is easy for customers to understand? Please refer to slides 25 - 27 for more information.

Extremely easy	Somewhat easy	Neither easy nor difficult	Somewhat difficult	Extremely difficult	Unsure

○ To what degree do you understand how BC Hydro came up with the participation and peak demand reduction assumptions for the proposed optional residential time-of-use rate? Please refer to slides 29-35 for more information.

- Do you think these assumptions are reasonable? Please refer to slides 29-35 for more information.

  Yes No Unsure

  Please provide your comments.

- Compared to the old time-of-use rate design, do you agree that this concept does a better job mitigating the potential for people to save without reducing peak demand? Please refer to slides 37-41 for more information.

  Yes No Unsure

  Please provide your comments.

- Do you think this rate provides enough savings potential to encourage people to shift their consumption? Please refer to slides 37-41 for more information.

  Yes No Unsure

  Please provide your comments.

- Do you agree with BC Hydro's Bonbright Assessment of this proposed optional time-of-use rate design? Please refer to slides 43-45 for more information.

  Yes No Unsure

  Please provide your comments.

- Compared to the proposed rate design (+5/-5), would you be interested in the following slightly different rate designs? Please refer to slide 47 for more information.

  - Alternative option 1: 3 cent off-peak credit (-) / 3 cent on-peak debit (+)

    Yes No Please explain your answer:

  - Alternative option 2: 1 to 5 cent off-peak credit (-) / 7 cent on-peak debit (+)

    Yes No Please explain your answer:

I am interested in something else:

____

- Do you support BC Hydro advancing the proposed optional credit/charge residential time-of-use rate? Please refer to slide 49 for more information.

Yes No Unsure

Please provide any further comments you have about the optional residential time-of-use:

____

End of Block: Optional Time-of-Use Feedback Form

Appendix B: Workshop Follow-Up Emails

1. Subject: BC Hydro Optional Time-of-Use Rate Workshop

Sent by: Stephen Cheeseman, Chinook Power Corp

Question:

Given the attached workshop document would you be able to provide me with an updated table 1 (just for the RIB) forecast revenue for the +/-5cent and +/-3 cent TOU options?

BC Hydro response:

Thanks for your question regarding our recent workshop materials.

Based on our modelling, we expect to have around 255,000 optional time-of-use rate participants and a revenue loss of around $15M in fiscal 2030 with the +/- 5 rate. There will be a corresponding capacity saving benefit from participants' load shifting. For reference, the fiscal 2030 RIB revenue forecast is around $2.74B.

We have not conducted detailed participation and load shifting modelling for the +/- 3 alternative rate design. However, we expect the participating and load shifting response of the +/- 3 rate will be lower than +/- 5 as the estimated savings and price ratios are lower to attract participants and encourage the same level of behavioural changes. It is reasonable to assume that the +/- 3 alternative would result in a revenue loss of no more than $9M (60% of $15M) in fiscal 2030.

Follow-up question:

How do you quantify the capacity saving benefit?

BC Hydro response:

Here's how we calculate the capacity savings benefit.

Customer capacity savings are estimated as follows:

- For household load, we assumed a 5% capacity reduction of the coincidental peak (in January) of participants.
- For EV load, we assume 1 kW capacity reduction per vehicle (average peak EV load during the peak period, happens at around 5-6pm)

Capacity saving values are estimated as follows:

- $65/kW-year for non-bulk transmission and distribution savings each year starting the rate launch
- An additional $109/kW-year for capacity long-run marginal cost applies starting fiscal 2032 when BC Hydro is no longer in surplus.

2. Subject: Follow-up: Optional Residential Time-of-Use rate question

Sent by: Peter Helland, Residential Consumer Intervener Association

BC Hydro email responding to questions posed during workshop:

Thanks for joining our Optional Residential Time-of-Use workshop on November 29. We're following up on a question you raised. You'd asked if the benefit-cost ratio of the optional rate could achieve 1 when only considering household shifting. At the workshop, we responded a lot of the benefit is coming from EV adoption. We hadn't look at the benefit-cost without EV load, but we said we'd take it away and look at it.

We've since looked at the benefit-cost ratio without EV load and have concluded it would not achieve 1 without it.

Mr. Helland's response:

Thank you for looking into this issue for me. Very helpful/insightful. The challenge for RCIA is always "fairness" and cost causation (as I'm sure you spend considerable time worrying about as well). EVs are emblematic of this issue as lower income people will struggle to buy EVs (under today's and near future scenarios), and therefore RCIA worries about cross subsidization impacts between different residential ratepayers within the larger residential class.

As a result, I'll request that when you file with the BCUC, that BC Hydro's filing include a discussion about EV penetrations required to reach breakeven (i.e. 1). Not sure if this would be classified as a breakeven or sensitivity analysis on EV penetration, but this is an issue that we are interested in.

3. Subject: BC Hydro Optional Time-of-Use Rate Workshop

Sent by: Ivan Tang, City of Vancouver

Question:

I attended the subject workshop last Tuesday and I'm starting to digest the information and presentation materials. I understand City of Vancouver will be submitting feedback consolidated from various groups. I would like to understand if the optional TOU rate would be applicable to district energy providers (such as the NEU) and/or other Stream A and B thermal energy systems, that predominantly serve residential end-users. The feedback from my branch would be highly dependent on this condition.

Considering that feedback is due in only ten days, I would appreciate a quick response to this question to help guide our internal discussion and feedback. Happy to schedule a call/meeting soon to chat further if that would be more convenient for you.

BC Hydro response:

Thanks for reaching out with your question.

Since district energy providers take BC Hydro service under general service rates, they wouldn't be eligible for the proposed optional residential time-of-use rate. However, residential customers living in district energy providers' service buildings would still be able to participate in the optional residential time-of-use rate for their other household electricity needs that aren't provided by the district energy system.

BC Hydro will be exploring optional general service rates that can encourage electrification in the near future, including the needs of district energy and EV charging for multi-unit buildings and workplaces.

Follow-up question:

Thanks for your prompt response. It is encouraging to hear that BC Hydro will be exploring optional general service rates in the near future (I assume you mean TOU rates). This would be critical to delivering energy needs, especially in areas that are constrained by infrastructure limitations. Are you able to advise what the rough schedule might be for exploring TOU rates for general service customers?

One potential concern that comes to mind is disparities in what end-users in a hypothetical [multi-unit] building that is served by a district energy provider might pay, compared to the same building which is fully electrified.

BC Hydro response:

We don't have a specific timeline for the optional Commercial TOU work at this time. We've got some other priority filings to complete. But, it's definitely on our radar.

Regarding your concern, did you want to have a brief discussion on this topic or rather, were you simply wanting to bring it forward as a concern?

Follow-up response:

Given the upcoming deadline this week for feedback, I think I'll look to incorporate something in the consolidated feedback from CoV and will reach out separately as needed. Appreciate your offer.

BC Hydro Optional Residential Time-of-Use Rate Application

Appendix D-7A

Perception Survey by Sentis

sentis

BC Hydro
Rate Design Research
Report Draft

BC Hydro

REVISED: February 5, 2021

500 – 602 West Hastings Street, Vancouver, BC V6B 1P2
sentisresearch.com

Adam Di Paula | adipaula@sentisresearch.com | 604.306.5633
Ayden Verhulst | averhulst@sentisresearch.com | 604.618.8673

sentis

Objectives & Approach

sentis

METHOD

Approach

A random sample of residential customers with an email address on file who have given consent to be contacted

15-minute email-to-online survey

Survey Responses

Year	Date	Invitations	Completed Surveys	Participation Rate
2020	December 11 - 30	8,427	978	12%

Total results accurate to **±3%** (19 times out of 20)

The survey results have not been weighted

Highlights

4

sentis

HIGHLIGHTS

1. Support for a Flat Rate Structure

The results illustrate the challenges that exist with respect to getting BC Hydro customers to support (or at least be more open to) a flat rate structure.

Only 29% of customers initially support the flat rate, and support is strongly tied to two related factors:

- The extent to which customers find their current bills reasonable
- The extent to which their bills will go up with a flat rate

→ This is why support is lowest among those living in condos/apts (22%). They are the group most likely to consider their current bills reasonable, are most likely to feel that the current rate system works for them - and they will experience the largest percentage increases in their bills under a flat rate.

While those living in small detached homes are less likely than those living in condos/apts to feel the current system works for them, they are no more likely to support a flat rate. These customers will also experience higher bills under a flat rate.

Support for the flat rate is substantial (61%) only among those living in larger family homes - who represent 19% of customers surveyed. By and large, these customers consider their current bills unreasonable and feel that the current system doesn't work for them – and their bills will likely decrease under a flat rate.

There is a notable percentage of customers who indicate that they don't know if they support a flat rate (25%). These customers tend to have usage patterns that make it harder for them to predict how a flat rate would impact them. Consistent with this, this group is much more likely to indicate that they don't know if the current system works for them compared to those who either support or opposed the flat rate concept.

2. Changing the Basic Charge

→ Combining a 'higher basic charge' with a 'lower flat rate' does not have an appreciable impact on support for a flat rate among those living in condos/apts or small detached homes.

Also, across all three household profile groups, there is very little support for the 'same lower basic charge' and a 'higher flat rate'. In general, it is difficult to get customers to endorse any option that refers to 'higher' charges or rates.

Further, support for the flat rate structure is not related to what customers claim they value with respect to their electricity. For example, those who place a high degree of importance on getting electricity from a clean source are no more likely to support a flat rate even though GHG reduction is one of the stated benefits of a flat rate.

sentis

HIGHLIGHTS

3. Impact of Cost Saving Programs & Smart Thermostats

→ **Customers who initially don't support the flat rate are hesitant to increase their acceptance of it when informed that BC Hydro could offer more programs to help customers save on electricity. Their acceptance depends on how much savings they could achieve with such programs.**

Support for the flat rate does increase among those living in condos/apts and small detached homes when these customers are told that they could receive a smart thermostat that would help them manage their home heating more effectively.

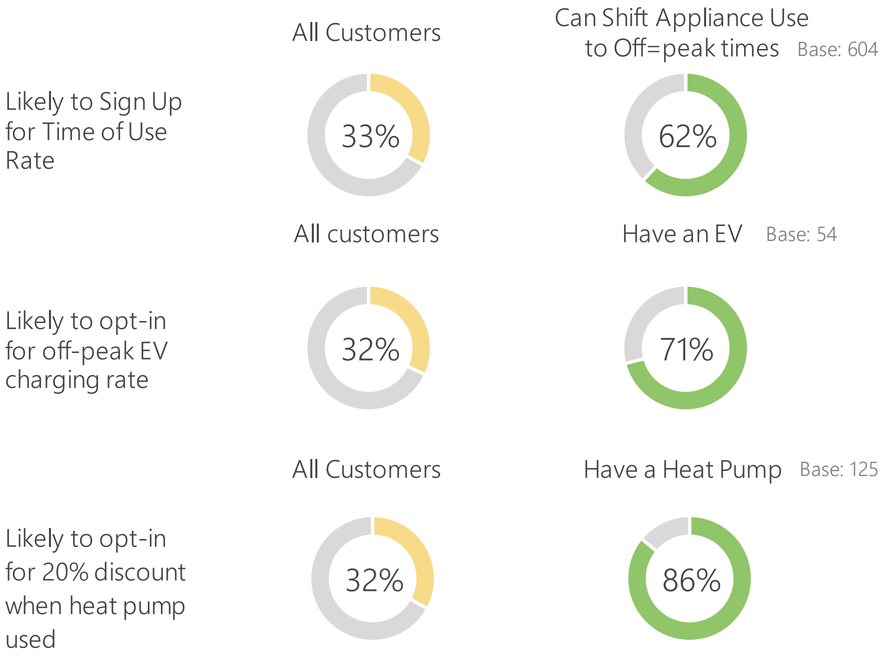
However, the results illustrate the current challenges with promoting demand response programs. Even though customers are informed that it would result in a lower electricity bill, the prospect of BC Hydro having remote control of the thermostat decreases support for the flat rate substantially.

Also, low-income households are no more likely to support a flat rate structure in this case than either moderate-income or high-income households.

4. Interest in Optional Rates

62% of customers can shift the use of their appliances to off-peak times.
6% of customers own an electric vehicle (EV)
13% of customers have a heat pump

Interest in optional rates is strong among customers for whom the rate is currently most relevant:



sentis

Summary of Findings

sentis

Current Rate Structure

IMPRESSIONS OF BC HYDRO ELECTRICITY RATES

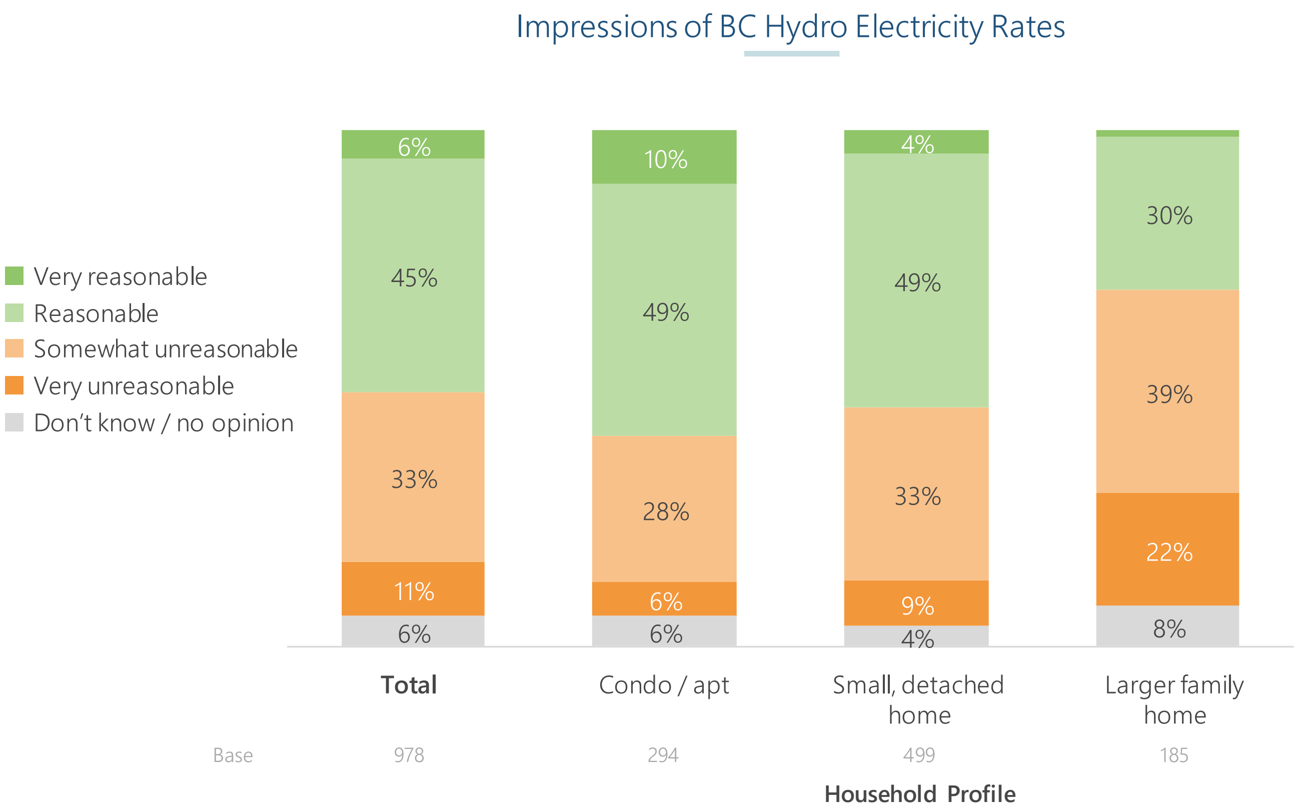
Half (51%) of BC Hydro customers consider the price they pay for electricity to be reasonable, while 44% consider the price they pay unreasonable. Perceptions of price vary significantly by household profile, with those living in larger family homes significantly more likely (61%) than those living in small detached homes (42%) or condos/apts (34%) to consider the price they pay unreasonable.

This is due in large part to bill size. On average, 77% of the electricity bills among those living larger family homes include a Step 2 charge, compared to 50% among those living in small detached homes and 19% among those living in condos/apts.

Other notable subgroup differences in price perceptions:

Income: Those in low-income households are more likely to consider the price they pay to be unreasonable (49%), compared to those in moderate (40%) and high-income households (37%)

Main Home Heat Source: Those in homes heated mainly by electricity are more likely to consider the price they pay to be unreasonable (50%) compared to those in homes heated mainly by natural gas (38%).



Base: Total (978)
A1. In general, would you say the price you pay for electricity from BC Hydro is...

ASSESSING CURRENT RATE STRUCTURE

After selecting the profile group that is most similar to their household, customers were given a description of BC Hydro's current two-stepped rate.

For residential electricity charges, BC currently uses **a two-stepped rate** to encourage people to save electricity. The two-stepped rate **charges customers one rate up to a limit of electricity used** - about 1350 kWh - in each billing period and a **higher rate for all electricity used beyond the 1350 kWh limit**. To illustrate, the typical residential customer is charged the following:

- Step 1 is 9.35 cents per kWh, up to a 1,350 kWh per two-month period
- Step 2 is 14.03 cents per kWh for usage above this

In addition to the two-stepped rate for electricity used, BC Hydro bills also include a basic charge ($6.30 per month per account), which covers some of the costs related to customer service (billing, metering, call centre, etc.).

If we apply this to the basic description of your household that you selected in the previous question, the average annual electricity cost would look like this:

	A	B	C
			
	Customer pays only at Step 1 electricity charge, never Step 2	Customer pays at Step 2 electricity charge sometimes	Customer pays the Step 2 electricity charge most of the time
Average annual electricity charge today	$450 ($37.50 per month)	$870 ($90 per month in winter, $60 per month in summer)	$2130 ($250 per month in winter, $110 per month in summer)
% of customers surveyed	30%	51%	19%

sentis

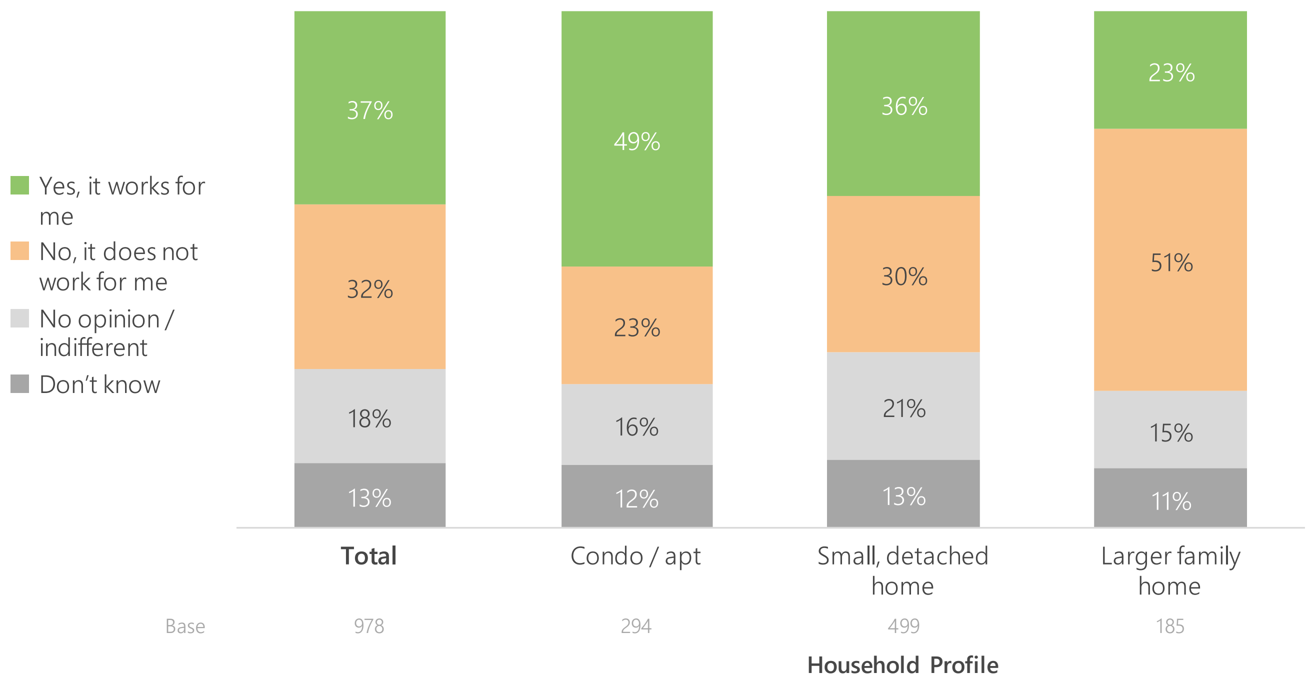
DOES THE CURRENT RATE STRUCTURE MEET CUSTOMERS NEEDS?

Overall, customers are fairly evenly split when it comes to whether or not the current two-stepped rate meets their needs.

37% indicate that the two-stepped rate works for them, while 32% indicate that it doesn't. Another 31% either don't know or don't have an opinion.

Again, however, there are significant differences by household profile – with those living in larger family homes the least likely to feel that the current two-stepped rate meets their needs.

If Rates Meet Customer Needs by Household Profile



Base: Total (978)
A6. Would you say the current residential rate as described above generally meets your needs?

WHY CURRENT STRUCTURE WORKS / DOES NOT WORK

Overall, the main reasons customers give for why the current system works for them are financial – either because their current electricity bills fit within their budget or because they can generally stay within the Step 1 rate (and keep their bills affordable).

Reasons vary based on customer type, however. Those living in condos/apts are more likely to mention financial reasons while those living in small-detached homes and larger family homes (who are more likely than condo/apt dwellers to pay Step 2 rates) are more likely to mention that the current system encourages conservation. Most customers living in condos/apts don't have any bills with Step 2 charges (61%), compared to only 25% of those living in small-detached homes and 9% of those living in larger family homes.

When asked why the current system doesn't work for them, customers living in condos/apts were the most likely to mention that the average electricity charge given for their household profile does not match what they actually pay. Some said that what they actually pay is more, some said it is less. Those living in larger family homes were the most likely to mention that their bills are too high under the current system.

A relatively common sentiment among customers who indicate that the current system doesn't work for them is that the current system is unfair. Some think it's unfair because it penalizes them for circumstances that they can't easily control (e.g., where they live, type of heating system, age of house, or size of household). These circumstances don't make it possible for them to benefit from the Step 1 rate. Others think it's unfair because, despite their best efforts to conserve electricity, they still "get penalized" by the Step 2 rate.

Because I don't have a choice give my home. I can stay cold and pay less, or warm up and pay more with step 2. my opinion is customers with only electrical heating homes have to by charged with price Step 1 only.

I am an environmental advocate and I am incredibly frugal with my electric usage due to the costs, yet the cost is still prohibitive for me. If I had the money, I would, and I eventually will, transition to sustainable energy for my residence.

	Total	Condo	Smaller Detached Home	Larger Family Home
Yes, works for me	302	120	150	32
Affordable/ Reasonable/ Fits in budget	27%	35%	25%	13%
Always usually stay in Step 1	17%	24%	14%	0%
Motivates/Encourages energy conservation	13%	7%	16%	19%
No problems/ It works/ Makes sense	8%	5%	9%	19%
Easy to understand	5%	5%	6%	3%
Good to monitor usage/ Helps control use	5%	2%	8%	3%
No, does not work for me	298	65	143	90
Mention that amount they pay is not consistent with example provided in survey	21%	31%	24%	9%
Cost too high (General)	18%	11%	14%	30%
Step 2 rate is punitive/unfair to customers who can't avoid it due to circumstances (e.g., location, family size, home type)	15%	12%	15%	19%
Always/often pay Step 2 rate	14%	11%	14%	16%
Cost too much/Easy to get into Step 2 even if you try to conserve energy	12%	8%	13%	13%
Change threshold for Step 2 rate so easier to stay at lower rate	5%	6%	6%	3%
Step 2 rate penalizes customers to use more of a cleaner energy source	4%	0%	6%	4%

Only main mentions are shown.
A7. Can you please share your thoughts on why [it works for you / it doesn't work for you]?

IMPRESSIONS OF CURRENT RESIDENTIAL RATES

Whether or not a customer feels that the current two-stepped rate meets their needs depends in large part on the extent to which they perceive the price they pay for electricity to be reasonable.

Among those who consider the price that they currently pay for electricity to be *very reasonable*, 70% feel that the current two-stepped rate works for them and only 6% do not.

Among those who consider the price that they currently pay for electricity to be *very unreasonable*, only 11% feel that the current two-stepped rate meets their needs while 73% do not.

How Attitudes Towards Pricing Impacts Feelings Toward Current Two-Stepped Rate

Attitudes Towards Current Price for Electricity (A1)

Do Current Residential Rates Meet Needs?		Very Unreasonable	Somewhat Unreasonable	Reasonable	Very Reasonable
	Base	(103)	(323)	(442)	(54)
	Yes, current rates work for me	11%	23%	51%	70%
	No, current rates do not work for me	73%	45%	17%	6%

Base: Total (978)
A1. In general, would you say the price you pay for electricity from BC Hydro is...
A6. Would you say the current residential rate as described above generally meets your needs?

sentis

Flat Electricity Rate

INTRODUCING THE FLAT RATE CONCEPT

This is how the flat rate concept was first introduced to customers in the survey.

BC Hydro is looking at changing from the current two-stepped rate to a flat rate, which simply means *one rate for the electricity used during the billing period*.

The **benefits of a flat rate** include:

- **Simpler bills**: charging one flat rate means bills are easier to understand.
- **Fairness**: all customers pay the same rate.
- **More affordable power for customers in electrically-heated homes**: many customers are pushed into the step 2 rate in the colder months when they turn on their heat.
- **Helps customers reduce greenhouse gas emission** by saving money on electricity for clean technology such as heat pumps and electric vehicle charging.

Depending on what kind of home you have and how much electricity you use, a flat rate would increase or decrease your bill. If there was a change from a 2-step rate to a flat electricity rate, the change may be introduced gradually over a five-year period.

See below for a hypothetical illustration based on the example of the average profile you selected.

ONLY SHOW OPTION SELECTED IN A5

	A	B	C
			
Annual electricity charge today	$450	$870	$2130
Annual charge after year 5: % change vs. today:	$572 +27%	$1004 +15%	$2004 -7.6%

Note: the prospective figures assume a higher basic charge and a flat rate in the 10.6 cents per kWh range. These are for illustrative purposes only.

sentis

IMPRESSION OF FLAT ELECTRICITY CHARGE CONCEPT

Customers who initially express that they don't support the flat rate concept outnumber those who do, by a factor of 2 to 1.
Initial support is tied strongly to household profile. Only a small percentage (14%) of those living in larger family homes don't support the flat rate concept, and 61% do support it. In the survey, these customers were informed that their annual electricity bill could *decrease* by 7.6% over a five-year period.

In contrast, only two-in-ten of those living in either condos/apts or in small detached homes support the flat rate concept. Both of these groups were informed that their annual electricity bill could increase over a five-year period. Those living in condos/apts were informed that their bill could increase by 27% and those living in small detached homes were informed that their bill could increase by 15%.

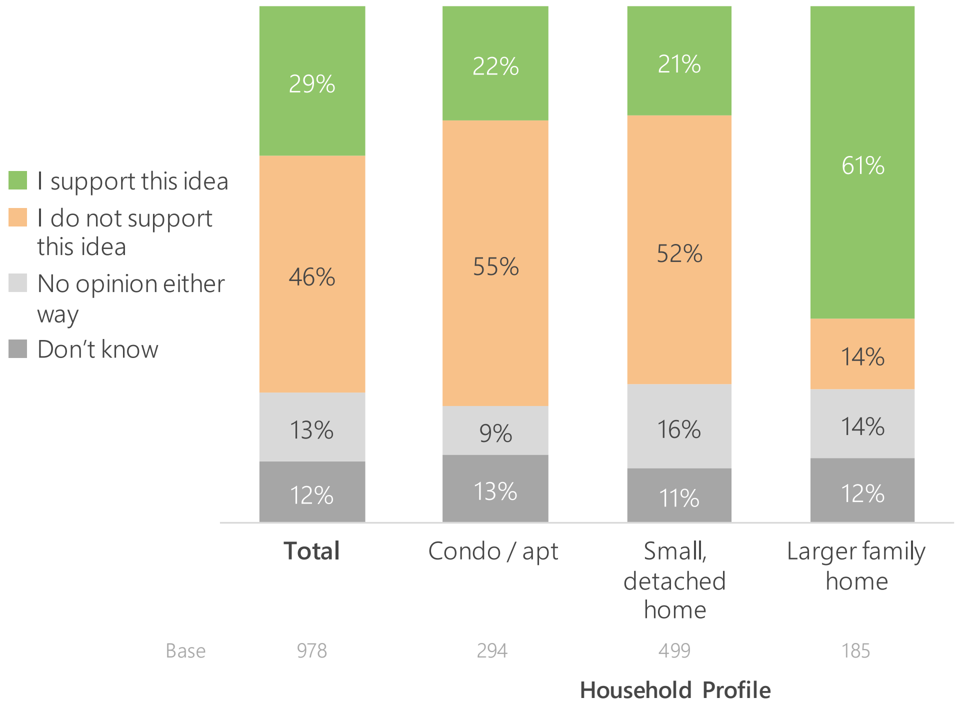
Despite the fact that the percentage increase for those living in small detached homes is almost half of what it is for those living in condos/apts, (and that those living in small detached homes are less likely than those living in condos/apts to indicate that the current rate structure works for them) the reaction to the flat rate concept among these two groups is highly similar. It may be that any increase above a few percentage points will initially be met with opposition.

Other notable subgroup differences in initial reactions to the flat rate concept:

Income: Those in low-income households are less likely to indicate that they support the flat rate concept (25%) compared to those in moderate (32%) and high-income households (32%)

Main Home Heat Source: Those living in homes heated mainly by electricity are more likely to support the flat rate concept (36%) than those living in homes heated mainly by natural gas (22%).

Initial Impressions of Flat Rate Concept



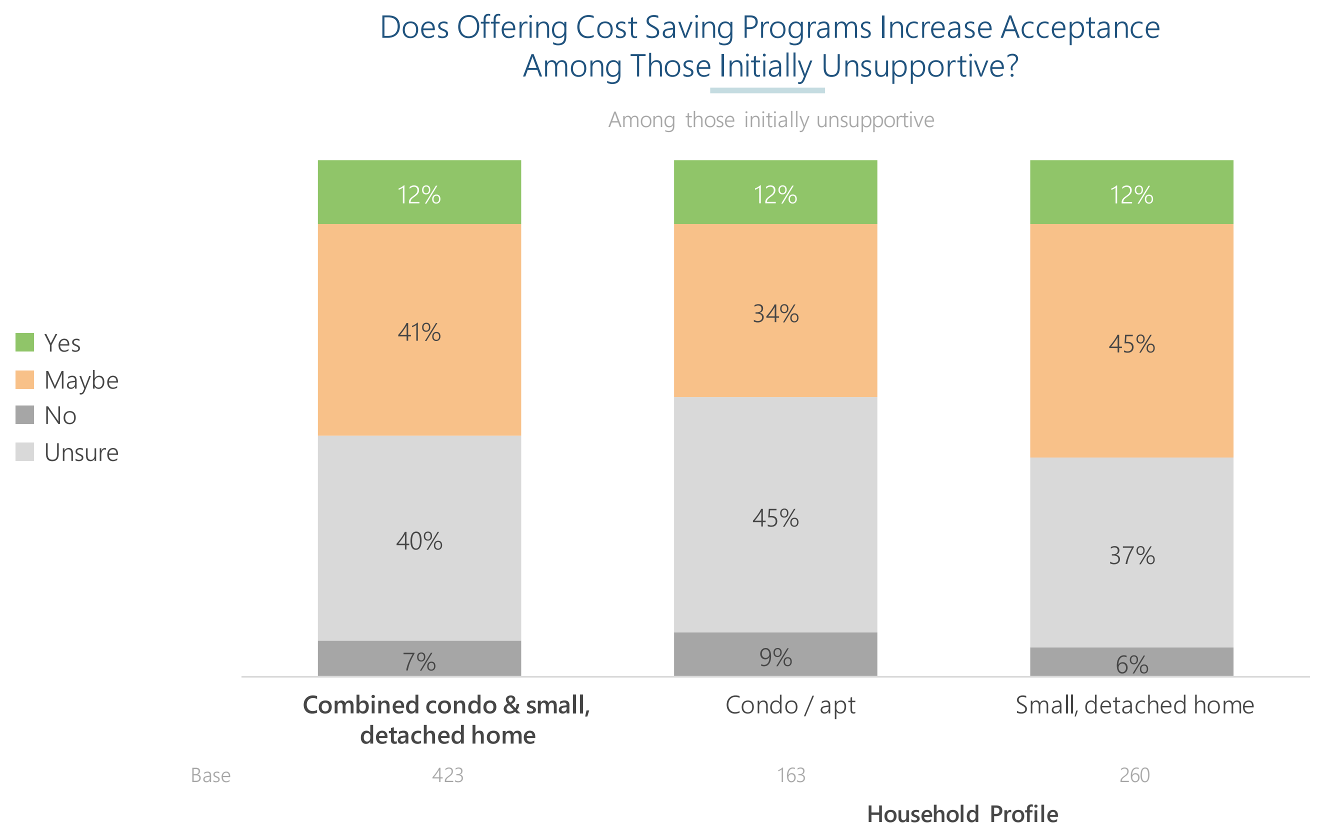
Base: Total (978)
B1. Based on the above illustration, which of the following statements best expresses your impression of the flat electricity charge concept?

sentis

INCREASING ACCEPTANCE OF FLAT RATE CHARGE

Customers living in condos/apts or small detached homes who initially express that they are not supportive of the flat rate are hesitant to increase their acceptance of the flat rate charge with the prospect of BC Hydro offering more programs to help customers save on electricity.

The fact that 8-in-10 of these customers (81%) with either 'maybe' or 'unsure' indicates that their acceptance depends on how much savings they could achieve with such programs.



Base: Condo / apt and small, detached home customers who do not initially support the flat rate charge (423)
B2. Would you be more accepting of the flat electricity charge if BC Hydro offered more programs to help customers find more ways to save on electricity?

sentis

IMPACT OF BC HYDRO OR SMART THERMOSTATS

Customers living in condos/apts or small detached homes do increase their support for the flat rate when informed that they can install a BC Hydro-provided smart thermostat to manage their home heating. Those who become more supportive outnumber those who become less supportive by a factor of two to one.

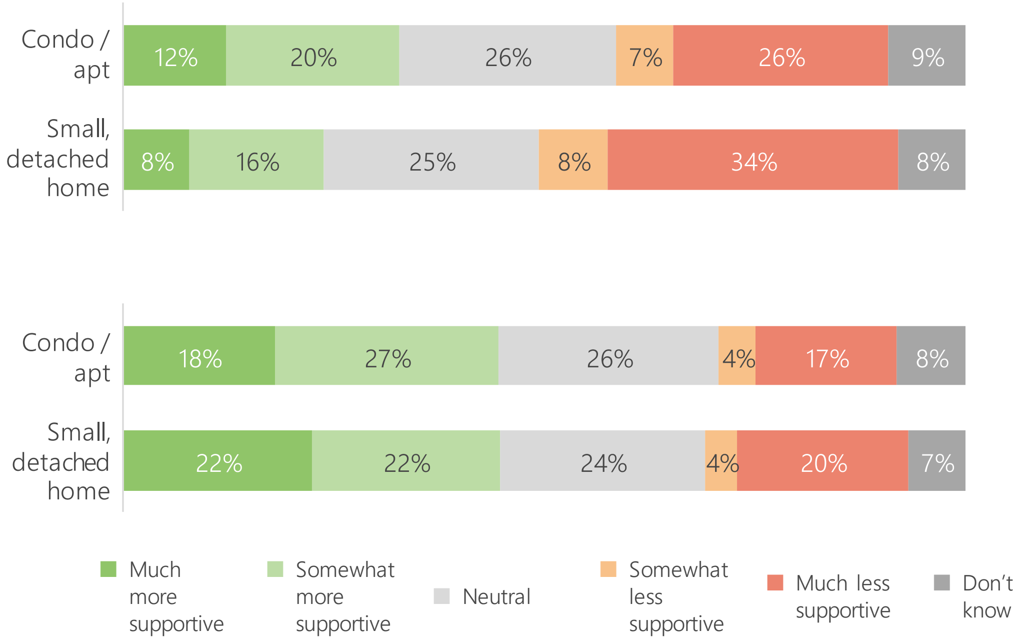
However, the prospect of BC Hydro being able to control the thermostat decreases support significantly – even when customers are informed that this would lower their bill. This is particularly the case among those living in small detached homes.

Other notable subgroup differences in reactions to the smart thermostat:

Income: Smart thermostats (but not those controlled by BC Hydro) are particularly likely to increase support among high-income households (68%) compared to moderate-income (44%) and low-income households (34%).

BC Hydro thermostat - BC Hydro installs a free thermostat that allows BC Hydro to manage home heating based on the customer's needs in exchange for a lower bill. However, the customer can manually change the settings when desired. BC Hydro has access to the data via this thermostat.

Smart thermostat – Customer installs a smart thermostat provided by BC Hydro that allows them to more effectively manage home heat through a smartphone. BC Hydro has no access to the data via this thermostat.



sentis

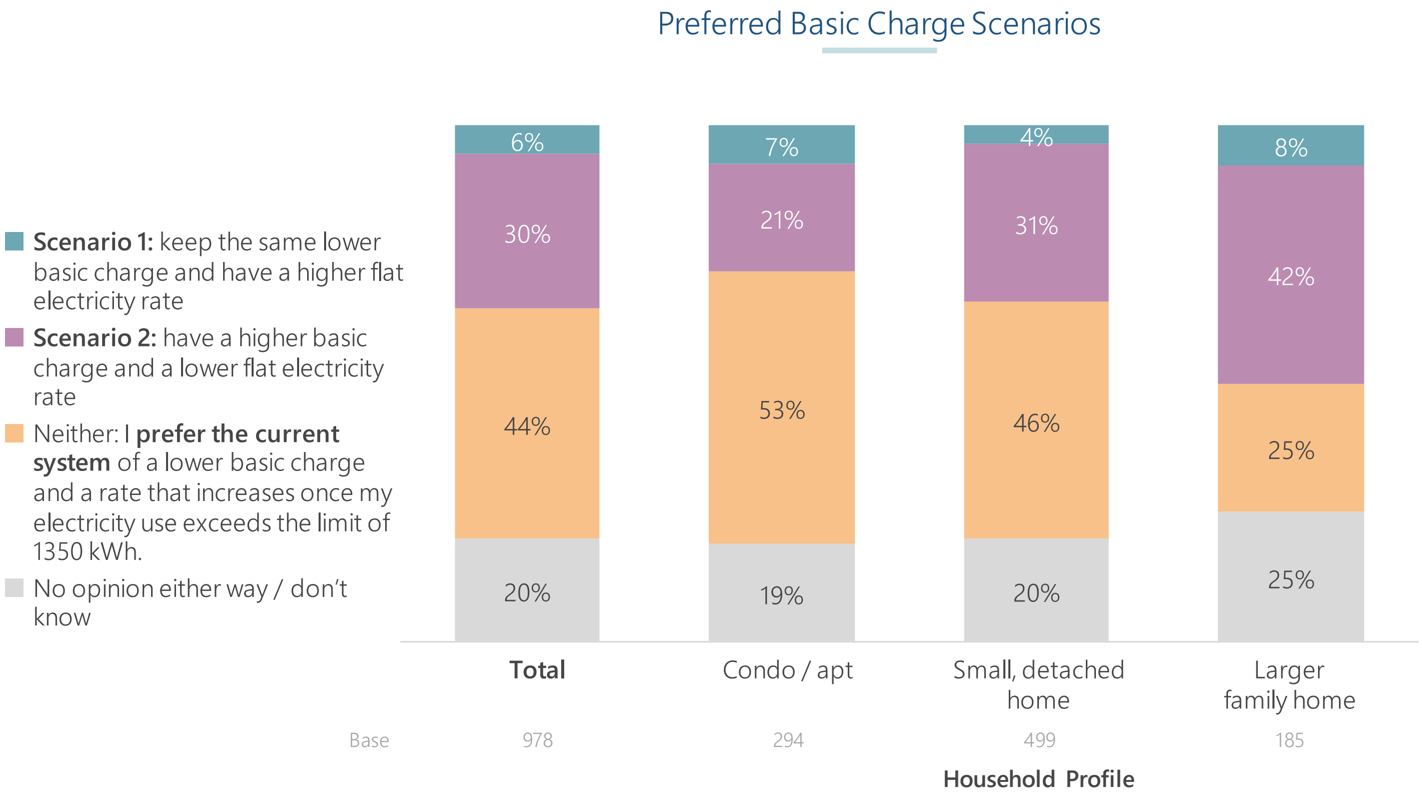
Basic Charge Changes

INITIAL REACTIONS TO BASIC CHARGE CHANGES AND RATES

Only a small percentage of customers prefer Scenario 1. In Scenario 1, all customers – regardless of household profile – likely expect that their bills would increase substantially.

Among those living in condos/apts and those living in small detached homes there is a clear preference for the status quo – particularly among those living in condos/apts.

Those living in larger family homes have the strongest preference for Scenario 2. Note, however, that their preference for Scenario 2 is not as strong as their support for the flat rate concept. While 61% express support for the flat rate concept, 42% have a preference for Scenario 2 – when the flat rate concept is combined with a higher basic charge. An unspecified higher basic charge may lead some of those in this household profile to assume that Scenario 2 will result in higher bills.



Base: : Condo / apt and small, detached home customers
C1. In addition to the two stepped-rate for electricity used, BC Hydro bills also include a basic charge, which covers some of the costs related to customer service (billing, metering, call centre, etc.).
Today the basic charge is $6.30 per month per customer account. BC Hydro is considering increasing the basic charge to more adequately cover the cost of service. The benefit of a higher basic charge is that the electricity charge would be less per kilowatt hour. Which of the following do you prefer?

FINAL REACTIONS TO BASIC CHARGE CHANGES AND RATES

This is how the various scenarios were presented at the end of the survey.

To recap, here are the current rates compared to the potential flat rate scenarios. Please review the details and indicate which scenario you support. Note that for the flat rate scenarios, these use figures from the previous illustrative examples.

Note: respondents were only shown the costing relevant to their self-reported household profile.

	Current BC Hydro rate: Basic charge plus a two-stepped rate	**New Rate Concept 1** A smaller increase in the basic charge and a higher flat rate	**New Rate Concept 2** A larger increase in the basic charge and a lower flat rate
Rate	9.35 cents per kWh within 1,350 kWh over 2 months Then 14.03 cents per kWh	10.59 cents per kWh	9.64 cents per kWh
Monthly basic charge	• $6.30	• $12.50	• $20.28
IF PROFILE A CONDO/APT Total annual electricity cost (basic charge + usage)	• $450	• $572	• $627
IF PROFILE B SMALL DETACHED HOME Total annual electricity cost (basic charge + usage)	• $870	• $1004	• $1020
IF PROFILE C LARGER FAMILY HOME Total annual electricity cost (basic charge + usage)	• $2130	• $1968	• $1898
Features	• Cheaper for smaller / lower usage homes	• Easier to understand electricity cost • Cheaper for larger / higher usage homes and electrically heated homes • Save money on high winter bills	• Easier to understand electricity cost • Cheaper for larger / higher usage homes and electrically heated homes • Save money on high winter bills

sentis

FINAL REACTIONS TO BASIC CHARGE CHANGES AND RATES

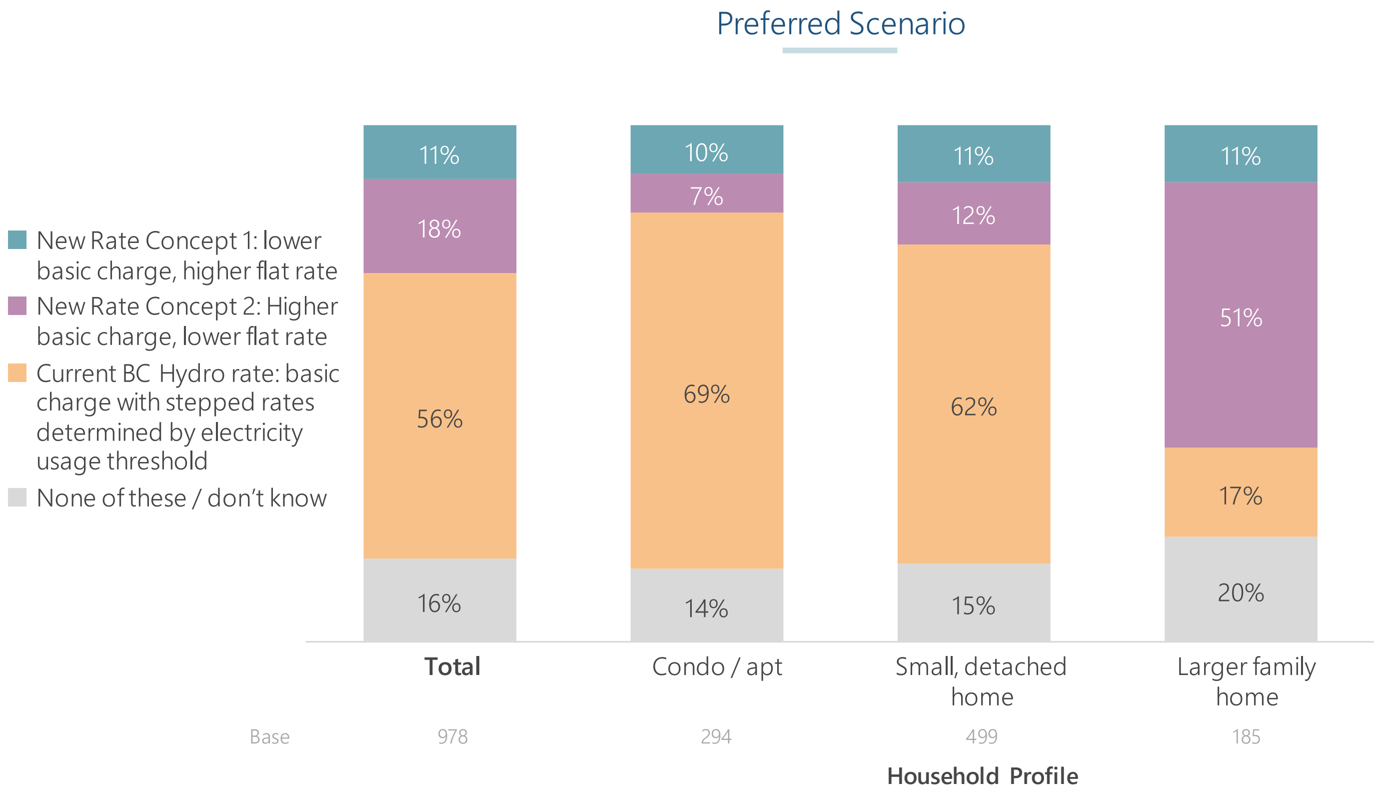
This question produces the strongest preference for the status quo among those living in condos/apts and small detached homes. It is particularly strong among condo/apt dwellers – 7-in-10 prefer the status quo and only 7% prefer New Rate Concept 2. Based on the electricity costs provided in the question, this group would experience the highest increase in annual costs – from $450 under the current rate structure to $627 under New Rate Concept 2 (a 39% increase).

Those living in larger family homes do show a clear preference for New Concept 2. This group's annual electricity costs would decrease from $2,130 to $1,898 (an 11% decrease).

Other notable subgroup differences in final reactions:

Income: Those in low-income households are more likely to support the current rate structure (66%) compared to moderate (55%) and high-income households (53%).

Main Home Heat Source: Those living in homes heated mainly by natural gas are more likely to support the current rate structure (63%) than those living in homes heated mainly by electricity (49%).



Base: Total (978)
G1. To recap, here are the current rates compared to the potential flat rate scenarios. Please review the details and indicate which scenario you support. Note that for the flat rate scenarios, these use figures from the previous illustrative examples.

sentis

Optional Electricity Rates

Appliance Time of Use

sentis

ABILITY TO CHANGE TIMING OF ELECTRICITY USE

Overall, just under half of customers indicate that they could adjust the timing of the use of their washer, dryer or dishwasher to take advantage of lower off-peak electricity rates. Those living in condos/apts are less likely to indicate that they can adjust the timing of their use of these appliances.

Much smaller percentages of customers indicate that they would be able to adjust a space heating or cooling appliance to take advantage of lower-off peak electricity rates.

Proportion That Could Adjust Their Timing of Use

	Total	Condo / Apt	Small, detached home	Larger family home
Base	(978)	(294)	(499)	(185)
Washer	47%	39%	51%	52%
Dryer	47%	39%	51%	50%
Dishwasher	48%	41%	50%	54%
Space (room) heating	17%	17%	17%	18%
Space (room) cooling	12%	10%	13%	14%

■ / ■ % yes

■ Lower than other household profiles

Base: Total (978)

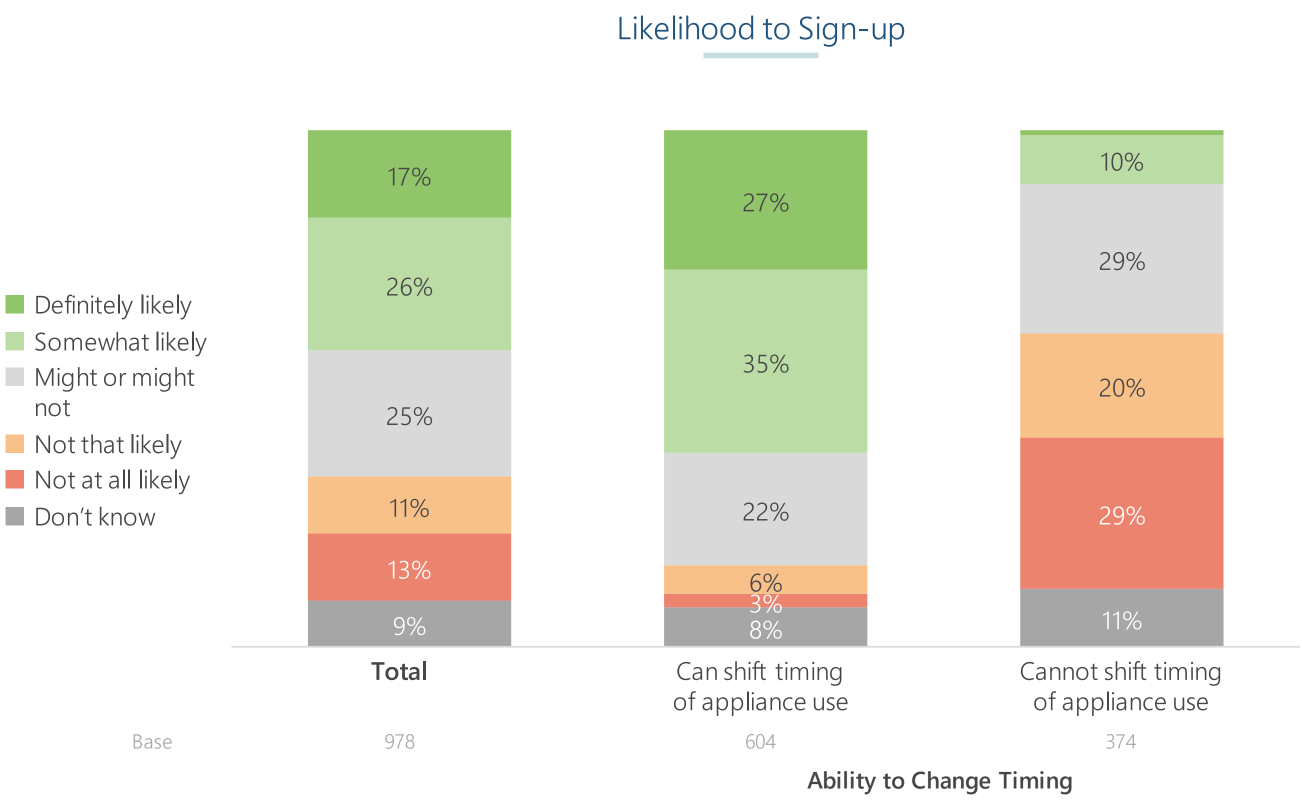
D1. BC Hydro is also exploring other optional rates. Customers would be able to choose to stay on the standard rate or they could sign up for an option that meets their needs. A time of use rate is one option. This rate helps shift electricity use away from peak demand times (i.e. 4 p.m. to 8 p.m.) by offering a lower rate for using power during off-peak times (i.e. 11 p.m. to 7 a.m. or weekends) and a higher rate for electricity used during peak times. If time of use rates became available, could you change the timing of the use of any of the following electrical appliances to take advantag e of a lower off-peak charge?

LIKELIHOOD OF SIGNING UP FOR TME OF USE OPTION

Overall, 43% of customers indicate that they are likely to sign up for a time of use option, while just under one-quarter (24%) are not likely.

However, 62% of customers who indicated that they could operate at least one of their appliances during off-peak times indicate that they are likely to sign up for a time of use option.

Consistent with their lower stated ability shift appliance use to off-peak times, those living in condos/apts are less likely to sign up for a time of use option (35%), compared to those living in small detached homes (45%) or larger family homes (48%).



Base: Total (978)
D2. Based on this time of use rate concept, what is the likelihood that you will sign up if it became available to you?

sentis

REASONS FOR LIKELIHOOD OF SIGNING UP

The most common reason that customers are likely to sign up for a time of use option is the prospect of lower electricity bills.

Most of those who indicate that they might sign up want more information or say it depends on the cost savings that could be achieved.

The most common reasons that customers are not likely to sign up for a time of use option are that they simply don't want to change their usage to off-peak times or unable to do so.

	Total	Condo	Smaller Detached Home	Larger Family Home
Likely to sign-up	368	87	196	85
Reduces cost / more economical / cheaper	28%	28%	27%	31%
I can change my time of use / can take advantage of program	16%	14%	16%	18%
Need more information / details	14%	9%	13%	19%
More off-peak use better for the system environment / already do this	10%	11%	12%	6%
Depends on the cost difference / cost savings	8%	3%	9%	12%
Like being able to control my use to access lower rates	8%	9%	8%	6%
Good idea / It is used elsewhere	8%	10%	7%	7%
Might or might not sign-up	219	65	116	38
Need more information / details	30%	23%	36%	24%
Depends on the cost difference/ cost savings	23%	15%	26%	29%
Don't want to change my time of use / not interested / hassle	8%	6%	9%	5%
Don't know if I'll be able to change my time of use	8%	12%	5%	8%
Depends on what time periods would qualify	7%	6%	7%	11%
Not likely to sign-up	223	79	103	41
Don't want to change my time of use / not interested / hassle	36%	33%	38%	37%
Can't change time of use on some or all things / can't take advantage of program	25%	28%	21%	29%
Current bill already low/ not relevant for my situation	13%	20%	12%	5%

D3. Why are you [definitely / somewhat likely / unlikely to sign up?] / Why do you say you might or might not sign up? Only main mentions are shown.

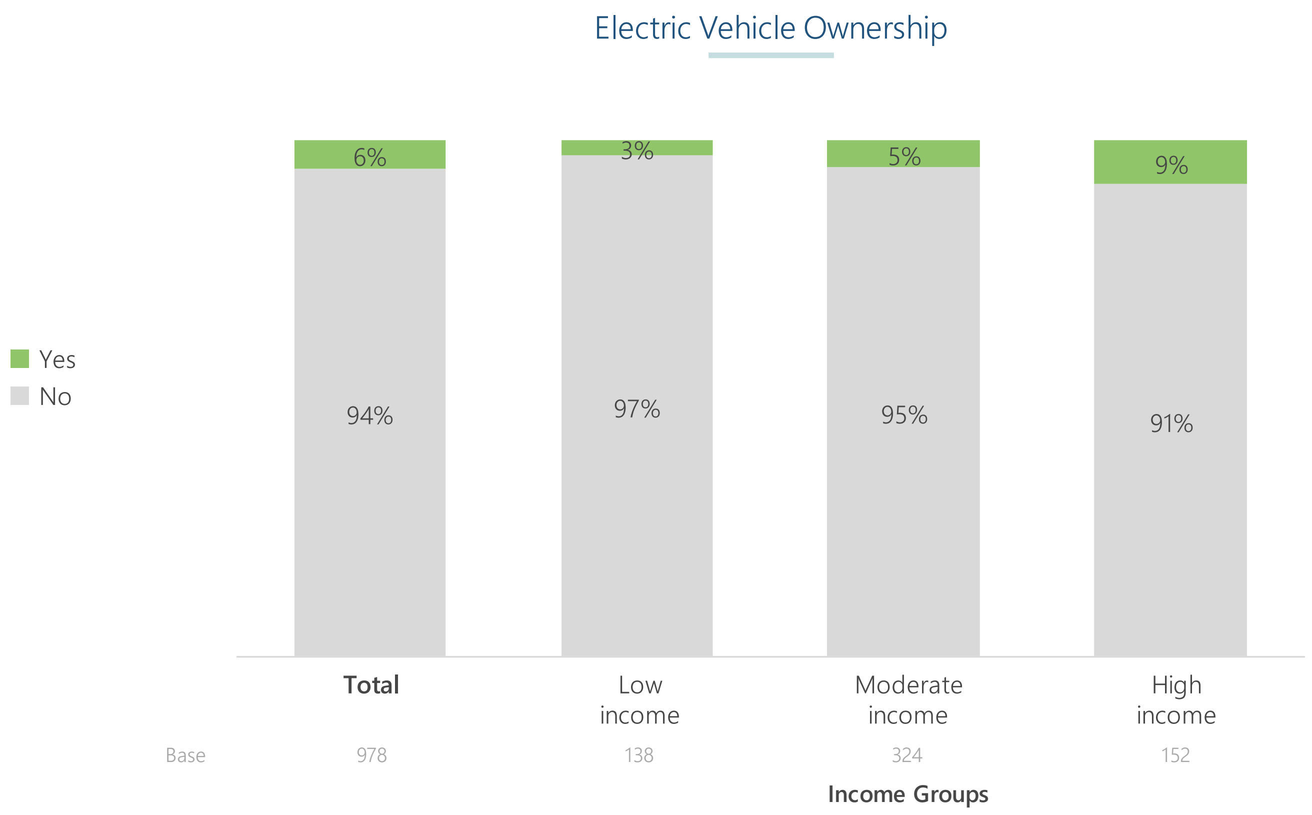
Optional Electricity Rates

Electric Vehicles

ELECTRIC VEHICLE OWNERSHIP

Six percent of customers report having an electric vehicle.

EV penetration is higher in high-income households (9%) compared to moderate-income (5%) and low-income households (3%).



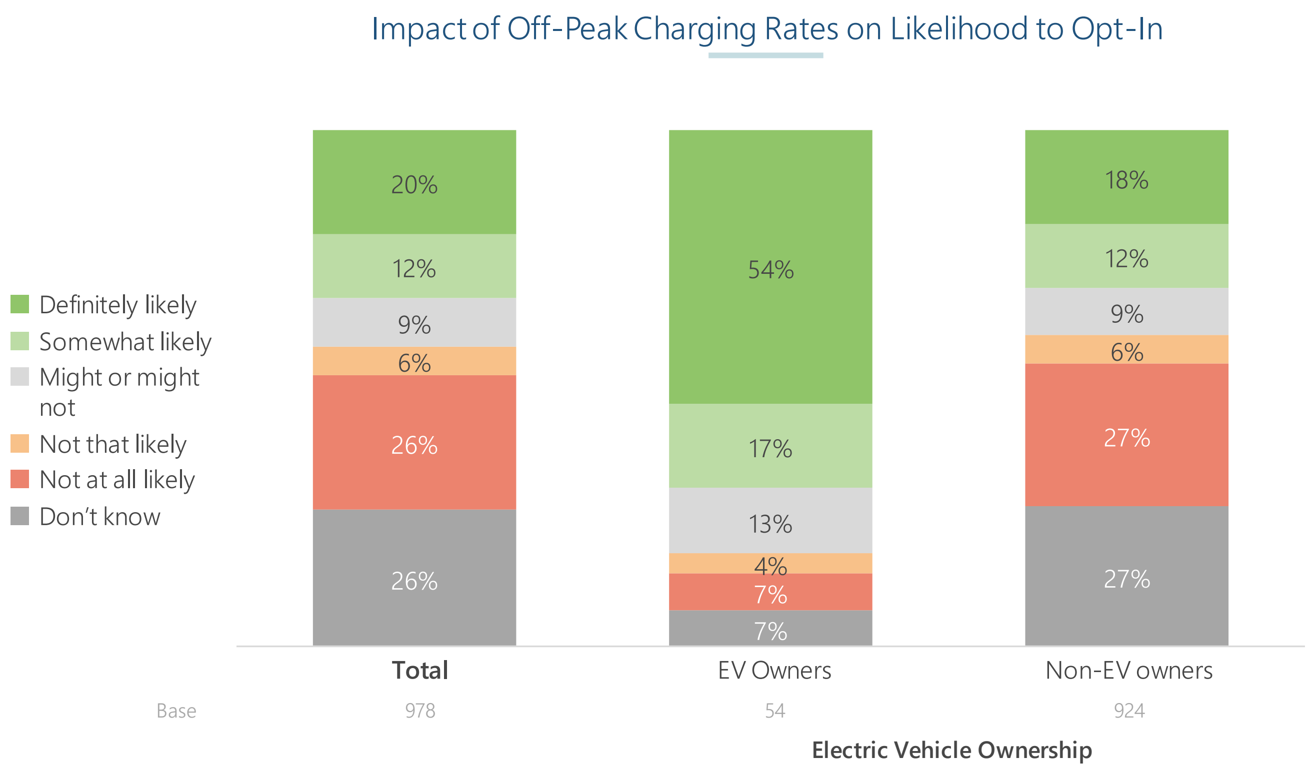
Base: Total
E1. Do you have an electric vehicle (that is, a vehicle that runs on battery power and needs to be recharged with electricity)?

sentis

IMPACT ON LIKELIHOOD TO OPT-IN

Overall, just under one-third of customers indicate that they are likely to opt in to receive a lower electricity rate in exchange for charging an EV during off-peak times.

Current EV owners are very likely to opt in – over half (54%) indicate that they are 'definitely likely' to opt in.



Base: Total
E2. For many customers with electric vehicles, "plugging in" while parked at home is the most convenient way to charge the battery. An off-peak electric vehicle home charging rate would allow customers to charge their vehicles at home at a lower cost. If an off-peak rate for electric vehicle charging became available, what is the likelihood that you will sign up (opt in)?

sentis

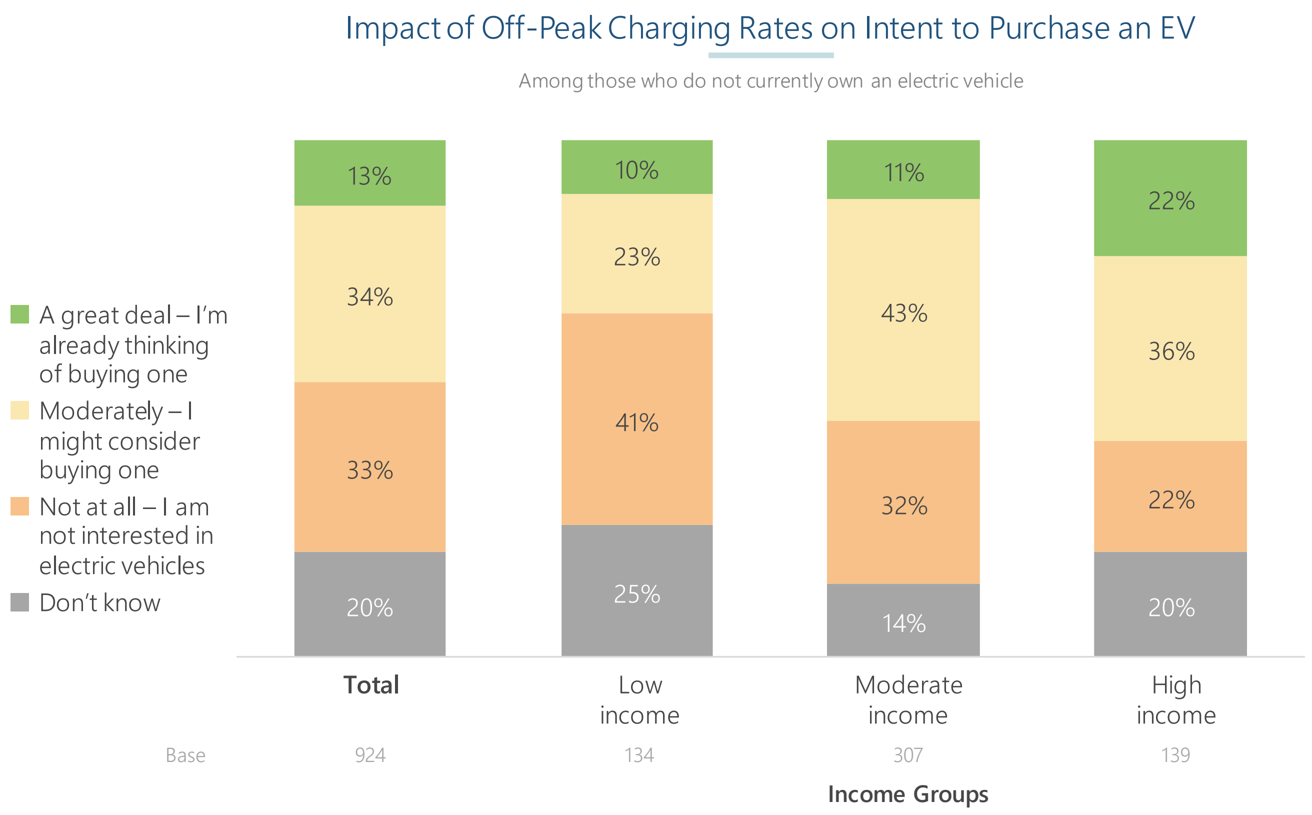
IMPACT ON INTENT TO PURCHASE AN EV

The prospect of a lower off-peak charging rate does have some influence on non-EV owner EV buying intentions.

However, while only one-third (33%) indicate that a lower off-peak charging rate has no influence on their interest in an EV purchase, the majority (54%) indicate that it influences them moderately or that they don't know. This is probably due to the fact that these customers are unlikely to know how much it actually costs to charge an EV.

Other notable subgroup differences in reactions to off-peak charging:

Income: Only 23% of low-income households indicate that lower off-peak charging rates would increase their motivation to buy and EV, compared to 43% of moderate-income households and 36% of high-income households.



Base: Those who do not currently own an electric vehicle
E3. To what extent would an off-peak rate for electric vehicle charging influence you to buy an electric vehicle in the future?

sentis

Optional Electricity Rates

Heat Pumps

INTRODUCING THE FLAT RATE CONCEPT

sentis

This is how heat pumps were first introduced to customers in the survey.

Heat pumps manage the temperature in your home and can replace a gas furnace or electric baseboard heaters. Key benefits of heat pumps include reducing greenhouse gas emissions and the ability to use the unit for air conditioning in hot months.

Here is what a ductless heat pump looks like outside, and what the duct head looks like inside.

The cost to install a new heat pump ranges between $7,000 and $14,000, depending on the type of unit.
Rebates vary depending on the situation, but typically range between $1,000 and $3,000.

To further illustrate, if a home that is electrically heated gets a ductless heat pump costing $7,000, then a $1,000 rebate is available and the net cost to the customer is $6,000.

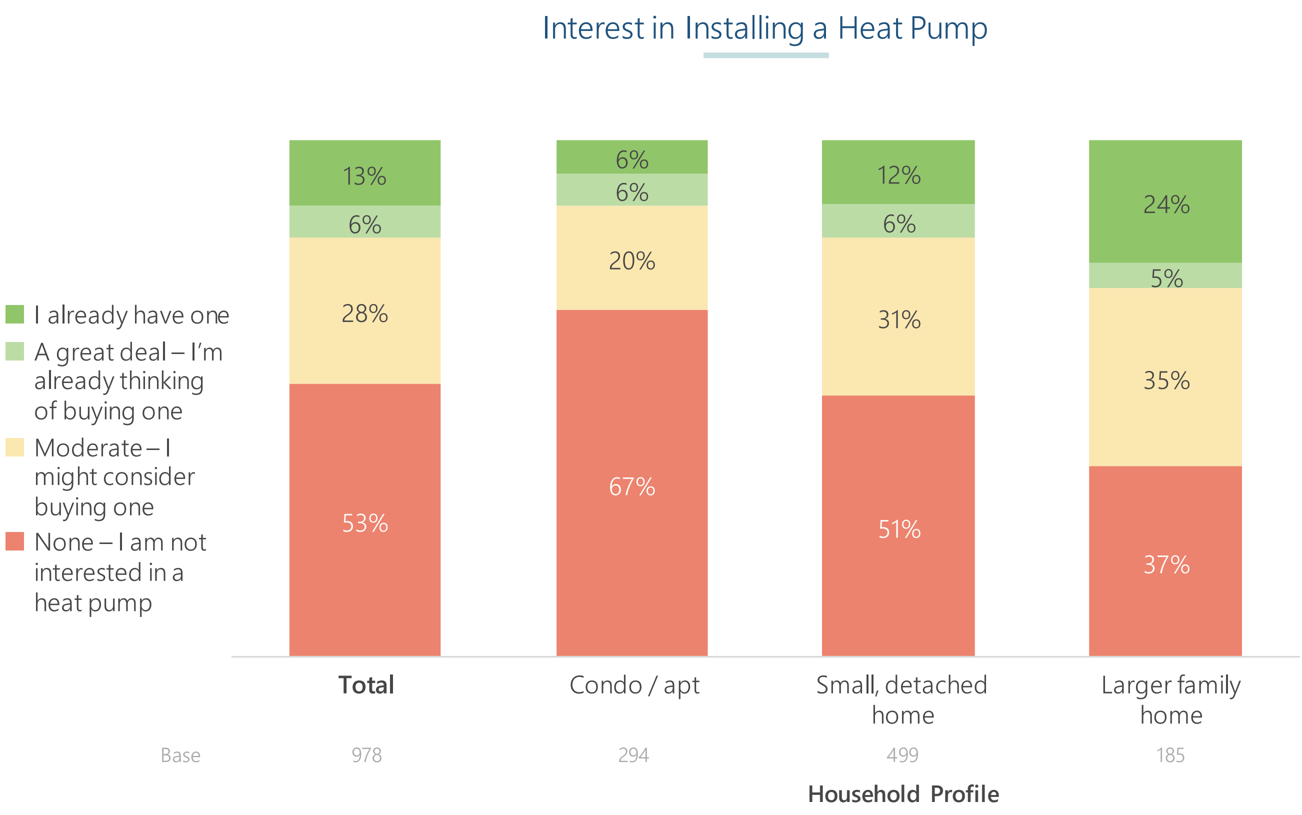
If a home with a natural gas furnace gets a variable speed central heat pump that costs $14,000, then a rebate of $3,000 is available and the net cost to the customer is $11,000.

HEAT PUMPS CURRENT USE AND INTEREST

Current use of heat pumps and interest in installing a heat pump in the future vary by household profile. At 24%, those living in larger family homes are the most likely to report that they currently use a heat pump.

Those living in condos/apts are most likely to indicate that they are not interested in installing a heat pump in the future (67%) followed by those living in small detached homes (51%) and those living in larger family homes (37%).

Note, however, that across all groups only a small percentage react by indicating that they're already thinking of buying one.

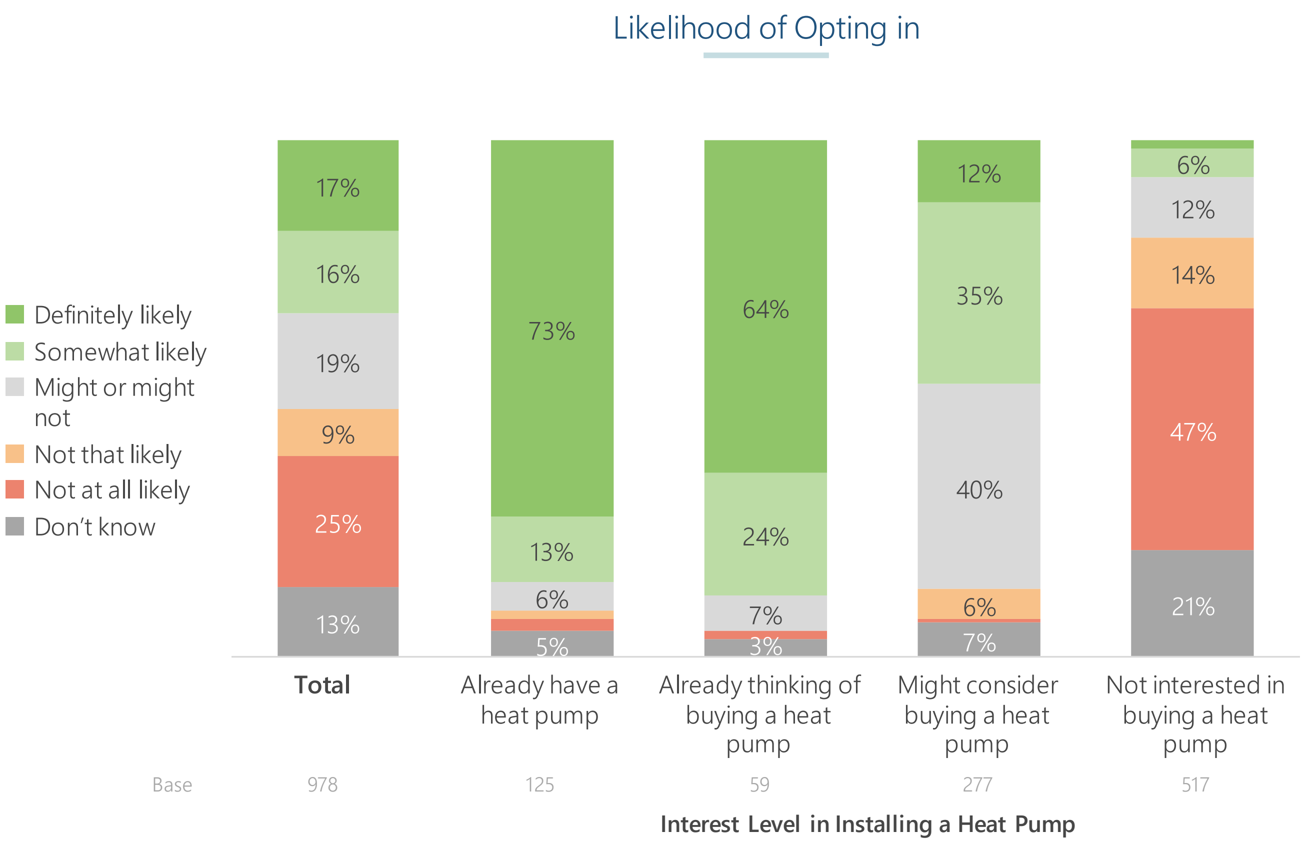


Base: Total
F1. Given this overview of heat pumps, what is your interest level in installing a heat pump in the future?

LIKELIHOOD OF OPTING IN WITH 20% DISCOUNT

The likelihood that a 20% discount on electricity used to operate the heat pump will motivate customers to opt in for this discount depends on their current ownership and interest in heat pumps. Those who already have a heat pump have the strongest intentions to opt in, followed by those who already thinking of buying a heat pump and those who might consider buying one.

Only 7% of those who initially expressed that they are not interested in buying a heat pump indicated that the discount would make them more likely to opt in.



Base: Total
F2. If a discount, say 20%, applied to electricity specifically for heat pump usage became available, what is the likelihood that you will sign up (opt in) for that discounted rate?

sentis

Billing & Customer Profile

sentis

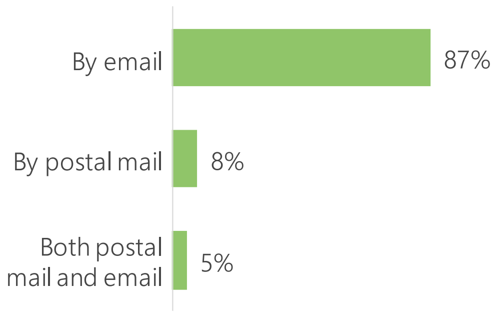
BC HYDRO BILLS

Just over one-third of customers (35%) review their BC Hydro bill thoroughly. Only 8% don't review their bill at all because they are on the preauthorized payment plan.

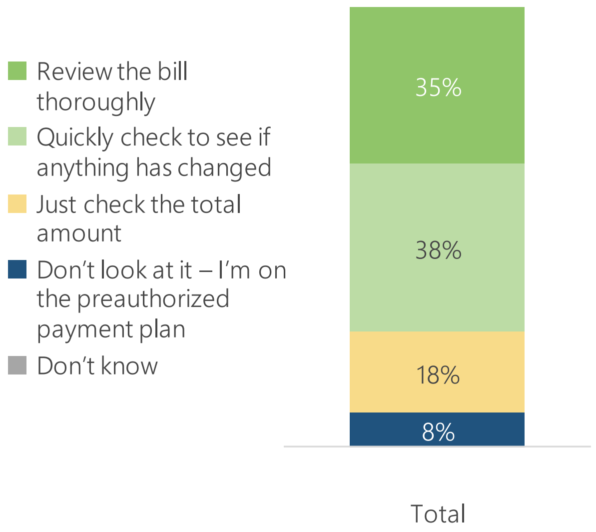
Notable subgroup differences in how customers review their bill:

Rate perceptions: Those who consider the price that they pay for electricity to be unreasonable are much more likely to review their bill thoroughly (46%) compared to those who consider the price they pay to be reasonable (28%).

How Customers Receive BC Hydro Bills



How Customers Review Their Bills

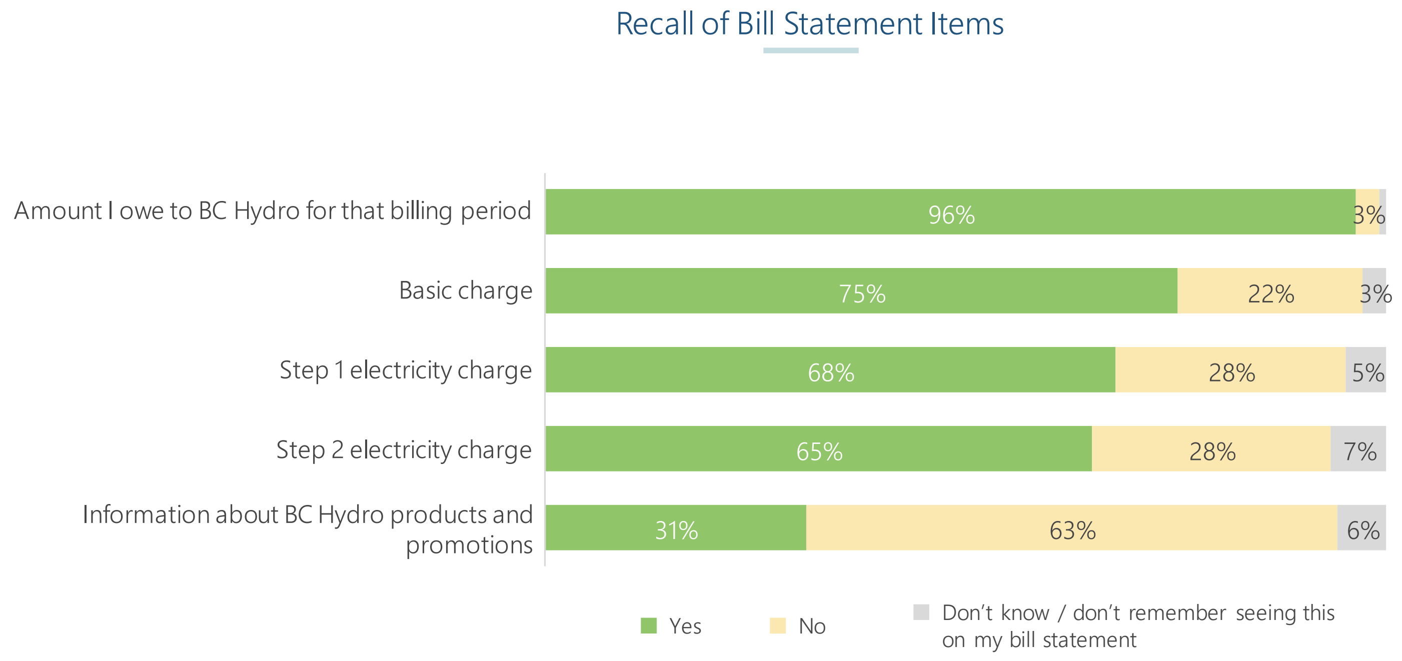


Base: Total (978)
A2. Which of the following best describes how you receive your BC Hydro bill?
A3. Generally speaking, when you get your BC Hydro bill, how closely do you look at it? Would you say you...

BC HYDRO BILLS PROMPTED RECOGNITION

Virtually all customers typically look at the amount they owe for the billing period. Three-quarters typically look at the Basic charge and two-thirds look at Step 1 and Step 2 charges.

Customers are much less likely to attend to information about BC Hydro products and promotions.



Base: Total (978)
A4. We're now going to show you a few items that you can find on your bill statement. Please indicate if the item is somethin g you typically look at.

IMPORTANCE OF ATTRIBUTES OF ELECTRCITY SERVICE

Customers place the highest importance on affordability, followed by simplicity and control.

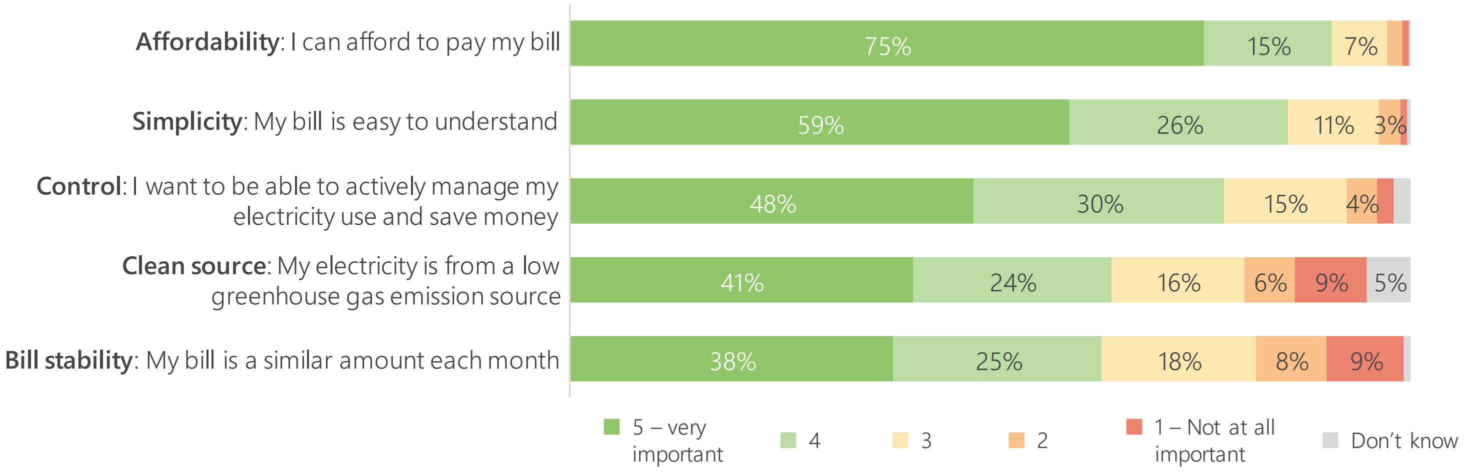
They place relatively less importance on bill stability and their electricity being generated from a clean source. However, these two attributes are still considered important by 63% and 65% of customers, respectively.

Notable subgroup differences in importance:

Income: Those in low-income households place more importance on bill stability (50% rate this as *very important)* than those in moderate-income households (36%) and high-income households (30%).

Those in low-income households also place more importance on control (64% rate this as *very important)* than those in moderate-income households (42%) and high-income households (38%).

What Customer Prioritize for Electricity Service



Base: Total (978)
A8. Please review the following aspects or attributes of electricity service and give a rating on how important each one is to you.

sentis

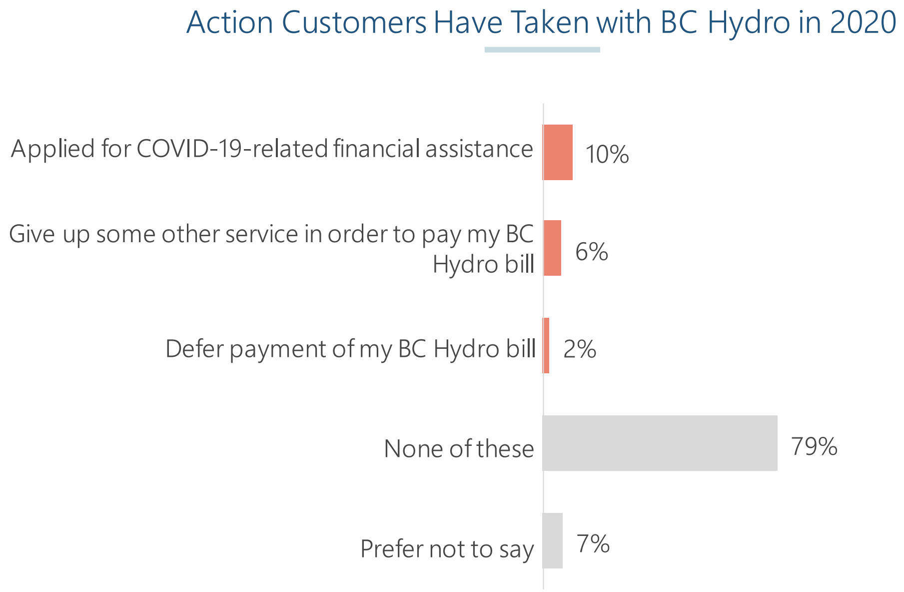
FINANCIAL HARDSHIPS

Fourteen percent of customers indicated that they had taken one of three actions as a result of their financial circumstances in 2020.

Notable subgroup differences in actions taken:

Income: Those in low-income households were more likely to apply for COVID-19-related assistance (14%) than those in moderate-income households (10%) and high-income households (7%).

Those in low-income households were also more likely to give up some other services to pay their BC Hydro bill (14%) than those in moderate-income households (5%) and high-income households (0%).



Base: Total (978)
W4. Have you had to do any of the following in 2020 with BC Hydro? Please select all that apply.

sentis

Appendix

sentis

RESPONDENT PROFILE

		Self Reported Household Type			Region			
	Total	A. Condo	B. Smaller Detached Home	C. Larger Family Home	Vancouver Island	Lower Mainland	Southern Interior	Northern Interior / North Coast
Region	978	294	499	185	196	537	154	91
Lower Mainland / South Coast	55%	72%	49%	43%	N/A			
Vancouver Island	20%	14%	19%	32%				
Southern Interior	16%	11%	19%	15%				
Northern Interior / North Coast	9%	3%	13%	9%				
Home Ownership	978	294	499	185	196	537	154	91
Own	80%	59%	88%	91%	84%	76%	84%	87%
Rent	19%	39%	10%	9%	14%	23%	15%	11%
Other	1%	1%	1%	0%	1%	1%	1%	1%
Prefer not to say	1%	1%	1%	1%	1%	1%	0%	1%
Income Level	616	205	300	111	117	340	105	54
Low	24%	24%	25%	18%	25%	20%	30%	31%
Moderate	52%	51%	52%	52%	59%	50%	52%	48%
High	25%	25%	22%	30%	16%	31%	17%	20%
Self Reported Household Type								
A - Condo or apartment	30%	N/A			21%	39%	21%	10%
B - Smaller detached home or townhome	51%				48%	46%	60%	71%
C - Larger family home or mobile home or older detached home or home with multiple suites 4 or more occupants	19%				31%	15%	18%	19%

41

sentis

RESPONDENT PROFILE

		Self Reported Household Type			Region			
	Total	A. Condo	B. Smaller Detached Home	C. Larger Family Home	Vancouver Island	Lower Mainland	Southern Interior	Northern Interior / North Coast
Home Type	978	294	499	185	196	537	154	91
Detached home (built on a foundation)	57%	7%	74%	89%	66%	49%	65%	69%
Condominium or apartment	24%	80%	1%	0%	14%	34%	14%	7%
Duplex / rowhouse / townhouse	14%	11%	19%	4%	13%	16%	9%	9%
Mobile or modular home (no foundation)	4%	2%	5%	6%	4%	1%	10%	15%
Other	1%	1%	1%	1%	3%	1%	1%	0%
Main Source of Home Heating	978	294	499	185	196	537	154	91
Electric (NET)	39%	68%	18%	48%	60%	38%	29%	16%
Electric baseboard heating	27%	60%	10%	21%	35%	31%	15%	7%
Electric heat pump	9%	7%	7%	17%	23%	4%	8%	4%
Electric furnace	3%	2%	2%	10%	3%	3%	5%	5%
Natural gas	39%	14%	60%	24%	19%	41%	47%	60%
A mix of gas and electric heating	11%	6%	13%	14%	10%	13%	5%	12%
Wood	3%	0%	4%	5%	4%	1%	8%	4%
Other	8%	12%	5%	9%	7%	7%	11%	7%
Age of Home (built within the last…)	978	294	499	185	196	537	154	91
5 years	11%	15%	10%	10%	13%	11%	11%	13%
10 years	11%	12%	9%	12%	7%	11%	11%	16%
20 years	17%	18%	17%	16%	15%	18%	19%	13%
30 years	19%	17%	19%	23%	18%	21%	17%	16%
40 years	13%	12%	13%	12%	16%	12%	13%	10%
More than 40 years ago	26%	18%	31%	24%	29%	25%	25%	27%
Don't know	3%	7%	1%	2%	2%	3%	4%	3%

BC Hydro Optional Residential Time-of-Use Rate Application

Appendix D-7B

Summary: Your Power Poll No. 2 Results April 2021

Summary: Your Power Poll No. 2 Results
April 2021

The main objective of this survey to BC Hydro's Your Power Poll members (customer panel) was to test the content of the core questions to be used in subsequent BC Hydro customer surveys on residential rate proposal(s). The opportunity also allowed BC Hydro to test how understandable the language and presentation of the material was to survey respondents.

1 Background

- During the Residential Rate Redesign customer and stakeholder engagement process, a number of engagements (surveys, workshops, etc.) were conducted by BC Hydro. One engagement involved asking the BC Hydro customer panel (known as Your Power Poll, or YPP) to provide feedback on proposed questions intended for the broader customer survey planned later in the year.
- This summary presents the key findings from the survey to YPP during the spring of 2021.

2 Sample Profile

- The survey was active from April 9 to 12, 2021. The BC Hydro customer panel was invited to offer feedback on topics relating to familiarity with residential rates, priorities BC Hydro should consider in potential rate design, and preferences relating to rate design types.
- The YPP panel is open to any member of the public who wishes to engage on topics put forth by BC Hydro. YPP is not intended to be a representative sample of BC Hydro customers. Therefore, the results of the surveys put to YPP membership are considered a directional gauge of customer sentiment at a

general level; they should not be interpreted to as representative of opinions of all segments within the Residential customer base.

- YPP membership is intended for BC Hydro account holders but does not exclude non-account holders. Commercial customers, Residential customers outside of Zone 1 areas, and BC Hydro employees are also permitted to join YPP.

3 Respondent Profile for the Survey

- A total of 1,931 YPP members participated in the survey, which reflected a response rate of about 45% at the time. A typical response rate for YPP surveys is 30%, indicating that members were particularly interested in this subject.
- The YPP membership typically reflects an older demographic (those 55+), males, and over-indexed in terms of dwelling type (detached homes) and region (Vancouver Island). Specific demographics for this specific survey were not extracted at the time and cannot be reconstructed due to the subsequent change in software used for YPP activities.
- Typically, the YPP membership tends to be more knowledgeable about energy-related topics (such as conservation) and about BC Hydro relative to the general customer or public.

4 Key Findings

The survey was designed to test initial customer understanding of the key topics and test the language of questions/information to be used for a more comprehensive survey put to customers at a later date.

The survey covered four broad topics:

1. Familiarity with current rate and bills

    - 35% claimed familiarity with BC Hydro rate and charges on the bill, while another 49% cited general familiarity with the rate (total of 84% familiarity).
    - In terms of how often homes go into Step 2, 34% said every bill, 18% said most bills, and 23% said some of the bills. Only 13% said Never, while 12% weren't sure. Note this was self-assessed, without validation against actual billing data.
    - In the follow-up asking YPP members to critique the presentation of the "frequency in Step 2" question itself, 61% said it was fine, 21% said they needed to see their bills to confirm, and 18% thought the answer options were too vague.

2. Aspects of affordability in both comparative terms to other service costs and in general

    - Members were asked to compare what they pay for BC Hydro electricity relative to car insurance, wireless phone, home Internet, and natural gas services ((if applicable). 30% of respondents said electricity costs more than car insurance, 43% said it costs more than wireless phone, 40% said it costs more than home Internet, and 24% said it costs more than natural gas. Again, this was a self-reported estimation, rather than asking members to compare precise amounts from actual bills.
    - When asked how often they compare electricity bills to other common bills, 21% said they do regularly, and 25% said sometimes. Over half (52%) said they don't compare.
    - When asked to pick the most appropriate definition of "affordability" out of a list of four options, 62% chose "Affordability is my ability to pay for things based on my income." 18% chose "Affordability is defined by what I expect to pay for a product or service." 8% chose Affordability really means my

willingness to pay for things" while 7% chose "The affordability of something is defined by the costs of other things I buy." The remaining 6% said they were unsure.

3. Understanding of the stepped rate and other potential rates for Residential customers

    - To help validate customer understanding of utilities terminology, respondents were asked to pick one term out of four options that best describes how they understood what they pay for electricity. A large majority, 82%, said "rate" while 6% said "price" and 4% said "charge." The remaining 7% offered their own ideas.

    - Respondents were shown an illustration of the stepped rate to differentiate between what the Step 1 rate and Step 2 rates are, as well as the threshold when a customer moves from Step 1 into Step 2. When asked if the illustration aided in understanding the Stepped rate, 77% of the comments reflected they understood or mostly understood the illustration, while 3% expressed partial understanding and 7% said no.

4. Impressions of statements that relate to the Bonbright principles, including a ranking exercise

    - Customers were shown the Bonbright principles and then asked if anything in the list was unclear to them. Some comments reflect confusion in understanding the intended meaning of the principles, but the majority of the comments reflected questions about applying the principles in practice, degree of relevance to their own situations, or opinions about rates.

    - In a bank of statements about electricity rates and service, the level of agreement (Strongly/Somewhat Agree) varied:

        - 97% agreed electricity is an essential service;

Page 4 of 5

  - 86% agreed all customers should be able to access a minimum level of electricity;
  - 47% agreed the charges are applied fairly to all customers;
  - 47% agreed the charges are fair to them;
  - 43% agreed they support BC Hydro exploring ways to offer rates based on customer household income; and
  - 34% agreed they would be willing to pay more for electricity to help keep electricity affordable for those in need.

- Respondents were shown a list of seven aspects of BC Hydro's electricity service, and then asked to pick up to three they would use to describe what is most important about the service. The ones picked most often as number one were "It is affordable" (23%), "Every customer has access to reliable service" (21%), and "Our electricity is clean" (16%).

5. Preference for current stepped rate vs possible other rates

- When shown a list of various rate types and asked to pick the most preferred one, time of use was selected by 30% of respondents. This was followed by stepped rate (23%). No other option exceeded the 20% level.
- Notably, in the follow-up question asking respondents about interest in being able to choose multiple rate options, 70% indicated the desire to pick two or more of the options (47% said they'd pick two, 20% said they'd pick three, and 3% said they'd pick more than three). Only 30% indicated they would prefer to pick one option.

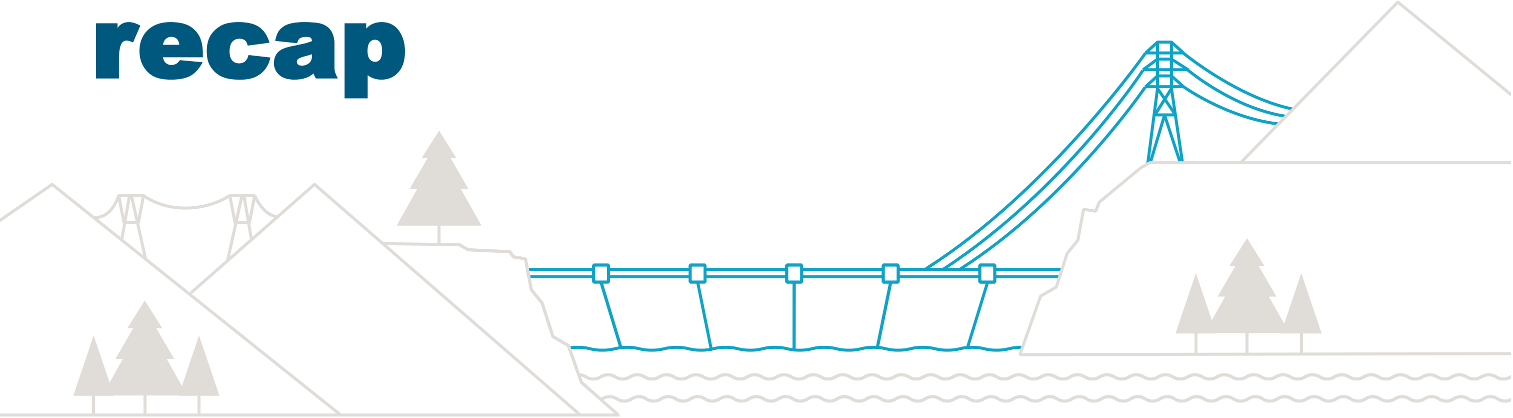
Page 5 of 5

BC Hydro Optional Residential Time-of-Use Rate Application

Appendix D-7C

Public Survey No. 1 by BC Hydro

Rates phase 1 customer surveys recap



July 2021

BC Hydro
Power smart

Methodology

Key points	Customer survey	Public survey
Fielding method	Online & phone May 10 to 31, 2021	Online via BCH website starting April 28 to June 30, 2021
Respondent	Invited from randomized representative customer list	Open to anyone
Completion sample size	Final n=821 (749 online and 72 phone)	Final n=22,680
Notes	• Weighted to reflect residential base • Certain questions had to modified for phone interviews, causing some results to be treated separately from online completes	• Not weighted due to respondent self-selection and open to non-account holders. • Data pulled for this summary is “as of June 2, 2021.” Sample n=21,475. Results collected after this did not materially affect the overall results presented here.

Methodology: notes about Customer survey

- The customer list used to invite customers to the survey was based on a randomized sample, accounting for the split in the database of those with or without known email addresses. Below are some considerations when reviewing the results for those completing the survey via phone.

	Phone interviews
Sample size	72
Notes	• Some questions from the main survey were not transferrable to a verbal interview. Instead, they were modified to be easier to answer over the phone. The results are highlighted in the slides, where applicable. • The phone interviewees tended to skew: • Older, especially in the 75+ category • More likely to live alone • More likely to live in apartments / condos • More likely to reside in Southern Interior or Vancouver Island
Representation	• As a result of the age skew, this subsample was weighted down to count for 56 out of the 821 total responses collected.

Key insights

- The representative Customer survey collected feedback from a random sample drawn from the Residential account holder database. The **Customer survey** should be considered as the **primary source** of feedback.
- The Public survey acted as a broader public engagement activity, enabling the collection of larger volumes of comments across various customer profiles, including some that may be non-account holders.
- Generally, the findings confirm:
    - **Affordability** and **keeping bills low** are important themes to customers.
    - Those who are often impacted by the Step 2 rate seek change, while those who are not impacted by Step 2 rate prefer the status quo.
- Of the potential rate options presented, **Time of use** drew the most interest. However, these options did not include details such as dollars, trade-offs, limitations, or other information specific to each one. Further details will need to be tested with customers to understand the level of interest in such options.

Overview

Demographics: basic customer data

Key demographics	Customer survey	Public survey
Regions		
• Lower Mainland	64.1%	42%
• Vancouver Island	16.1%	35%
• Southern Interior	13.1%	12%
• North	6.7%	7%
• Other	n/a	5%
Age		
• 18-34	12.7%	
• 35-54	35.6%	
• 55+	51.7%	
Income		
• Under $40K	17.2%	17.6%
• $40K to under $60K	12.8%	14.7%
• $60K to under $80K	11.3%	13.7%
• $80K to under $100K	9.9%	12.3%
• $100K to under $120K	6.7%	9.6%
• $120K and over	18.1%	19.1%
• Prefer not to say	24.0%	13.1%

- The customer survey more closely reflects the expected regional distribution. The public survey had significant skews in Lower Mainland (under) and Vancouver Island (over)
- Age was not included in the public survey, but it was asked in the customer survey to compare against database records. It was also used to weight the final sample.
- Gender was not asked in either survey.

Demographics: dwelling profile

Key demographics	Customer survey	Public survey
Dwelling type		
• Single detached home	**52.3%**	**57.8%**
• Duplex or similar	**3.2%**	**4.3%**
• Apartment or condominium	**27.5%**	**21.4%**
• Row / town house	**13.1%**	**11.3%**
• Mobile home	**3.1%**	**4.2%**
• Other	**1.0%**	**1.0%**
Own or rent the home		
• Own	**77.2%**	**77.2%**
• Rent	**21.8%**	**22.0%**
• Live with family but I do not own the home	**1.0%**	**0.8%**
Renters: is electricity included in rent?		
• Yes, included	**0.9%**	**1.1%**
• No, I /we pay the bill	**99.1%**	**98.9%**

- The customer survey had more respondents in Apt/Condo and Row/townhome categories.
- The public survey had more respondents in the detached home, duplex, and mobile home categories.
- Although respondents were not asked about consumption or bill amounts, dwelling type combined with region are two variables that influences opinions about the stepped rate and interest level in alternatives.

Energy use in the home

Key demographics	Customer survey	Public survey
Fuels used for home / water heating		
• **Electricity from BCH**	**73.2%**	**75.2%**
• **Natural gas**	**53.6%**	**35.6%**
• **Propane**	**2.0%**	**3.4%**
• **Wood**	**7.1%**	**11.0%**
• **Heating Oil**	**0.9%**	**1.4%**
• **Solar panels**	**0.2%**	**1.5%**
• **Other**	**2.0%**	**3.4%**
• **Electricity from other provider**	**n/a**	**2.9%**
Derived analysis		
• **Electricity only**	**44.1%**	**53.3%**
• **Electricity + natural gas**	**29.1%**	**20.2%**

- The results here are from the question "Which energy sources do you use to heat your home and/or water?" (select all that apply)
- The public survey reflects a higher proportion of customers relying on electricity without natural gas.
- As might be expected, the public survey also shows more customers using alternative sources of energy vs. those in the customer survey.

Understanding of current rates

Key demographics	Customer survey	Public survey
Familiarity with the bill		
• Very familiar	22.2%	36.7%
• Familiar	47.3%	46.5%
• Somewhat familiar	25.4%	14.3%
• Not very familiar	5.2%	2.5%
Knowledge of current rate structure		
• Same rate for everyone	5.8%	8.5%
• Rates vary based on amount of electricity used	70.4%	75.0%
• Specific rates for specific uses	2.3%	1.2%
• Rates vary based on time of day	7.8%	5.4%
• Unsure	13.7%	9.4%

- Public survey respondents tend to be more familiar with the bill and slightly more aware of rate structure.

Paying the bills

	Customer survey	Public survey
Frequency in Step 2 (self reported)		
• Every bill	**21.2%**	**32.6%**
• Most of the bills	**15.0%**	**17.0%**
• Some of the bills	**21.9%**	**20.9%**
• Never	**13.0%**	**14%**
• Unsure	**28.9%**	**15.5%**
Customers were asked about other typical bills over a year. Compared to electricity, they pay more for:*		
• Car insurance	**41.0%**	**40.4%**
• Cellular phone plan	**23.8%**	**22.8%**
• Home internet	**29.5%**	**26.8%**
• Natural gas**	**11.2%**	**16.2%**

Compare reported vs. actual: Representative sample
Based on the customer records in the sample file, over the past 24 months, the distribution was:

- 4% - every month
- 21% - 12-23 months
- 41% - 1-11 months
- 31% - none

Surprise?
Of these 31% our records confirm as **never into Step 2**, only 31% correctly said "Never." The rest either think they are (34%) or unsure (35%).

*calculation based on total denominator. This question had to be modified for the phone version of the representative survey. In this case, 25.8% of phone respondents said other bills were higher than the BC Hydro bill
**34.5% in the Customer survey said they do not have natural gas. For all other services, the percentage of those not subscribing were in the low single digit range.

10

Attitudes towards rates and bills

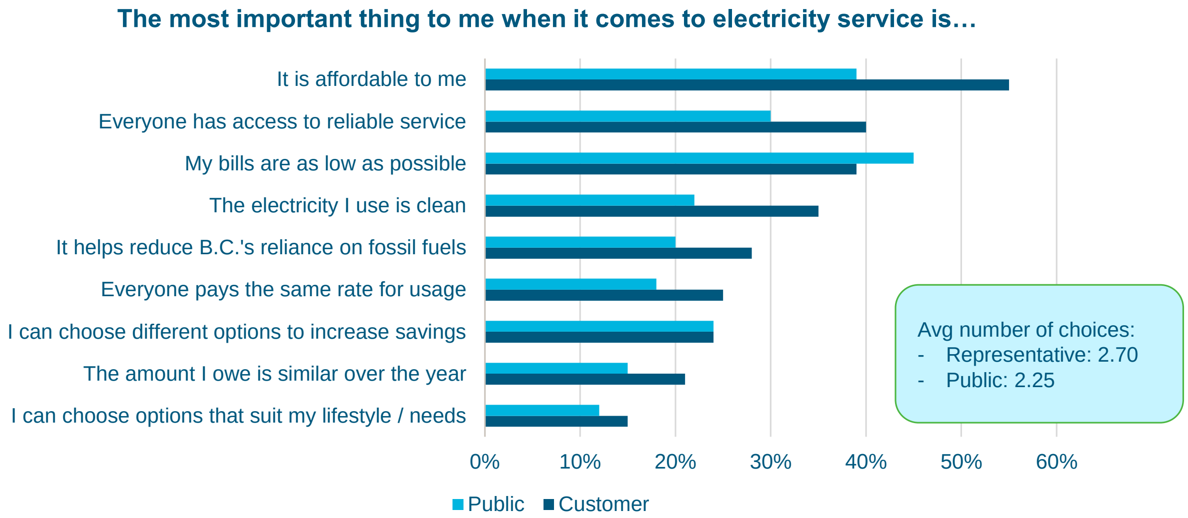
- Customers were asked to rate their level of agreement with the following bank of statements relating to rates and bills in general.
- Below are the results for the combined Agree + Strongly Agree responses.

	Customer survey	Public survey
Statements on rates and bills		
• All customers should be able to access a minimum level of electricity	**88.2%**	**82.3%**
• I'm **willing to pay a little more** for my electricity if it keeps electricity affordable for those in need	**43.6%**	**34.4%**
• The charges are fair to all customers	**52.0%**	**38.2%**
• I just want to pay the lowest rate	**85.3%**	**82.1%**
Customers who not agreeable to pay a little more to keep electricity affordable for others, they were asked their answer was related to COVID-19 impact.	**N=405**	**N=11,035**
• Yes	**15.2%**	**12.0%**
• No	**84.8%**	**83.5%**

Top priorities regarding electricity service

- Customers were presented with a "complete the sentence" question and could choose up to three options from the list below.

Phone (n=72)
23%
42%
23%
14%
4%
4%
3%
10%
7%



12

Affordability: how customers define it

- Customers were presented with a list of alternative definitions of affordability. The table below shows each definition ordered by frequency of selection.
- Most customers defined affordability relative to their incomes, but it was not unanimous. A notable minority in each survey chose other definitions.
- Managing customer expectations will influence how customers think about current and future rate designs.

	Customer survey	Public survey
Affordability is defined by		
• My ability to pay for things based on my income	**59.1%**	**62.7%**
• What I expect to pay for a product or service	**15.7%**	**16.3%**
• My willingness to pay for a product or service	**9.3%**	**7.9%**
• My ability to pay for unexpected expenses	**6.6%**	**4.2%**
• The costs of other things I buy	**3.9%**	**4.5%**
• I'm not sure how to define it	**5.4%**	**4.5%**

13

Affordability: how customers define it

- Customers were also able to comment on the definition through a comment box.

Key themes: Customer survey

1. Electricity is an essential service
   - Equal access regardless of income
2. Affordability is based on income
3. Rates should be lower
   - Too expensive, paying too much
4. Standard of living
   - Able to pay for necessities

Key themes: public survey

1. Rates considerations
   - Fairness; RIB rate; Fixed income / seniors
2. Affordability
   - Ability to pay; depends on things
3. Conservation / Electrification / Environmental
4. Rates, bills & fees
5. BC Hydro / Gov of BC

Attitudes towards electricity management

- Customers were asked to rate their level of agreement with the following statements relating to energy usage in the home.
- Below are the results for the combined Agree + Strongly Agree responses.

Statements on home electricity use	Customer survey	Public survey
• I expect to pay a lower rate if I switch to clean electricity from natural gas or another type of fossil fuel.	48.3%	48.5%
• I actively manage the electricity my household uses	84.7%	91.4%
• I'm interested in technology for my home that could give the option of letting BC Hydro directly manage specific electricity use.	32.0%	39.0%
• There's not much I can do to control my home's energy efficiency.	41.5%	32.2%

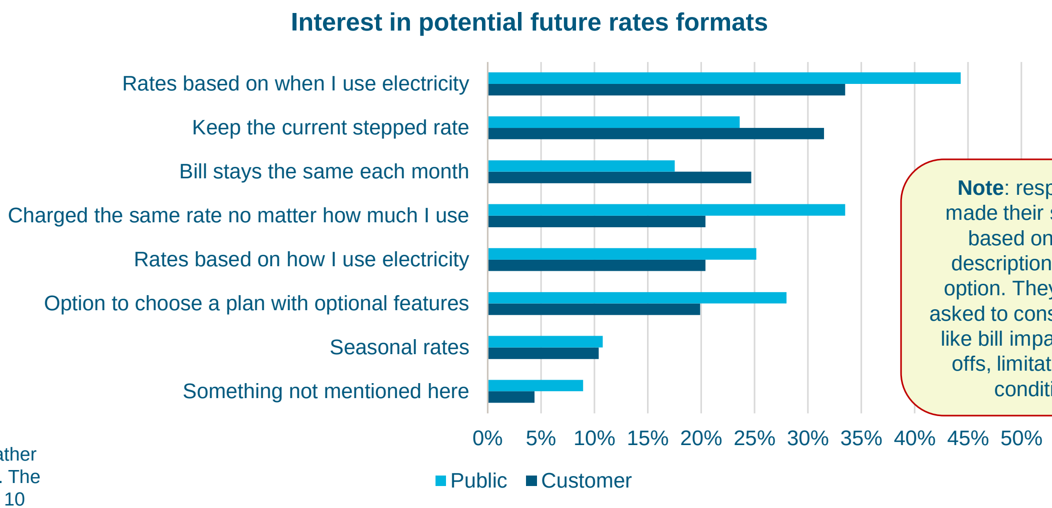
15

Preferences on future rate design

- Customers were presented with concepts relating to potential future rate options / design and were asked to select up to three options that they were most interested in.

Phone (n=72)
5.6
6.7
6.4
5.8
5.1
4.8
5.3

Phone respondents were asked to rate each item rather than selecting up to three. The rating mean scores out of 10 are presented above.



Note: respondents made their selections based on simple descriptions of each option. They were not asked to consider details like bill impacts, trade-offs, limitations, and conditions.

16

Preferences on future design: themes

- Customers had the opportunity to elaborate on their future design preference via an open end.
- Key themes are below, in order of magnitude; where notable, the strongest sub-themes are also listed.

Key themes: Customer survey

1. **Rates that build in incentives**
   - Rates for off-peak periods
   - Should be rewarded for lower usage
   - Encourage lower usage
2. **Managing household budget**
   - Bill predictability
3. **Want alternative to current state**
   - Dislike Step 2, can't stay out of Step 2
   - Penalizes for things out of our control
4. **Like to have control over usage / bills**

Key themes: public survey

1. **Rates, bills & fees**
   - Stepped rate; TOU; keep rates low
2. **Rates considerations**
   - Flexibility; Fairness; lack of alternative sources/choice
3. **Cons'vn / Electrifi'n / Environ**
   - EVs; efficiency
4. Views on Affordability
5. BC Hydro / Gov of BC
6. Energy options
7. Low income
8. Feedback about the survey

Demographics: additional profiling

Additional profile variables	Customer survey	Public survey
Applicable situations in the home		
• Medical equipment needing continuous power	3.5%	3.9%
• No alternative energy sources where I live	28.6%	26.1%
• Unable to make my home more energy efficient	26.7%	28.1%
• I live in a non-integrated area	0.5%	0.2%
• Net metering customer	0.2%	9.2%
• None of these apply	54.4%	32.6%
EV ownership: yes	7.0%	9.9%
Follow-ups		
• Owners: will get another one within a year	19.9%	19.4%
• Non-owners: will get or very interested to get one	25.9%	30.0%
Heat Pumps		
• Already have one	13.4%	18.0%
• Considering one	13.3%	11.2%
• Maybe	n/a	24.7%
• No	44.7%	23.7%
• Haven't heard of that before	28.6%	23.4%

END

BC Hydro Optional Residential Time-of-Use Rate Application

Appendix D-7D

Concepts Survey by Sentis

sentis

BC Hydro

Rates Engagement Survey

GRAPHICAL REPORT

PREPARED FOR

KC Sato

BC Hydro

June 18, 2021

500 – 602 West Hastings Street, Vancouver, BC V6B 1P2
thesentisgroup.com

Adam DiPaula | adipaula@sentisresearch.com
Stephanie Yuen | syuen@sentisresearch.com
Mun Chan | mchan@sentisresearch.com

sentis

CONTENTS

sentis

Objectives & Approach

sentis

As part of its process of re-evaluating how electricity rates are structured, BC Hydro is gathering feedback from residential customers in three phases:

Phase 1: Understanding Needs

- Understand how residents currently use and manage home electricity
- Gauge resident priorities when it comes to the cost of electricity
- Collect preferences for possible future rate structures

This report covers the findings from Phase 1.

Phase 2: Gathering Input on Possible Approaches

- Develop potential options for future rate structures
- Measure appeal and gather feedback on possible approaches

Phase 3: Gathering Feedback on the Proposed Approach

- If BC Hydro decides on a new approach, residents will have an opportunity to provide final feedback on the proposal before it goes to the BC Utilities Commission

sentis

METHOD

821 BC Hydro customers contacted by email or phone

Those contacted by phone were encouraged to do the survey online, but also had the option of completing the survey over the phone.

Survey Dates: May 10-31, 2021

Email reminders and phone follow-up calls were made to encourage participation

Survey Responses

Method	Completed Surveys	Response Rate
Total	**821**	**8%**
Email to Online	572	11%
Phone Recruit to Online	171	4% (38% once recruited)
Phone	72	2%

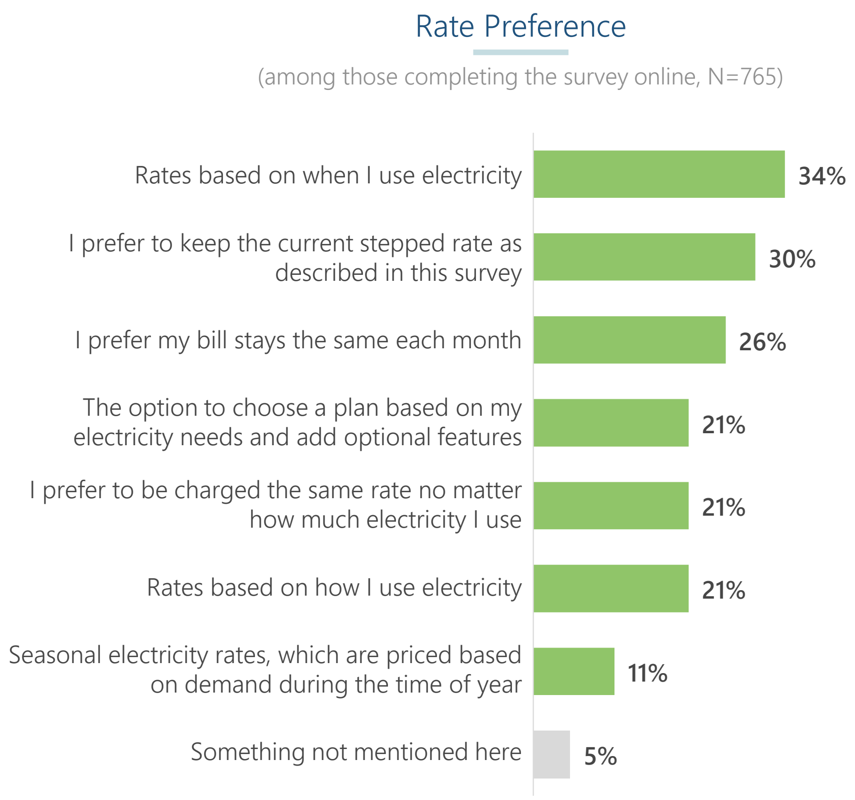
Note: 30% of the completed surveys were initiated by phone because this reflects the percentage of customers that do not have an email address in BC Hydro's customer database.

Total results accurate to **±3.6%**
(19 times out of 20)

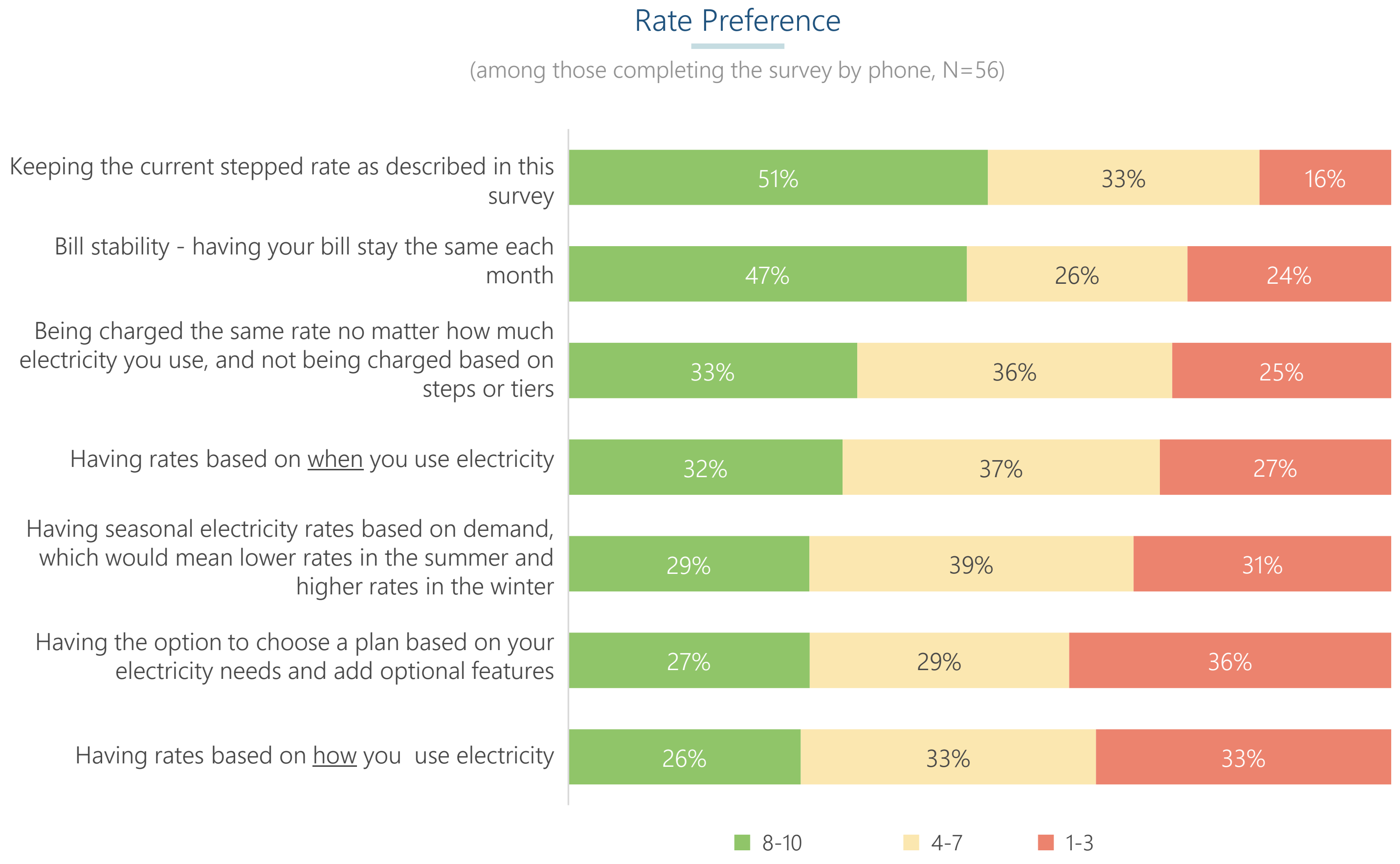
Results weighted by age to reflect BC Hydro's total residential customer base

Summary of Findings

PREFERENCES FOR FUTURE RATE DESIGN: ONLINE

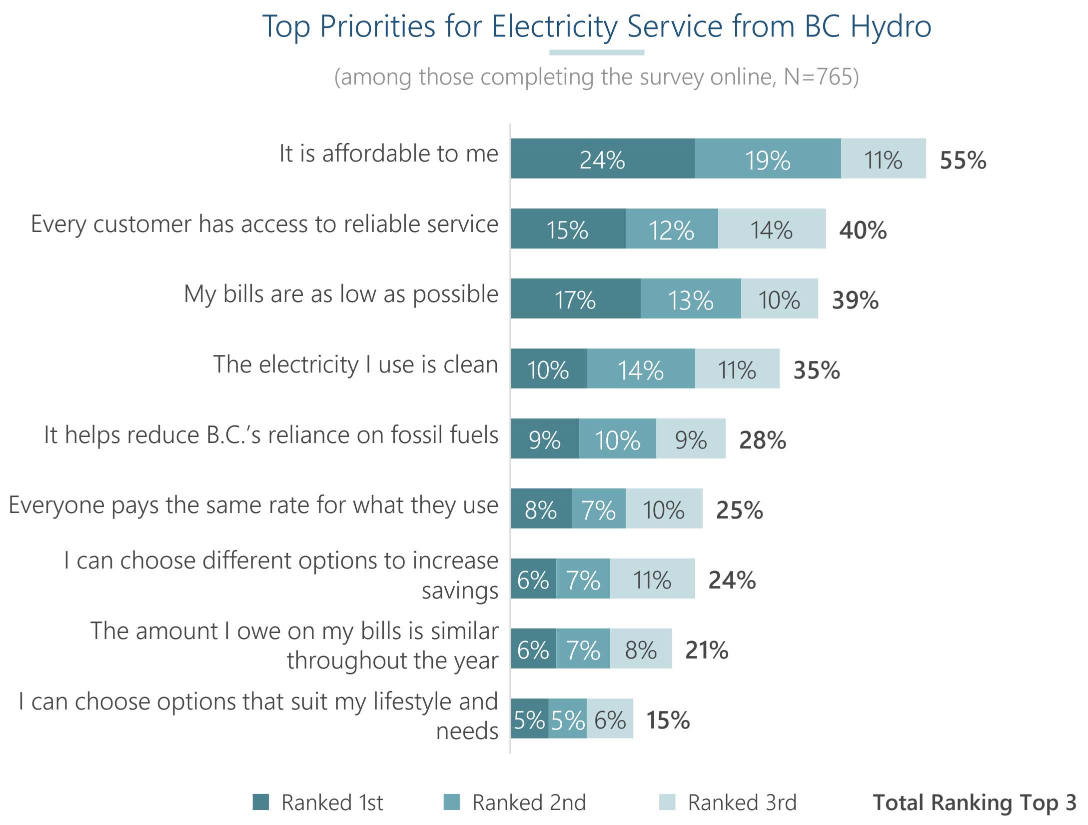


PREFERENCES FOR FUTURE RATE DESIGN: PHONE



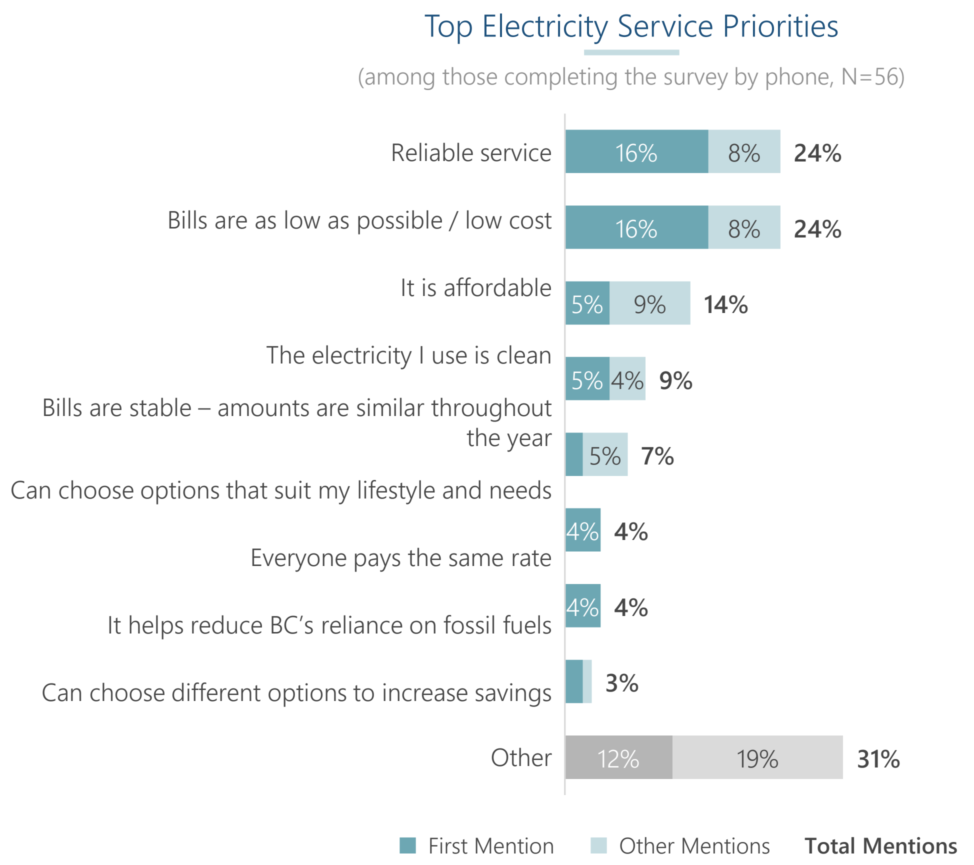
sentis

PRIORITIES FOR BC HYDRO ELECTRICITY: ONLINE



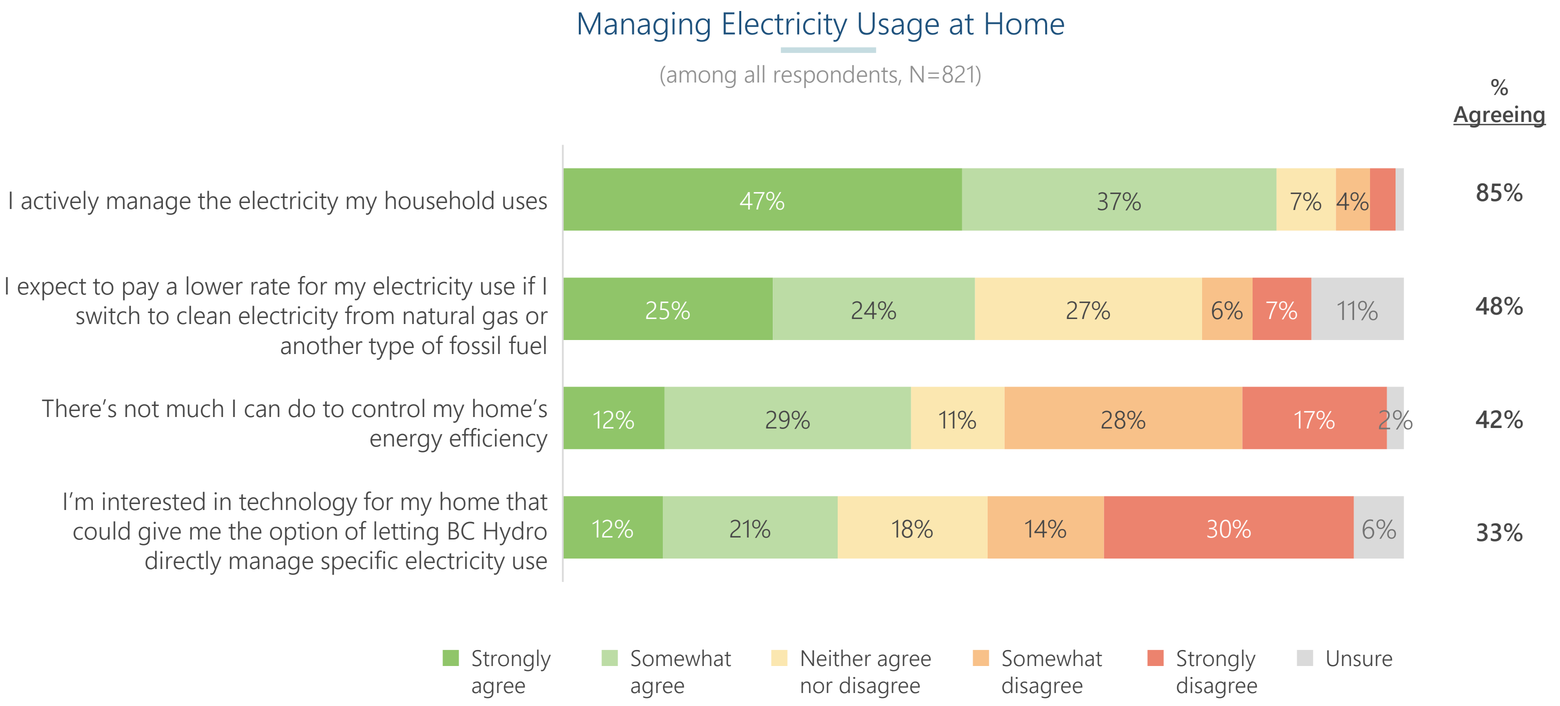
B3. What are your top priorities when it comes to electricity provided by BC Hydro? Please choose up to 3 items from the list below that best complete this sentence:

PRIORITIES FOR BC HYDRO ELECTRICITY: PHONE

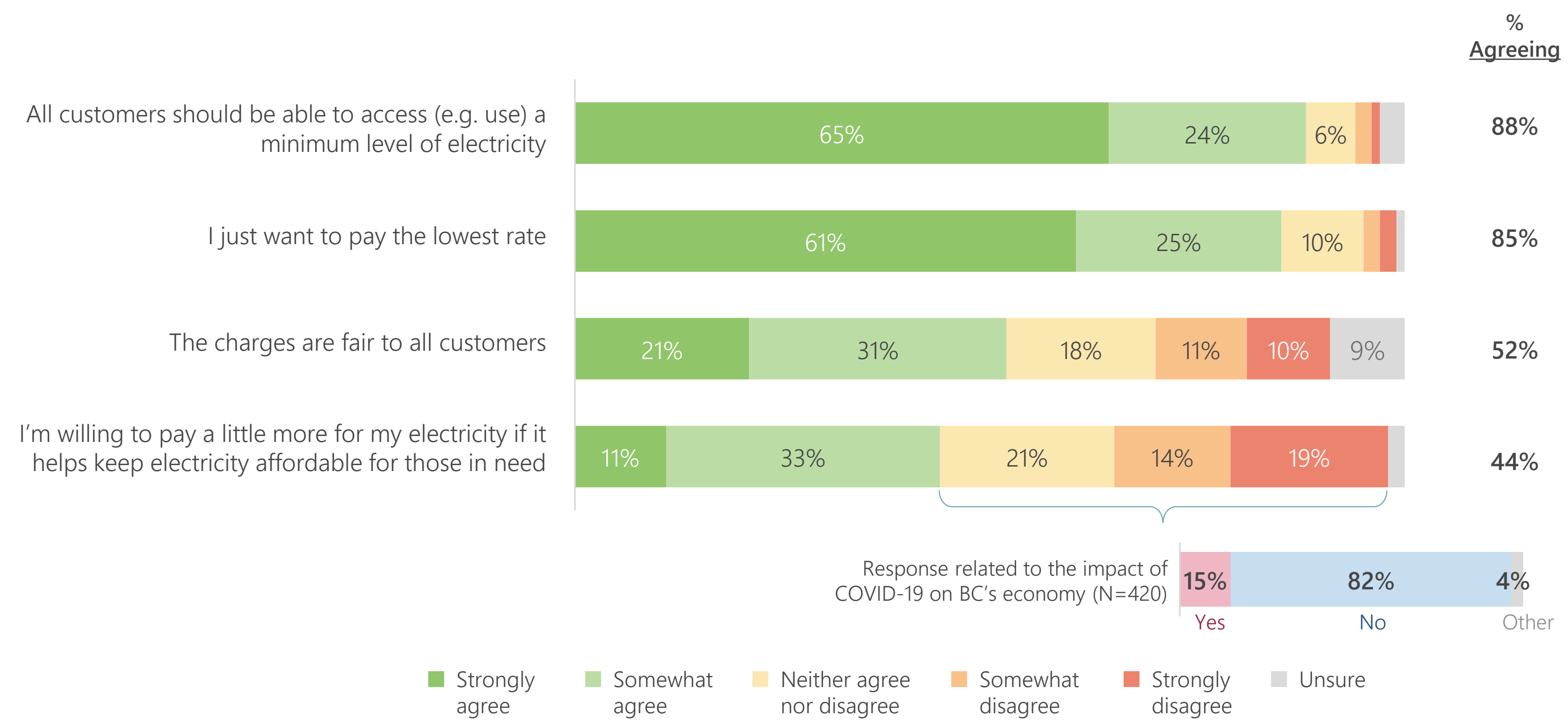


What is your top priority when it comes to electricity provided by BC Hydro? / B3b. Do you have any other priorities?

MANAGING HOME ENERGY USE



VALUES & PRIORITIES



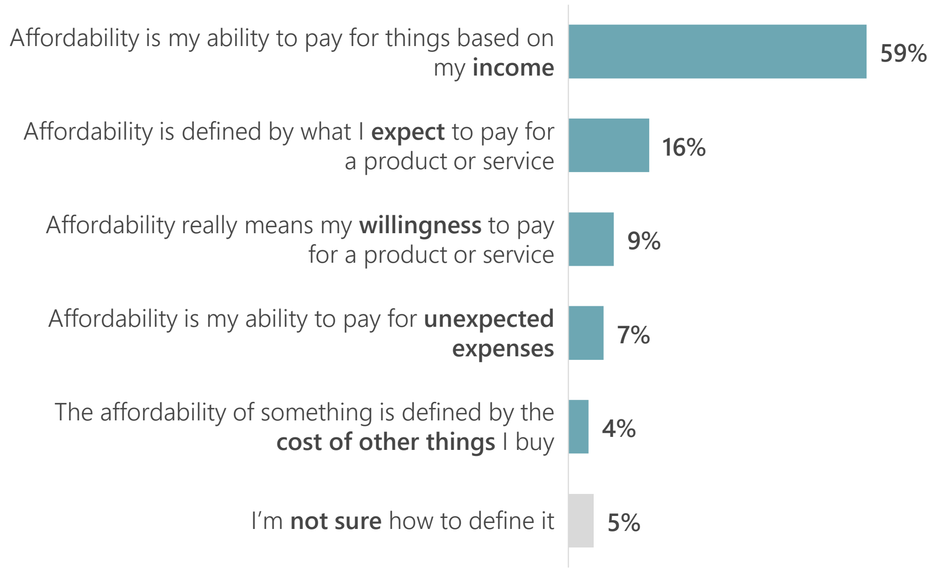
Sample: B1: Total respondents (821); B2: Among those asked online and neither/somewhat/strongly disagree on willingness to pay a little more for electricity if it helps keep electricity affordable for those in need (420)
B1. When determining electricity rates, BC Hydro considers the following in terms of the customer perspective: I. Efficiency: The price of electricity should encourage customers to use electricity efficiently while discouraging waste. ; II. Fairness: Electricity rates should be fair for all customers. ; III. Pricing: Electricity rates should be affordable for customers / The way electricity is priced should be reasonably easy for customers to understand. ; IV. Stability: Rates should ensure relatively stable bills for customers. To what extent do you agree or disagree with the following statements relating to how residential customers are charged for electricity today?
B2. [ONLINE-ONLY] Is your response to the last statement [B1_b] related to the impact of COVID-19 on B.C.'s economy?

sentis

AFFORDABILITY

Customers' Definition of Affordability

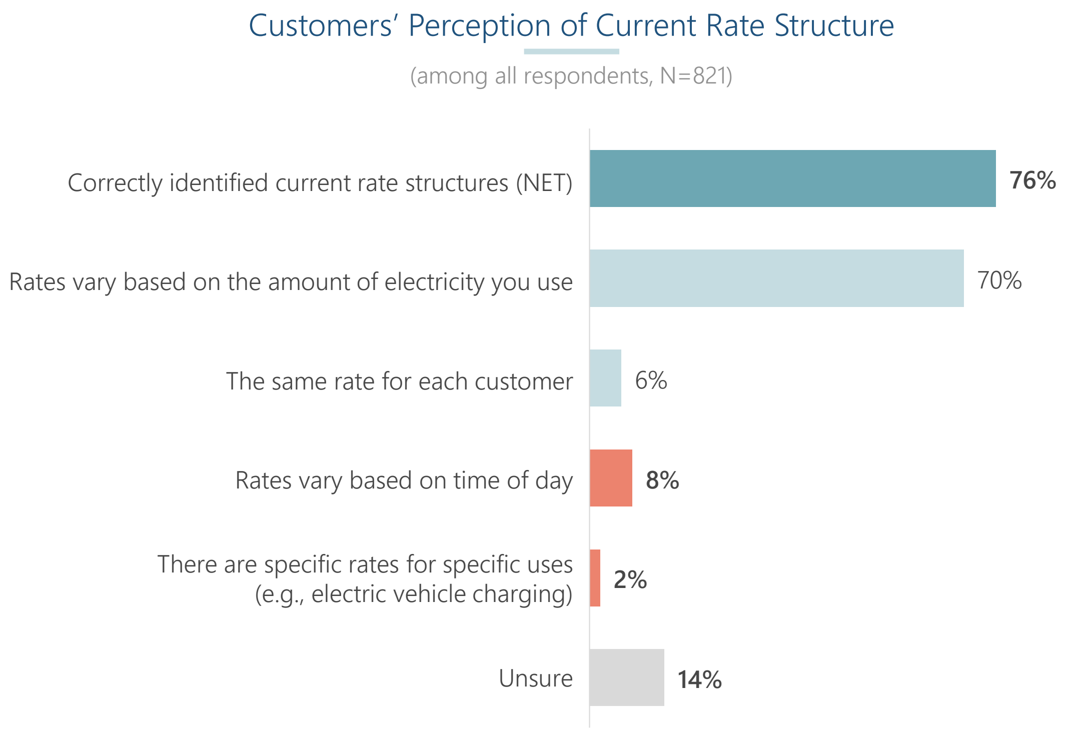
(among all respondents, N=821)



16

sentis

PERCEPTION OF CURRENT RATE STRUCTURE



sentis

CURRENT BILL PERCEPTIONS

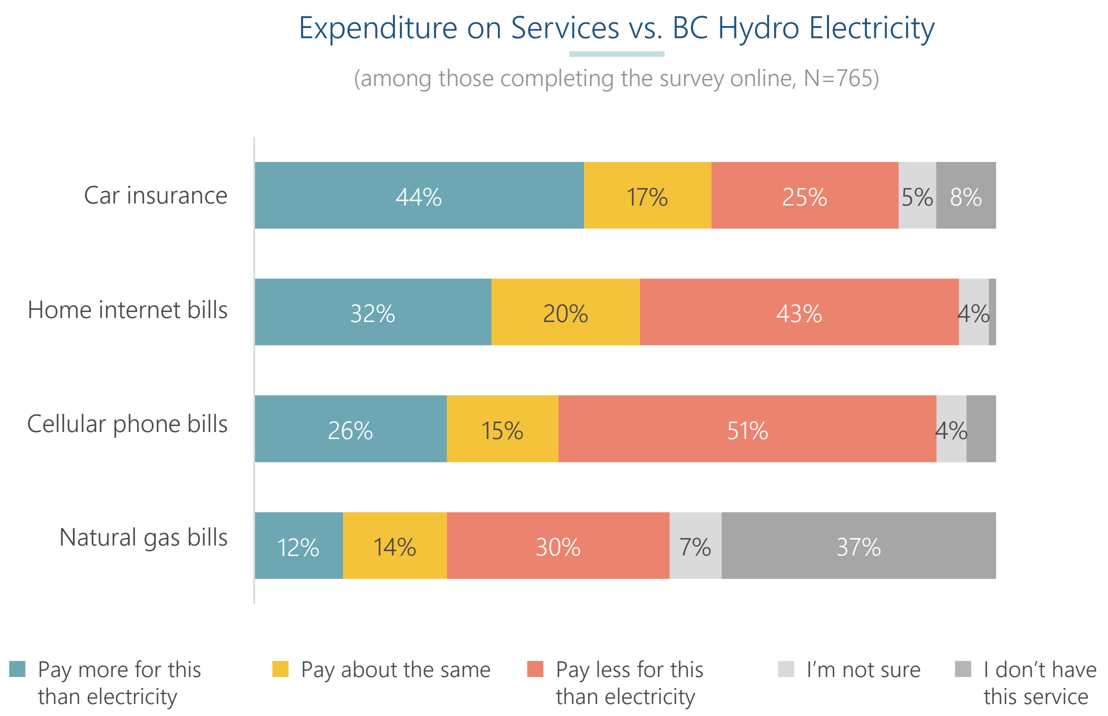
Perception of Step 2 Charge Frequency

(among all respondents, N=821)

Percent of Time in Step 2	Total	Every Bill	Most Bills	Some Bills	Never	Unsure
	821	174	123	180	107	238
0%	**31%**	9%	14%	29%	75%	37%
>0% - <50%	**23%**	10%	21%	38%	15%	24%
50% - 99%	**25%**	31%	44%	21%	7%	22%
100%	**49%**	21%	11%	4%	18%	22%

22%,49%, 21%, 11%, 4%, 18%

SPENDING ON HYDRO VS. OTHER BILLS: ONLINE

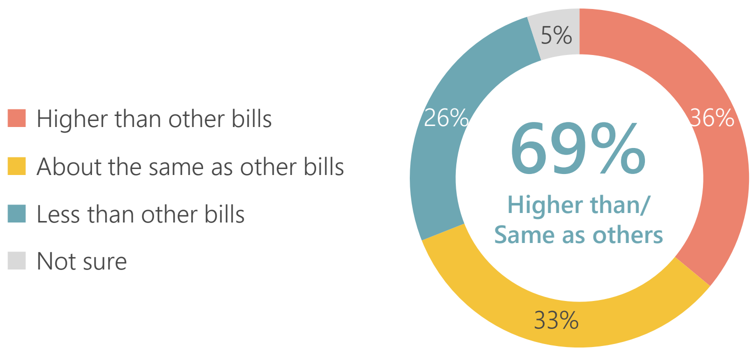


sentis

SPENDING ON HYDRO VS. OTHER BILLS: PHONE

Expenditure on Other Bills vs. BC Hydro Electricity

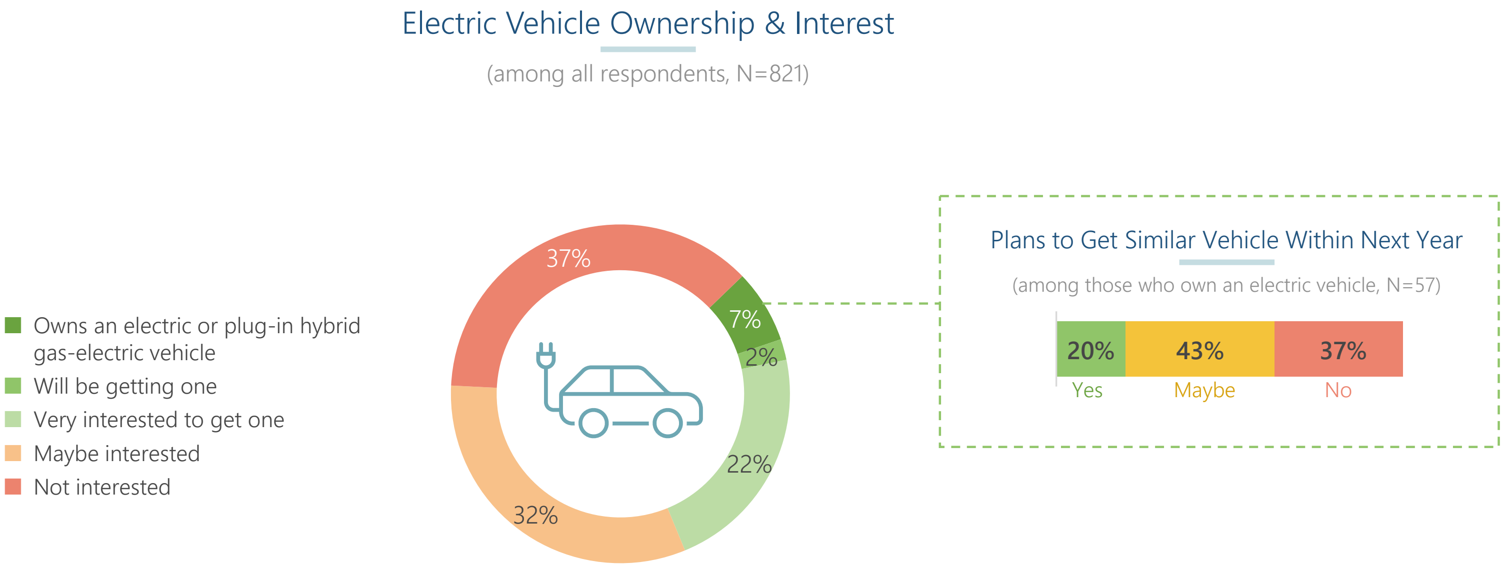
(among those completing the survey by phone, N=56)



20

sentis

ELECTRIC VEHICLE OWNERSHIP & INTEREST



sentis

ELECTRIC VEHICLE OWNERSHIP & INTEREST: PRIORITIES & PREFERENCES

Preferences for Future Rate Design

% selecting

	Total	Own EV	Strongly Intend	Maybe	No interest
Number of respondents	765	57	192	261	255
Rates based on when I use electricity	**34%**	49%	32%	34%	31%
I prefer to keep the current stepped rate	**30%**	18%	27%	34%	31%
I prefer my bill stays the same each month	**26%**	16%	25%	26%	29%
The option to choose a plan based on my electricity needs & add optional features	**21%**	35%	32%	18%	14%
I prefer to be charged the same rate no matter how much electricity I use	**21%**	11%	19%	22%	24%
Rates based on how I use electricity	**21%**	26%	27%	19%	17%
Seasonal electricity rates	**11%**	5%	10%	10%	14%
Something not mentioned here	**5%**	2%	3%	5%	6%

Priorities for BC Hydro Electricity Service

% selecting

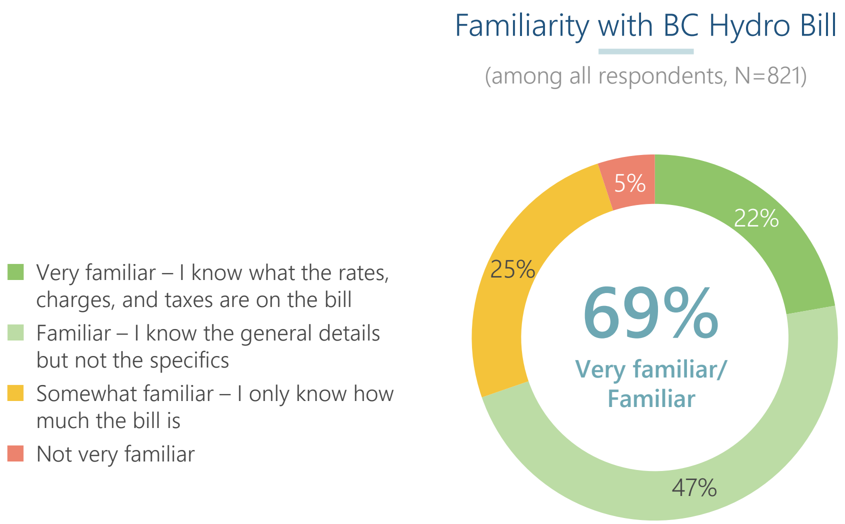
	Total	Own EV	Strongly Intend	Maybe	No interest
Number of respondents	765	57	192	261	255
It is affordable to me	**55%**	42%	48%	60%	57%
Every customer has access to reliable service	**40%**	35%	42%	44%	37%
My bills are as low as possible	**39%**	34%	33%	36%	48%
The electricity I use is clean	**35%**	47%	46%	38%	21%
It helps reduce B.C.'s reliance on fossil fuels	**28%**	37%	42%	27%	17%
Everyone pays the same rate for what they use	**25%**	19%	22%	26%	27%
I can choose different options to increase savings	**24%**	40%	27%	18%	23%
The amount I owe on my bills is similar throughout the year	**21%**	10%	20%	21%	24%
I can choose options that suit my lifestyle and needs	**15%**	23%	13%	18%	13%

Higher than others

22

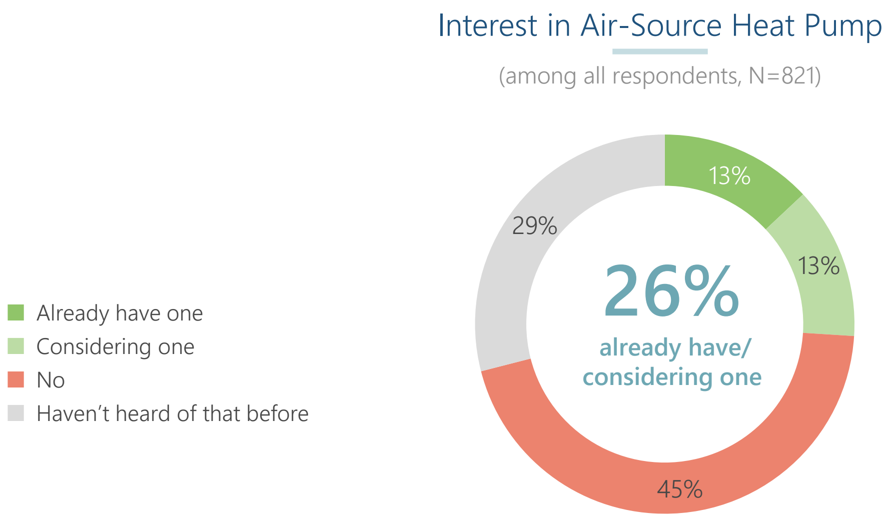
sentis

FAMILIARITY WITH BC HYDRO BILL



sentis

INTEREST IN AIR-SOURCE HEAT PUMP



Appendix

sentis

APPENDIX

Respondent Profile

RESPONDENT PROFILE

	Total	L.Main	VI / Coast	South Int.	North/ N. Coast
	Region				
	821	526	132	107	55
Region					
Lower Mainland	64%	100%	-	-	-
North / North Coast	7%	-	-	-	100%
Southern Interior	13%	-	-	100%	-
Vancouver Island / South Coast	16%	-	100%	-	-
Age					
18-24	2%	2%	0%	2%	0%
25-34	11%	13%	9%	4%	14%
35-44	17%	18%	20%	9%	15%
45-54	18%	18%	16%	22%	14%
55-64	21%	22%	18%	20%	18%
65-74	18%	16%	15%	25%	27%
75+	13%	10%	21%	18%	11%
Income Group					
Number of respondents	624	409	92	79	44
Low income	21%	21%	22%	22%	15%
Moderate income	57%	55%	58%	61%	74%
High income	22%	25%	20%	17%	11%

	Total	L.Main	VI / Coast	South Int.	North/ N. Coast
	Region				
	821	526	132	107	55
Household Income					
Under $20,000	5%	5%	4%	8%	0%
$20,000 to under $40,000	12%	10%	15%	17%	13%
$40,000 to under $60,000	13%	12%	15%	10%	15%
$60,000 to under $80,000	11%	12%	9%	11%	15%
$80,000 to under $100,000	10%	10%	11%	7%	13%
$100,000 to under $120,000	7%	7%	3%	8%	11%
$120,000 to under $140,000	6%	7%	3%	4%	11%
$140,000 to under $160,000	2%	2%	1%	1%	0%
$160,000 to under $180,000	3%	3%	4%	2%	2%
$180,000 to under $200,000	2%	1%	3%	5%	0%
$200,000 or more	6%	8%	2%	1%	0%
Prefer not to say	24%	22%	30%	26%	20%

sentis

RESPONDENT PROFILE

		Region			
	Total	L.Main	VI / Coast	South Int.	North/ N. Coast
	821	526	132	107	55
Household Type & Household Size					
1 person in apt/condo	14%	16%	12%	11%	2%
2+ people in apt/condo	15%	19%	15%	2%	2%
1 or 2 people in townhome/ duplex	9%	9%	9%	5%	12%
3+ people in townhome/ duplex	8%	11%	4%	1%	0%
1 or 2 people in single detached	28%	19%	41%	48%	53%
3+ people in single detached	26%	26%	19%	33%	30%
Household Type					
Single detached home	52%	44%	59%	72%	76%
Mobile or modular home (no foundation)	3%	1%	3%	11%	8%
Townhouse / rowhouse	13%	16%	11%	3%	5%
Duplex / triplex or similar	3%	3%	2%	2%	6%
Apartment or condominium	27%	34%	25%	12%	4%
Other	1%	1%	1%	1%	1%
Household Size					
1	26%	25%	31%	30%	17%
2	37%	34%	41%	39%	50%
3	14%	16%	10%	12%	12%
4	13%	14%	11%	11%	13%
5	5%	6%	4%	6%	2%
6	2%	3%	2%	1%	2%
7	2%	2%	1%	1%	3%

		Region			
	Total	L.Main	VI / Coast	South Int.	North/ N. Coast
	821	526	132	107	55
Heat Source					
Electricity from BC Hydro	73%	74%	85%	69%	50%
Natural gas	54%	56%	32%	61%	71%
Propane	2%	2%	2%	3%	3%
Wood	7%	3%	10%	16%	22%
Heating oil	1%	<1%	4%	1%	0%
Solar panels	<1%	0%	1%	1%	0%
Other	2%	1%	4%	1%	1%
None of there	0%	0%	0%	0%	0%
Percent of Bills in Step 2					
0%	31%	34%	25%	21%	35%
>0% - < 50%	23%	23%	15%	24%	30%
50% - 99%	25%	22%	34%	27%	23%
100%	22%	20%	25%	28%	12%
Number of Services Customers Pay Less for Than Electricity					
0	31%	33%	19%	33%	31%
1	23%	24%	18%	21%	29%
2	20%	21%	25%	14%	18%
3	18%	15%	27%	19%	17%
4	8%	7%	11%	13%	5%

sentis

RESPONDENT PROFILE

	Total	L.Main	VI / Coast	South Int.	North/ N. Coast
		Region			
	821	526	132	107	55
Home Ownership					
Own home	77%	73%	77%	90%	91%
Rent home	22%	26%	22%	10%	9%
Live with family but do not own the home	1%	1%	1%	0%	0%
Person Paying Bill					
I pay the bill	93%	93%	91%	95%	97%
I split the bill with other(s)	4%	4%	6%	1%	0%
Another family / household member pays the bill	3%	2%	4%	4%	3%
Electricity Included in Rent					
Yes, it's included	1%	1%	0%	0%	0%
No, I / we pay the bill	99%	99%	100%	100%	100%
Electricity Usage & Special Circumstances					
Someone has a condition requiring continuous power for medical equipment	4%	3%	3%	7%	4%
I rely solely on electricity because I can't access alternative energy sources where I live	29%	32%	29%	19%	15%
I'm a BC Hydro net metering customer	<1%	<1%	0%	1%	0%
I'm unable to make the home more energy efficient	27%	25%	33%	29%	24%
I live in a BC Hydro non-integrated area (NIA)	1%	<1%	1%	3%	0%
None of these apply	54%	54%	51%	58%	63%
Electric Vehicle Ownership / Interest					
Own	7%	8%	6%	4%	2%
Strongly intend	24%	29%	18%	13%	13%
Might	32%	32%	41%	25%	30%
No interest	37%	31%	36%	57%	55%

BC Hydro Optional Residential Time-of-Use Rate Application

Appendix D-7E

Time-of-Use Survey by Leger

Report

Residential Optional Time-of-Use Survey

DATE 2023-02-15

41016-024

Table of Contents

BACKGROUND & METHODOLOGY

Leger

Background & Objectives

BACKGROUND

Utilities across North America and globally have offered time-varying rates to customers for years and more recently, with the increase in electric vehicles and other technologies, been introducing end-use time-of-use rates. For many, this is due to addressing capacity needs of the electricity grid and the growing interest and support customers are showing for choice when it comes to how they use and pay for electricity.

OBJECTIVES

The study objectives include:

- Understanding more about EV drivers use around charging their vehicles, including their home charging set-up.
- Learning if our non-EV drivers are interested and likely to be EV owners in the next five years and what their preferences are around charging their vehicle in the future.
- For non-EV owners, today and in the future, is there interest in an optional whole-home time-of-use rate?
- Exploring preferences and likelihood of participation in optional time-of-use rates including their willingness to shift to "off-peak" periods.

Methodology

METHODOLOGY

The survey questionnaire had two unique entry links. This report shows the combined results for both groups.

- EV network participants - members who used our public charging stations 2 times or less in the past year, increasing the chances of getting people likely to charge at home.
- BC Hydro customers – Randomized customers who are likely non-EV owners.

Data collection methodology – web survey. Leger provided the two survey links and BC Hydro deployed the survey to its contact list.

Number of completions – EV network 4,598 invitations (n=510) 11% completion and BC Hydro customer invitations 10,000 (n=499) 5% completion. Overall completes 1,009.

The analysis in this report is based on EV owners and Non-EV owners. 40 respondents from the BC Hydro customer list were moved to the EV owner category and 4 respondents were moved from the EV network list to the Non-EV owner category based on the answer to EV ownership. Overall total of 546 EV owners and 463 Non-EV owners.

Fieldwork was conducted from October 14 to October 28, 2021.

Leger was responsible for questionnaire review, survey hosting and programming, providing the survey links for each group, data collection and data processing. BC Hydro deployed the survey links via email to the two groups.

*Please note, all data in this report, with a few exceptions, are rounded to the nearest percentage. Because of this, some tables and charts may not add up to 100% exactly.


KEY FINDINGS

Key Findings

Since EV owners charge their vehicles mostly at home, BC Hydro should continue exploring home charging needs and continue providing offers for home charging.

- The non-networked Level 2 EV charger is most popular among EV owners. This type of EV charger is also preferred by potential future customers.
- ChargePoint and Tesla are the top models of chargers mentioned by EV drivers, but there is opportunity for other brands such as Bosch, AddEnergie/FLO etc. to gain market share as well.

Most EV drivers and six in ten non-EV owners support the idea of simple overnight time-of-use rates.

- BC Hydro has more opportunity to be successful in launching simple overnight time-of-use rate among EV owners as they're more likely to select this option compared to non-EV owners.
- We recommend providing more information regarding the programs and rates, as the main barriers for not choosing both traditional and overnight time-of-use rates include penalties, high costs and preferring current rates/programs.

Non-EV owners think the whole home time-of-use rate better fits their lifestyle, while EV owners are equally split between EV time-of-use rate and whole home time-of-use rate.

- Year-round time-of-use rate is the preferred option among both non-EV owners and EV owners. However, EV drivers are more likely to say they're ready to shift their charging needs to overnight during specific months.
- An opportunity to lower bills is the main motivator for signing up for a time-of-use rate. BC Hydro should consider including incentives on each billing cycle as it's the most preferred option.


RESPONDENT PROFILE

Leger

RESPONDENT PROFILE OF EV OWNERS

Gender

Male
65%

Female
32%

**3% prefer not to say*

Age

19-34
10%

35-54
44%

55+
45%

**3% prefer not to say*

Type of home

Own
92%

Rent
7%

**1% prefer not to say*

Region

Region	
Lower Mainland/Fraser Valley	59%
Vancouver Island and Sunshine Coast	33%
Thompson Okanagan Columbia/ Kootenays	7%
North	1%

Type of home

Type of home	
A single-detached home or duplex	76%
A townhouse or row home	13%
An apartment or condo	9%
A manufactured home	1%

**1% other/prefer not to say*

Strata/Non-Strata

Among those who own an apartment/condo or a townhouse/row home

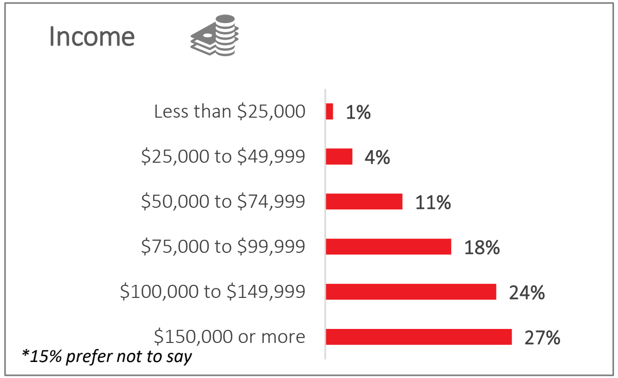
Strata Complex
90%

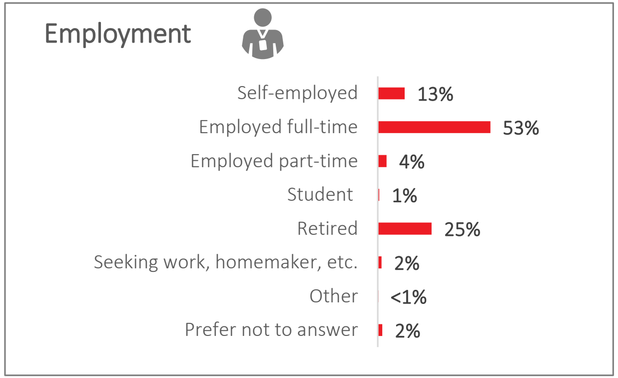
Non-strata Complex
8%

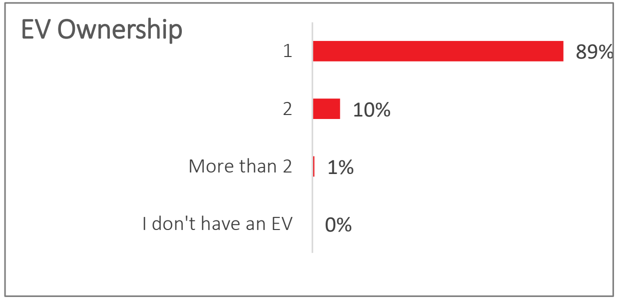
**2% don't know*

9

RESPONDENT PROFILE OF EV OWNERS







Leger

RESPONDENT PROFILE OF NON - EV OWNERS

Gender

Male	50%
Female	46%

**5% prefer not to say*

Age

19-34	15%
35-54	37%
55+	44%

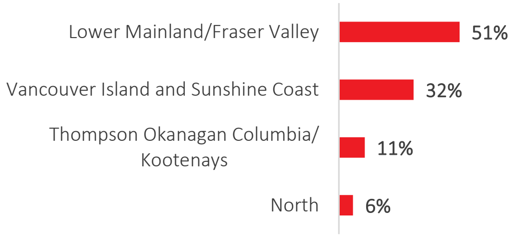
**4% prefer not to say*

Type of home

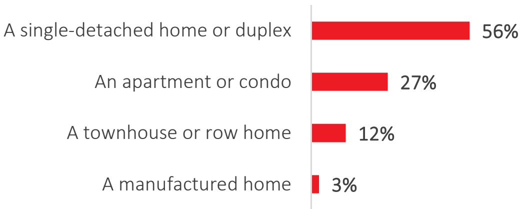
Own	76%
Rent	20%

**4% prefer not to say*

Region



Type of home



**1% other/prefer not to say*

Strata/Non-strata

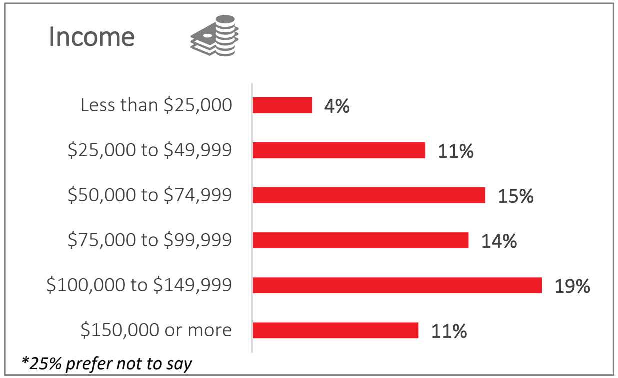
Among those who own an apartment/condo or a townhouse/row home

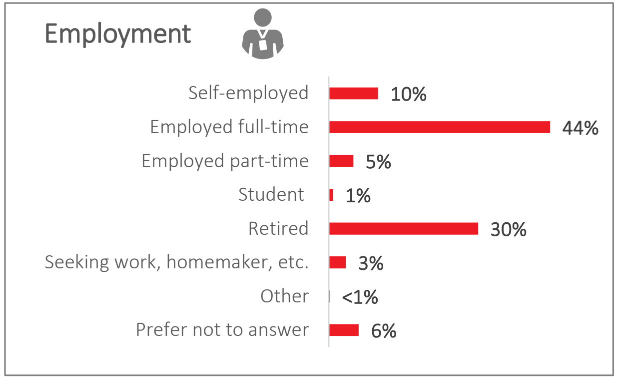
Strata Complex	74%
Non-strata Complex	19%

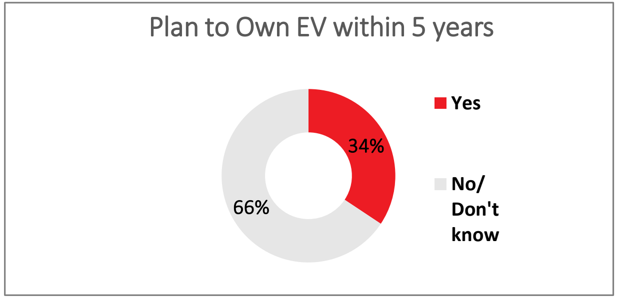
**8% don't know*

11

RESPONDENT PROFILE OF NON - EV OWNERS





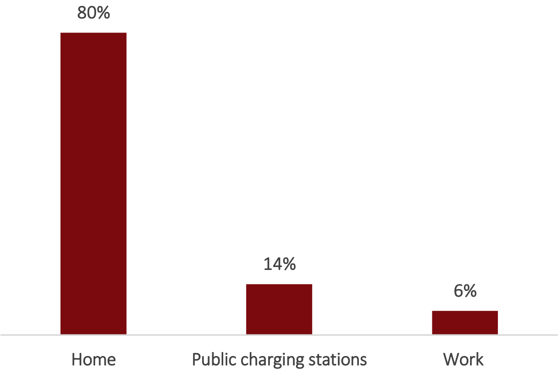



DETAILED RESULTS
HOME CHARGING NEEDS OF EV DRIVERS

Nearly all EV owners charge their EVs at home, but they also rely on other charging locations to meet their needs

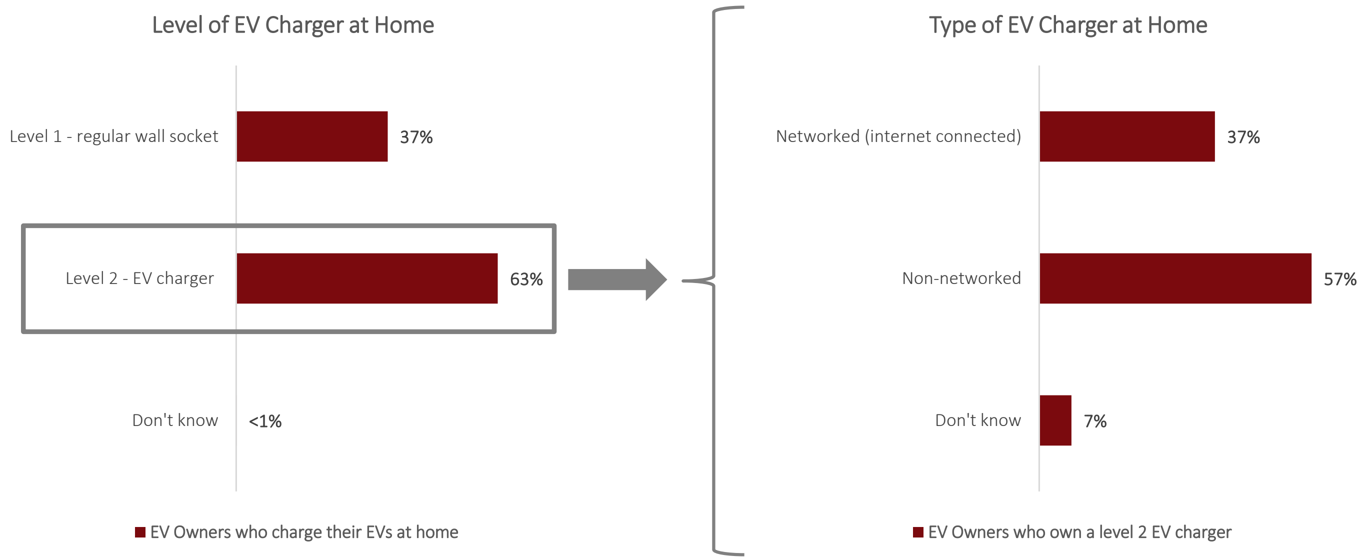
EV owners use the following for charging	YES	NO
Home	**95%**	**5%**
Public charging stations	84%	16%
Work	21%	79%

On average, EV Owners meet their charging needs through the use of the following charging locations.



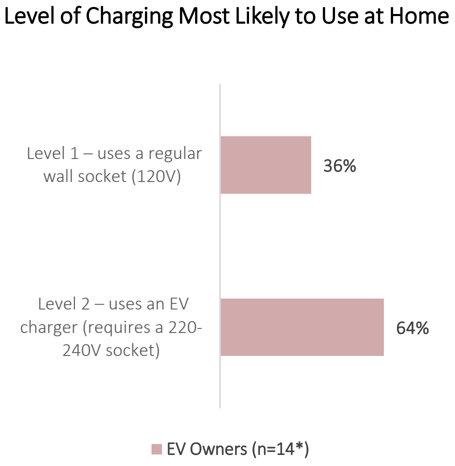
Q6. Using your best estimate, how often do you charge your electric vehicle at the following locations? (Open-numeric)
BASE: EV owners (n=546)

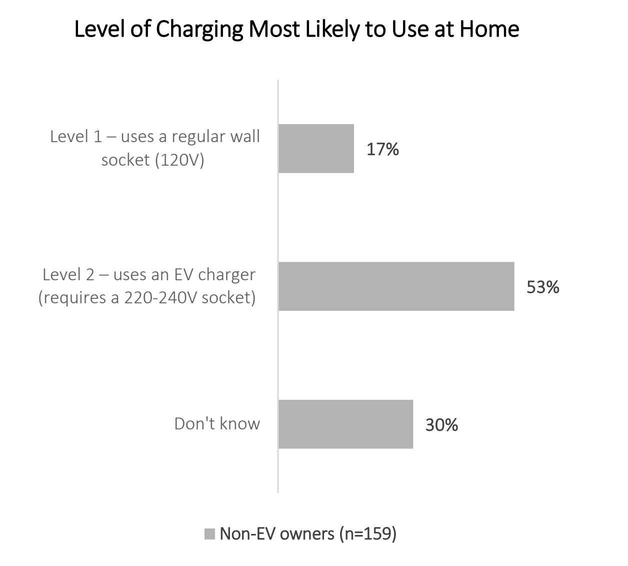
A Level 2–EV charger is most popular for those who charge at home, among them, a non-networked charger is more commonly used



Q7. What level is the EV charger you have at home? BASE: EV owners who charge their EVs at home (n=519)
Q8. Is your charger…? BASE: Those EV owners who own a level 2 EV charger (n=328)

Slightly over half of non-EV owners who plan to purchase an EV indicate they are more likely to use a Level 2 EV charger at home





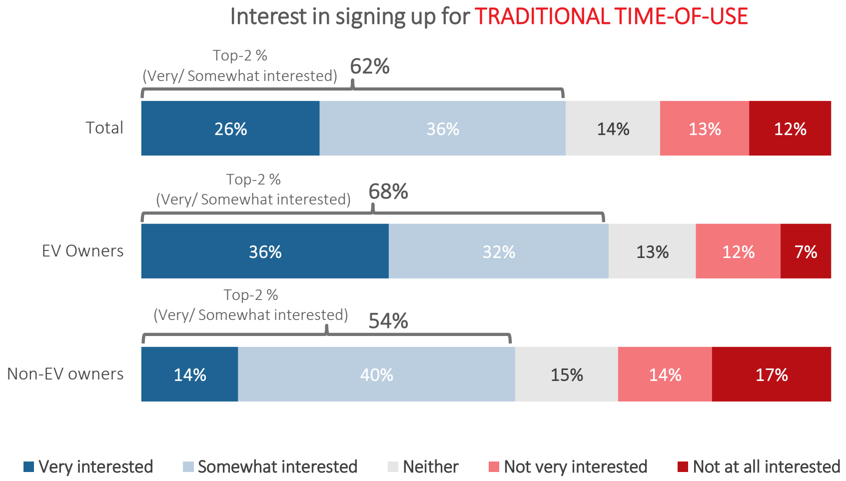
**Caution small sample size for EV owners*

Q11. What level charging are you most likely to use at home?

BASE: Those who are likely to start charging an EV at home or plan to purchase an EV in the next 5 years - Total (n=173), EV owners (n=14*), Non –EV owners (n=159)


DETAILED RESULTS
OPTIONAL CHARGING RATES AND PROGRAMS

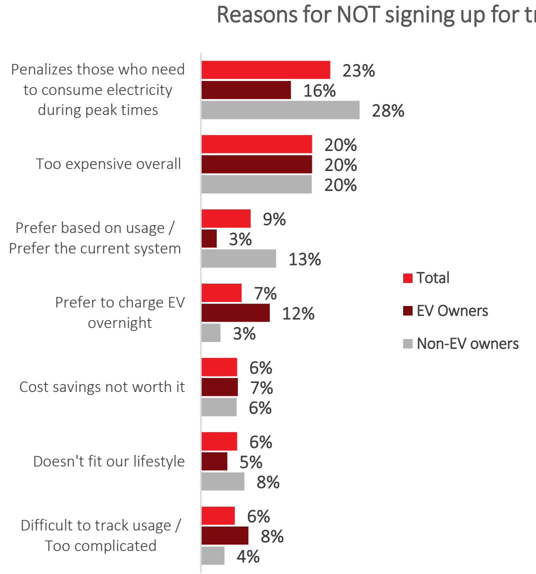
If BC Hydro offered traditional time-of-use rates, two-thirds of EV owners and slightly more than half of non-EV owners would be interested in signing up



Q12. How interested would you be in signing up for the following time-of-use rates if BC Hydro offered the option to customers?
BASE: Total sample (n=1009), EV owners (n=546), Non-EV owners (n=463)

*The **"traditional" time-of-use** rate design uses a daytime rate that's similar to BC Hydro's current residential rate, and a higher rate during the dinner time period when demand for electricity is highest, and a lower rate during the overnight period when demand is lowest.

The main barriers for those not interested in signing up for the traditional time-of-use rates are penalties and high costs



"Why charge me more when I may need it the most. Or it may be a more convenient time to charge."

"There is too much likelihood of forgetting a setting change when trying to utilize or avoid certain charging times, especially in the early evening. And I feel it might well increase my costs as well."

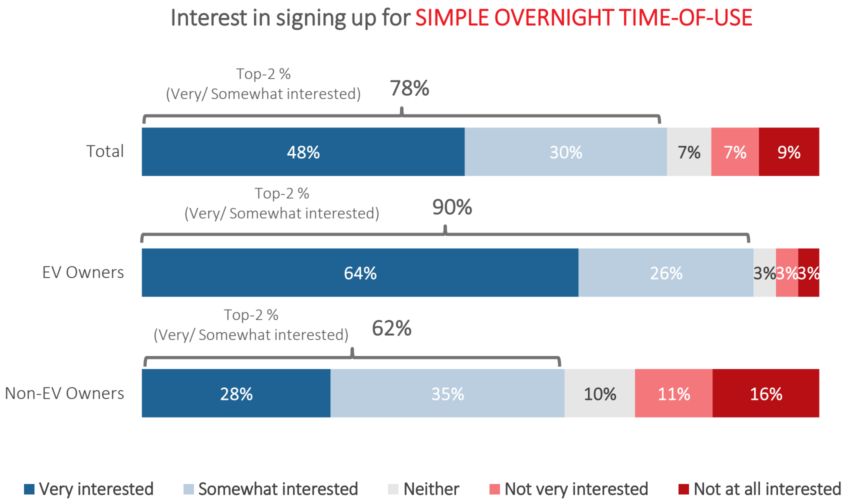
"I prefer to have a lower rate overnight."

"Too many people in my house that would need to use electricity during peak times, and I would not be able to control that."

Q12a. Why would you not be interested in signing up for traditional time-of-use rates? Is there any other information you'd need? (Open-ended)
BASE: Those who are not interested in signing up for traditional time-of-use rates – Total (n=250), EV owners (n=107), Non-EV owners (n=143)

Leger

If simple overnight time-of-use rates were offered by BC Hydro most EV owners would be interested in signing up and only six in ten non-EV owners would be interested

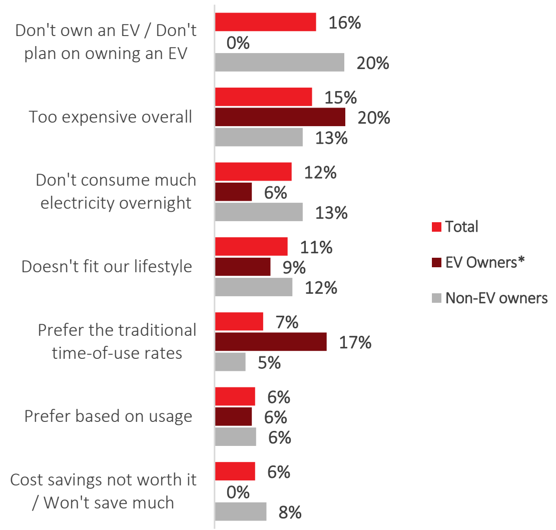


Q12. How interested would you be in signing up for the following time-of-use rates if BC Hydro offered the option to customers?
BASE: Total sample (n=1009), EV owners (n=546), Non-EV owners (n=463)

Leger

The main reasons mentioned by non-EV owners that are not interested in the simple overnight time of use rates are not owning an EV, high costs and not much energy consumed overnight

Reasons for NOT signing up for simple overnight time-of-use rates



"It shouldn't matter what time of day we use electricity. It should be a blanket cost with that same rate across the whole day."

"Cannot always plan for overnight charging."

"More expensive. Would like flexibility of three different time of day rates."

"It's not convenient."

"I live in a condo. No charging capabilities."

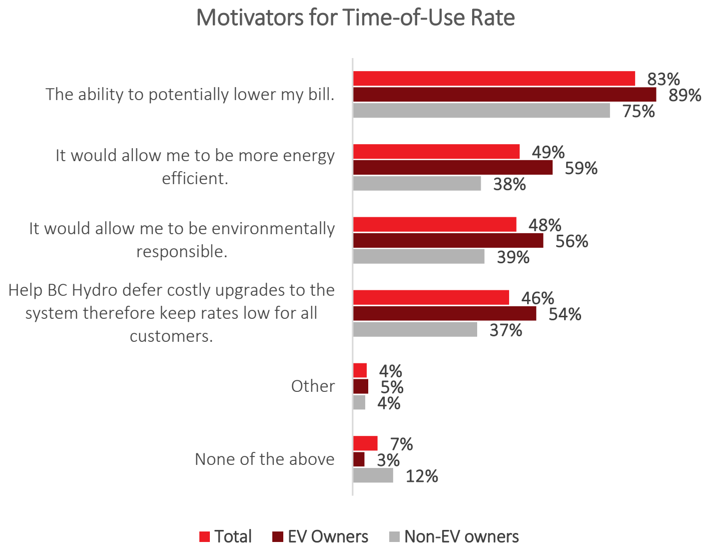
"Not sure of the benefit it we are not using hydro during the overnight time period."

**Caution small sample size for EV owners*

Q12b. Why would you not be interested in signing up for simple overnight time-of-use rates? Is there any other information you'd need? (Open-ended)

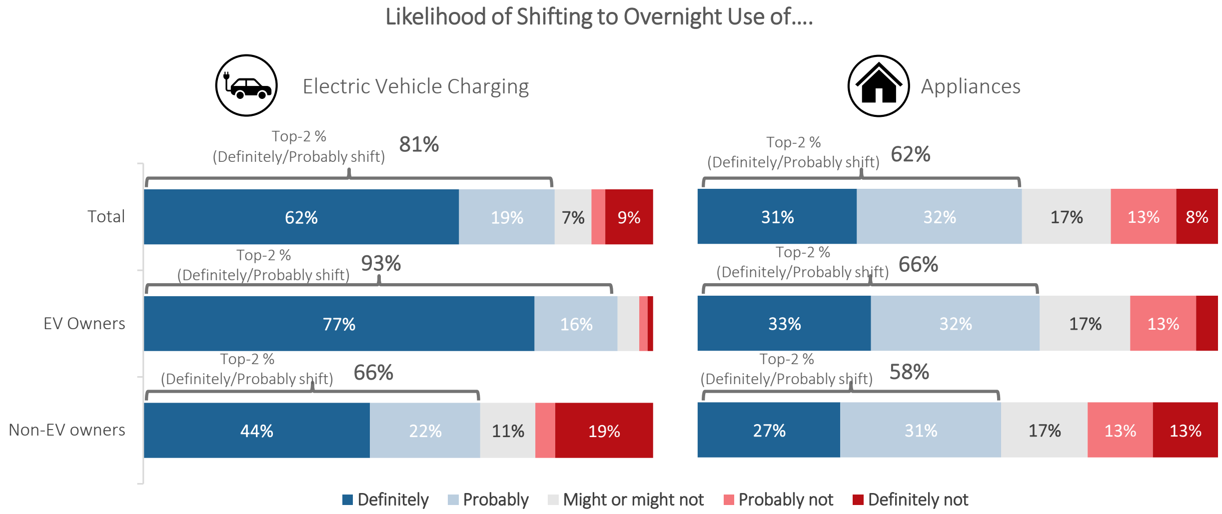
BASE: Those who are not interested in signing up for simple overnight time-of-use rates - Total (n=161), EV owners (n=35)*, Non-EV owners (n=126)

The ability to lower electricity bills is the top motivator for signing up for a time-of-use rate



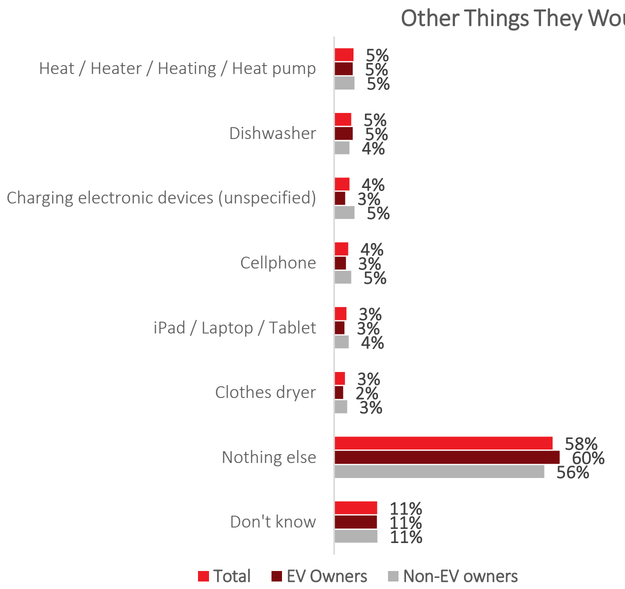
Q13. What would motivate you to sign up for a time-of-use rate?
BASE: Total sample (n=1009), EV owners (n=546), non-EV owners (n=463)

EV owners are more likely to shift their EV charging to overnight instead of their appliances in order to lower their bill



Q14. Knowing that shifting when you use electricity can potentially lower your bill, how likely are you to shift the use of the following to overnight?
BASE: Total sample (n=1009), EV owners (n=546), non-EV owners (n=463)
*Non-EV owners were asked the same question as BC Hydro wanted to know what their answers would be based on a hypothetical scenario

A wide variety of other household items could be shifted to overnight charging but most could not identify any others



"Dishwasher, electronic device charging."

"Dishwasher or laundry."

"Slow cooker, charging laptop, phone etc."

"Dishwasher, dryer, car, charging electronics (phones), etc."

"Set heaters lower during peak times."

"Cell phone and iPad charging."

"Washing machine, dryer, dishwasher."

Q14a. Is there anything else that uses electricity that you would shift to overnight? (Open-ended)
BASE: Total sample (n=1009), EV owners (n=546), non-EV owners (n=463)

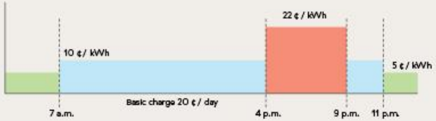

DETAILED RESULTS
NEW RESIDENTIAL RATE OPTIONS

Voluntary Opt-In Time-of-Use Rate Scenarios

SCENARIO A

Whole Home Time of Use rate

This enables customers to take advantage of a lower rate at times when there's lower demand for electricity. For example, this option would charge customers a lower rate for running their appliances (e.g. dishwasher, clothes dryer.) later in the evening, or charging an electric vehicle overnight. The lowest rate would be applicable from 11 p.m. to 7 a.m. and the highest rate would be applicable from 4 p.m. to 9 p.m.

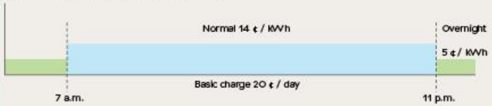


SCENARIO B

Electric Vehicle Time of Use rate

The Electric Vehicle Time of Use Rate (EV-TOU), encourages charging during a lower priced period between 11 p.m. and 7 a.m. and has a higher energy rate between 7 a.m. and 11 p.m. To participate in the EV-TOU rate, a separate BC Hydro meter must be installed, however it's anticipated that Measurement Canada will soon certify specific networked Level 2-EV chargers to enable the chargers to be used as an approved metering device to apply EV-TOU pricing to the EV charging load.

When planning for the installation of a networked or non-networked Level 2 charger, a certified electrical contractor can advise you whether a service upgrade is needed. In addition to the cost for the charger, upgrades to customer service equipment can range from $2,000 – $3,000 or more, depending on the existing service configuration. When planning this work, it can also be determined if the installation of a second BC Hydro meter can be accommodated.



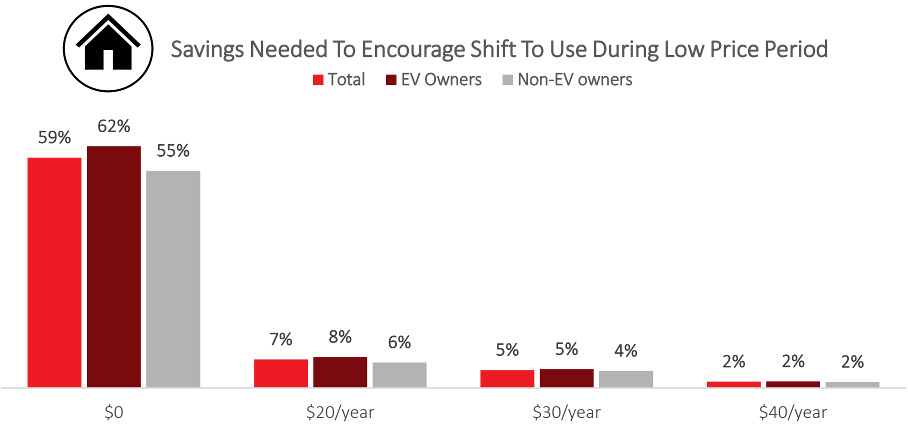
SCENARIO C

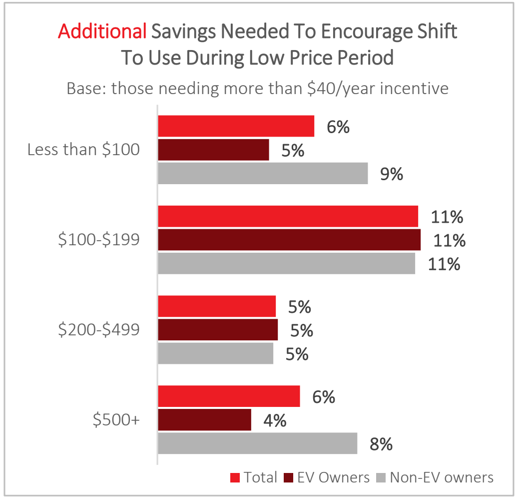
Utility Managed Electric Vehicle charging

Customers install a compatible networked-Level 2 charger* at home and can participate in a program with an annual incentive of ~$30 that allows BC Hydro to manage your EV's charging on around 20 days a year. You plug it in, but BC Hydro would determine when to start charging it. The start time of charging would be the optimal time for the electrical system in your local area. This helps better manage the electricity demand from EVs across B.C. and can help to defer costly upgrades to the system. Your EV would be charged by the time you need it the next day. You may choose to opt out of this charging option at any time and always have full override control of the EV charger.

*The cost difference between a non-networked and networked-Level 2 charger is around $300-$450.

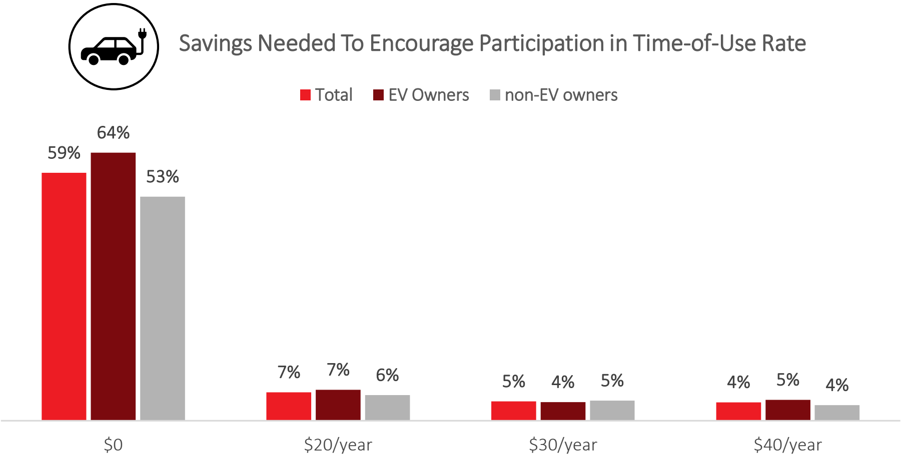
Shifting use of appliances: over half of respondents do not need incentives, but nearly one-quarter are looking for more than $100 annually

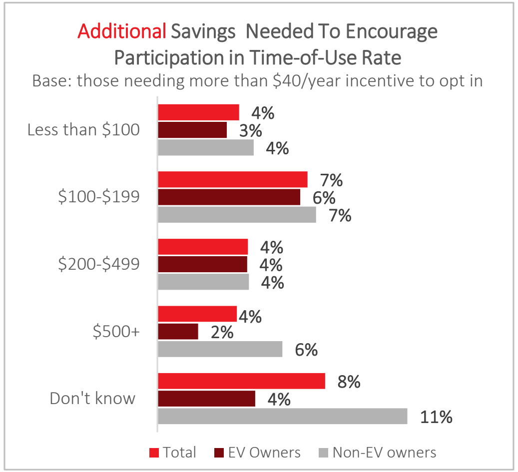




Q15. Thinking about your household's annual electricity costs, would the following additional amount of savings encourage you to shift the use of high energy consuming appliances (e.g. dishwasher or clothes dryer) to the lower price period? BASE: Total sample (n=1009), EV owners (n=546), non-EV owners (n=463).
Q15a. What amount of additional savings would encourage you to shift the use of high energy consuming appliances (e.g., dishwasher or clothes dryer) to the lower price period? (Open-ended) BASE: Those who are not encouraged by $40/year - Total (n=282), EV owners (n=132), non-EV owners (n=150).

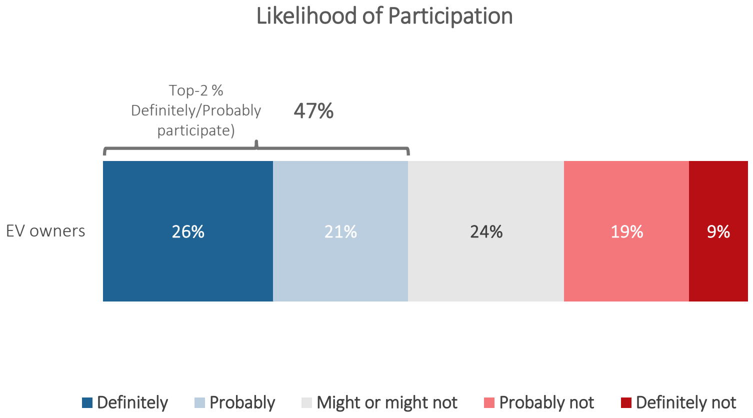
EV time of use rate: almost one-third of EV owners and almost half of non-EV owners would require an incentive to opt in





Q16. When using the above example to think about your electricity bill and how much you currently spend on EV charging at home, if you can charge your vehicle during the overnight period, you could reduce your electricity costs by opting in to this time-of-use rate. Would the following amount of annual savings on your household's electricity costs encourage you to participate in this time-of-use rate? BASE: Total sample (n=1009), EV owners (n=546), non-EV owners (n=463).
Q16a. What amount of annual savings on your household's electricity costs would you need to see for you to participate in this time-of-use rate? (Open-ended) BASE: Those who are not encouraged by $40/year - Total sample (n=258), EV owners (n=108), non-EV owners (n=150).
*Non-EV owners were asked the same question as BC Hydro wanted to know what their answers would be based on a hypothetical scenario

Almost half of EV owners who have a non-networked charger at home are likely to participate in either scenario (B or C)



SCENARIO B

EV time-of-use rate: When planning to install a networked or non-networked Level 2 charger, a certified electrical contractor can advise you whether a service upgrade is needed. In addition to the cost for the charger, upgrades to customer service equipment can range from $2,000 - $3,000 or more, depending on the existing service configuration.

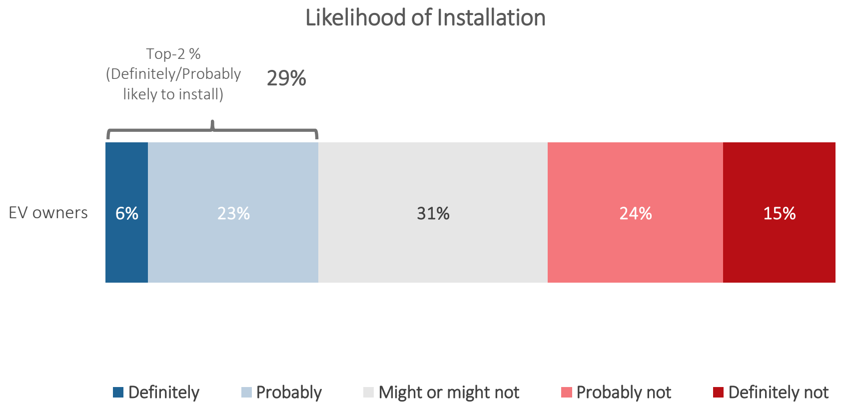
When planning this work, it can also be determined if the installation of a second BC Hydro meter can be accommodated. The second BC Hydro meter can track the at-home EV charging during periods of lower electricity demand to help reduce associated charging costs. This would include a lower rate for 8 hours a day between 11 p.m. and 7 a.m. but would have a higher rate between 7 a.m. and 11 p.m.

SCENARIO C

Utility-managed EV charging: Customers install a compatible networked-Level 2* charger at home and can participate in a program with an annual incentive of ~$30 that allows BC Hydro to manage your EV's charging on around 20 days a year. You plug it in, but BC Hydro would determine when to start charging it. The start time of charging would be the optimal time for the electrical system in your local area. This helps better manage the electricity demand from EVs across B.C. and can help to defer costly upgrades to the system. Your EV would be charged by the time you need it the next day. You may choose to opt out of this charging option at any time and always have full override control of the EV charger.
*The cost difference between a non-networked and networked-Level 2 charger is around $300-$450.

Q17. In order to participate in Scenario C (Utility managed EV charging), a Level 2-networked EV charger must be installed in your home. In the future, a Level 2-networked EV charger may also enable participation in Scenario B (EV time-of-use-rate) without the need for a second BC Hydro meter. How likely are you to participate in either scenario (B or C)?
BASE: EV owners who have a non-networked EV charger at home (n=186)

Of those with non-networked EV chargers who did not say they are definitely likely to participate in scenario B and C, likelihood to install a Level 2-networked charger is low even if offered a $200 incentive



Q17b. How likely would you be to install a Level 2-networked or internet-enabled charger in your home if you received an additional $200 incentive to help cover the costs of the charger?
BASE: EV owners who selected Probably, Might or might not, Probably not and Definitely not at Q17 (n=137)

Leger

Looking closer at the scenarios

SCENARIO A

Whole home time-of-use rate: This enables customers to take advantage of a lower rate at times when there is lower demand for electricity. For example, this option would charge customers a lower rate for running their appliances (e.g. dishwasher or clothes dryer later in the evening or charging an EV overnight). The lowest rate would be applicable from 11 p.m. - 7 a.m. and the highest rate would be applicable from 4 p.m. – 9 p.m.

SCENARIO B

EV time-of-use rate: When planning to install a networked or non-networked Level 2 charger, a certified electrical contractor can advise you whether a service upgrade is needed. In addition to the cost for the charger, upgrades to customer service equipment can range from $2,000 - $3,000 or more, depending on the existing service configuration.

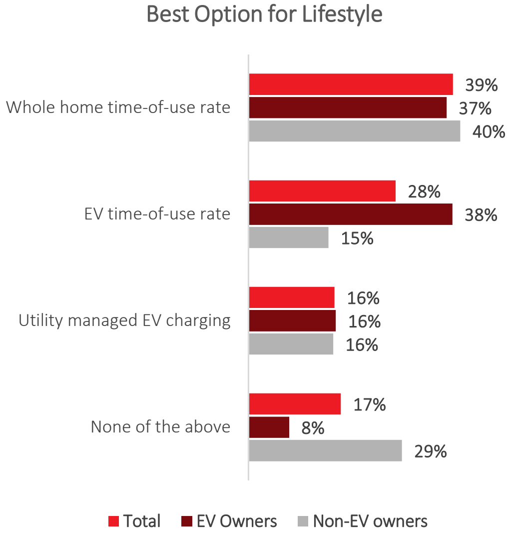
When planning this work, it can also be determined if the installation of a second BC Hydro meter can be accommodated. The second BC Hydro meter can track the at-home EV charging during periods of lower electricity demand to help reduce associated charging costs. This would include a lower rate for 8 hours a day between 11 p.m. and 7 a.m. but would have a higher rate between 7 a.m. and 11 p.m.

SCENARIO C

Utility-managed EV charging: Customers install a compatible networked-Level 2* charger at home and can participate in a program with an annual incentive of ~$30 that allows BC Hydro to manage your EV's charging on around 20 days a year. You plug it in, but BC Hydro would determine when to start charging it. The start time of charging would be the optimal time for the electrical system in your local area. This helps better manage the electricity demand from EVs across B.C. and can help to defer costly upgrades to the system. Your EV would be charged by the time you need it the next day. You may choose to opt out of this charging option at any time and always have full override control of the EV charger.

*The cost difference between a non-networked and networked-Level 2 charger is around $300-$450.

Non-EV owners have the strongest preference for the whole home time-of-use rate, while EV owners are evenly split between the EV time-of-use and whole home time-of-use rate



Q18. Which of the following options best suits your lifestyle?
BASE: Total sample (n=1009), EV owners (n=546), non-EV owners (n=463)

Leger

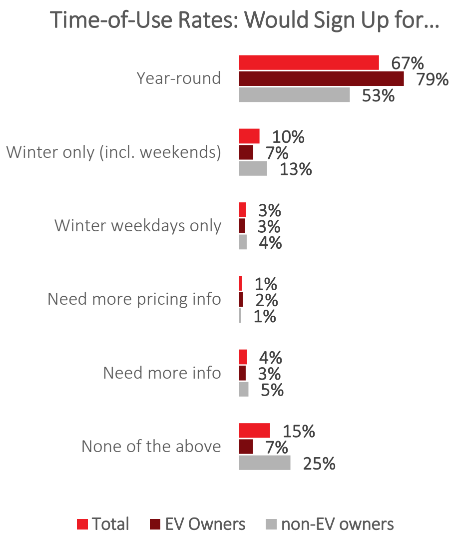
Reasons for choosing each of the scenarios

Whole Home Time-of-Use Rate	EV Time-of-Use Rate	Utility Managed EV Charging
Easy to manage/ control myself – **20%**	Easy to manage/ control myself – **22%**	Easier to let utility manage/Don't have to monitor myself – **24%**
Save money/Lower costs – **17%**	Save money/Lower costs – **16%**	Save money/Lower costs – **19%**
Do not have an EV – **16%**	Easy/Convenient/Simple – **14%**	Efficient use of energy/grid – **18%**
Easy/Convenient/Simple – **14%**	I usually charge EV overnight – **8%**	Full override control of EV charger – **9%**
Flexibility – **11%**	Difficult/Don't want to shift TOU for dishwasher/clothes washer/dryer– **7%**	Easy/convenient/simple – **7%**
Eliminates the need for upgrade – **8%**	Flexibility – **6%**	Best option for me/ Most logical – **7%**
Efficient use of energy /grid – **5%**	Already have programmable charger– **5%**	Fits my family lifestyle/schedule/needs– **6%**
Fits my lifestyle/schedule/needs – **5%**		

Q19. Tell us why you selected (pipe in from above) and why that option would work for you. (Open-ended)

BASE: Those who selected "Whole home TOU" (n=389), those who selected "EV TOU" (n=280), those who selected "Utility managed EV charging" (n=164)

A year-round time-of-use rate is most popular among both groups, however, it is of more interest amongst EV owners



Q20. Thinking back to the time of use rate scenarios discussed earlier…Which of the following options for time-of-use rates would you be interested in signing up for:
BASE: Total sample (n=1009), EV owners (n=546), non-EV owners (n=463)

Leger

Reasons for choosing each of the scenarios

Year Round

Easy/Convenient/Simple – **13%**

Save money/Lower costs – **13%**

Use EV all year around – **11%**

Use electricity all year around – **10%**

Fits my lifestyle/schedule/needs – **8%**

Easy to manage – **7%**

Best option/ Logical option – **7%**

Prefer the same rate all year around – **5%**

Winter Only (including weekends)

Use more electricity during winter– **32%**

Fits my lifestyle/schedule/needs – **12%**

Best option/ Logical option – **8%**

Save money/ Lower costs – **6%**

Use more electricity in the summer – **6%**

Less electricity usage during the summer – **4%**

Efficient use of energy/grid – **4%**

Use electricity all year round – **3%**

Winter Weekdays Only

Use electricity more on weekdays – **21%**

Use more electricity during winter – **18%**

Fits my lifestyle /Schedule – **18%**

Best option/ Logical option– **9%**

Use more electricity in the summer – **6%**

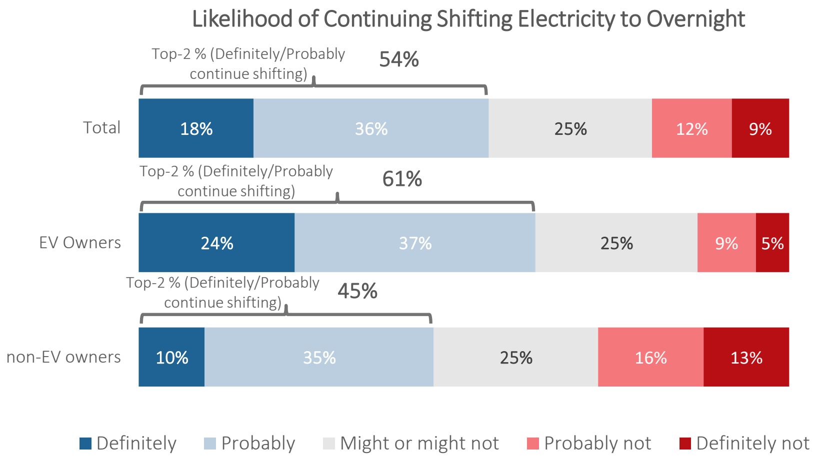
Efficient use of energy/grid – **6%**

Save money / Lower costs – **3%**

Don't understand / Need more information – **3%**

Q21. Tell us why you selected (pipe in from above) and why that option would work for you. (Open-ended)
BASE: Those who selected “Year Round” (n=674), those who selected “Winter only, including weekends” (n=99), those who selected “Winter weekdays only” (n=33)

EV owners are more likely then non-EV owners to continue shifting their electricity use to overnight during specific months where there is no time-of-use rate offered



Q23. If the time-of-use rate was only offered during a select number of months (e.g. during the winter) and you'd be shifting your electricity use to overnight periods, how likely would you be to continue shifting electricity use to overnight periods during the months when there isn't a time-of-use rate offered?
BASE: Total sample (n=1009), EV owners (n=546), non-EV owners (n=463)

Leger

Reasons for choosing/not choosing overnight shift during specific months

Continuing Shifting Electricity to Overnight

54% Likely

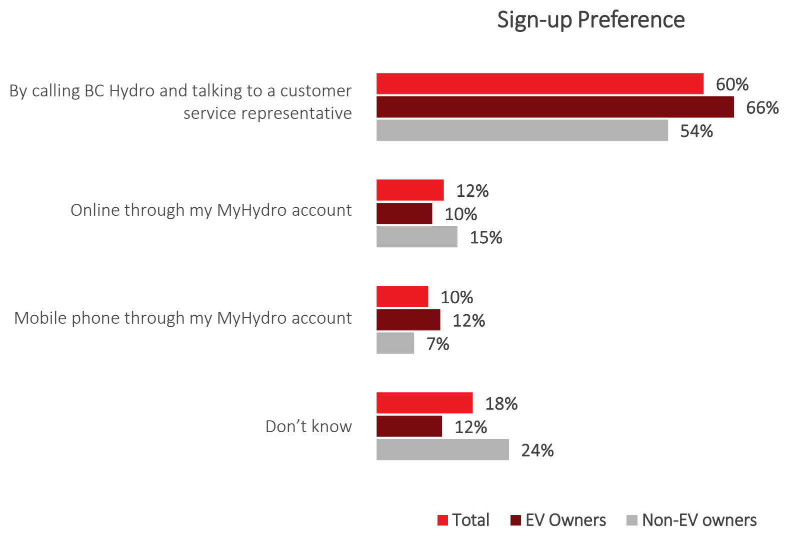
- Can establish a routine/Good habits – **23%**
- Prefer to charge EV overnight – **12%**
- Save money/ Lower costs – **11%**
- Efficient use of energy/grid – **6%**
- Best option/ Logical option – **5%**
- Fits my lifestyle/schedule – **5%**
- Easy/convenient/simple – **5%**
- It depends on many factors – **4%**

21% Unlikely

- Need a financial incentive – **22%**
- Doesn't fit our lifestyle – **12%**
- Don't consume much electricity overnight– **7%**
- Use electricity all year round – **4%**
- Prefer based on usage – **4%**
- Not interesting / Not motivating – **4%**
- Too complicated – **4%**
- Unethical – **4%**

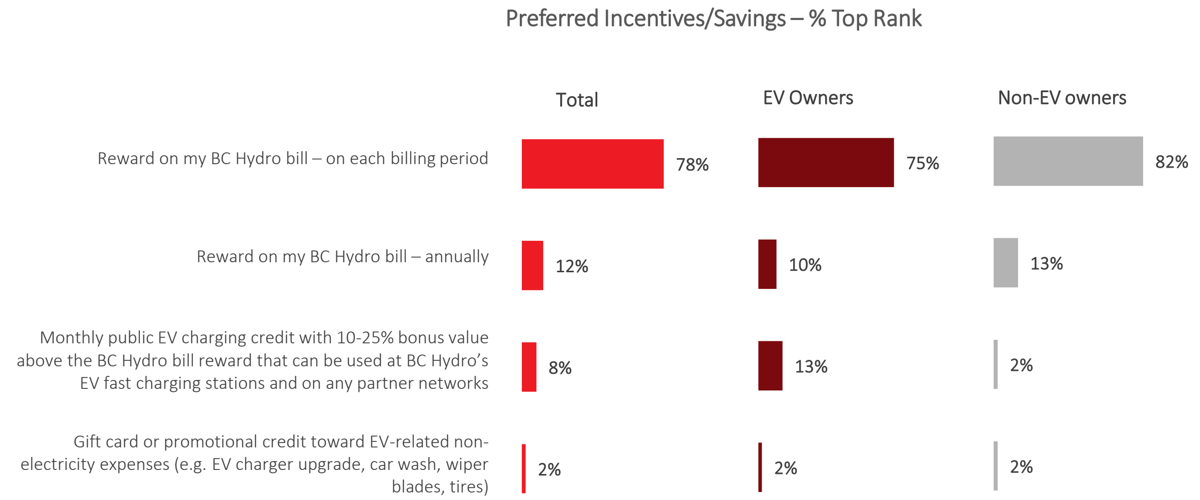
Q23B. Tell us why you selected (pipe in from above) and why that option would work for you. (Open-ended)
BASE: Those who are **likely** choose overnight shift during specific months (n=543), those who are **unlikely** choose overnight shift during specific months (n=213)

The preferred method to sign-up for an optional rate is to call BC Hydro



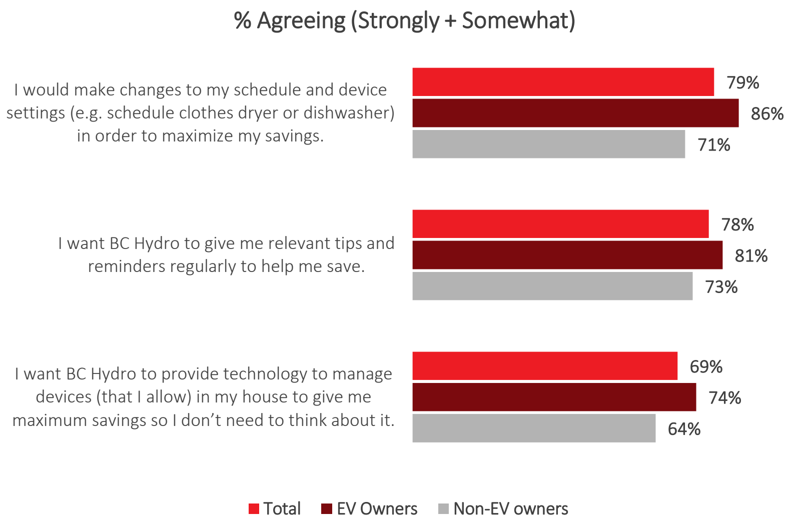
Q25. How would you prefer to sign-up for an optional rate?
BASE: Total sample (n=1009), EV owners (n=546), non-EV owners (n=463)

The ideal method to receive incentives when participating in a program is on a BC Hydro bill on each billing period



Q26. What is your preference of how you'd like to receive your incentive/savings when participating in a program? Please rank the following in order of preference from 1 to 4, where 1 is most preferred and 4 is least preferred.
BASE: Total sample (n=1009), EV owners (n=546), non-EV owners (n=463)

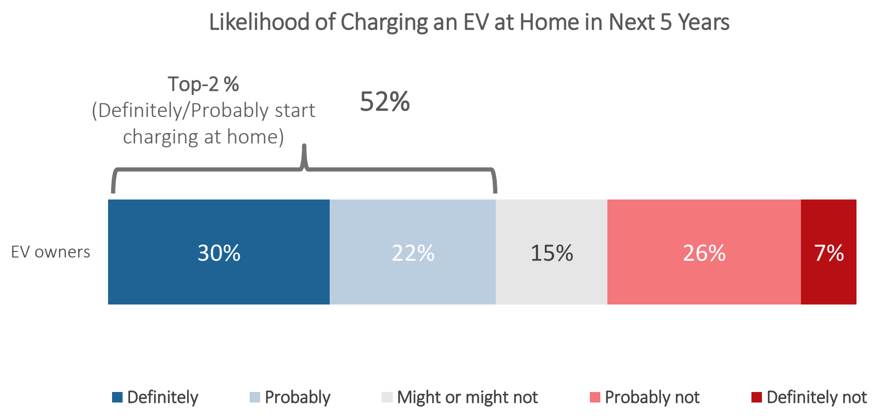
Agreement is strong among both groups on wanting relevant tips from BC Hydro and making changes to device schedule/settings to save



Q29. Taking advantage of an optional time-of-use rate may mean some day-to-day schedule changes for you, or changes to your appliance and equipment settings. Thinking about these, how much do you agree with each of the following statements?
BASE: Total sample (n=1009), EV owners (n=546), non-EV owners (n=463)


APPENDIX

Only 27 EV owners currently do not charge at home but half of them are likely to start within the next 5 years

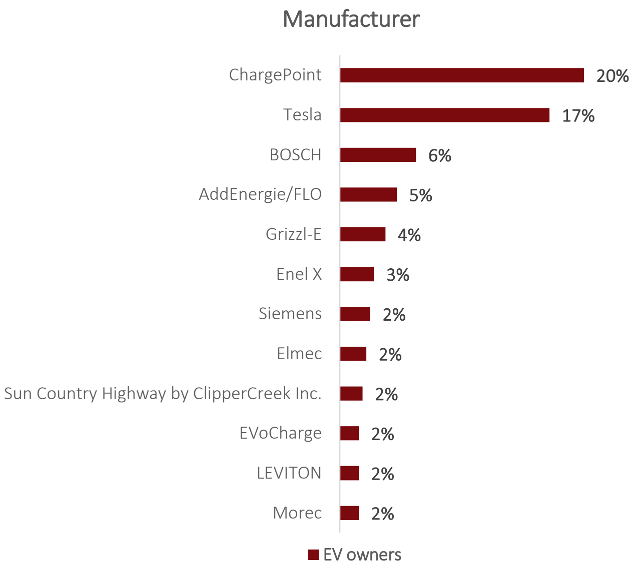


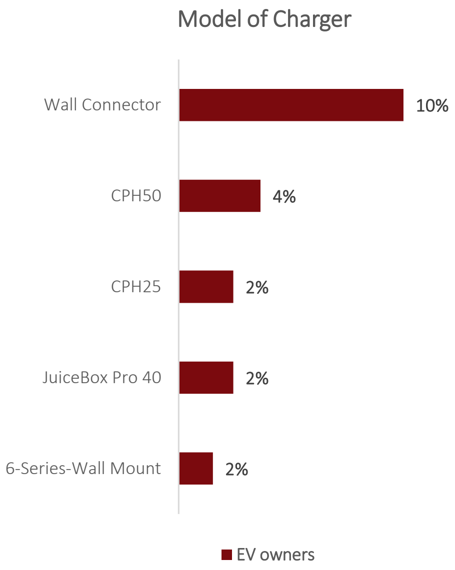
**Caution small sample size for EV owners who do not charge at home*

Q10. How likely are you to start charging an electric vehicle at home within the next 5 years?

BASE: EV owners who do not charge at home (n=27*)

ChargePoint and Tesla are the top models of chargers among EV owners



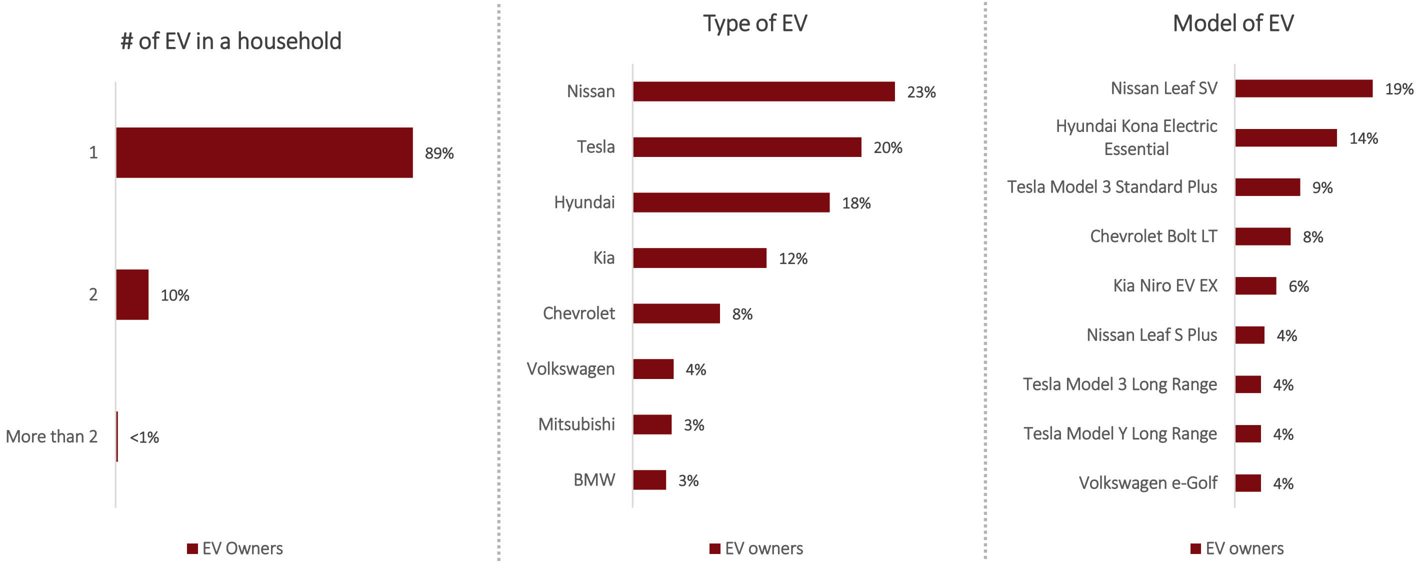


**Mentions less than 2% are not shown*

Q9. What's the make and model of your Level 2 charger?

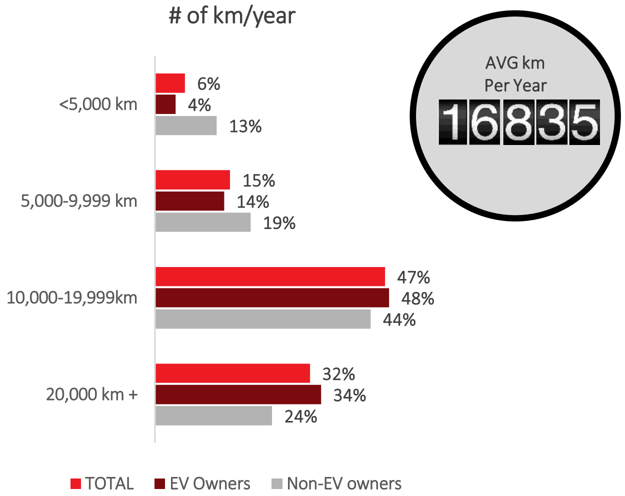
BASE: Those EV owners who own a level 2 EV charger (n=328)

Most EV owners have only one EV per household--Nissan, Tesla and Hyundai are the most popular models among them



Q2. How many EVs (plug-in electric or plug-in hybrid) does your household have? BASE: EV owners (n=546)
Q3. What type of EV do you drive? BASE: It includes types/models for all the vehicles EV drivers own, EV owners (n=604)

On average, both EV owners and non-EV owners drive nearly 17,000 km per year

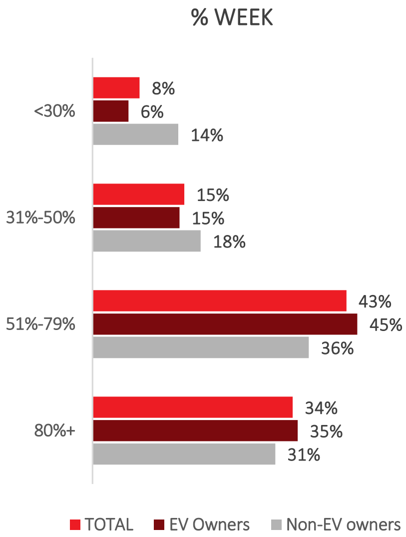


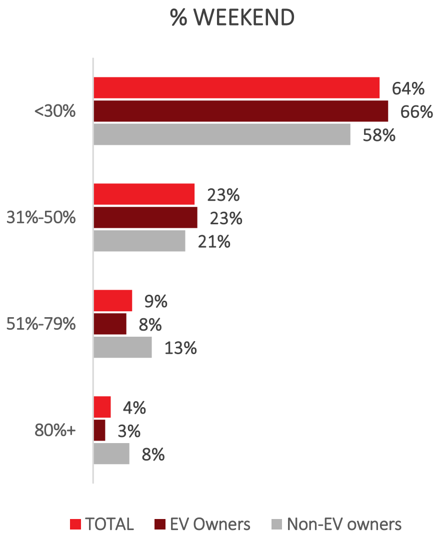
Q5. As best as you can estimate, how far do you drive in a year (in kilometres)? (Open-numeric)

BASE: Those who plan to purchase an EV within the next 5 years or those who have an EV. Total sample (n=705), EV owners (n=546), non-EV owners (n=159)

*Based on the final frequencies, open-numeric responses were combined into the following ranges to make it easier to interpret data: <5000km, 5000-9999km, 10000-19999km, 20000km+. In addition, based on all the open-numeric answers the average mean score was calculated.

The majority of drivers are on the road mostly during the week than on weekends

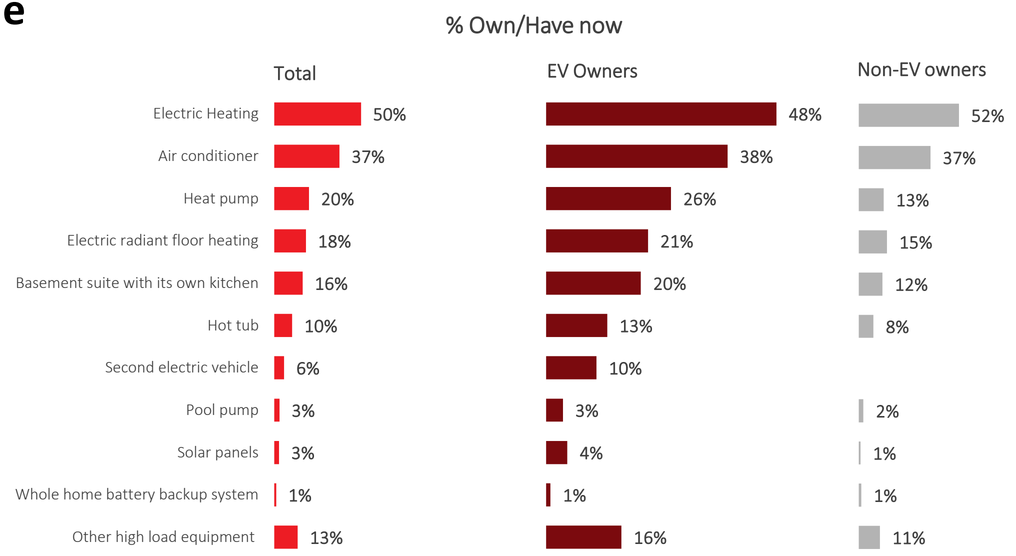




Q5a. Thinking about how much you drive in an average week, how much is that during the week vs. on the weekends? (Open-ended)

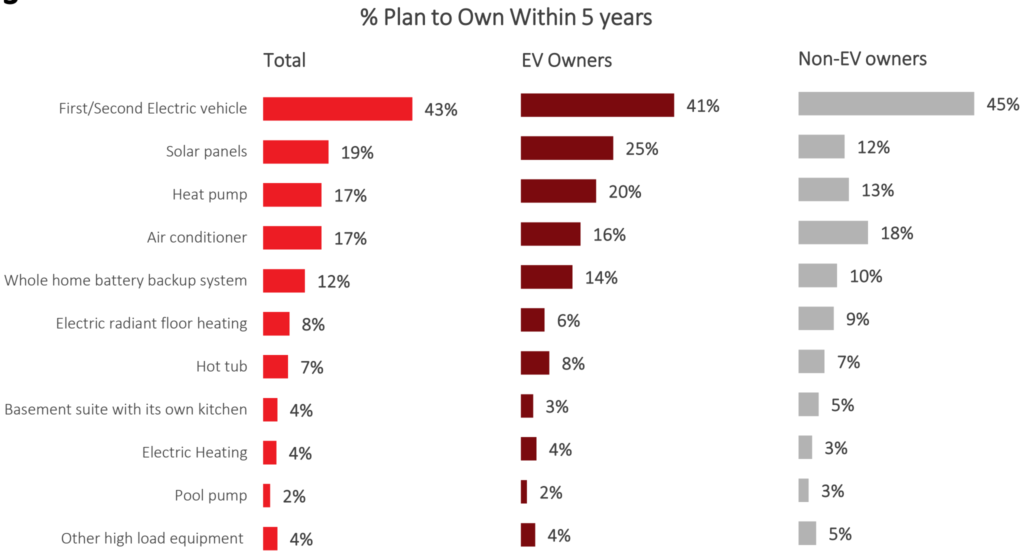
BASE: Those who plan to purchase an EV within the next 5 years or those who have an EV. Total sample (n=705), EV owners (n=546), non-EV owners (n=159)

EVs, electric heating and air conditioners are the top-3 items that both EV drivers and non-EV owners currently have at home



Q27. An optional time-of-use rate could have an impact on your electricity costs (either lower or higher) based on how you use electricity, the number of devices in your home that require a lot of electricity and when you use those devices. Which of these do you have in your home, or plan to have in your home within the next 5 years?
BASE: Total sample (n=1009), EV owners (n=546), non-EV owners (n=463)

A first or second EV, and solar panels are the top items that both EV drivers and non-EV owners are planning to have within the next 5 years



Q27. An optional time-of-use rate could have an impact on your electricity costs (either lower or higher) based on how you use electricity, the number of devices in your home that require a lot of electricity and when you use those devices. Which of these do you have in your home, or plan to have in your home within the next 5 years?
BASE: Total sample (n=1009), EV owners (n=546), non-EV owners (n=463)

Leger

RESPONDENT PROFILE (Total sample)

Gender

Male	Female
58%	38%

**4% prefer not to say*

Age

19-34	35-54	55+
12%	41%	45%

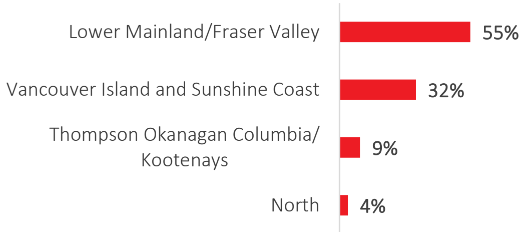
**2% prefer not to say*

Type of home

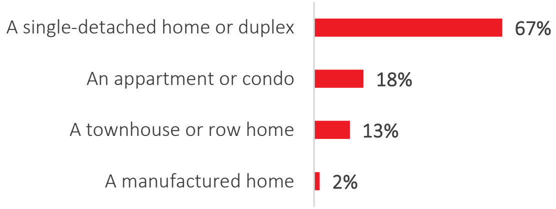
Own	Rent
85%	13%

**2% prefer not to say*

Region



Type of home



Strata/Non-strata

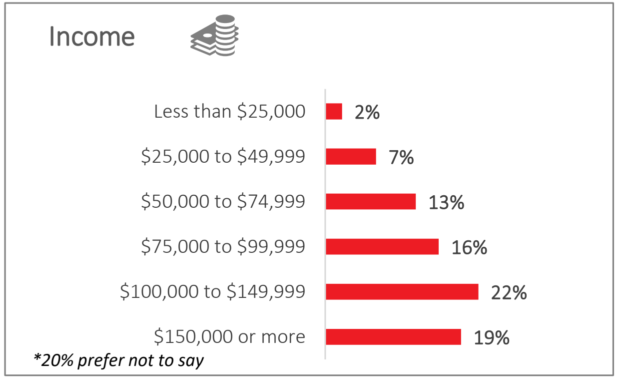
Among those who own an apartment/condo or a townhouse/row home

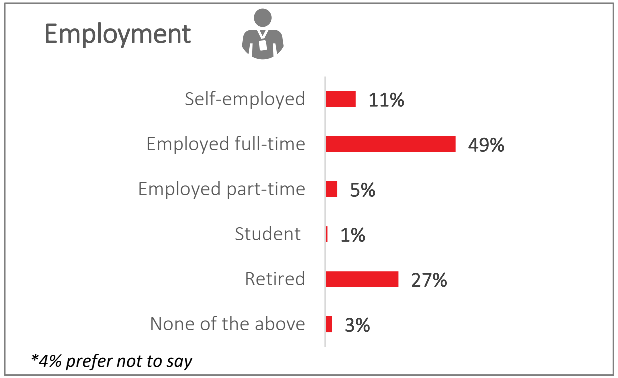
Strata Complex	Non-strata Complex
80%	14%

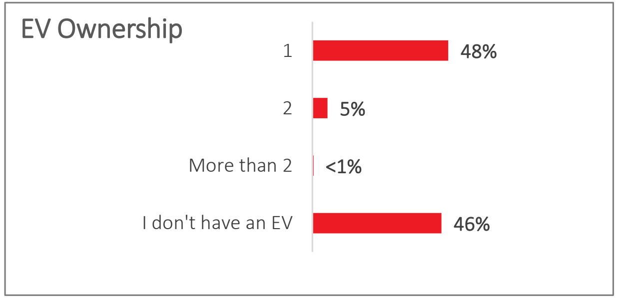
**5% don't know*

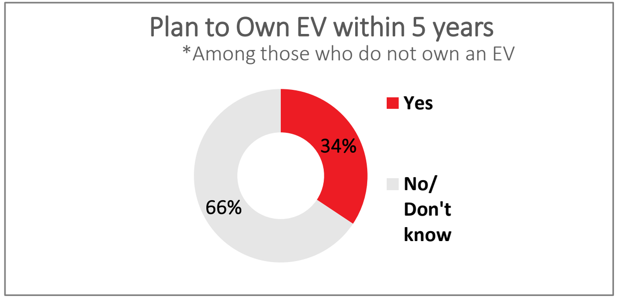
49

RESPONDENT PROFILE (Total sample)










QUESTIONNAIRE

Questionnaire

Introduction:

[For EV Network list]

Thanks for taking part in our EV time-of-use charging survey. By completing the survey by October 28, 2021, you'll be entered in a draw for a chance to win one of five $75 Amazon gift cards.

Electric vehicles are becoming more popular because the government has set a goal that 100% of all new light-duty (passenger) vehicles sold in B.C. will be electric by 2035.

At BC Hydro, we're ready to support the increased charging needs of our customers for the next several years, but expect that within the next 5-10 years, charging will need to shift to "off-peak" periods of high demand on our system to help manage the demand on the grid, and we need to get ready now.

We're exploring optional EV charging rates and programs focused on EV owners that have a Level 2 EV charger (220-240 volts) installed in their home. This is due to this type of charger having a higher demand for power, compared to a Level 1 charger that uses a standard 120 volt wall socket and doesn't draw much more power than a microwave. The cost to buy and install a Level 2 charger is estimated at $750-$3,000 depending on whether upgrades are required to your electrical service equipment, with rebates available from CleanBC.

BC Hydro is collecting feedback in accordance with the Freedom of Information and Protection of Privacy Act Section 26(c). Your feedback will help us or provide us with insights to inform future optional rate designs. All responses are submitted in confidence and treated accordingly. If you have questions about why your information is being collected, please contact evsupport@bchydro.com.

[For general customer list]

We're exploring new rate options for our residential customers. One of the options we're considering is an optional time-of-use rate. This means during different periods of the day, rates for using electricity will vary. The variation in rates will coincide with periods of higher and lower demand for electricity on our system.

Through this survey, we're looking for your feedback on this rate option.

By completing the survey by October 28, 2021, you'll be entered to win one of five $75 Amazon gift cards.

[NTD: Sent to 5,000 EV network members & customer list of 4,000]

Section 1 - Getting to know you a bit better:

1. Which of these B.C. Regions do you live in? (select one)
   a) Lower Mainland/Fraser Valley (Vancouver to Hope, including Whistler and Squamish)

Residential Rates Engagement Phase 2
TOU Specific Survey Questions

   b) Vancouver Island, the Sunshine Coast (including Powell River) or the Gulf Islands
   c) Thompson Okanagan Columbia/Kootenays
   d) North (100 Mile House, Williams Lake, Prince George and north)
   e) Prefer not to answer [TERMINATE]
   f) Outside of BC [TERMINATE] "Thanks for your interest in our survey, but it's for BC Hydro customers who reside in B.C. You will now exit the survey."

2. How many EVs (plug-in electric or plug-in hybrid) does your household have? (select one)
   a) 1 [GO TO Q3]
   b) 2 [GO TO Q3]
   c) More than 2 [GO TO Q3]
   d) I don't have an electric vehicle [GO TO Q4]

3. What type of EV do you drive?
   Make: ____________
   Model: ____________
   Year: ____________

   If Q2 = D ask Q4

4. Do you plan to purchase an electric vehicle within the next 5 years? (select one)
   Yes (skip to Q5, 5a and 11)
   No (ask Q4B)
   Don't know (ask Q4B)

   B) We have some questions about optional time-of use-rates. Are you interested in continuing the survey to answer those? (select one)
   Yes (skip to Q12)
   No (terminate)

   [BASE: ASK Q5 if Q4=Yes OR Q2=A THRU C]

5. As best as you can estimate, how far do you drive in a year (in kilometres)? Open-end

[BASE: ASK Q5a if Q4=Yes OR Q2=A THRU C]

5a. Thinking about how much you drive in an average week, how much is that during the week vs. on the weekends? Please provide a percentage breakdown that totals 100%.

- Weekdays (Monday to Friday)? ______%
- Weekends (Saturday and Sunday)? _____ %

Leger

Questionnaire

[BASE ASK Q6 if Q2=A THRU C]

6. Using your best estimate, how often do you charge your electric vehicle at the following locations? Please provide a percentage breakdown that totals 100%.

a. Home ____%
b. Work ____%
c. Public charging stations ____ %

If Q6a = more than 0% ask Q7

7. What level is the EV charger you have at home? (select one)
   a. Level 1 – regular wall socket (120V)
   b. Level 2 – EV charger (220-240V)
   c. Don't know

If Q7 = b ask Q8

8. Is your charger… (select one)
   a. Networked (internet connected)
   b. Non-networked
   c. Don't know

Ask if Q7 = b

9. What's the make and model of your Level 2 charger?
   Make ____
   Model_ ___

If Q6a = 0%

10. How likely are you to start charging an electric vehicle at home within the next 5 years? (select one)
    a. Definitely
    b. Probably
    c. Might or might not
    d. Probably not
    e. Definitely not

If Q10 = a and b OR if Q4=YES

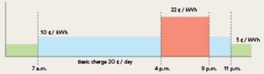
11. What level charging are you most likely to use at home? (select one)
    a. Level 1 – uses a regular wall socket (120V) – can charge approximately 8km of range per hour of charging
    b. Level 2 – uses an EV charger (requires a 220-240V socket, like your clothes dryer) – can charge approximately 30km of range per hour of charging
    c. Don't know

Residential Rates Engagement Phase 2
TOU Specific Survey Questions

Scenario A –

Whole Home Time of Use rate

This enables customers to take advantage of a lower rate at times when there's lower demand for electricity. For example, this option would charge customers a lower rate for running their appliances (e.g. dishwasher, clothes dryer.) later in the evening, or charging an electric vehicle overnight. The lowest rate would be applicable from 11 p.m. to 7 a.m. and the highest rate would be applicable from 4 p.m. to 9 p.m.



15. Thinking about your household's annual electricity costs, would the following additional amount of savings encourage you to shift the use of high energy consuming appliances (e.g. dishwasher or clothes dryer) to the lower price period?

a. $0 additional savings needed, using energy when most efficient is the right thing to do
   Yes [Go to Q16]
   No [Go to b]

   [Programmer notes: For the rest of follow-ups repeat the same question] Would the following additional amount of savings encourage you to shift the use of high energy consuming appliances to the lower price period?
b. $20 / year
   - Yes [Go to Q16]
   - No [Go to c]
c. $30 / year
   - Yes [Go to Q16]
   - No [Go to d]
d. $40 / year
   - Yes [Go to Q16]
   - No [Go to Q15a]

Ask 15a if 15d is no

15a. What amount of additional savings would encourage you to shift the use of high energy consuming appliances (e.g. dishwasher or clothes dryer) to the lower price period?
Open-end

Scenario B -

Leger

Questionnaire

Electric Vehicle Time of Use rate	The Electric Vehicle Time of Use Rate (EV–TOU), encourages charging during a lower priced period between 11 p.m. and 7 a.m. and has a higher energy rate between 7 a.m. and 11 p.m. To participate in the EV–TOU rate, a separate BC Hydro meter must be installed, however it's anticipated that Measurement Canada will soon certify specific networked Level 2–EV chargers to enable the chargers to be used as an approved metering device to apply EV–TOU pricing to the EV charging load. When planning for the installation of a networked or non–networked Level 2 charger, a certified electrical contractor can advise you whether a service upgrade is needed. In addition to the cost for the charger, upgrades to customer service equipment can range from $2,000 – $3,000 or more, depending on the existing service configuration. When planning this work, it can also be determined if the installation of a second BC Hydro meter can be accommodated.

16.

Calculating home charging electricity costs:

Average annual mileage = 15,000 km

Mileage rating = 0.2 kWh / km

Electricity rate (step2) = $0.14 / kWh

Average annual mileage		Mileage rating		Average annual energy consumption for charging
15,000 km	×	0.2 kWh / km	=	3,000 kWh / year

If we assume that most of the charging will be on the Step 2 rate and that 80% of the charging will occur at home, your home charging electricity costs could be 3,000 kWh/yr x 0.8 x $0.14 = **$336** per year

When using the above example to think about your electricity bill and how much you currently spend on EV charging at home, if you can charge your vehicle during the overnight period, you could reduce your electricity costs by opting in to this time-of-use rate.

Would the following amount of **annual** savings on your household's electricity costs encourage you to participate in this time-of-use rate?

a. $0 savings needed, using energy when most efficient is the right thing to do.
   - Yes – Go to Q17
   - No – Go to b

   [Programmer notes: For the rest of follow-ups repeat the same question "Would the following amount of annual savings on your household's electricity costs encourage you to participate in this time-of-use rate?"]

Residential Rates Engagement Phase 2
TOU Specific Survey Questions

b. $20 / year
   - Yes – Go to Q17
   - No – Go to c

c. $30 / year
   - Yes- Go to Q17
   - No- Go to d

d. $40 / year
   - Yes – Go to Q17
   - No – Go to Q16a

Ask 16a if 16d is no
16a. What amount of **annual** savings on your household's electricity costs would you need to see for you to participate in this time-of-use rate?
Open-end

Scenario C –

Utility Managed Electric Vehicle charging	Customers install a compatible networked–Level 2 charger* at home and can participate in a program with an annual incentive of ~$30 that allows BC Hydro to manage your EV's charging on around 20 days a year. You plug it in, but BC Hydro would determine when to start charging it. The start time of charging would be the optimal time for the electrical system in your local area. This helps better manage the electricity demand from EVs across B.C. and can help to defer costly upgrades to the system. Your EV would be charged by the time you need it the next day. You may choose to opt out of this charging option at any time and always have full override control of the EV charger. *The cost difference between a non–networked and networked–Level 2 charger is around $300–$450.

Ask only if Q8 = B (non-networked participants)

17. In order to participate in **Scenario C** (**Utility managed EV charging**), a Level 2-networked EV charger must be installed in your home. In the future, a Level 2-networked EV charger may also enable participation in Scenario B (EV time-of-use-rate) without the need for a second BC Hydro meter. How likely are you to participate in either scenario (B or C): (select one)
    a. Definitely
    b. Probably
    c. Might or might not
    d. Probably not
    e. Definitely not

If Q17 = b, c, d, e ask Q17B
17B. How likely would you be to install a Level 2-networked or internet-enabled charger in your home if you received an additional $200 incentive to help cover the costs of the charger? (select one)

Questionnaire

b. Definitely
c. Probably
d. Might or might not
e. Probably not
f. Definitely not

ASK ALL

Section 3: Looking closer at the scenario(s) you prefer

Scenario A - Whole home time-of-use rate: This enables customers to take advantage of a lower rate at times when there is lower demand for electricity. For example, this option would charge customers a lower rate for running their appliances (e.g. dishwasher or clothes dryer later in the evening or charging an EV overnight). The lowest rate would be applicable from 11 p.m. - 7 a.m. and the highest rate would be applicable from 4 p.m. – 9 p.m.

Scenario B - EV time-of-use rate: When planning to install a networked or non-networked Level 2 charger, a certified electrical contractor can advise you whether a service upgrade is needed. In addition to the cost for the charger, upgrades to customer service equipment can range from $2,000 - $3,000 or more, depending on the existing service configuration.

When planning this work, it can also be determined if the installation of a second BC Hydro meter can be accommodated. The second BC Hydro meter can track the at-home EV charging during periods of lower electricity demand to help reduce associated charging costs. This would include a lower rate for 8 hours a day between 11 p.m. and 7 a.m. but would have a higher rate between 7 a.m. and 11 p.m.

Scenario C – Utility-managed EV charging: Customers install a compatible networked-Level 2* charger at home and can participate in a program with an annual incentive of ~$30 that allows BC Hydro to manage your EV's charging on around 20 days a year. You plug it in, but BC Hydro would determine when to start charging it. The start time of charging would be the optimal time for the electrical system in your local area. This helps better manage the electricity demand from EVs across B.C. and can help to defer costly upgrades to the system. Your EV would be charged by the time you need it the next day. You may choose to opt out of this charging option at any time and always have full override control of the EV charger.
*The cost difference between a non-networked and networked-Level 2 charger is around $300-$450.

18. Which of the following options best suits your lifestyle? (select one) (randomize)
    a) Whole home time-of-use rate

Residential Rates Engagement Phase 2
TOU Specific Survey Questions

    b) EV time-of-use rate
    c) Utility-managed EV charging
    d) None of the above

19. Tell us why you selected (pipe in from above) and why that option would work for you. (open-end)

20. Thinking back to the time of use rate scenarios discussed earlier (whole home, EV end-use), an optional time-of-use rate may be offered only during the winter months (November to February), weekdays during the winter months, or year-round. Limiting the application of time-of-use rates for the winter peak period only will maintain flexibility for our customers and encourage load shifting when the system needs it the most. If an optional time-of-use rate was limited to the winter months, as an example, you'd go back to the default residential rate for the balance of the year.

    Which of the following options for time-of-use rates would you be interested in signing up for:

    a. Year-round
    b. Winter only (including weekends)
    c. Winter weekdays only
    d. Need more information (specify)
    e. None of the above

21. Tell us why you selected (pipe in from above) and why that option would work for you. (open-end)

22. If the time-of-use rate was only offered during a select number of months (e.g. during the winter) and you'd be shifting your electricity use to overnight periods, how likely would you be to continue shifting electricity use to overnight periods during the months when there isn't a time-of-use rate offered? (select one)
    a. Definitely
    b. Probably
    c. Might or might not
    d. Probably not
    e. Definitely not

23. Tell us why you selected (pipe in from above) and why that option would work for you. (open-end)

Section 4: Participation in an optional rate or program

24. How would you prefer to sign-up for an optional rate? (select one) (randomize)
    a. By calling BC Hydro and talking to a customer service representative
    b. Online through my MyHydro account
    c. Mobile phone through my MyHydro account

Questionnaire

d. Don't know

25. What is your preference of how you'd like to receive your incentive/savings when participating in a program? Please rank the following in order of preference from 1 to 4, where 1 is most preferred and 4 is least preferred. [randomize order]
    a. Reward on my BC Hydro bill – on each billing period
    b. Reward on my BC Hydro bill – annually
    c. Monthly public EV charging credit with 10-25% bonus value above the BC Hydro bill reward that can be used at BC Hydro's EV fast charging stations and on any partner networks, including FLO and ChargePoint)
    d. Gift card or promotional credit toward EV-related non-electricity expenses (e.g. EV charger upgrade, car wash, wiper blades, tires)

26. An optional time-of-use rate could have an impact on your electricity costs (either lower or higher) based on how you use electricity, the number of devices in your home that require a lot of electricity and when you use those devices. Which of these do you have in your home, or plan to have in your home within the next 5 years?
    Select all that apply. [randomize list]
    [GRID] Have now / plan to have within next 5 years/NA/Not applicable
    a. Heat pump
    b. Hot tub
    c. Basement suite with its own kitchen
    d. Electric vehicle
    e. Second electric vehicle
    f. Electric Heating
    g. Pool pump
    h. Electric radiant floor heating
    i. Solar panels
    j. Air conditioner
    k. Whole home battery backup system (e.g. Powerwall)
    l. Other high load equipment

27. Taking advantage of an optional time-of-use rate may mean some day-to-day schedule changes for you, or changes to your appliance and equipment settings. Thinking about these, how much do you agree with each of the following statements?
    a. I want BC Hydro to give me relevant tips and reminders regularly to help me save.
    b. I would make changes to my schedule and device settings (e.g. schedule clothes dryer or dishwasher) in order to maximize my savings.
    c. I want BC Hydro to provide technology to manage devices (that I allow) in my house to give me maximum savings so I don't need to think about it.
        a) Strongly Agree
        b) Somewhat Agree
        c) Neither
        d) Somewhat Disagree
        e) Strongly Disagree

Residential Rates Engagement Phase 2
TOU Specific Survey Questions

Thank you for your responses so far. We have just a few more questions to go for classification purposes.

DEMOGRAPHICS

D1. Which of the following age groups do you fall under?

1. 19 to 24
2. 25 to 34
3. 35 to 44
4. 45 to 54
5. 55 to 64
6. 65 to 74
7. 75+
99. Prefer not to answer

D2. Which of the following do you identify as?

1. Male
2. Female
95. Other
99. Prefer not to say

D3. What type of housing do you primarily reside in?

1. An apartment or condo building [GO TO D3A]
2. A townhouse or row home [GO TO D3A]
3. A single-detached home or duplex
4. A manufactured home (i.e., mobile home or modular home)
5. Other, please specify:

D3A. Are you in a strata or non-strata complex?

1. Strata complex
2. Non-strata complex
3. Don't know

D4. Do you currently rent or own your home?

1. Own
2. Rent
99. Prefer not to answer

D5. Which of the following best describes your employment status?

1. Self employed
2. Employed full-time

Questionnaire

3. Employed part-time
4. Student
5. Retired
6. Other employment arrangement (please specify)
7. None of the above (e.g. seeking work, homemaker, on sabbatical, etc.)

99. Prefer not to answer

D6. Which of the following categories best describes your total household income before taxes?

1. Less than $25,000
2. $25,000 - $49,999
3. $50,000 - $74,999
4. $75,000 - $99,999
5. $100,000 - $149,999
6. $150,000 or more

98. Don't know
99. Prefer not to answer

D7. Finally, would you like to enter the contest for a chance to win 1 of 5 $75 gift cards to [$XX fast charging credit for EV members list / $XX gift card for general pop list]?

1. Yes (Go to D8)
2. No (GO TO END)

D8. Please provide the following contact details to enter the contest.

Contest Terms (please attach pdf)

Your personal information will be handled in accordance with the BC Freedom of Information and Protection of Privacy Act and will be used solely as a means of contacting you should you win the draw.

First name:
Last name:
Email address:
Phone number:

D9. In order to improve our surveys in the future, please rate on a 5-point scale how satisfied you are with the survey you filled out today?

1. Very satisfied
2. Somewhat satisfied
3. Neither satisfied nor dissatisfied
4. Somewhat dissatisfied
5. Very dissatisfied

CLOSE SURVEY _ REDIRECT TO https://electricvehicles.bchydro.com/

BC Hydro
Power smart

BC Hydro Optional Residential
Time-of-Use Rate Application

Appendix D-7F

Summary Report – Public Survey No. 2 by BC Hydro
November 2021

Summary Report – Public Survey No. 2 by BC Hydro
November 2021

1 Background

- During the Residential Rate Redesign customer and stakeholder engagement process, a number of engagements (surveys, workshops, etc.) were conducted by BC Hydro, including polls open to the general public via BC Hydro's website.
- This summary presents the key findings from the second open poll, which was held during the autumn of 2021.

2 Sample Profile

- The second public poll was active from October 29 to December 1, 2021. The survey was offered by BC Hydro as a link on www.bchydro.com using survey software managed by BC Hydro.
- Unlike traditional surveys where respondents are contacted using a randomized list from the customer database and responses are managed to reflect a representative sample, an open poll is provided for any interested respondents to proactively provide feedback. Therefore, the results of the poll reflect a non-representative sample and should not be interpreted to necessarily reflect the opinions of the general Residential customer base.
- As respondents were not required to identify themselves through logging into their BC Hydro account or any of the poll questions, the sample may include Residential account holders, residents in account holder homes, and those living in non-BC Hydro service areas. Although the survey content was specifically related to Residential customers in Zone 1 areas, it did not preclude other types of BC Hydro customers from participating.

Page 1 of 7

3 Respondent Profile

- A total of 5,935 respondents participated in the poll. However, not all respondents fully completed the survey, resulting in some variation in sample size depending on the question.
- The sample is biased compared to the general residential base in several respects:
  - ▶ Dwelling type: 67% of respondents live in detached homes, compared to 50% in the overall residential base. Respondents in the apartment/condo category comprise only 14% in the poll compared to 29% in the overall base; and
  - ▶ Region: 41% live in the Vancouver Island/Gulf Islands/Sunshine Coast, which is double the proportion in the overall base. The Lower Mainland/Fraser Valley/South Coast region comprises only 40% of respondent, compared to 59% in the general base.
- The majority of respondents fell into the older demographic. In aggregate, 61% were 55 years or older, whereas for the overall base this is 50%.
- There was a broad range of respondents in terms of household income. 28% fell under $60,000, 34% were between $60,000 and under $120,000, and 21% were $120,000 or above. 17% preferred not to say. Compared to the overall base, this is somewhat skewed to the middle- and higher-income levels.

4 Key Findings

The poll asked respondents to consider the current stepped rate on four aspects, and then asked about those same four aspects with respect to a potential flat rate. Brief descriptions and visualizations were provided before asking about the respective rates.

Page 2 of 7

How strongly do you agree or disagree the [current stepped / flat] rate structure meets the following criteria? (shown separately)

	Stepped rate (% Somewhat/strongly agree)	**Flat rate (% Somewhat/strongly agree)**
Keeps rates affordable	41	38
Is easy to understand	66	83
Is fair for all customers	36	41
Encourages the use of clean hydroelectricity over other types of fuels	27	31

5 Commentary

- The highest Agreement level in general came on the criteria relating to the rate being easy to understand. This was in reference to the brief conceptual descriptions provided, but the answer for Stepped Rate may be influenced by other aspects drawing from actual experience with it as customers, e.g., how it actually works, why it exists, etc. (as reflected in the open end comments).
- For the affordability criteria, the level of agreement was more of split, with more respondents disagreeing than agreeing. This resulted in total agreement at a moderate level. This pattern occurred for both Stepped (41%) and Flat (38%) rate.
- The fairness criteria responses reflected the pattern for affordability. In other words, the agreement levels were modest on both Stepped (36%) and Flat (41%) because there were more who disagreed than agreed that these rates are fair for all customers.
- The criteria relating to the rate encouraging use of hydroelectricity saw the lowest levels of agreement and higher levels of disagreements, with a bigger gap on the Stepped rate (net agreement of minus 23%) compared to the Flat rate (net agreement of minus 7%).

Page 3 of 7

Respondents reviewed brief descriptions and visualizations of two potential voluntary rates, whole-home time-of-use (reflecting peak, off-peak, and overnight periods) and electric vehicle time-of-use (based on an overnight rate via a separate meter).

What is your interest in this voluntary option? (shown separately)

	Whole-home (%)	Electric vehicle charging (%)
I'm interested	42	29
I may be interested in the future	26	38
I'm not interested	32	34

6 Commentary

- Stated interest in the whole home time-of-use option was moderate, but when combined with the possibly interested category, totalled 68%. However, as reflected in some of the open-ended comments, respondents expressed the desire for more details on how it would work. There is also the concern about how punitive this rate might be for those who cannot shift usage to the favourable periods.
- Stated interest in EV time-of-use was lower than for whole home, but if combined with the possibly interested category, the total interest level is reflected in two-thirds of the sample (67%). Based on the comments, those interested in this option recognize the benefits for charging their EVs or future EVs. It should be noted that in the description, separate metering was mentioned, but no details were provided.

7 Comment Themes

There were two main opportunities for respondents to provide open ended comments within the poll. One was for feedback on the rate topics presented (3,201 comments), and the other was on any other general feedback (1,415 comments).

The topics with the largest mentions were relating to rate types, energy sources, heating, and cost.

The respondents focused on stepped rate, and to a lesser extent flat rate. Some respondents expressed support for the current stepped rate. Comments reflected living in smaller home, lower consumption/ability to conserve electricity, and the usefulness in encouraging conservation. However, most respondents expressed negative comments, citing inability to avoid step 2, lack of choice to use alternative sources (e.g., natural gas not available), and having a larger household (e.g., families).

There was a mixed reaction to the flat rate concept. Some comments reflected a more positive impression of it as an alternative to stepped rate. However, others raised skepticism that it was a better alternative, citing impacts to lower income customers and the removal of incentive to conserve.

8 Sample verbatims from Public Survey No. 2

Topic	Verbatim
Fixed income	Affordability is a big issue for those on a fixed income. Consumption can only be reduced so far, heat can be turned down, lights can be turned off, etc., but when basic consumption still puts one into the more expensive step 2 rate, what more can be done? And then, as rates rise over the years, affordability becomes exacerbated.
Affordability	The current system punishes those who work from home, retired or who are disabled. We have to choose between a higher power bill (that those of us on a fixed income can not afford) or waiting around all day till we're supposed to be sleeping to use our power at a more reasonable cost.

Page 5 of 7

Topic	Verbatim
RIB is fair to low income customers	I believe that the current two-tier system is beneficial to low-income households.
RIB is unfair to those who electrify	The current rate system penalizes those of us with heat pumps and EV's, because there is no way to keep consumption in Tier 1, even though these are green assets. Also you (or the province) give incentives to purchase them, but then punishes their use. So either a flat rate or a system that encourages usage at non peak times is more fair.
RIB is unfair to customers who don't have another heating option	In a location where there is no other heating option except electricity which is the most expensive method of heat, maybe a more equitable delivery option should be implemented.
RIB encourages conservation	I like the 2-step system as it encourages people to use less power. However, for small users like us the Step 2 should not kick in so soon. We should stay at Step 1 longer. The difference from Step 1 to Step 2 is huge.
RIB is easy to understand	The current step-rate system works for us, simple to understand and rewards energy saving practices. To encourage good practices, continue to focus on consumer education and the use of technology to reduce peak demand.
Flat Rate would not encourage electrification	Please don't revert to a flat rate. That would punish those who made recent green renovations, such as a heat pump. Another step could also be a useful change to the rate structure, to further encourage green renovations. The option for lower rates for EVs is a great idea.
TOU doesn't work for condo dwellers	Using appliances at night in multi unit buildings in not an option as washers and dryers can not be operated in quiet times. Any shared electric car charging stations would also need to be used on a 24 hour basis so there would be no saving advantage.
TOU and seniors	I like the idea of having a lower rate at certain times. As a senior it would help me keep my hydro costs lower.
TOU is unfair to families	We are a family of four with young kids. We have to run clothes and dishwashers often and cannot really time shift those activities. So the expensive 16:00-22:00 would not be good for us.
TOU is not fair to people who WFH	Many people are still working from home so increasing the rate during the day doesn't seem fair, although a decreased rate overnight may be reasonable.
TOU is a good tool	I feel changing to a time of use format would promote energy conservation and permit BC Hydro to operate more efficiently, reducing the peaks in energy demand and giving customers a financial incentive to shift their energy usage to lower use times. Without such an incentive, many people would not change their energy consumption habits.
Previous TOU experience	I used "Whole-Time-of-Use" rate for electricity in Ontario and found it to be not only savings-focused for clients, it was 'conscious-oriented' as clients often used their electricity more wisely because they were incentivized to lower their electricity costs while giving tangible consideration to the environment regarding climate change.

Topic	Verbatim
TOU for EV owners	I would definitely subscribe to a time of use charge from my EV. Such a rate structure would encourage me to sell my wife's car and buy another EV. It would certainly encourage further purchases of EV's
TOU at odds with conservation	A concern for the voluntary whole home time-of-use rate is that this rate structure encourages large and noisy appliances to be run when most people are sleeping. More noise issues will occur in multi-unit homes. I can also see how this can lead to an increase in electricity usage overall because energy costs are cheaper overnight. This potentially goes against our goals to reduce energy use for a greener planet. Similar issue with the flat rate structure, without a step 2 rate, there will be less incentive to limit high energy usage.
TOU support electrification	I am happy to see that BC Hydro is considering an improved rate structure to account for the implementation of electric vehicles, heat pumps and electric furnaces, all of which we are going to need to transition to very soon to fight climate change.
Fairness	No one size fits all but it would be good to find the one method which would help meet the needs of keeping hydro as a clean energy fuel while maintaining a reasonable cost to homeowners. Giving homeowners a choice as to when they could access electricity at a lower rate by choices they personally make as to how and when they use electricity is a good model.

BC Hydro Optional Residential Time-of-Use Rate Application

Appendix D-7G

Options Survey by Sentis

sentis

Rate Design Survey: Phase II

REPORT

PREPARED FOR

BC Hydro Corporate and Market Research

BC Hydro

December 23, 2021

Suite 900-2025 Willingdon Avenue, Burnaby, BC V5C 0J3
thesentisgroup.com

Adam DiPaula | adipaula@sentisresearch.com
Stephanie Yuen | syuen@sentisresearch.com
Mun Chan | mchan@sentisresearch.com

sentis

CONTENTS

sentis

Objectives & Approach

sentis

BACKGROUND & OBJECTIVES

As part of its process of re-evaluating how electricity rates are structured, BC Hydro is gathering feedback from residential customers in three phases:

Phase 1: Understanding Needs

- Understand how residents currently use and manage home electricity
- Gauge resident priorities when it comes to the cost of electricity
- Collect preferences for possible future rate structures

Phase 2: Gathering Input on Possible Approaches

- Develop potential options for future rate structures
- Measure appeal and gather feedback on possible approaches
- Measure how reactions to different rate structure options vary by usage segment

This report covers the findings from Phase 2.

Phase 3: Gathering Feedback on the Proposed Approach

- If BC Hydro decides on a new approach, residents will have an opportunity to provide final feedback on the proposal before it goes to the BC Utilities Commission

sentis

METHOD

Approach

1,346 BC Hydro customers surveyed
BC Hydro customers invited by email or phone (if no email address was on file)

All email invites deployed by BC Hydro, except for:
- The initial soft launch of 2,694 invites by Sentis
- Invites sent to interested customers who were contacted by phone

Those contacted by phone were encouraged to take the survey online.

Survey Dates: November 10 - December 2, 2021

Email reminders and phone follow-up calls were made to encourage participation

Survey Responses

Method	Completed Surveys	Response Rate
Total	**1,346**	**3%**
Email to Online	1,248	4%
Phone Recruit to Online	98	2% (26% once recruited)

Total results accurate to **±2.6%**
(19 times out of 20)

Results weighted by age & region to reflect BC Hydro's total residential customer base

sentis

METHOD

REPORTING NOTES

Respondents were classified into one of six Home & Heating segments based on similar home and heating characteristics, namely their home size (by square footage) and self-reported main home heating source (electricity or mixed – natural gas and/or electricity):

	Electricity			Mixed	
	E1	E2	E3	M1/M2	M3
Home Square Footage (sqft)	Under 1,000	1,000-2,500	2,501-4,000	Under 1,000 / 1,000-2,500	2,501-4,000
Home & Water Heating Source	Electric only			Natural Gas and/or Electric	
Estimated Usage (kWh/year)	3,120	8,200	15,300	2,500 / 6,800	12,900

Note: The M1 and M2 segments were combined for analysis purposes given that the information that they were shown regarding how their bill would change under the flat rate structure was highly similar. Also, their rate preferences are highly similar.

sentis

Highlights

KEY TAKEAWAYS

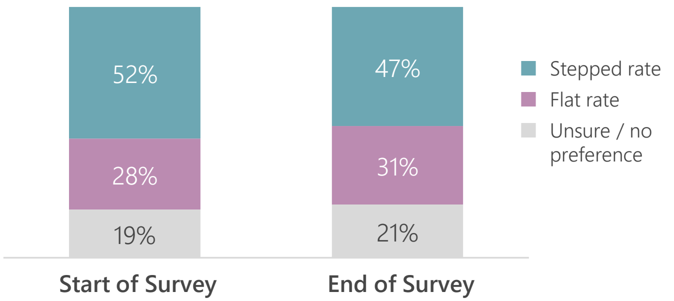
Customers place a high degree of importance on the predictability of their electricity costs. Of the 13 rate considerations presented, respondents ranked ensuring that **rates are stable and not subject to short-term market fluctuations** as the most important priority that BC Hydro should consider when designing electricity rates. Respondents draw a sharp distinction between bill predictability and bill stability – having electricity bills that are similar throughout the year was among the least important considerations.

Respondents ranked the consideration representing the stepped rate (customers are rewarded for conserving electricity) as the second most important priority that BC Hydro should consider when designing electricity rates. The consideration representing the flat rate (all customers are charged the same rate per kilowatt hour) was ranked eighth.

Consistent with their rate design priorities, respondents showed a clear – but not overwhelming – preference for the stepped rate. Earlier in the survey, 52% expressed a preference for the stepped rate, while 28% expressed a preference for the flat rate. Later in the survey – after being told that replacing their fossil fuel use electricity would increase their electricity spending but decrease their fossil fuel spending – the gap in preference narrowed somewhat, with 47% preferring the stepped rate and 31% preferring the flat rate.

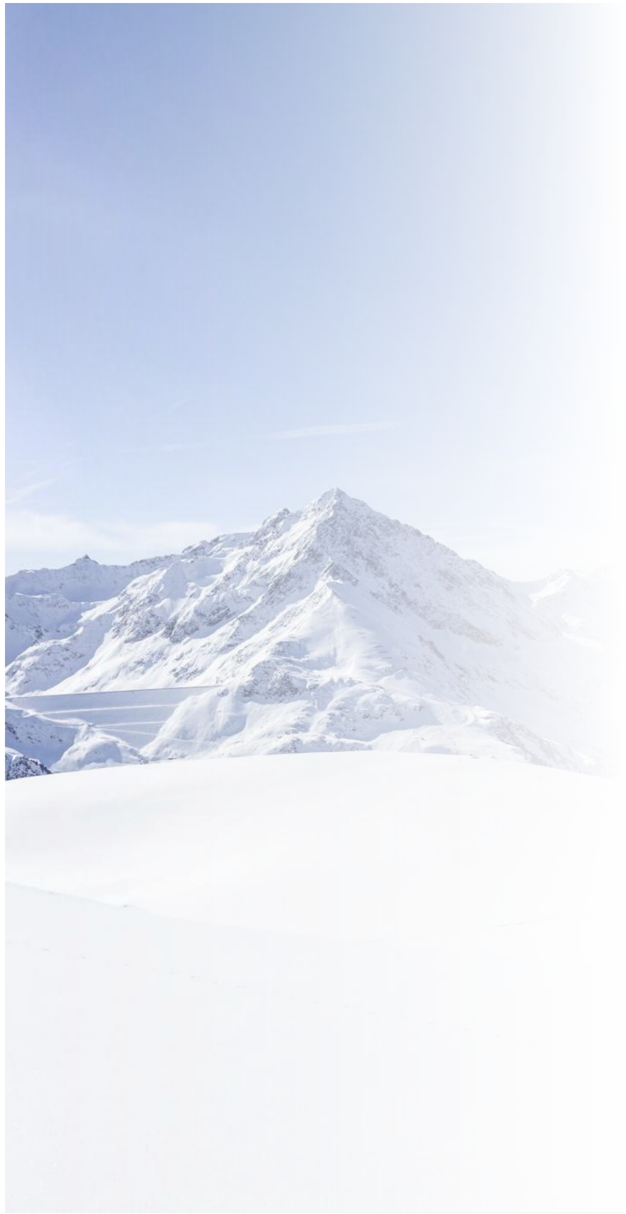
Rate Preference

Among all respondents (n=1,346)



Which rate is preferred is largely a function of how the flat rate will impact a customer's bill. Respondents who were presented with the largest bill increases under the flat rate showed the strongest preference for the stepped rate, while those who were presented with bill decreases showed the strongest preference for the flat rate. Consistent with this, saving money was among the most common reasons given for why one rate is preferred over the other.

However, the cost implications of the flat rate are not the only factor driving rate preferences. The other common reasons given for rate preferences indicate that those who prefer the stepped rate versus those who prefer the flat rate have different energy use mindsets. Those who prefer the stepped rate have a reduction mindset – the most common reason they give for preferring the stepped rate is that it encourages energy conservation. Those who prefer the flat rate have a shift mindset. Among the most common reasons they give for preferring the flat rate is that it encourages customers to switch their energy use from fossil fuels to electricity.



KEY TAKEAWAYS

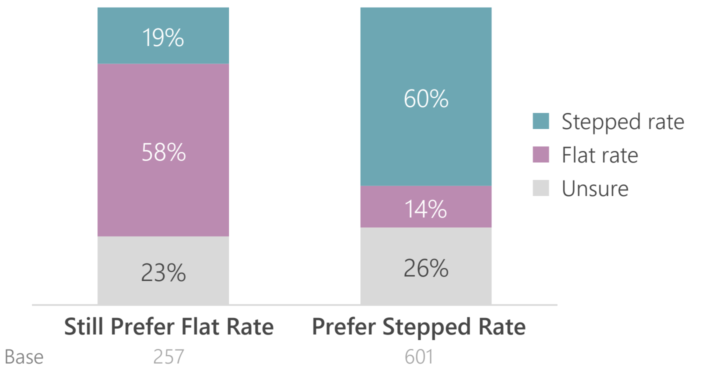
The shift mindset is key to increasing acceptance of the flat rate. This is illustrated by taking a closer look at those who prefer the flat rate even though their bills will likely be higher. Specifically, two-in-ten (19%) indicated a preference for the flat even though the bill amount they were shown for the flat rate was higher than the bill amount they were shown for the stepped rate.

Those presented with a higher bill under the flat rate

Reason for rate preference (Base)	Still Prefer Flat Rate	Prefer Stepped Rate
(Base)	257	601
Encourages switch from fossil fuels	20%	2%
Encourages energy conservation / reduce wasteful usage	5%	40%
Save money / lower bills / cheaper	15%	35%
Use a lot of electricity	19%	<1%
Fairer / Everyone pays the same rate	13%	<1%
Bills more predictable / stable	13%	<1%

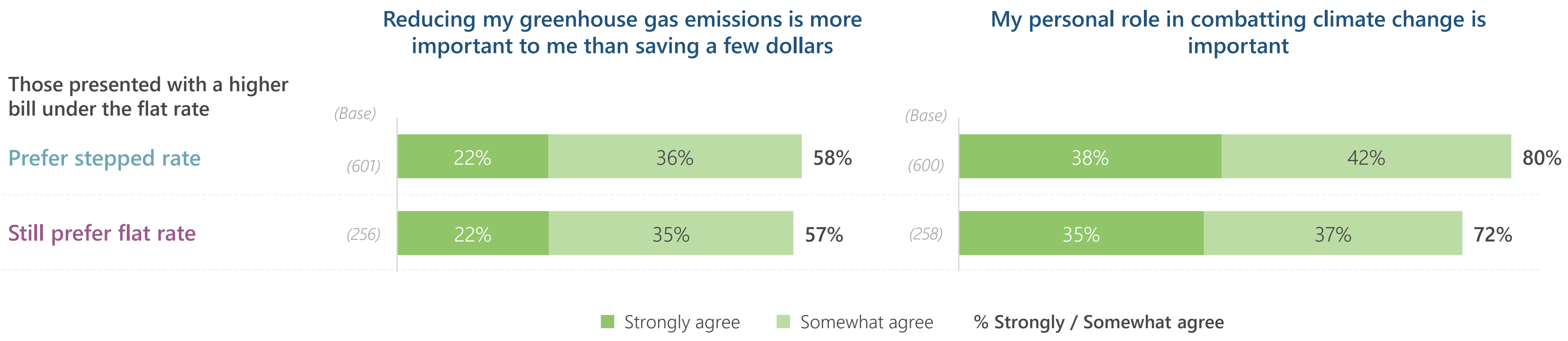
These results show that those who prefer the flat rate (even though they'll pay more) understand the benefits of electrification. They see the connection between moving a greater share of their energy use to electricity and GHG reduction, while those who prefer the stepped rate do not. Instead, they see energy conservation (including reducing electricity use) as an important goal – not electrification.

Rate that encourages the use of clean electricity over other sources of energy

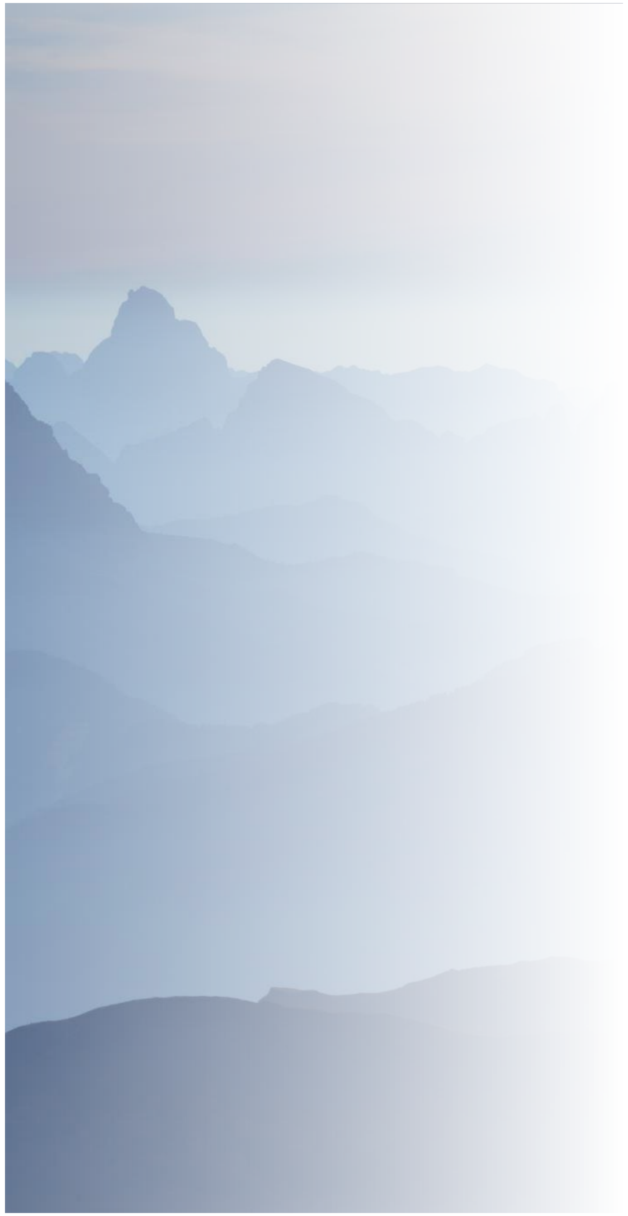


KEY TAKEAWAYS

Focusing communications on electrification would resonate well as those who support the stepped rate are just as likely as those who support the flat rate (even though their bills may be higher) to express a strong commitment to GHG reduction and taking a personal role in minimizing the impacts of climate change.



Furthermore, the results show that the benefits of electrification vis-à-vis climate change are generally not well understood among customers. Only 30% of customers selected the flat rate as the rate that would encourage the use of electricity over other energy sources, while 41% selected the stepped rate as the rate that would lead to this change.

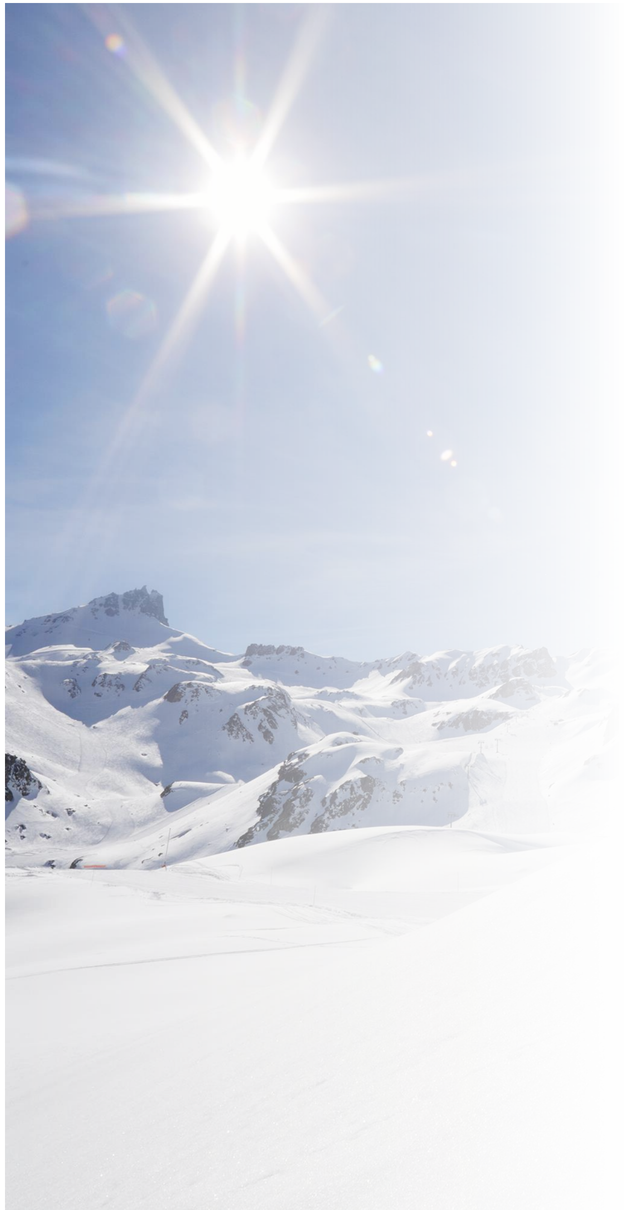


KEY TAKEAWAYS

sentis

In addition to emphasizing the connection between electrification and climate change, we also suggest the following with respect to communicating about the flat rate:

- **Don't focus on bill simplicity** – having a bill that is easy to understand is not among the key considerations for customers. Customers care much more about the amount they owe than about how the amount was arrived at.
- **Don't focus on cost of service** – this a difficult concept for customers to understand. Many customers won't see anything wrong with "some customers paying disproportionately more while others paying disproportionately less". Also, customers were just as likely to consider the stepped rate as the rate that better reflects the cost to serve customers as they were to consider the flat rate as the rate that better reflects this.
- **Related to the above point, don't focus on fairness** – respondents who prefer the stepped rate and those who prefer the flat rate both have good arguments for why their preferred rate is fair. The stepped rate is fair because "it doesn't reward those who waste electricity." The flat rate is fair because "it doesn't penalize you for your circumstances" (e.g., where you live, the size of your family, etc.).
- **Have a strategy for explaining how the flat rate impacts low-income households** – Ensuring that electricity is affordable for low-income households was ranked among the most important priorities that BC Hydro should consider when designing electricity rates. The flat rate value proposition that resonates with customers (other than cost) is that the flat rate encourages electrification. However, low-income households are the households least able to participate in the shift to electricity – they are less likely to buy electric cars and install heat pumps. They are also more on the fence when it comes to agreeing with statements like "reducing my greenhouse has emissions is more important to me than saving a few dollars" and "my personal role in combatting climate change is important."



KEY TAKEAWAYS

Overall, there is more support for BC Hydro exploring a rate that includes a higher basic charge and a lower energy charge (47%) than there is opposition (31%). Attitudes toward this rate are tied strongly to preferences for the stepped vs. the flat rate. While over two-thirds (68%) who prefer the flat rate support a higher basic charge and a lower energy charge, only 37% of those who prefer the stepped rate support this. This difference is due in large part to the fact that respondents were told that an increase in the basic charge would results in customers who usually stay in Step 1 paying more than they would under either the stepped rate or flat rate.

M3 is the segment that is most split with respect to rate preferences – 39% prefer the stepped rate while 38% prefer the flat rate. To understand what might be driving this split, we compared these two groups within the M3 segment on a number of characteristics. Among the most significant differences between these groups is how the kilowatt usage and billing information presented for the stepped rate in the survey differed from the actual usage and billing information in the database.

Among those supporting the stepped rate, the survey overestimated their usage by an average of 4,400 kw/h – and their bill for the stepped rate presented in the survey was on average 69% higher than their actual bill. Contrast this with those who support the flat rate. The survey underestimated their usage by an average of 1,364 kw/h – and their bill for the stepped rate presented in the survey was 11% lower than their actual bill.

sentis

Summary of Findings

13

sentis

SUMMARY OF FINDINGS

Electricity Rate Priorities

sentis

CUSTOMER PRIORITIES FOR ELECTRICITY RATES

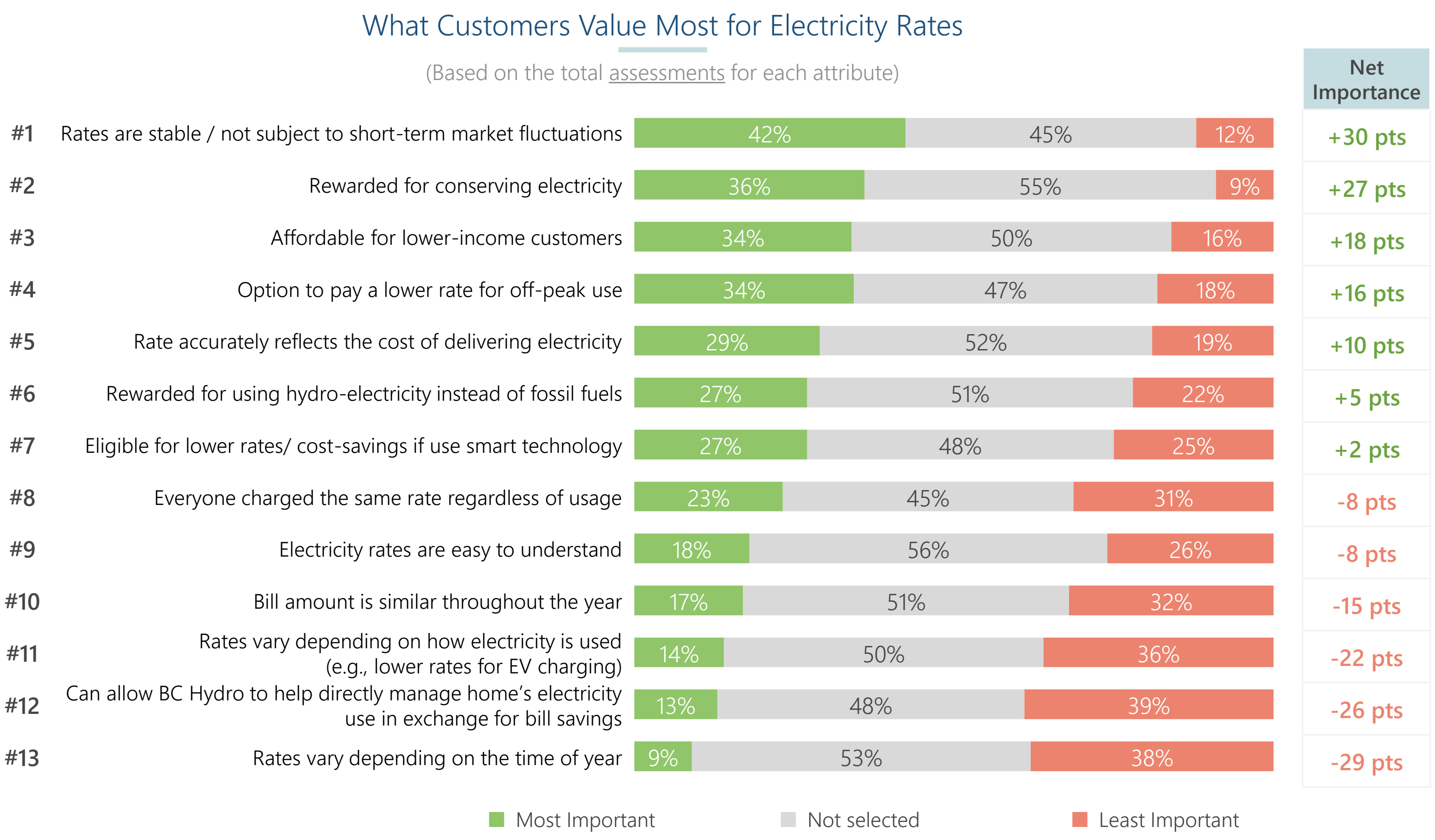
Respondents were asked to complete an exercise in which they were presented with 13 sets of considerations for electricity rates. Each set had four considerations, and respondents were asked to select which is most important and which is least important to them.

Rate stability was the most likely to be selected as the top priority when presented (42% of the time). Further, it was only selected as the lowest priority 12% of the time, for a net importance score of +30.

The next top priorities are being rewarded for conserving electricity (+27 in net importance), affordability for lower-income customers (+18) and the option of time-of-use rates (+16).

Conversely, the lowest priorities include seasonal rates (with higher rates in the winter), allowing BC Hydro to help directly manage their home's electricity use (which is often viewed as surveillance) and end-use rates.

The flat rate concept ranked #8 out of 13, with slightly more respondents ranking it the least important than the most important, with a net score of -8.



Based on a total of 69,992 assessments. Each respondent was presented with 13 sets of considerations and each attribute was presented a total of 4 times.
Q9. In this exercise, you will be presented with a series of considerations. For each set, please pick which one you think should be the highest priority and the lowest priority.

sentis

SUMMARY OF FINDINGS

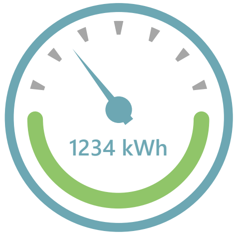
Flat Rate vs. Stepped Rate

CONTEXTUALIZING RESIDENTIAL RATES

Before they were given the details of the two rate structures, respondents were presented the following information about BC Hydro's current residential rate:

Energy charge

This is the rate BC Hydro charges for the electricity used by customers (measured in kilowatt hours).



Basic charge

This is a daily charge added to customers' bills (comes out to around $6.30 per month) that covers various fixed and operational costs, such as billing, metering and customer support.

We're looking for your feedback on comparing the current rate and another option we're exploring. In this next section, we'll provide a description, including the potential benefits and drawbacks for each.

sentis

OPTION 1
STEPPED RATE

Respondents were presented the following information about the current stepped rate:

Energy charge:

- Step 1: 9.39 cents per kilowatt hour (kWh) up to 1,350 kWh over two months;
- Step 2: 14.08 cents per kWh above this threshold

Basic charge: $6.30 per month

Benefits

- There will be no impact to customers as the structure would remain as it is today
- Encourages energy conservation
- Customers who use less electricity will likely have lower costs as they'll stay in the Step 1 threshold

Drawbacks

- Customers who use more electricity are likely to go into Step 2 and have higher costs, including lower income customers, customers with large households, or those who live in rural areas
- Could be a barrier for some customers to switch from fossil fuels to electricity for heating and transportation due to the higher Step 2 rate
- Doesn't reflect BC Hydro's cost of service – low consumption customers are paying less than the cost of providing electricity service to them while high consumption customers are paying more

		Electricity			Mixed		
		E1	E2	E3	M1/M2		M3
Basic charge		$75.60			$75.60		
Estimated Usage (kWh/year)	Step 1	3,100	6,500	7,800	2,500	6,300	7,900
	Step 2	20	1,700	7,500	0	500	5,000
Step 1 Charge		$291.09	$610.35	$732.42	$234.75	$591.57	$741.81
Step 2 Charge		$2.82	$239.36	$1,056.00	$0.00	$70.40	$704.00
Total bill		$369.51	$925.31	$1,864.02	$310.35	$737.57	$1,521.41
Monthly Average Cost		$30.79	$77.11	$155.34	$25.86	$61.46	$126.78

Note: cost breakdown shown on an annual basis

sentis

SUGGESTIONS FOR IMPROVING CURRENT STEPPED RATE

When asked what respondents would change about the current stepped rate, the top two requests are to increase the threshold for Step 2 or to remove the Step 2 charges entirely (each mentioned by about one-in-ten).

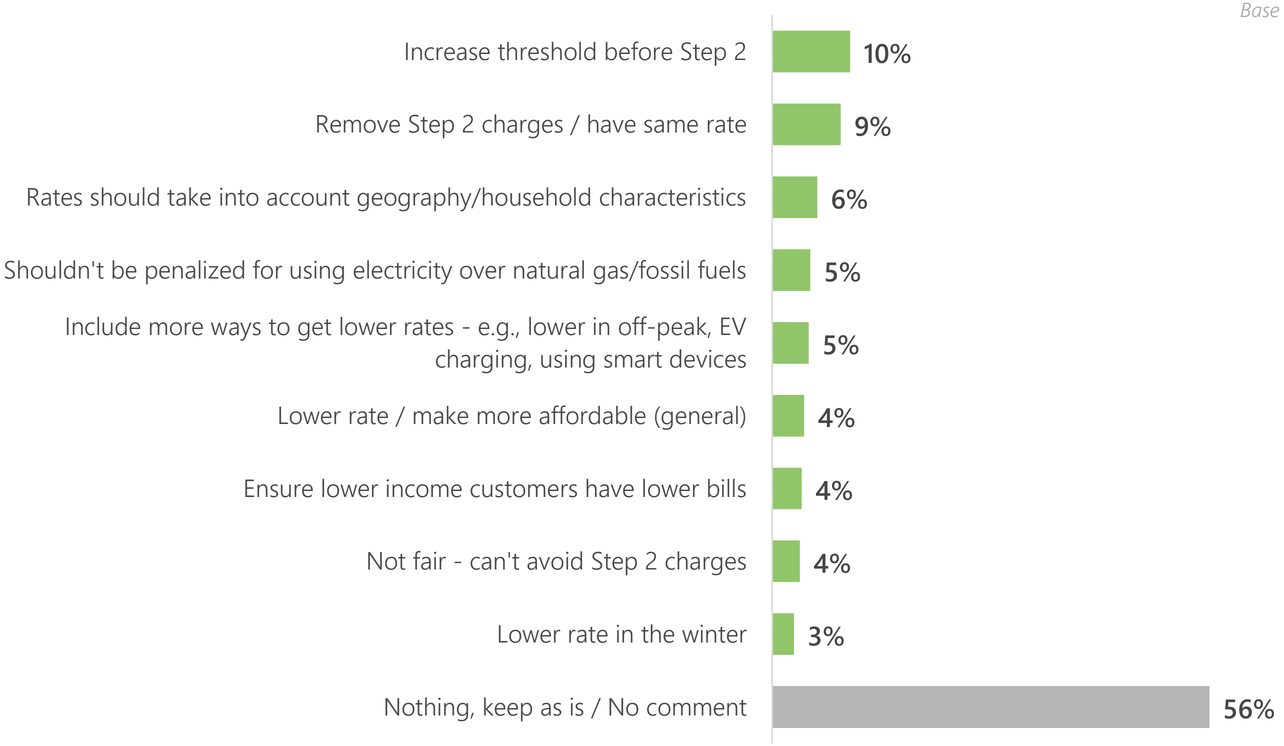
These two requests were made much more frequently by those who prefer the flat rate than those who prefer stepped rate.

Just over half (56%) had no suggestions or comments on how to change the current rate.

Those who prefer the stepped rate were far less likely to offer suggestions or comments than those who prefer the flat rate.

If You Could Change One Thing About The Current Stepped Rate, What Would It Be?

(among all residential respondents)



By Rate Preference

	Stepped Rate	Flat Rate	Unsure
Base	669	384	293
Increase threshold before Step 2	8%	14%	9%
Remove Step 2 charges / have same rate	1%	26%	5%
Rates should take into account geography/household characteristics	3%	12%	3%
Shouldn't be penalized for using electricity over natural gas/fossil fuels	3%	9%	5%
Include more ways to get lower rates - e.g., lower in off-peak, EV charging, using smart devices	4%	6%	4%
Lower rate / make more affordable (general)	4%	4%	6%
Ensure lower income customers have lower bills	4%	4%	4%
Not fair - can't avoid Step 2 charges	1%	7%	5%
Lower rate in the winter	2%	3%	5%
Nothing, keep as is / No comment	67%	32%	60%

Significantly higher than flat rate
Significantly higher than stepped rate

Note: only mentions of 3% or more are shown
Base: Total (1,346)
Q11. If you could change one thing about the current stepped rate, what would it be? [open-end]

OPTION 2
FLAT RATE

sentis

Respondents were presented the following information about the proposed flat rate:

To better meet evolving customer needs, BC Hydro is considering an alternative option that would change how customers are charged for residential service. Two key considerations are behind this potential change:

- The rate needs to better reflect BC Hydro's cost of providing service to its customers, as some customers pay disproportionately more while others pay less.
- The rate must remain revenue neutral, meaning that any change that is made will not result in collecting more or less revenue than BC Hydro currently collects.

The alternative we're exploring is known as a flat rate. It includes one energy charge for electricity use and a basic charge that is the same as today.

Energy charge: 11.21 cents per kWh

Basic charge: $6.30 per month

Benefits

- Simplifies with one rate per kWh of usage applied to all residential customers (no Step 2)
- Lowers the incremental costs for customers to replace fossil fuels in the home (e.g., for heating and electric vehicles)
- Customers with higher electricity use may see reduced costs

Drawbacks

- Will lead to higher bills for customers who only pay for electricity under today's Step 1 rate
- There is no direct incentive to encourage electricity conservation

	Electricity			Mixed		
	E1	E2	E3	M1/M2		M3
Basic charge		$75.60			$75.60	
Estimated Usage (kWh/year)	3,120	8,200	15,300	2,500	6,800	12,900
Flat charge	$349.75	$919.22	$1,715.13	$280.25	$762.28	$1,446.09
Total bill	$425.35	$994.82	$1,790.73	$355.85	$837.88	$1,521.69
Monthly Average Cost	$35.45	$82.90	$149.23	$29.65	$69.82	$126.81
Difference (Flat minus Stepped bill)	↑ $55.85	↑ $69.51	↓ $73.29	↑ $45.50	↑ $100.31	↑ $0.28
Percentage Difference (from Stepped Rate)*	+15%	+8%	-4%	+15%	+14%	+<1%

*Note: cost breakdown shown on an annual basis | *Not shown to respondents in survey*

20

sentis

FLAT RATE IMPRESSIONS

After being presented with information on the flat rate, roughly one-quarter (23%) responded positively to the concept.

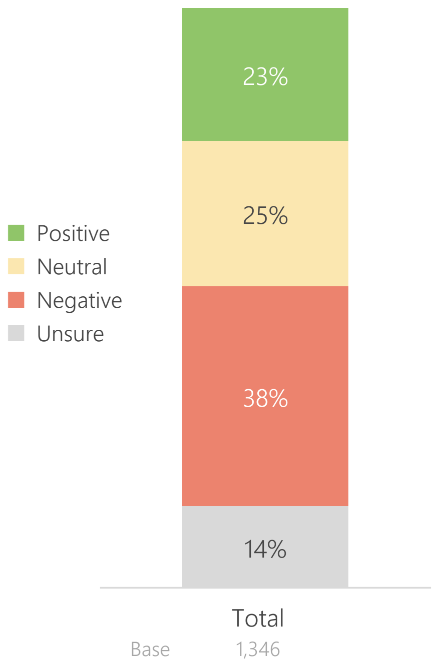
Another 38% had negative impressions of the flat rate, leaving another 39% who were either neutral (25%) or unsure (14%).

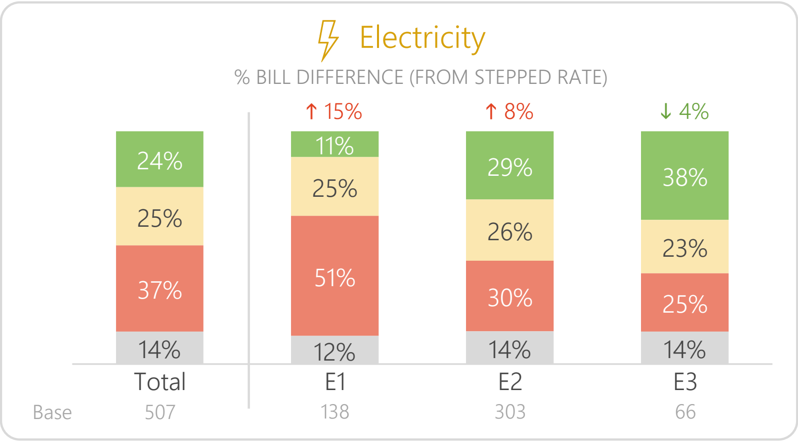
Those in group E3 were the most positive about the flat rate, while those in group E1 were the least. This can likely be attributed to the information provided on the impact the proposed flat rate would have on their bill, with group E3 presented with a 4% decrease and E1 shown a 15% increase.

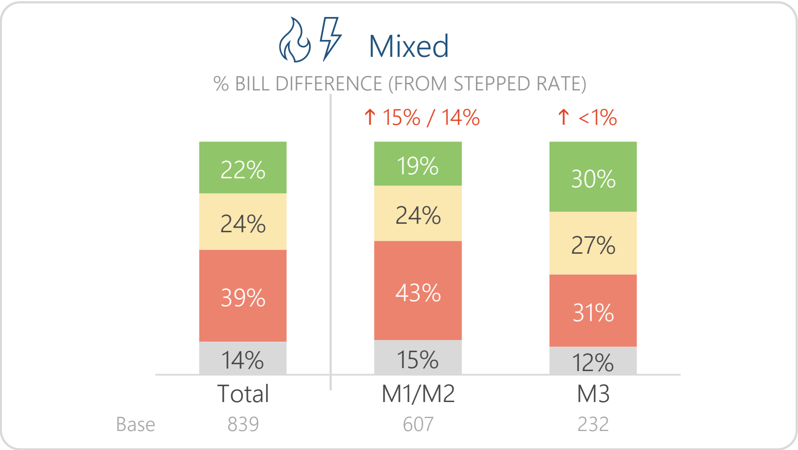
Positive impressions of the flat rate strengthens the more often respondents are in Step 2 (from a low of 10% positive among those who are never in Step 2 to a high of 39% among those who are always in Step 2).

Impression of Flat Rate

(among all residential respondents)







Q13. What is your impression of the flat rate based on what was described above?

HEAD-TO-HEAD COMPARISON STEPPED VS. FLAT RATE

When the two options were put side by side, respondents expressed preference for the stepped rate (52%) over the flat rate (28%) by about a 2:1 margin.

Another 8% indicated they have no preference between the two, and 11% were unsure.

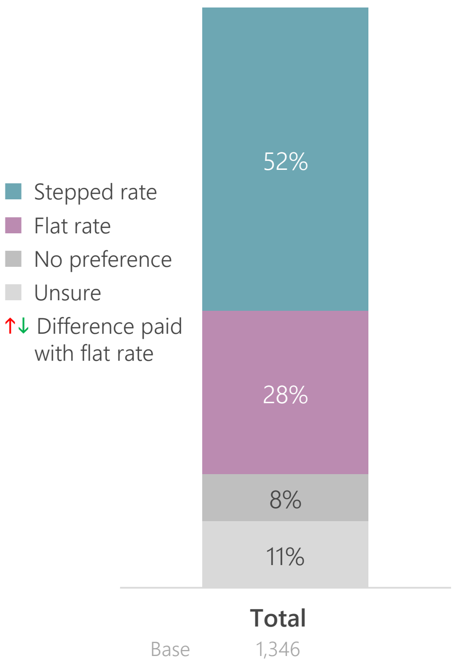
Rate preferences are largely a function of how a customer's bill will be impacted under the flat rate. Those whose bills will increase the most (E1 and M1/M2) have the strongest preference for the stepped rate while those whose bills will decrease (E3) show the strongest preference for the flat rate.

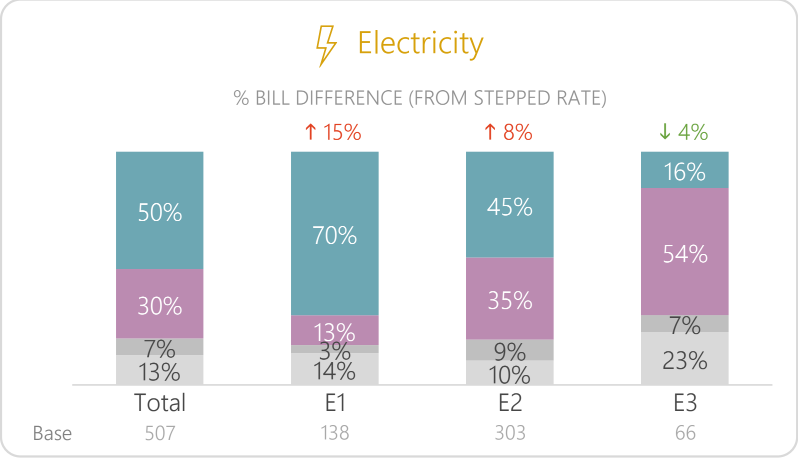
Those whose bills won't change (M3) are split between the stepped rate and the flat rate.

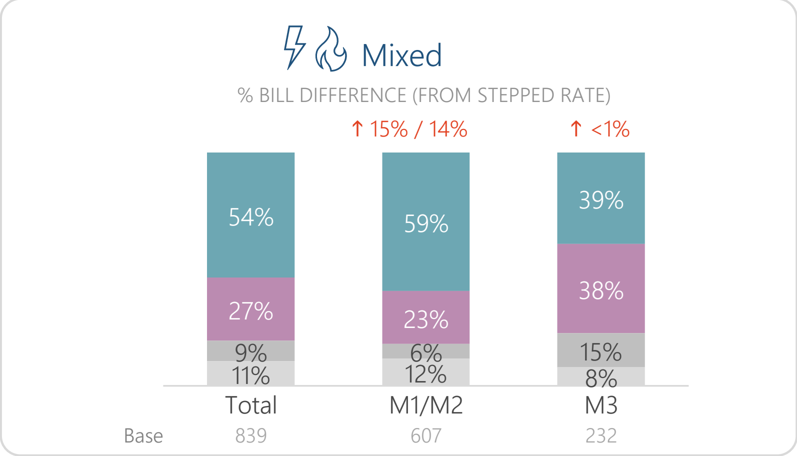
Those living in rural areas show the greatest preference for the flat rate (38%). They are the most likely to live in single-detached homes with electricity as a heat source. A significant percentage (41%) rely on wood as a heat source which is probably used to minimize their Step 2 charges.

Which Rate do Respondents Prefer?

(among all residential respondents)







Q15. Now let's compare the two options side by side. [Respondent shown side-by-side comparison of stepped and flat rate benefits, drawbacks, basic charge, energy charge, total bill and monthly average cost] Which one do you prefer?

RESIDENTIAL RATE PREFERENCE

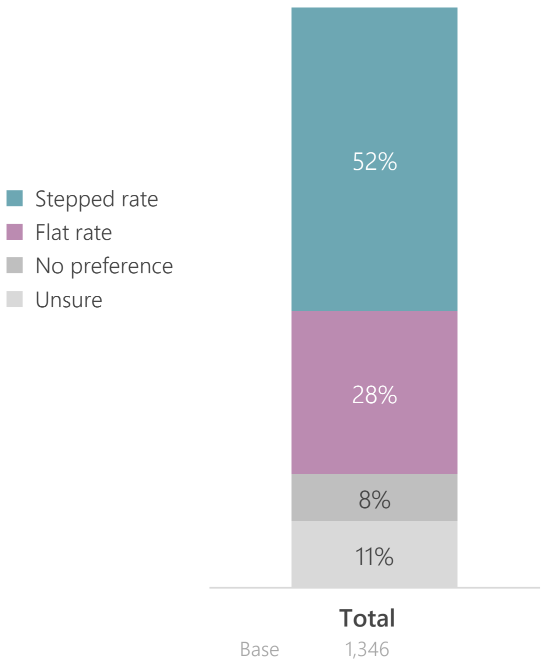
Those living in the North and in rural areas show the greatest preference for the flat rate (44% and 38%, respectively vs. 28% overall).

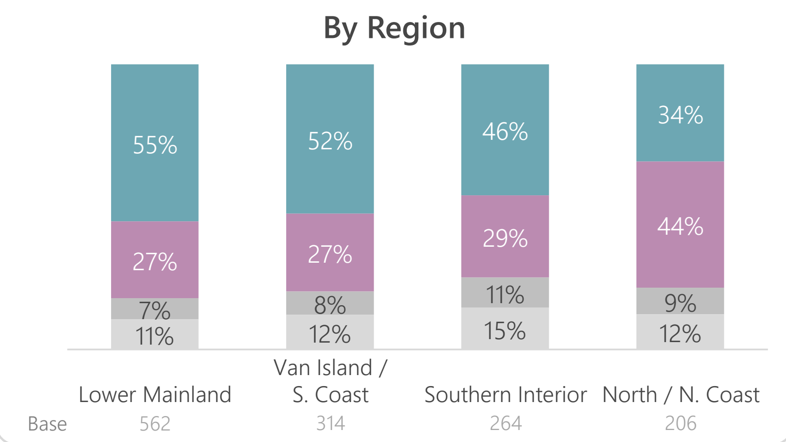
Northern residents are most likely to mention using a lot of electricity when asked for their rate preference reason (15% vs. 8% overall).

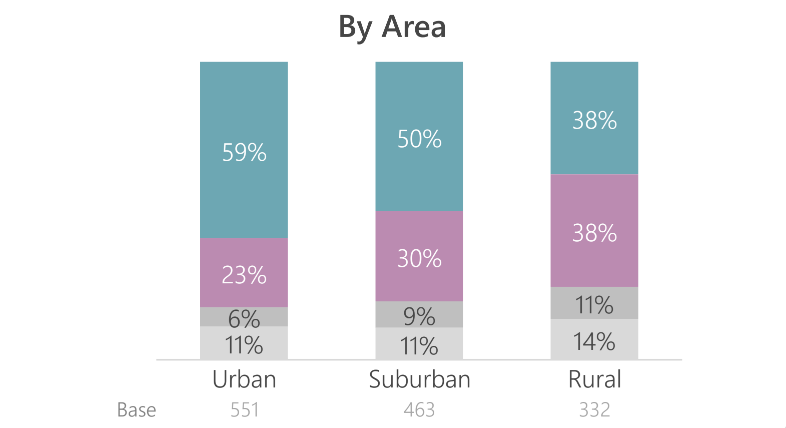
Given that they live in colder climates, both groups often pay Step 2 rates. They are also the groups that are most likely to rely on wood as a heat source – which they probably use to help minimize their Step 2 charges.

Which Rate do Respondents Prefer?

(among all residential respondents)







Q15. Now let's compare the two options side by side. [Respondent shown side-by-side comparison of stepped and flat rate benefits, drawbacks, basic charge, energy charge, total bill and monthly average cost] Which one do you prefer?

REASONS FOR RATE PREFERENCE

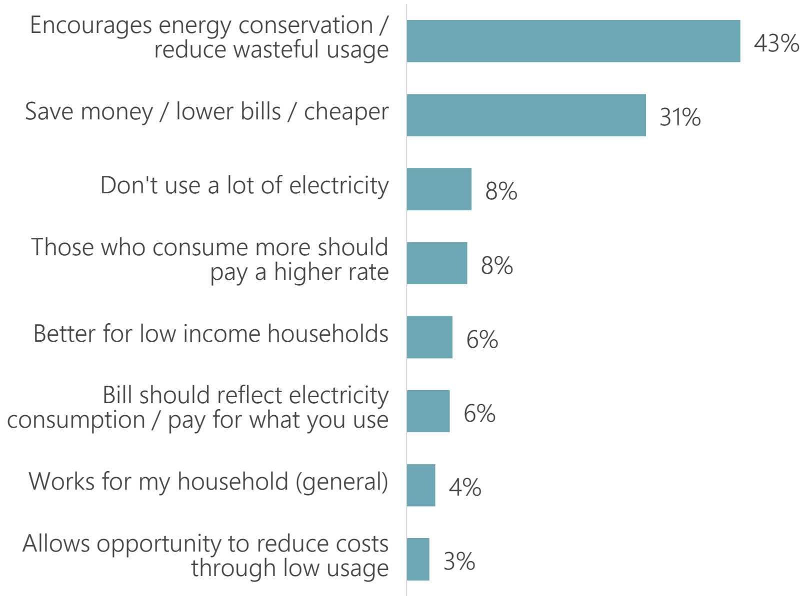
sentis

Those who prefer the stepped rate primarily like that it encourages energy conservation and saves them money (43% and 31% mentioning each, respectively).

Meanwhile, the flat rate is preferred because it benefits those who are heavier users of electricity (21%), encourages the switch from fossil fuels (19%), helps save money (17%) and is fairer since everyone pays the same rate (15%).

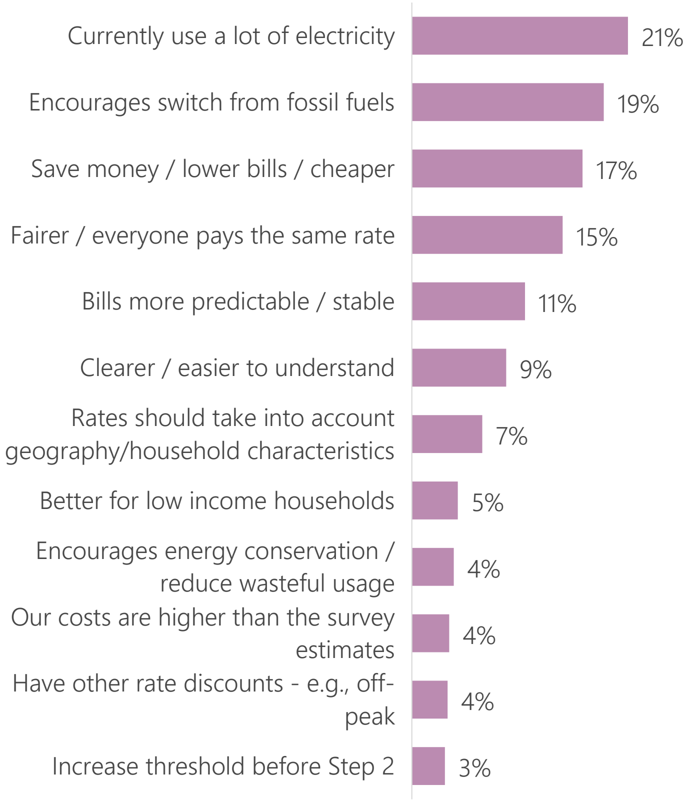
Why Stepped Rate is Preferred

(among those preferring stepped rate, n=669)



Why Flat Rate is Preferred

(among those preferring flat rate, n=384)



Note: only mentions of 3% or more are shown.
Q16. Please tell us why you said you prefer the [stepped rate / flat rate]. [open-end]

sentis

COMMENTS: REASONS FOR RATE PREFERENCE

Why Stepped Rate is Preferred

"I believe that people should be rewarded for conserving energy and not have to pay extra in order to cover others' cost. Less incentive to switch from fossil fuels may be a good thing because if we become fully dependent on BC Hydro the rates can be set wherever BC Hydro wants them"

"Although stepped rate doesn't reflect the actual cost of providing the service to low users, it definitely encourages lower, more efficient use of electricity. Lower electricity users do not have any other option to electricity other than a high-end electrical service driven by high electricity demands/users. I prefer the infrastructure costs be paid by those who need more electricity and have the funds to cover BC's exceptional power service. Thank you."

"I am living in a small apartment; this change will increase my bill. It will also decrease my motivation to use less electricity to keep the usage below Step 2."

"Aside from the increase in my personal rate, the goal of overall energy conservation is fundamentally important. Removing an incentive to conserve and giving higher-use consumers a reduction in costs while increasing rates for lower-use customers is both unwise and unfair. As always, flat taxes benefit the wealthy."

"Because customers who use less energy should not be penalized into paying BC Hydro more money, and instead should be rewarded. However, families who choose to be multigenerational and live together should also not be penalized. Base it on the number of adults per household."

Why Flat Rate is Preferred

"It's more reflective of actual cost and doesn't unduly incent or disincentivize conservation or switching from fossil fuels. BC Hydro should be a provider of electricity and not be involved in encouraging switching from fossil fuels or conservation. Those types of incentives or programs should be done by government, not BC Hydro."

"It's fair. As much as I am against raising rates that may impact lower income people, I believe it is unethical to charge people a higher rate just because they need/use more electricity."

"Because if you want to have "luxuries" like a hot tub or an electric car you would always go over into Step 2, so the flat rate gives more flexibility in how you chose to spend the electricity."

"We have an all wood / all electric household with an electric vehicle, so simple self interest. The flat rate would also remove a minor barrier to people buying EVs as a surprising number think an EV will cause their hydro bill to skyrocket."

"For the exact reasons you have mentioned. The stepped rate structure, based on an average customer, creates a disincentive for single family dwellings and those that live in colder climates to use electricity for heat or EVs. They are all likely in Step 2 already and therefore pay an effective subsidy to those resident in larger urban centers. The stepped rate structure creates disincentive to use electricity and instead provides an incentive to use natural gas for heat."

Note: Only showing a selection of comments
Q16. Please tell us why you said you prefer the [stepped rate / flat rate]. [open-end]

sentis

WHAT WOULD MAKE OTHER RATE MORE ACCEPTABLE

Lower rates and discounts or incentives for conservation are the top two ways to make the flat rate more acceptable (mentioned by 23% and 18% of stepped rate advocates).

Specific suggestions around cost include:

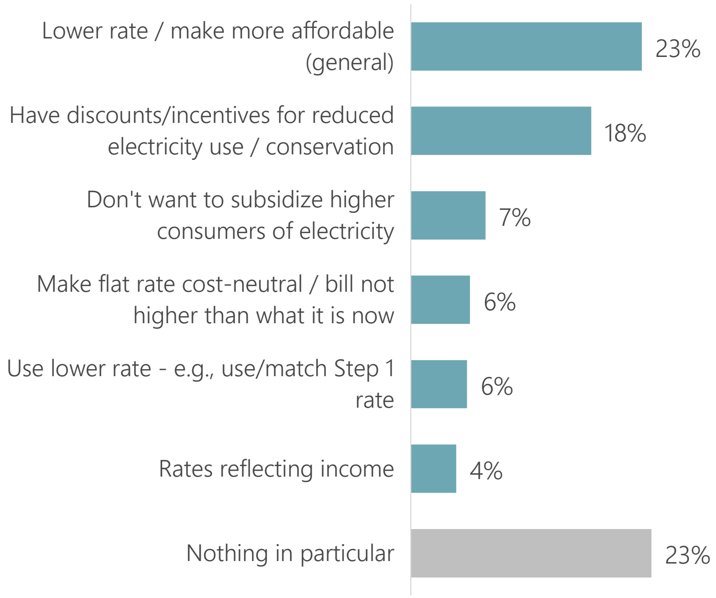
- Making the flat rate cost-neutral, so that bills don't increase (6%)
- Using a lower rate, like the Step 1 rate (6%)
- Designing rates that are reflective of income (4%)

Of note, close to one-quarter were not able to identify anything in particular that would make the flat rate more acceptable to them.

On the flip side, the top suggestion offered to make the stepped rate more acceptable is to increase the threshold before Step 2 (mentioned by 22% of flat rate preferers).

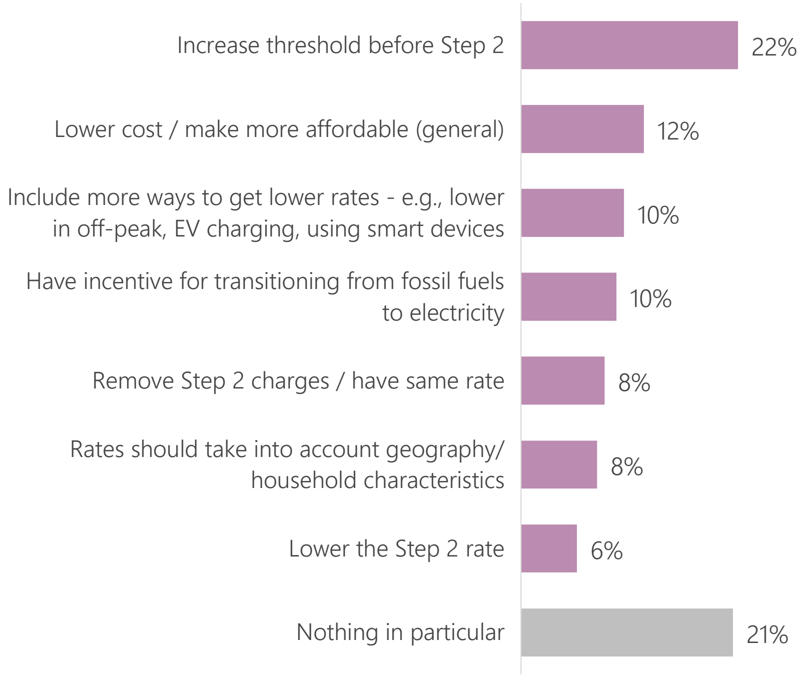
What Would Make Flat Rate More Acceptable

(among those preferring stepped rate and left a comment, n=568)



What Would Make Stepped Rate More Acceptable

(among those preferring flat rate and left a comment, n=336)



Note: only mentions of 4% or more are shown.
Q17. What, if anything, would help make the Flat rate more acceptable to you? | Q18. What, if anything, would help make staying with the Stepped rate more acceptable to you? [open-end]

COMMENTS: WHAT WOULD MAKE OTHER RATE MORE ACCEPTABLE

sentis

What Would Make Flat Rate More Acceptable

"Lower the rate. The current Step 1 rate is just barely tolerable. Increasing the rate will encourage me to find alternatives to BC Hydro."

"A flat rate is kind of like a flat tax…it negatively impacts the people at the bottom the most. Also, the added financial incentive to conserve energy is removed. A change to a flat rate would be a regressive move. To be honest, I have been considering replacing my natural gas furnace with an electric heat pump, and my gas inline water heater with electric. A change to a flat rate would negatively impact that decision… I likely wouldn't do it."

"Incentives to lower the rate by having a smart thermostat, efficient windows, etc. Flat rate is not attractive considering many homes use far more power than others. The ones who conserve should not be penalized for those who don't."

"Could it be based on square footage of one's accommodation? Something that would reflect the approximate assumed usage of hydro and charge higher users (and likely those who could afford it) more?"

"Reduced off-hours rate and/or rate incentives for GHG reducers such as heat pumps and electric cars."

"Lower rates in the cold months. Everyone's using more because they're indoors - I get it, but even with those that are low energy users, depending on the building they live in, they are paying a ton to heat the house (even by barely using the heat)."

What Would Make Stepped Rate More Acceptable

"Making the first tier actually an acceptable amount. It is absolutely impossible to stay any where near the first tier."

"Hydro is expensive. I would rather use fossil fuels, especially in this economy."

"I live in the Interior of BC with very cold weather in the winter unlike the Lower Mainland and Vancouver Island. Also, hot summers. Move Step 2 in the winter to recognize the cold weather conditions and reward me for having an all-electric house. Stop punishing me. I am a senior and environmentally focused."

"If the stepped rated were more attainable for everyone then I would support them. For example, if they were calculated regionally vs one size fits all. As responsible British Columbians, my family has done our part with ongoing updates to our home appliances, lighting and heating, to achieve a more efficient home. However, as a Northern and rural homeowner, it has been impossible to attain electrical usage below Step 1. Part of the issue is the climate of course, but rural properties also contain high load devices that urban customers don't require, such as water and sewage pumps for example. Rural customers will also require a higher usage once the electrification of transportation becomes more mainstream, simply because of the distance from services and employment. One more note I'd like to make on the current stepped system, as mentioned above, is that my family has been responsible with our electrical use and as such has incurred expenses upgrading our appliances, etc. However, because we are unable to reduce our load below the Step 2 threshold, we are also subsidizing others' power who don't face the same challenges. It's a double hit that seems unjust, but easily changed. Thank you for taking the time to understand your customers."

Note: Only showing a selection of comments
Q17. What, if anything, would help make the Flat rate more acceptable to you? | Q18. What, if anything, would help make staying with the Stepped rate more acceptable to you? [open-end]

sentis

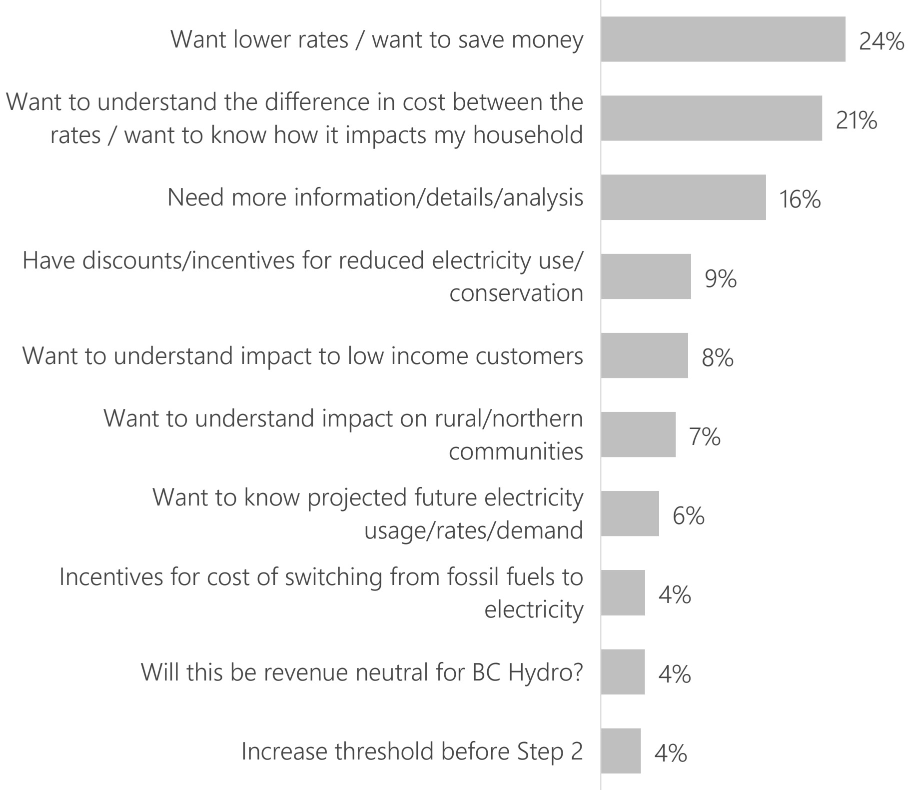
INFORMATION NEEDED FOR UNDECIDED RESPONDENTS

One-in-ten respondents were undecided regarding which rate they prefer.

When asked what would help them decide, the top two requests are for lower rates / to save money (24%) and to better understand the cost difference between the two – specifically in terms of how it would impact their household (21%).

Information Needed to Decide Between Rates

(among those who were unsure and left a comment, n=102)



Note: only mentions of 4% or more are shown.
Q19. What information do you need to decide between the Stepped rate and the Flat rate? [open-end]

sentis

SUMMARY OF FINDINGS

Residential Rate Perceptions

sentis

RATE PERCEPTIONS

The flat rate is most credited with ensuring that everyone pays the same rate per kWh for electricity, with 69% selecting it as the best match for that statement. It is less strongly associated with the other attributes, including encouraging the use of clean electricity over other sources (only 30% selecting vs. 41% selecting stepped rate as the best match).

The stepped rate is most credited with having the lowest impact on the bill (54%). It also receives more votes for being the rate that encourages electricity use over other sources and having the lowest impact on all customers' bills.

Respondents are evenly split on which rate better reflects the cost to serve customers.

Not surprisingly, respondents are more likely to credit the rate they prefer as best matching each statement.

	By Rate Preference						By Rate Preference		
	Stepped Rate	Flat Rate	Unsure	STEPPED RATE BEST MATCHES STATEMENT		FLAT RATE BEST MATCHES STATEMENT	Stepped Rate	Flat Rate	Unsure
Base	669	384	293				669	384	293
	79%	24%	32%	54%	Has the lowest impact on my bill	25%	9%	59%	19%
	60%	19%	21%	41%	Rate that encourages use of clean electricity over other sources	30%	14%	60%	28%
	58%	20%	22%	40%	Has the lowest impact on all customers' bills	26%	13%	53%	22%
	58%	9%	23%	37%	Rate that better reflects the cost to serve customers	37%	18%	80%	29%
	22%	3%	11%	15%	Everyone pays the same rate (i.e. cents per kWh) for electricity	69%	62%	92%	53%

Stepped rate   Flat rate

Base: Total (1,346)

Q20. Which rate do you think best matches the following statements?

EXPLORING CHANGES TO RATE STRUCTURE

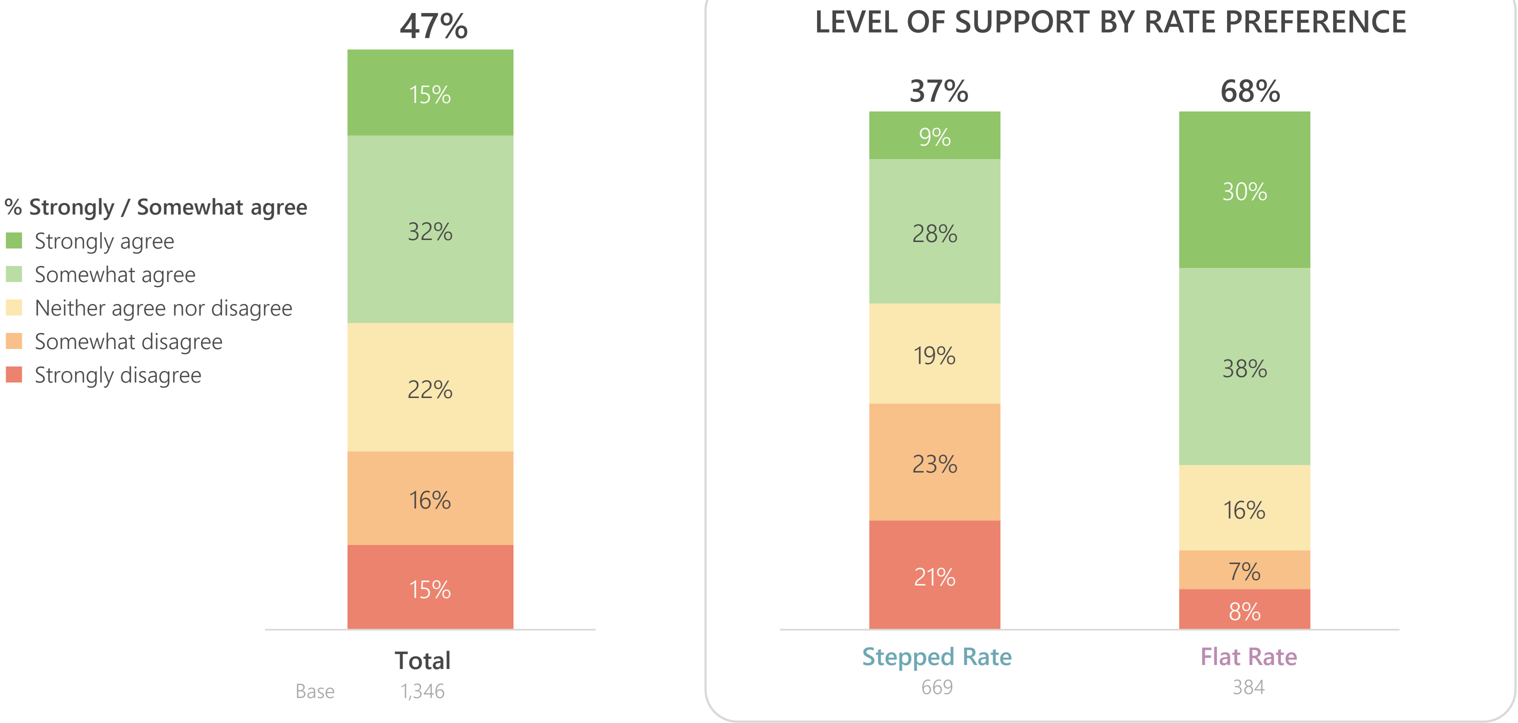
About half of respondents (47%) are open to exploring a rate that includes a higher basic charge and a lower energy charge.

Another three-in-ten (31%) are opposed, leaving 22% in between.

Those who prefer the flat rate are far more supportive than those who prefer the stepped rate (68% strongly/somewhat agreeing vs. 37%).

Supportive of Higher Basic Charge and Lower Energy Charge

(among all residential respondents)



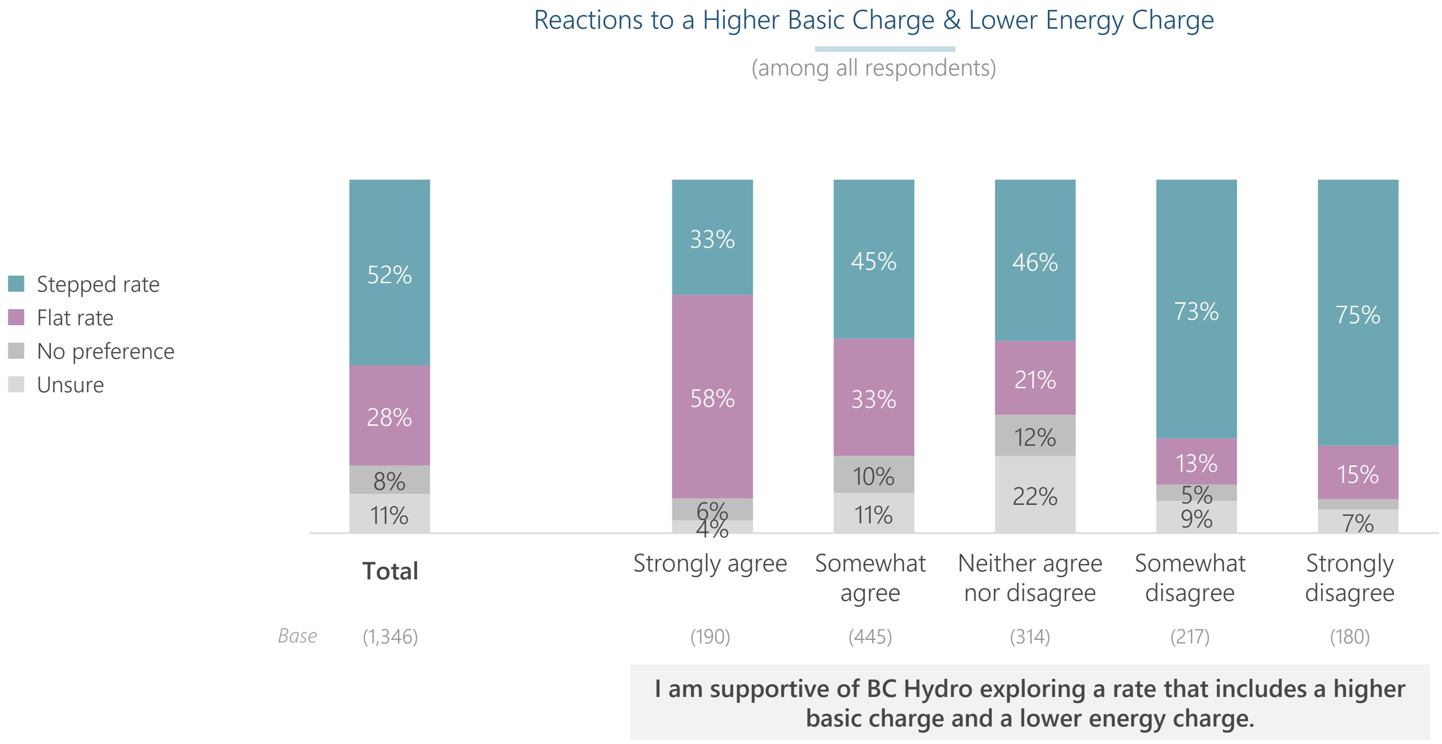
Q21. For the options we have covered so far, the basic charge is the same in both. For BC Hydro to more appropriately recover the fixed costs of service, a basic charge higher than today's amount would be needed. BC Hydro will collect the same amount of revenue through this rate design; therefore, a higher basic charge would allow for a lower energy charge per kWh. An increase in the basic charge would result in customers who usually stay in Step 1 paying more than either option above (current rate or the Flat rate). In considering this, what is your level of agreement to the following statement? I am supportive of BC Hydro exploring a rate that includes a higher basic charge and a lower energy charge.

sentis

EXPLORING A HIGHER BASIC CHARGE & LOWER ENERGY CHARGE

Those more open to exploring a change to BC Hydro's rate structure show the strongest support for the flat rate.

58% who strongly support exploring this option say they prefer the flat rate vs. 13-15% among those who are somewhat or strongly opposed.



Q21. For the options we have covered so far, the basic charge is the same in both. For BC Hydro to more appropriately recover the fixed costs of service, a basic charge higher than today's amount would be needed. BC Hydro will collect the same amount of revenue through this rate design; therefore, a higher basic charge would allow for a lower energy charge per kWh. An increase in the basic charge would result in customers who usually stay in Step 1 paying more than either option above (current rate or the Flat rate). In considering this, what is your level of agreement to the following statement? I am supportive of BC Hydro exploring a rate that includes a higher basic charge and a lower energy charge.

sentis

IMPLEMENTATION TIMELINE & TRANSITION PERIOD

Preferences are fairly evenly split when it comes to transitioning to a new rate.

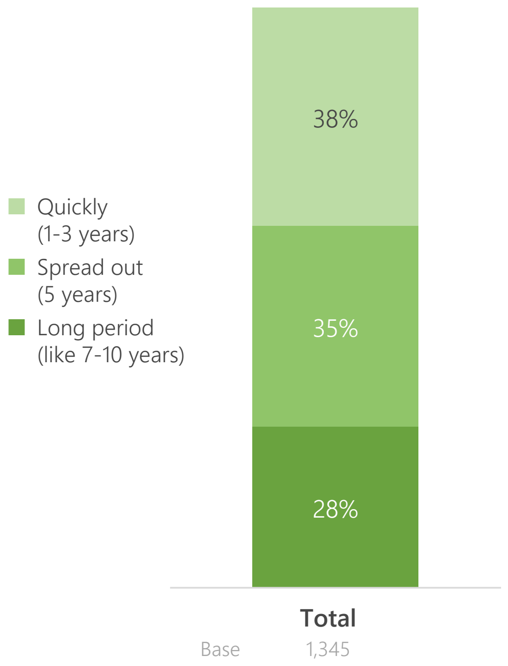
38% would prefer a quick transition (1-3 years), 35% would like it spread out over 5 years, and another 28% would like an even longer transition period of 7-10 years.

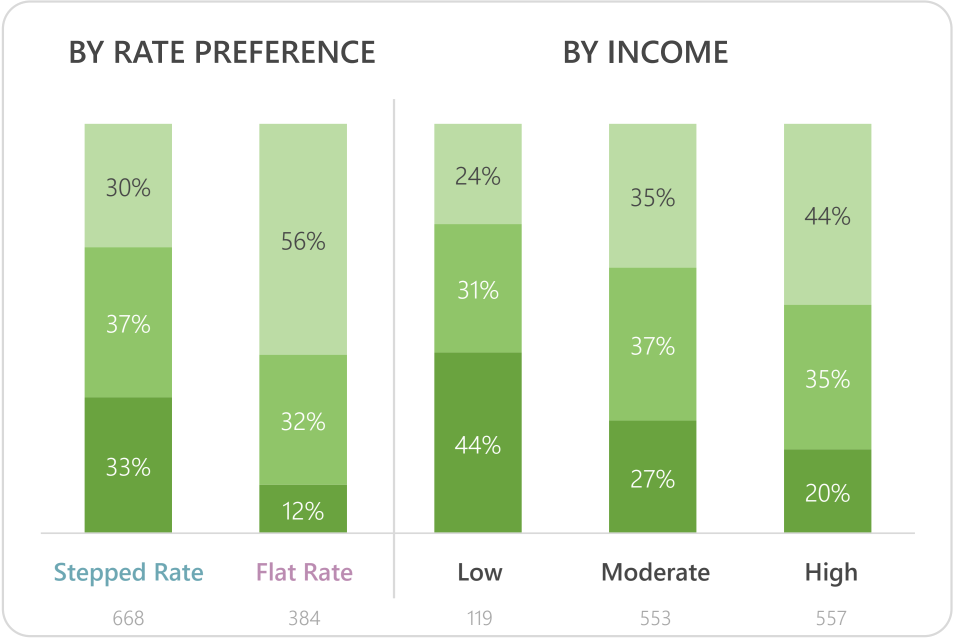
Those who prefer the flat rate are the most supportive of a quick transition.

The preference for a quick transition also increases within income.

Transition Period Preference

(among all residential respondents)





*Caution: small base (<30).

Q22. Typically, when a utility changes the way it charges customers, the new rate is introduced over a period of time to smooth potential bill impacts and to help customers adjust. Suppose BC Hydro introduces a new rate that could cause your bills to change. Which of the following best describes your preference in terms of a transition period?

33

SUMMARY OF FINDINGS

Current & Future Electrification Intent

34

sentis

INTENT TO ELECTRIFY IN NEXT 3 YEARS

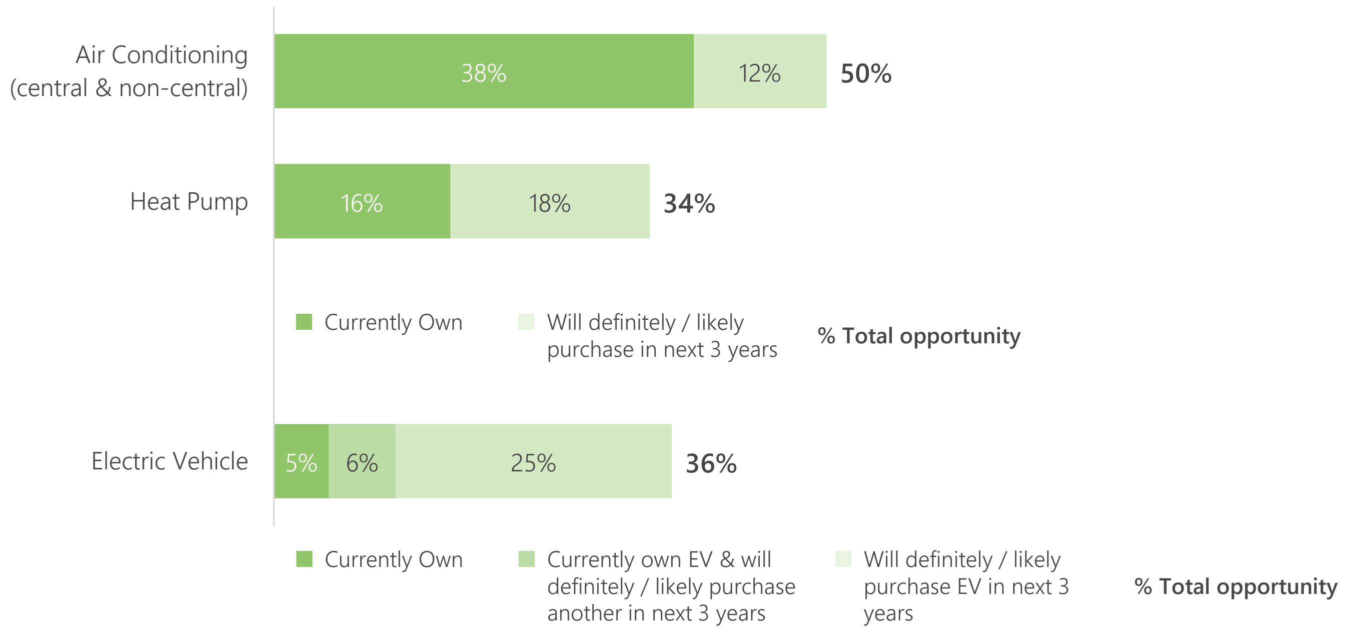
Respondents are the most likely to already have an air conditioner (38%) with another 12% saying they plan to buy one within the next three years.

16% currently own a heat pump, with another 18% who will likely purchase one in the next three years.

Respondents are most likely to electrify within the next three years by buying an electric vehicle. Three-in-ten intend to buy one in the next three years, including 6% who already own one.

Electrification Intent

(among all residential respondents, n=1,346)



Q26. Please provide your best estimate of the likelihood of the following events in the next 3 years: b. Buying [another/an] electric vehicle / c. Installing a heat pump that provides energy efficient heating and cooling / d. Buying an air conditioner | Q29. If you were to replace your fossil fuel use with electricity, your electricity use would increase, meaning you would be spending more on electricity. On the other hand, your fossil fuel use will decrease, meaning you would spend less on things like gasoline and natural gas. Considering this scenario, please indicate your level of agreement to the following statements.

sentis

CURRENT & FUTURE CONSUMPTION

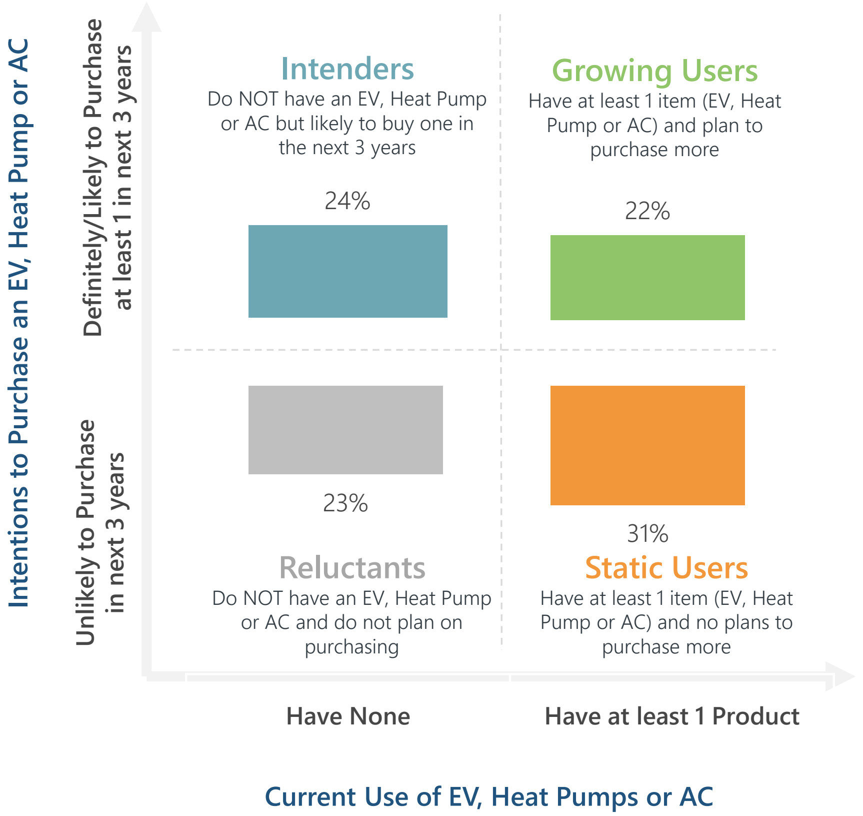
Respondents were segmented based on their current movement toward electrification and their plans to (further) electrify over the next three years.

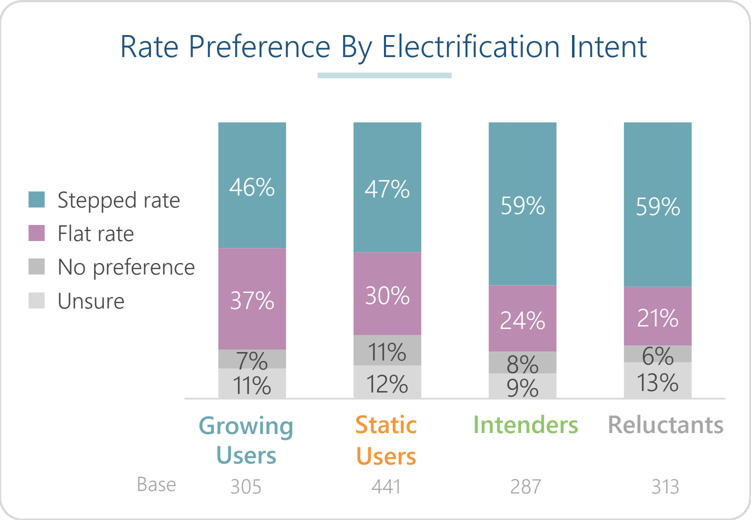
- 22% are considered **Growing Users** – they have at least one of the following – an EV, heat pump, air conditioning – and plan to add at least one more of these in the next three years.
- Another quarter (24%) are **Intenders**, who don't currently have any of these items, but plan to add at least one in the next three years.
- 31% are **Static Users** – they currently have at least one of the items but have no plans to electrify further.
- This leaves 23% who are **Reluctants** – they don't have any of these items and don't plan to add any in the next 3 years.

In line with their current adoption and future intentions regarding electrification, Growing Users are the most likely to prefer the flat rate while Reluctants are the least likely.

Intentions to Electrify & Current Consumption

(among all residential respondents)





Base: Total (1,346)

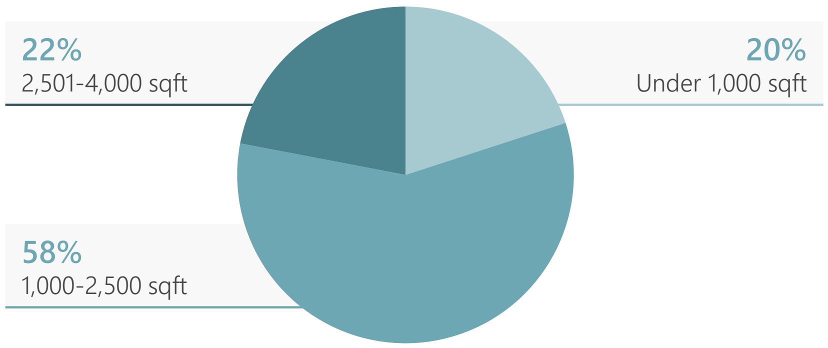
Q23. Do you or anyone in your household have an electric vehicle? | Q26. Please provide your best estimate of the likelihood of the following events in the next 3 years: b. Buying [another/an] electric vehicle / c. Installing a heat pump that provides energy efficient heating and cooling / d. Buying an air conditioner

MOVING TO A LARGER HOME IN BRITISH COLUMBIA

Broadly one-in-ten (11%) expect to move into a larger home in the next three years.

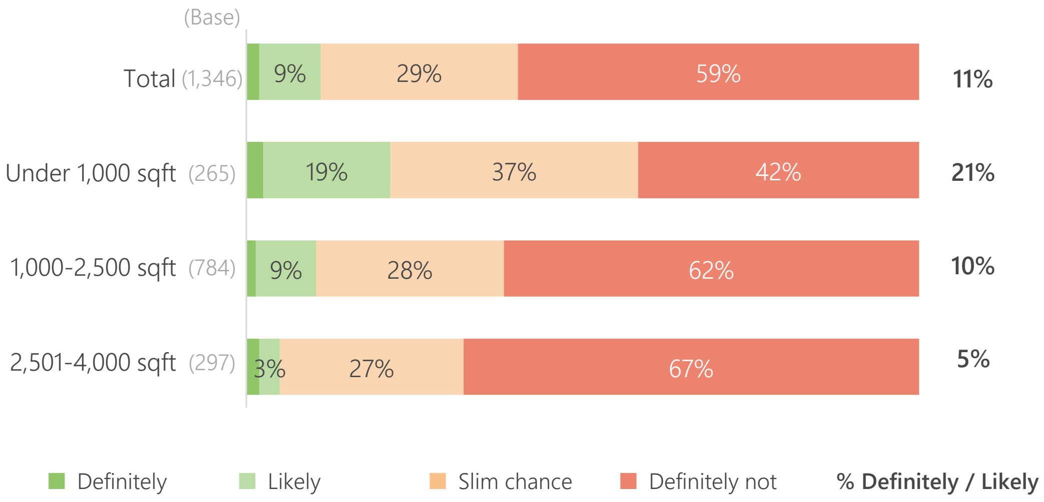
As one might expect, those living in smaller spaces (under 1,000 square feet) are the most likely to move into a larger space. The likelihood of upgrading in home size goes down the larger the space respondents are currently in.

Respondents' Home Size



Likelihood of Moving to a Larger Home in BC in the Next 3 Years by Current Home Size

(among all residential respondents)



Base: Total (1,346)

Q26. Please provide your best estimate of the likelihood of the following events in the next 3 years: a. Moving to a larger home in BC

HEAT PUMP CONSIDERATIONS

After being presented with more information about heat pumps, 14% indicated that they were more likely to get one. Another 36% say that they might consider it, leaving 33% who are not interested and 16% who are unsure.

Heat pump consideration increases with electricity usage, with those who are always in Step 2 expressing the most interest in getting a heat pump.

The top barriers to getting a heat pump include living in a home that cannot accommodate one (32%), cost of the unit (26%) and lack of familiarity (24%).

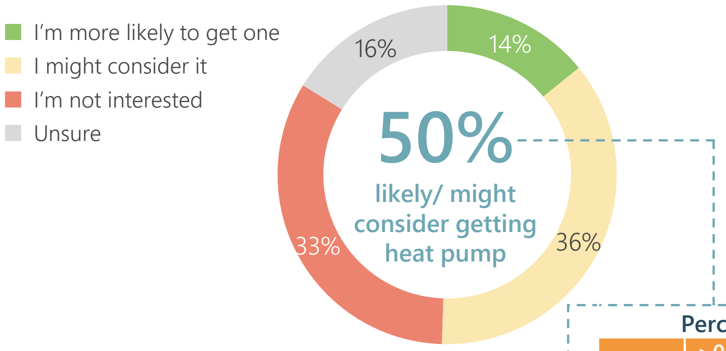
Change in Likelihood of Getting Heat Pump

(among residential respondents with no heat pump, n=1,130)

Respondents were presented the following information about heat pumps:

Heat pumps come in several types and sizes. Currently, there are rebates available for heat pump purchase to replace fossil fuel heating in the home. Depending on the unit, there is up to $6,000 from BC Hydro and CleanBC. Additionally, the federal government is offering up to $5,000 in rebates for energy efficiency upgrades under the Greener Homes Grant.

How does this information change your likelihood of getting a heat pump?

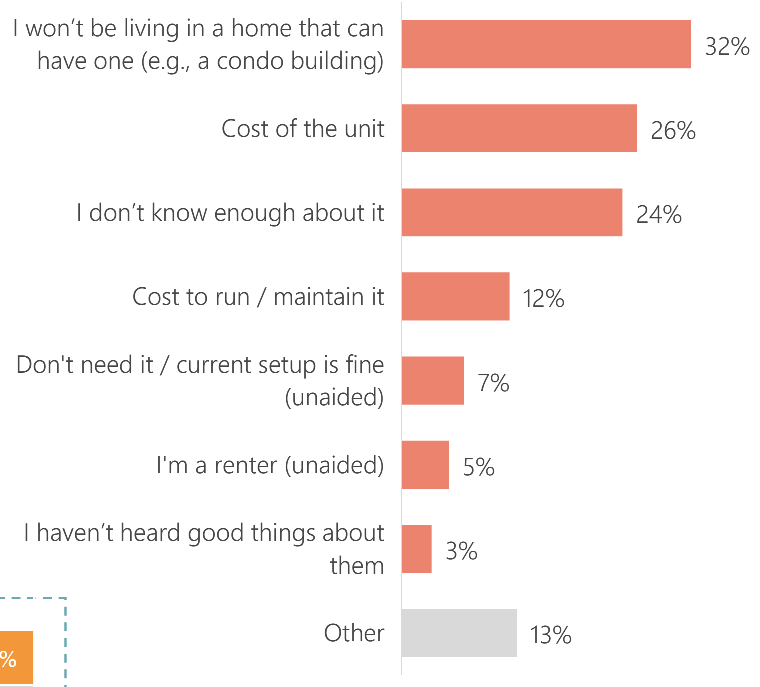


Percent in Step 2

0%	>0% - <50%	50% - 99%	100%
328	169	320	313
43%	46%	52%	**61%**

Reasons Wouldn't Consider Getting Heat Pump

(among residential respondents not interested in a heat pump, n=962)



Q27. Heat pumps come in several types and sizes. Currently, there are rebates available for heat pump purchase to replace fossil fuel heating in the home. Depending on the unit, there is up to $6,000 from BC Hydro and CleanBC. Additionally, the federal government is offering up to $5,000 in rebates for energy efficiency upgrades under the Greener Homes Grant. How does this information change your likelihood of getting a heat pump?
Q28. Why wouldn't you get a heat pump? Select all that apply.

sentis

VALUES & PRIORITIES

Almost all (93%) respondents agree that they are aware of their household's energy spend, including 64% who strongly agree.

Three-quarters (75%) agree that their personal role in combatting climate change is important. However, only 56% show a willingness to spend more to reduce their GHG emissions.

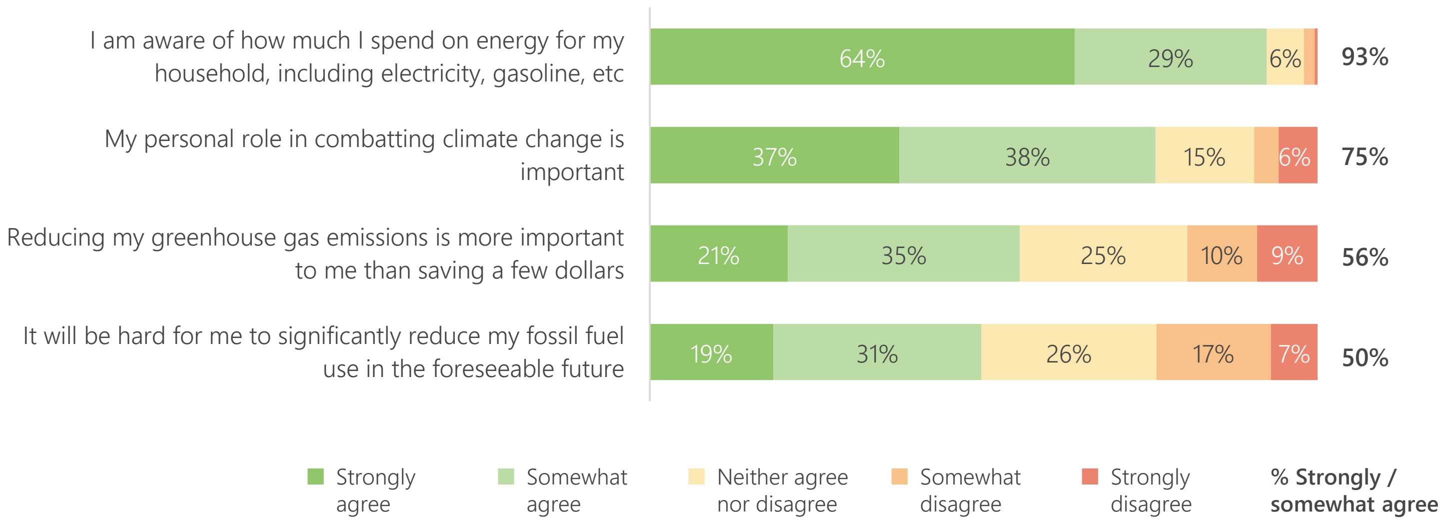
One-half feel that it will be hard to significantly reduce their fossil fuel use in the foreseeable future.

Before they gave their ratings respondents were presented with the following text:

"If you were to replace your fossil fuel use with electricity, your electricity use would increase, meaning you would be spending more on electricity. On the other hand, your fossil fuel use will decrease, meaning you would spend less on things like gasoline and natural gas".

What Residential Respondents Value & Prioritize

(among all residential respondents)



Base: Total (1,346)

Q29. Considering this scenario, please indicate your level of agreement to the following statements.

sentis

VALUES & PRIORITIES BY SUBGROUP

Those who mainly use electricity to heat their home are more likely to be motivated by being environmentally conscious.

Those in the Southern Interior and North are the most likely to be skeptical that they could significantly reduce their fossil fuel use.

Those with lower incomes are the least likely to prioritize combatting climate change and reducing GHG emissions.

Seniors (65+) are the most likely to agree that reducing GHG emissions is more important than saving money but are also more apt to say it will be challenging to reduce their fossil fuel use.

What Residential Respondents Value & Prioritize

	Total	Main Home Heating Source		Region				Age				Income		
% Strongly / Somewhat agree		Electric	Mixed	L.Main	VI/ Coast	South Int.	North/ N. Coast	18-34	35-54	55-64	65+	Low	Moderate	High
Base	1,346	507	839	562	314	264	206	187	431	227	437	119	553	558
I am aware of how much I spend on energy for my household, including electricity, gasoline, etc	92%	91%	93%	92%	94%	93%	94%	85%	92%	93%	94%	89%	95%	92%
My personal role in combatting climate change is important	76%	80%	73%	78%	76%	67%	64%	71%	74%	78%	80%	65%	76%	81%
Reducing my greenhouse gas emissions is more important to me than saving a few dollars	55%	60%	52%	59%	54%	46%	41%	52%	54%	56%	62%	43%	58%	59%
It will be hard for me to significantly reduce my fossil fuel use in the foreseeable future	50%	45%	53%	49%	47%	54%	61%	43%	47%	43%	57%	46%	55%	45%

Significantly higher than 1+ subgroup Significantly lower than 1+ subgroup

Q29. If you were to replace your fossil fuel use with electricity, your electricity use would increase, meaning you would be spending more on electricity. On the other hand, your fossil fuel use will decrease, meaning you would spend less on things like gasoline and natural gas. Considering this scenario, please indicate your level of agreement to the following statements.

RATE PREFERENCE REVISITED

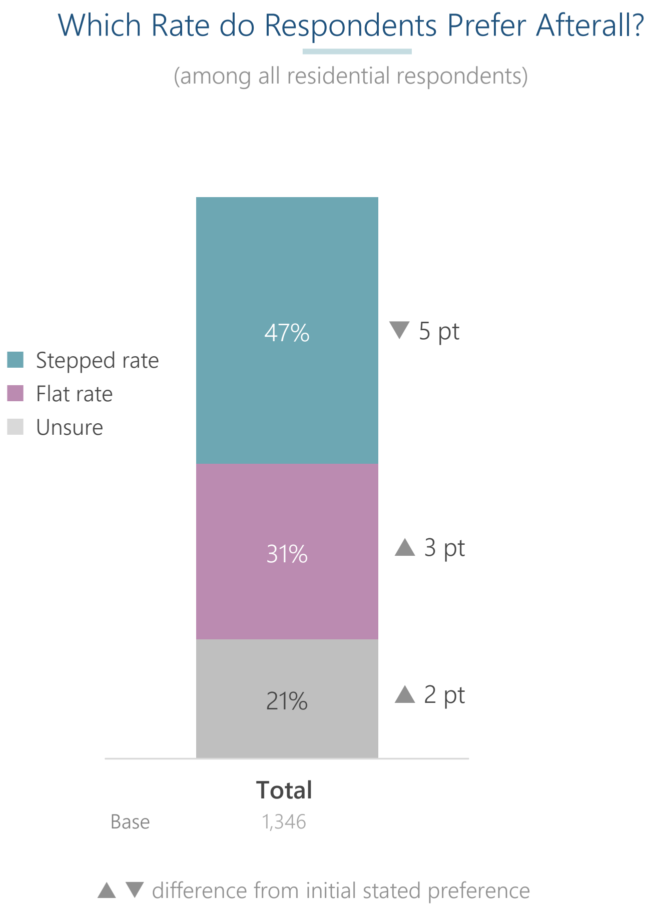
Toward the end of the survey, respondents were asked which rate might work best for them based on their possible electricity use in the future.

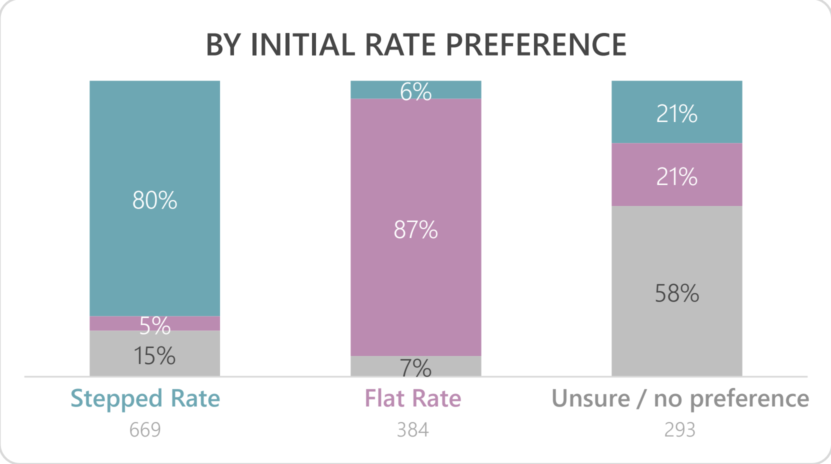
Overall, more continue to prefer the stepped rate (47%) over the flat rate (31%) but by a narrower margin compared to their initial preferences (1.5:1 vs. 1.8:1 at the outset of the survey).

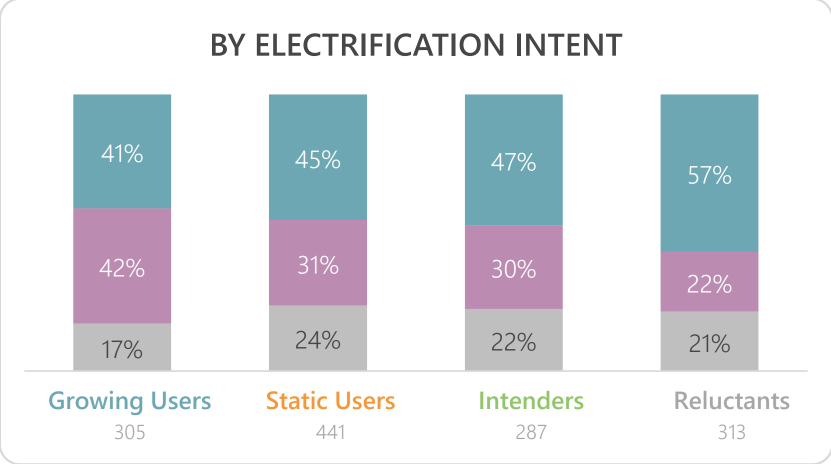
A small portion of respondents who indicated a preference at the start of the survey changed their mind (5-6% each).

Of those who were unsure, the majority remained uncertain by the end. The remaining four-in-ten were evenly split between the flat and stepped rate.

Preference for the flat rate increases with electrification intent.







Q30. Now thinking about your possible electricity use, which do you think might work best for you in the future?

Appendix

APPENDIX

Respondent Profile

sentis

RESPONDENT PROFILE

	Total	L.Main	VI/ Coast	South Int.	North/ N. Coast
		Region			
Base	1346	562	314	264	206
Region					
Lower Mainland	62%	100%	-	-	-
Vancouver Island / South Coast	21%	-	100%	-	-
Southern Interior	11%	-	-	100%	-
North / North Coast	6%	-	-	-	100%
Age					
18-24	1%	1%	1%	1%	1%
25-34	9%	9%	7%	9%	17%
35-44	18%	19%	12%	23%	29%
45-54	18%	22%	17%	6%	8%
55-64	17%	16%	17%	20%	19%
65+	31%	28%	39%	36%	24%
Prefer not to say	5%	5%	6%	6%	2%
Gender					
Male	53%	54%	49%	48%	52%
Female	40%	39%	42%	43%	42%
Other	<1%	<1%	1%	0%	1%
Prefer not to say	7%	6%	8%	8%	5%

	Total	L.Main	VI/ Coast	South Int.	North/ N. Coast
		Region			
Base	1346	562	314	264	206
Household Income					
Under $20,000	2%	2%	2%	2%	3%
$20,000 to under $40,000	9%	8%	8%	11%	17%
$40,000 to under $60,000	11%	10%	12%	10%	13%
$60,000 to under $80,000	9%	7%	12%	12%	12%
$80,000 to under $100,000	10%	10%	11%	8%	11%
$100,000 to under $120,000	9%	9%	8%	12%	12%
$120,000 to under $140,000	6%	7%	7%	4%	5%
$140,000 to under $160,000	6%	5%	8%	4%	5%
$160,000 to under $180,000	5%	5%	3%	3%	4%
$180,000 to under $200,000	3%	4%	2%	1%	4%
$200,000 or more	6%	8%	3%	5%	3%
Prefer not to say	23%	24%	25%	26%	11%
Income Group					
Base	1230	512	286	241	191
Low income	9%	9%	8%	12%	13%
Moderate income	43%	40%	46%	47%	56%
High income	48%	52%	47%	41%	31%

sentis

RESPONDENT PROFILE

	Total	L.Main	VI/ Coast	South Int.	North/ N. Coast
	Region				
Base	1346	562	314	264	206
Household Type					
Single detached home	59%	50%	70%	77%	79%
Manufactured home (such as mobile or modular home)	2%	1%	2%	6%	8%
Townhouse / rowhouse	14%	19%	6%	5%	2%
Duplex or similar	3%	4%	3%	3%	2%
Apartment or condominium	21%	26%	17%	8%	7%
Other	<1%	<1%	1%	1%	1%
Household Size					
Base	1230	512	286	241	191
1	21%	22%	18%	18%	24%
2	41%	36%	51%	46%	36%
3	14%	14%	14%	13%	14%
4	14%	15%	10%	13%	16%
5	6%	8%	4%	5%	6%
6	2%	3%	1%	3%	2%
7+	1%	1%	1%	1%	2%

	Total	L.Main	VI/ Coast	South Int.	North/ N. Coast
	Region				
Base	1346	562	314	264	206
Square Footage of Home					
Less than 1,000 square feet	20%	23%	16%	11%	16%
1,000 square feet to 2,500 square feet	58%	56%	63%	63%	60%
2,500 square feet to 4,000 square feet	22%	22%	21%	25%	24%
Type of Area					
Urban	48%	56%	38%	26%	29%
Suburban	35%	36%	35%	34%	24%
Rural	18%	8%	27%	40%	47%
Own or Rent					
Own	84%	82%	87%	89%	89%
Rent	15%	17%	13%	11%	10%
Neither – live with extended family / others	<1%	<1%	0%	<1%	1%

sentis

RESPONDENT PROFILE

	Total	L.Main	VI/ Coast	South Int.	North/ N. Coast
	Region				
Base	1346	562	314	264	206
Receive Bills For					
Heating	25%	27%	21%	25%	21%
Hot water	4%	4%	4%	4%	3%
Both heating and hot water	57%	53%	68%	59%	57%
Neither / not applicable	14%	17%	7%	12%	20%
Primary & Secondary Source of Home Heating					
Electricity	76%	75%	88%	70%	54%
Natural gas	58%	64%	36%	59%	68%
Wood	12%	7%	18%	21%	26%
Propane	3%	<1%	7%	9%	5%
Heating oil	1%	1%	4%	0%	1%
Other	4%	4%	2%	6%	6%
Main Source of Water Heating					
Electricity	47%	38%	73%	49%	47%
Natural gas	45%	53%	21%	45%	49%
Other	1%	<1%	1%	1%	1%
Unsure	7%	9%	6%	4%	2%

	Total	L.Main	VI/ Coast	South Int.	North/ N. Coast
	Region				
Base	1346	562	314	264	206
Main Home Heating Source					
Electric	38%	31%	61%	40%	32%
Mixed	62%	69%	39%	60%	68%
Home & Heating Segments					
E1	13%	14%	12%	8%	6%
E2	21%	15%	40%	24%	18%
E3	4%	2%	9%	8%	7%
M1/M2	44%	49%	27%	43%	51%
M3	18%	20%	11%	17%	17%
Percent in Step 2					
0%	29%	36%	17%	19%	23%
>0% - <50%	14%	14%	13%	17%	14%
50% - 99%	27%	24%	32%	33%	24%
100%	30%	26%	39%	31%	39%
Residential Customer Tenure					
Less than 2 years	7%	7%	8%	4%	7%
2-5 years	23%	22%	24%	27%	19%
5-10 years	26%	25%	24%	30%	28%
10-20 years	24%	23%	26%	22%	25%
20+ years	21%	22%	18%	16%	22%

sentis

RESPONDENT PROFILE

	Total	L.Main	VI/ Coast	South Int.	North/ N. Coast
		Region			
Base	1346	562	314	264	206
Electrification Segment					
Growing users	24%	26%	22%	24%	10%
Stagnant users	31%	28%	29%	52%	35%
Prospects	22%	24%	23%	8%	27%
Reluctants	23%	22%	26%	16%	28%
Own Electric Vehicle					
Yes	12%	14%	12%	5%	5%
No	88%	86%	88%	95%	95%
Own Heat Pump					
Yes	16%	11%	29%	17%	10%
No	84%	89%	71%	83%	90%
Home Cooling System					
Fans	57%	61%	52%	46%	61%
Non-central air conditioner(s), such as portable units or room/window units	25%	29%	15%	26%	31%
Central air conditioning	13%	12%	5%	40%	5%
Heat pump	13%	8%	26%	14%	8%
Other	3%	3%	2%	5%	1%
None of these	15%	14%	21%	8%	20%

	Total	L.Main	VI/ Coast	South Int.	North/ N. Coast
		Region			
Base	1346	562	314	264	206
Highest Level of Education					
Elementary school	<1%	<1%	<1%	0%	0%
Some high school	1%	1%	<1%	3%	3%
High school graduate	8%	5%	10%	12%	13%
Some college or technical school / CEGEP	11%	9%	12%	12%	21%
College or technical school / CEGEP graduate	18%	16%	16%	25%	29%
Some university	7%	7%	8%	6%	8%
University graduate	29%	31%	30%	21%	14%
Post graduate studies (masters / doctoral)	21%	25%	18%	14%	8%
Prefer not to say	5%	5%	6%	7%	4%

sentis

RESPONDENT PROFILE

	Total	L.Main	VI/ Coast	South Int.	North/ N. Coast
		Region			
Base	1346	562	314	264	206
Languages Spoken at Home					
Arabic	<1%	<1%	0%	0%	0%
Cantonese	4%	6%	<1%	0%	1%
Dutch	1%	1%	1%	1%	3%
English	89%	86%	94%	93%	95%
French	4%	4%	7%	4%	3%
Farsi	1%	1%	0%	0%	0%
German	2%	2%	1%	2%	1%
Hindi	1%	1%	<1%	0%	1%
Japanese	1%	1%	1%	0%	0%
Korean	1%	1%	<1%	0%	0%
Mandarin	3%	4%	1%	0%	2%
Punjabi	1%	2%	0%	0%	1%
Tagalog	1%	2%	1%	1%	0%
Vietnamese	1%	1%	<1%	0%	0%
Other	4%	4%	2%	4%	3%
Prefer not to say	6%	6%	4%	6%	2%

BC Hydro Optional Residential Time-of-Use Rate Application

Appendix D-7H

Time-of-Use Concept and Pricing Survey by Sentis

BC Hydro

Time of Use Rate Design Research

Full Report: February 6, 2023

sentis®

Adam DiPaula | adipaula@sentisresearch.com
Ayden Verhulst | averhulst@sentisresearch.com
Kate Wart | kwart@sentisresearch.com
thesentisgroup.com

CONTENT OVERVIEW

Where To Find What You’re Looking For

sentis

BACKGROUND

As part of its process of re-evaluating how electricity rates are structured, BC Hydro is gathering feedback from residential customers in three phases:

Phase 1: Understanding Needs

- Understand how residents currently use and manage home electricity
- Gauge resident priorities when it comes to the cost of electricity
- Collect preferences for possible future rate structures

Phase 2: Gathering Input on Possible Approaches

- Develop potential options for future rate structures
- Measure appeal and gather feedback on possible approaches
- Measure how reactions to different rate structure options vary by usage segment

Phase 3: Gathering Feedback on the Proposed Approach

- Measure understanding of, and interest in choosing, the optional time-of-use rate.

This report covers the findings from Phase 3.

sentis

OBJECTIVES & APPROACH

The purpose of this phase is to understand BC Hydro customers' perceptions of new potential electricity rate concepts.

The specific objectives of this research are as follows:

- Measure customer awareness of the current stepped rate structure
- Determine when customers currently use electricity when operating major appliances, preparing evening meals, and charging EVs
- Quantify the extent to which customers could shift their electricity use to off-peak times
- Gauge customer understanding of the TOU rate concept and their interest in learning more about it
- Measure the likelihood that customers will choose the TOU rate, and identify the main barriers to choosing this rate
- Test the appeal of versions of the TOU rate that vary the size of the credits and charges during the off-peak, peak, and overnight period
- Identify aspects of the TOU rate that could be modified to increase customer interest in considering the TOU rate

838 BC Hydro customers completed the survey

The survey questionnaire was designed by BC Hydro with input from Sentis. Sentis provided BC Hydro with a unique link to the online survey for each customer for distribution

Results were weighted by age and region to accurately reflect BC Hydro's customer base

The survey was open for completion from December 15 to December 23, 2022

The maximum margin of error for a sample of 838 is +/- 3.4% at the 95% level of confidence


Highlights
5

HIGHLIGHTS

sentis

The number of customers who are uninformed about the current rate structure is substantial.

Only a slim majority of customers (56%) are aware that their bills are currently calculated using the stepped rate structure, and most don't know how many of their bills have usage charges at the Step 2 rate.

This poses an additional challenge for communicating about the TOU rate because almost half of customers are learning about both the current rate structure and the proposed TOU rate structure simultaneously.

Behaviour change will need to be significant for customers to achieve a net benefit under the TOU rate.

The vast majority of customers (88%) prepare their evening meals during the peak period, and half (49%) currently do either their laundry or dishes during the peak period. Furthermore, it is not uncommon for customers to vary the times that they do each of these activities – four-in-ten (40%) don't have a set routine for laundry and three-in-ten (29%) don't have a set routine for when they do the dishes. Only a very small percentage of customers do any of these activities overnight.

Therefore, other than customers who have EVs (among whom already half charge overnight) it will be difficult for customers to realize net savings under the TOU rate without a significant shift in behaviour.

Customers do show a willingness to change some of their behaviours to align with the TOU rate.

Only 21% of customer say that they need to do their laundry during the peak period, and only 17% say that they need to run their dishwasher during this period. Further, over half of customers (58%) say that they could do both their laundry and dishes during an off-peak time.

However, customers are generally unwilling to shift the time they prepare evening meals – three-quarters (75%) say that they need to do this during the peak period. This is likely why customers are particularly likely to mention their inability to shift their evening meal prep time as a reason for not wanting to sign on to the TOU rate.

Overall, customers are divided on whether or not they would choose to add the TOU rate.

While 39% of customers said that they would likely choose the TOU rate, 32% said that they likely wouldn't.

The two strongest predictors of whether or not a customer will choose the TOU rate are EV ownership and whether or not the customer can shift both their laundry and dishwashing to off-peak times. Among EV owners/orderers, 59% say they're likely to choose it, while only 18% say they're not likely. Among those who can shift both their laundry and dishwashing, the respective figures are 56% and 12%.

Also note that the likelihood that customers will choose the TOU rate is related to their current consumption patterns. Among those who say they'll definitely choose the TOU rate, 52% already do their laundry during off-peak times and 37% already do their dishes during off-peak times. Among those who say they will definitely not choose the TOU rate, the respective figures are 31% and 20%.

sentis

HIGHLIGHTS

There are a few other variables that are related to how likely customers are to choose the TOU rate:

Age: those aged 55+ (who are more likely to be retired) are somewhat more likely to choose it – likely because they can more easily shift use to off-peak times.

Household size: larger households (4 or more) are somewhat less likely to choose it than smaller household sizes (3 or fewer) – likely because it is harder to control use as household size increases.

Income: Lower income households are somewhat less likely to choose it – perhaps because of the potential for bills to become less predictable under the TOU rate.

The following variables do not have any systematic relationship with how likely customers are to choose the TOU rate:

- Main home heating source
- Electricity consumption
- Region

Reactions to the TOU rate are based on whether or not customers feel that they can avoid peak period use.

Opposition to the TOU is driven by customers who say that they can't shift their use away from peak times, and therefore will experience higher bills. There are two kinds of "can't", however. There's a smaller group of customers who can't shift their use because of restrictions imposed by their strata or apartment complex. There's a larger group who can't shift their use because of a fixed routine that renders off-peak use impractical or inconvenient.

Currently, it appears that many customers don't give serious consideration to doing their laundry or running their dishwasher during the overnight period - or at least their immediate reaction is to consider doing these things impractical. It was not uncommon for customers to refer to the fact that they are sleeping during the overnight period when explaining why the TOU won't work for them.

Also, the prospect of modifying the TOU rate to increase the overnight credit is not something that makes customers more likely to consider choosing the TOU rate.

It was also rare for customers to indicate that they had appliances that could be set to run at specific times – or to mention that such a feature would make them more likely to choose the TOU rate.

Specifying the time commitment involved and offering a trial period could make customers more interested in the TOU rate.

Providing more details on the optional nature of the rate (e.g., indicating how long customers would need to sign on to the TOU rate before opting out) and a trial period to see how the TOU rate impacts their bills make customers more likely to consider the TOU. This is consistent with the fact that the most common additional information customers want to know is how the TOU rate will impact their bill.

A second charger is a non-starter.

Six-in-ten EV owners (59%) say they're likely to sign on to the EV-only charging rate. However, interest in this rate all but evaporates when the necessity of a second charger (and its attendant costs) is introduced.

13% DEFINITELY CHOOSE TO ADD TOU RATE

sentis

Who Are They?

91% can shift laundry & dishwasher to off-peak hours

39% have an electric vehicle or have ordered one

What Version They Prefer

Those who would definitely choose TOU prefer…

- Version 1 (+5 / -5) — 32%
- Version 2 (+3 / -3) — 15%
- Version 3 (+5 / +1 / -7) — 40%
- None of these / unsure — 13%

64% of those who prefer version 3 stated that it could **generate the most savings / had the lowest cost** given what they could currently shift.

In contrast, the most common reason provided among those who prefer version 1 is that it's **simple to understand** (38%).

What They Want to Know More About TOU

Top Reasons (among those commenting)

- 23% Practical information / tips about shifting activities and HE appliances
- 16% How will it impact my bill / provide more examples
- 9% What would billing and calculations look like?

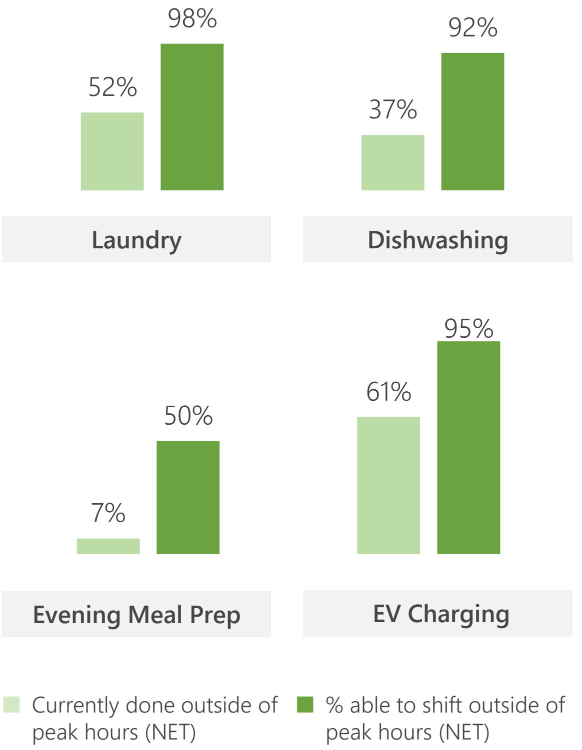
"Technologies that support shifting use. Most washing machines already have delayed start. Besides charging an electric car, what other uses are readily shifted? Are there smart hot water tanks (in contrast to on demand systems) for example."

Other Comments & Suggestions

"If we were to shift to the time of use rate, I would find it useful to be able to be shown on your daily consumption data how much electricity was used in each rate time period for each day. This would help the homeowner analyze and control their consumption better during the day."

"Those who reduce the need for additional peaking generation should be rewarded as much as practical."

Current Behaviour vs. Ability to Shift



Base: 115 customers who say they would definitely choose to add TOU

16% DEFINITELY NOT CHOOSE TO ADD TOU RATE

sentis

Who Are They?

35% living in households of 4+ people (vs. 25% overall)

59% in a single detached home
27% in an apartment or condo

17% in a low income household
43% in a moderate income household
40% in a high income household

6% have an electric vehicle or have ordered one

What Version They Prefer

Those who would definitely not choose TOU prefer...

Version	%
Version 1 (+5 / -5)	1%
Version 2 (+3 / -3)	10%
Version 3 (+5 / +1 / -7)	2%
None of these / unsure	86%

Of those who selected Version 2, 63% said it was because it was the **least punitive for peak time consumption / can't avoid it.**

Why They Would Not Add TOU

Top Reasons (among those commenting)

38%	Circumstances / routine dictate our power use / can't avoid peak time use
19%	Don't like this concept / not fair / not practical for people to shift use
17%	Negative / cynical comment about BC Hydro

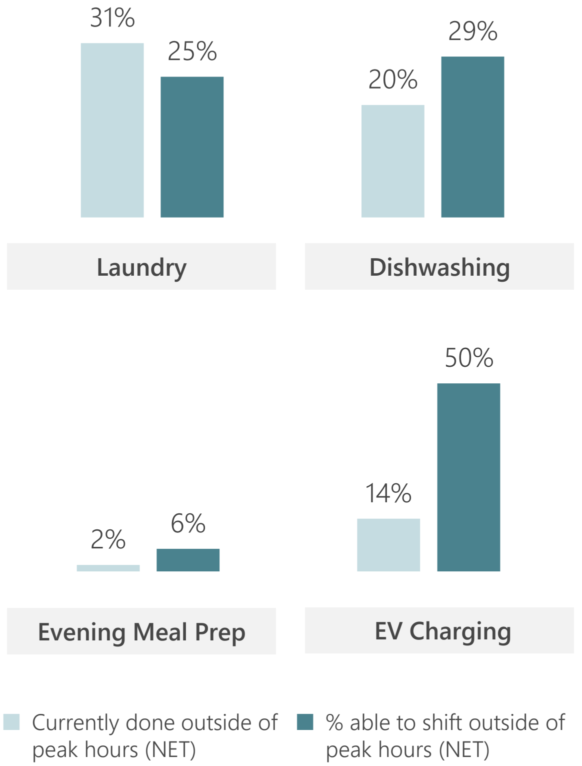
"I know that these time frames are the most heavily used. I get that. I want to eat my food hot and will eat after I cook. The dishwasher, I can choose when to run it. I don't have time to adapt my schedule to match this new plan. I'm a low energy user as it is... I sound angry. Please forgive. I am frustrated at having to change when I think there are other solutions."

Other Comments & Suggestions

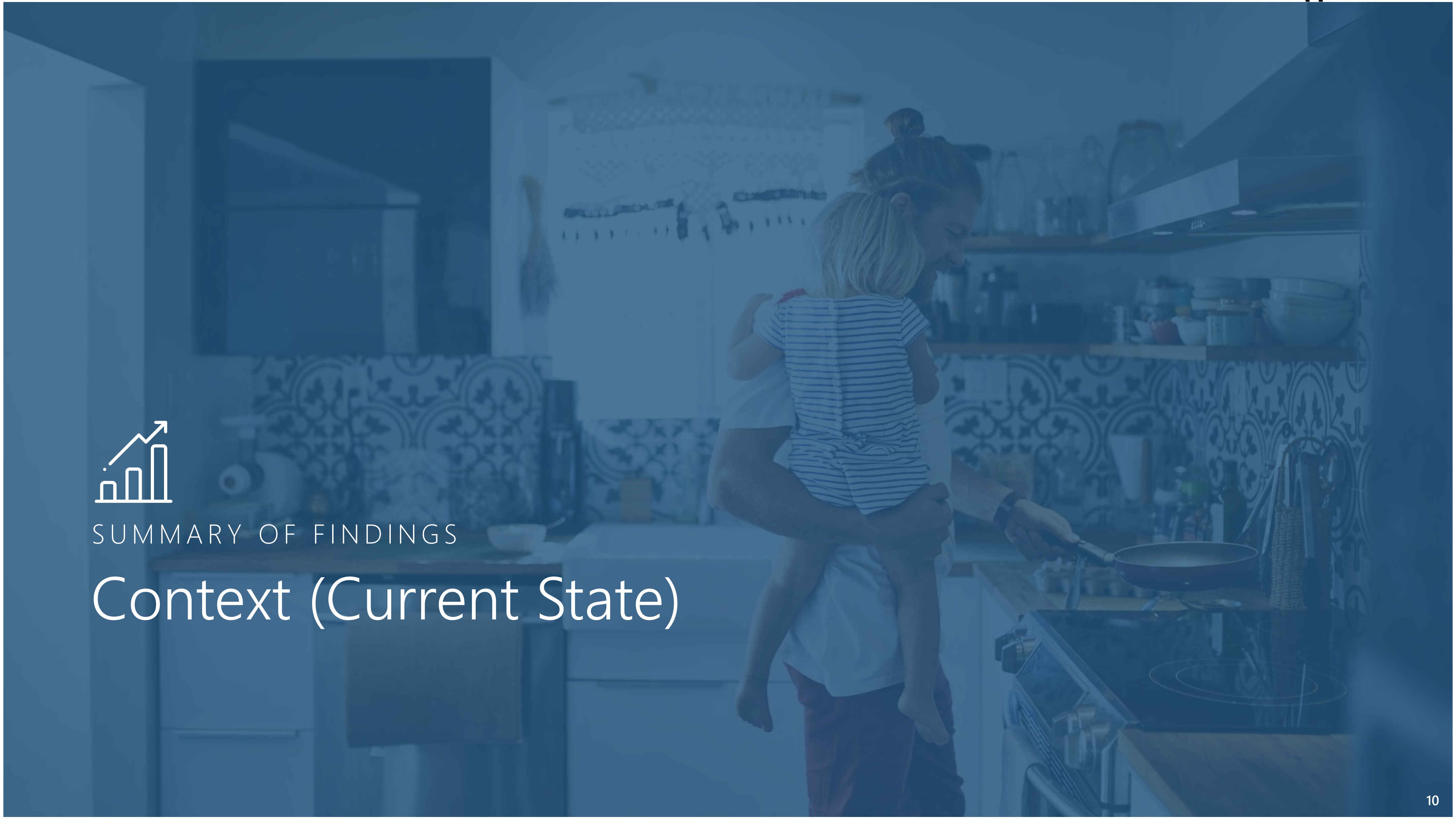
"I don't use much electricity. We seldom bother to use the dishwasher, only when there's company. But when the kids were at home and we worked, shifting use would have been difficult. Also, using appliances while one sleeps is not a good idea. What if there's a leak?"

"I get home at 5pm and need to complete my evening tasks before going to bed. Life is hard enough without worrying about being penalized for using a service we already pay for when we need it."

Current Behaviour vs. Ability to Shift



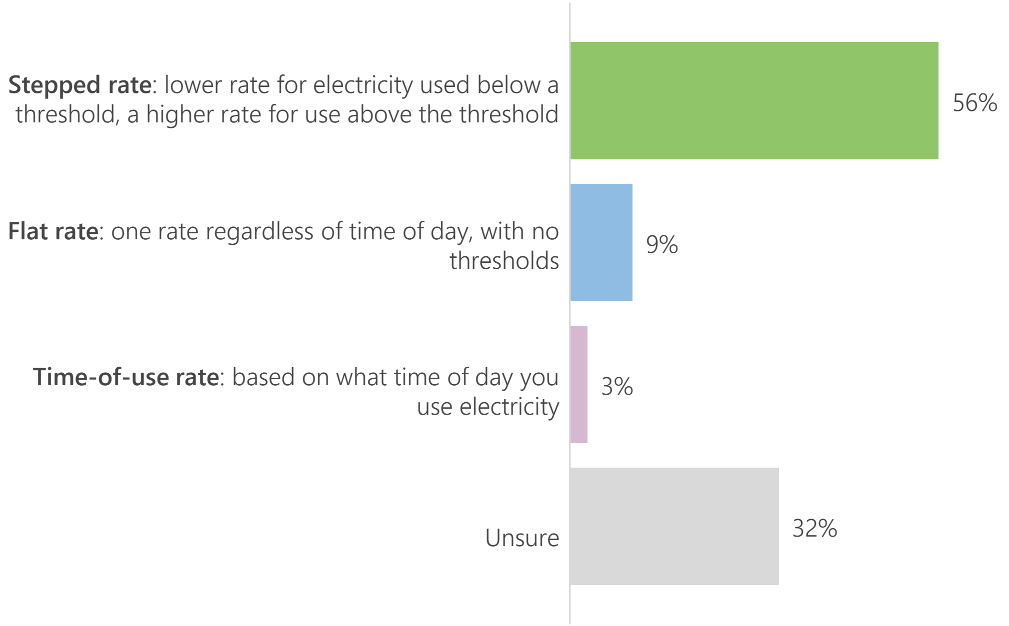
Base: 125 customers who would definitely not choose to add TOU


SUMMARY OF FINDINGS
Context (Current State)
10

Just over half (56%) of customers know what the current rate structure is.

Overall, 44% of customers aren't aware how their electricity bill is calculated. Just under one-third (32%) of customers say they're not sure how their bill is calculated while 12% assume it's calculated using a rate structure different from the stepped rate.

Rate Type Customers Think BC Hydro Uses



Base: Total (838)

B1. We're now going to get into electricity rates. Your BC Hydro bill is calculated based on how much electricity you have used in the billing cycle. This measure is known as kWh. Which of the following rate types do we currently use to calculate your electricity bill?

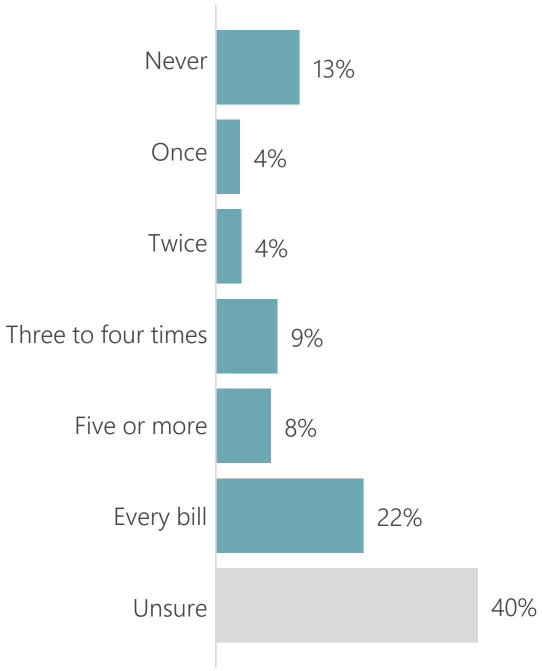
sentis

Most customers don't know how many of their bills are in Step 2.

Four-in-ten customers admit that they don't know how many of their bills have gone into Step 2 in the past 12 months.

Only 30% of customers (those who indicated that they've gone into Step 2 for either five or more bills or every bill) are reasonably accurate when it comes to reporting the number of their bills that have gone into Step 2.

How Often Customers Think They Have Gone into Step 2 in the Past Year



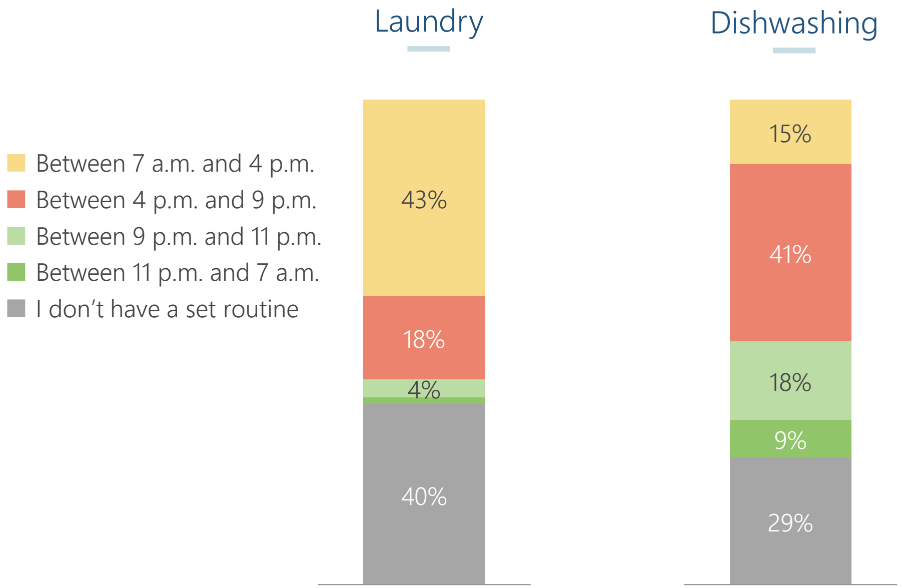
Avg. Number of Bills in Step 2 (from BC Hydro database)
837
3.89
4.19
4.78
5.94
5.87
6.56
5.55

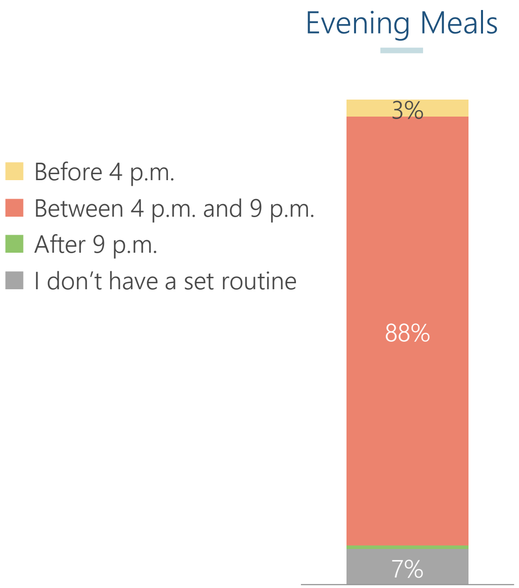
Base: Total (838)

B3. The answer to the previous question is "stepped rate." Here is an explanation and visual of how it works [EXPLANATION]. Thinking about your BC Hydro bills over the past year, how often has your household gone into Step 2 (i.e. having to pay the 14.08 cents per kWh rate)?

Almost all customers prepare evening meals during peak hours.

Only a very small percentage of customers currently have laundry, dishwashing, and evening meal preparation routines that would yield a net bill credit under the proposed TOU rate structure. Four-in-ten customers currently wash dishes during the peak period (which is the most common period for dishwashing) and the vast majority of customers prepare their evening meals during the peak period.





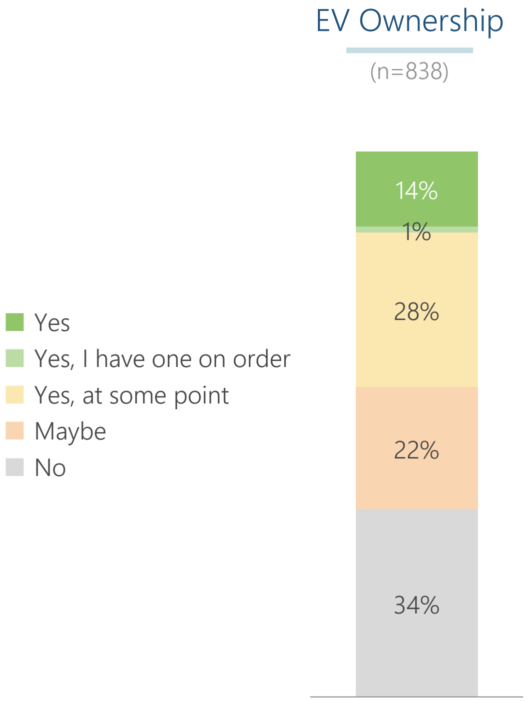
Base: Total (838)
A1. Typically, when are the dishes washed? / A4. At what time is the laundry usually done? / A6. During which time period are evening meals typically prepared in your home?

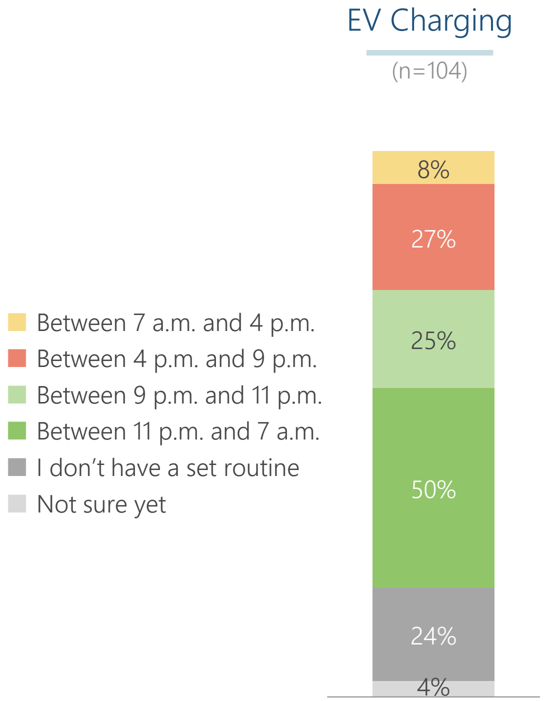
One quarter of EV owners currently charge their vehicles during the peak period.

sentis

Half of EV owners already have a routine in which they charge their vehicle during the overnight credit period (11 p.m. to 7 a.m.)

Only 27% of EV owners currently have a routine in which they charge their vehicles during the time in which a 5-cent charge would be incurred.





S5. Do you currently have an electric or plug-in hybrid electric-gas vehicle (EV)? / S6. Do you plan on getting an EV? / A9. When do you [typically / plan to] charge your EV at home?

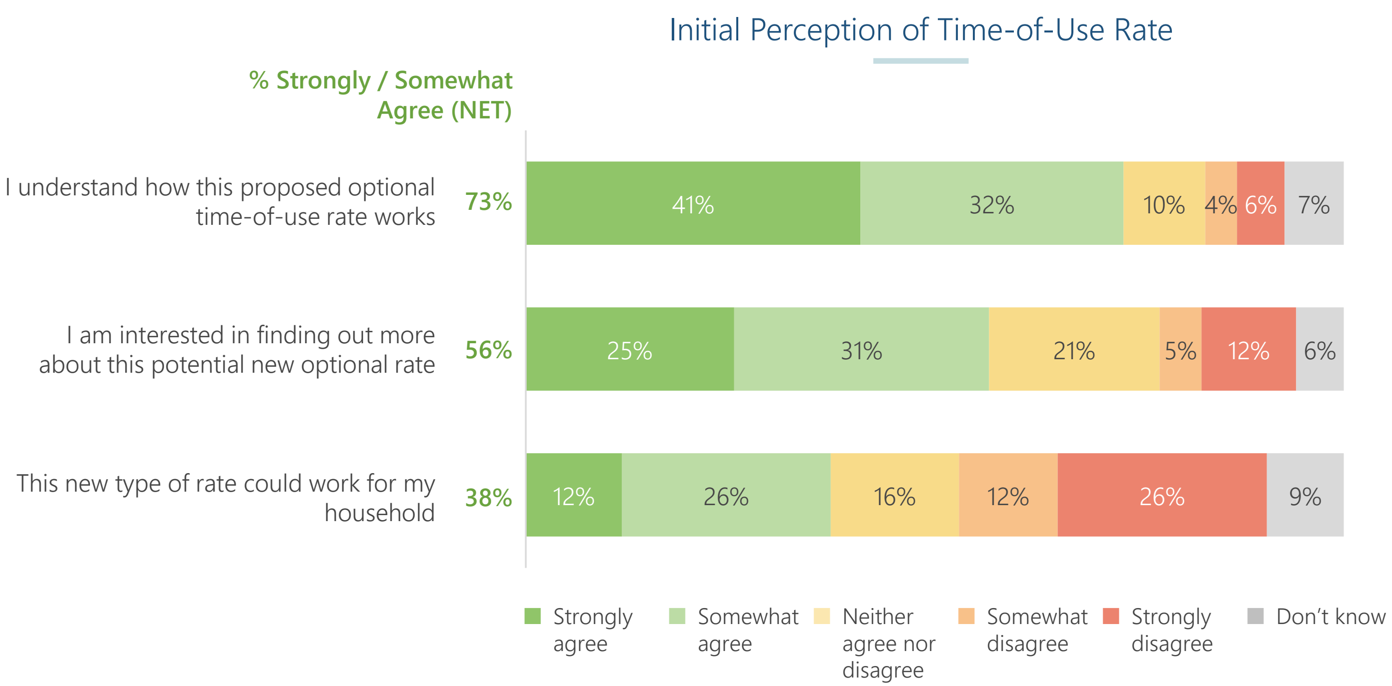

SUMMARY OF FINDINGS
TOU Rate Understanding & Appeal
15

sentis

38% of customers think the TOU rate could work for them.

Just under three-quarters (73%) of customers understand how the TOU rate works and the majority (56%) are interested in finding out more about it. Only 12% of customers are not at all interested in finding out more about it. Virtually all of these customers also strongly disagree that the TOU rate could work for their household. Therefore, they represent the subgroup of customers who are completely dug in in their opposition.

Overall, customers are divided regarding whether or not the TOU rate could work for their household. Just as many agree that it could work as disagree. Note that most of those customers who disagree that it could work *strongly* disagree that it could work.



Base: Total (822-834)
B4. Please indicate your level of agreement with the following statements:
B4a. I understand how this proposed optional time-of-use rate works. / B4b. This new type of rate could work for my household. / B4c. I am interested in finding out more about this potential new optional rate.

Customers who say they don't understand TOU tend to object to the rate concept, rather than say that they misunderstand any part of it.

sentis

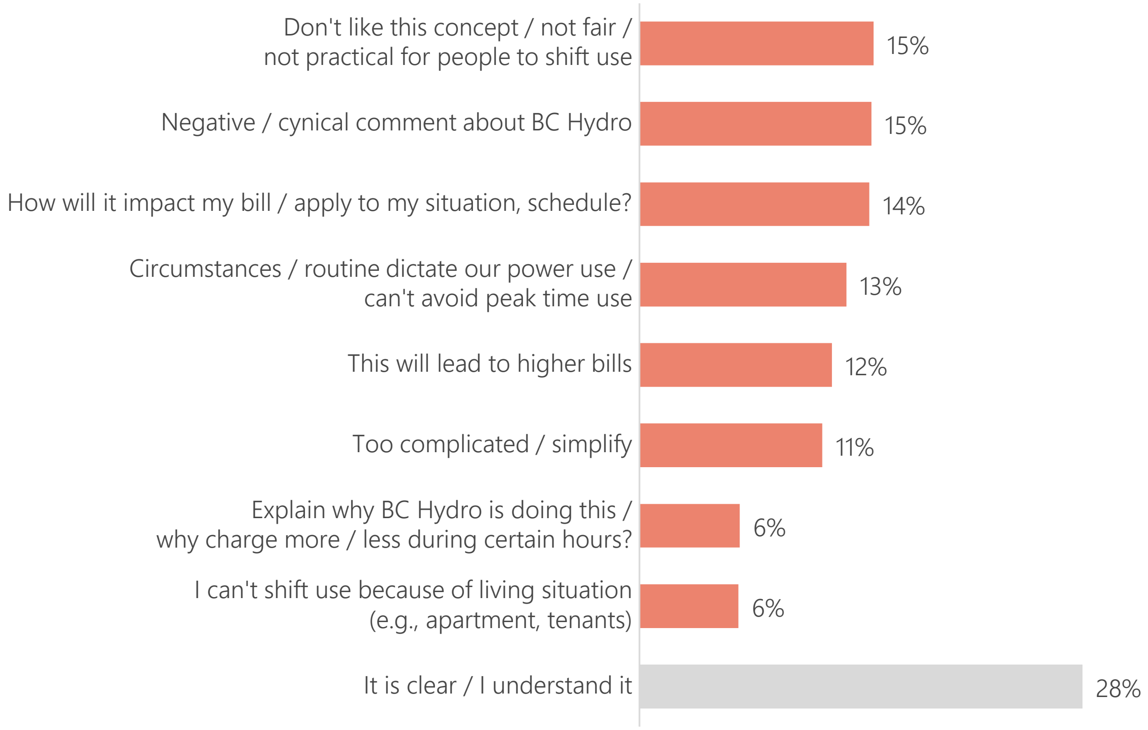
Virtually all of the customers who say that they don't understand the TOU rate at all also strongly disagreed that the TOU rate would work for their household.

This helps explain that, while they were asked what parts of the TOU rate they found unclear, these customers tended to respond with objections to the TOU rate or negative comments about BC Hydro.

The most common element that customers want clarification on is how the TOU will impact their bill.

What Customers Found Unclear

(Among those who rated neither / neutral, disagree or strongly disagree that they understand the TOU concept and left a comment, n=130)



Showing mentions of 5% or more.
B5. What parts of the optional time-of-use rate are unclear to you?

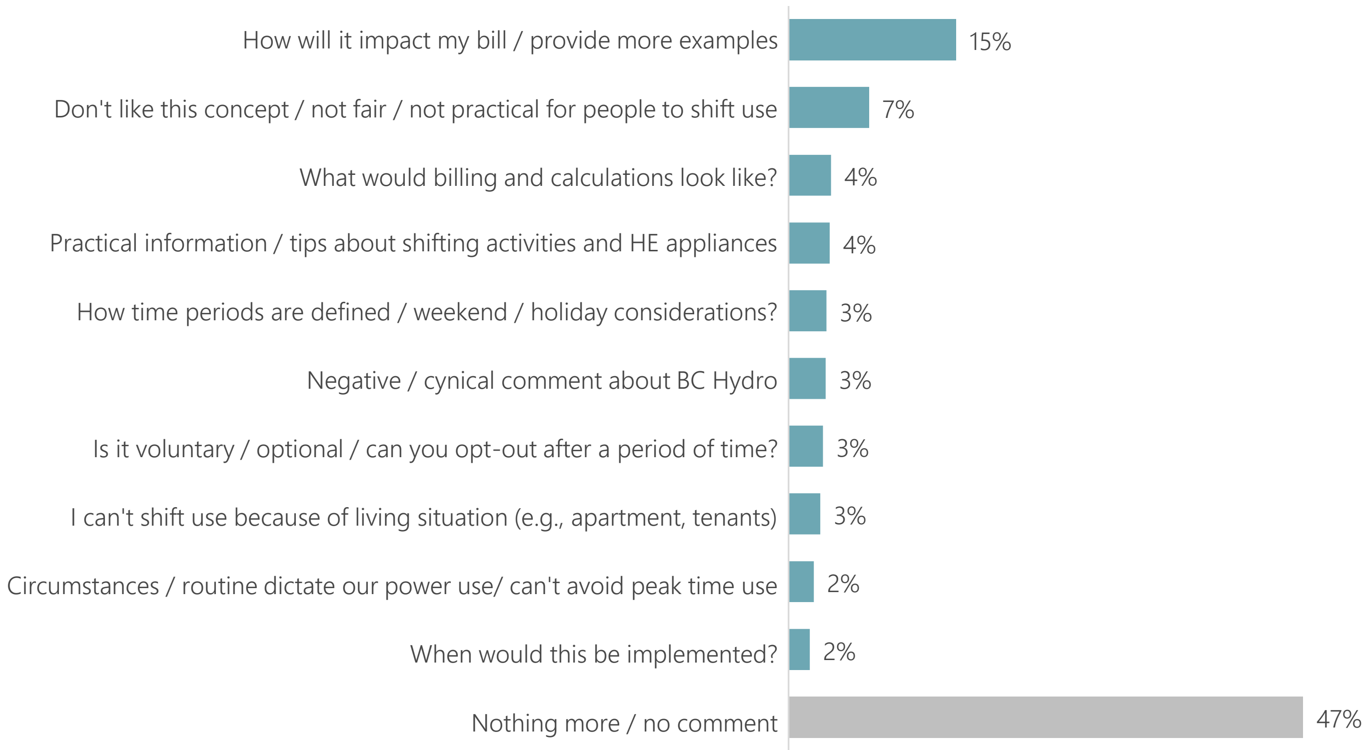
Customers would like to know how they personally will be impacted by TOU.

sentis

When asked what kinds of things they would want to know more about regarding the TOU rate, almost half of customers (47%) didn't provide any feedback.

The most common thing that customers mentioned is that they want to know how the TOU will impact their bill.

Information Customers Would Like About TOU



Base: Total (838)
Showing mentions of 2% or more.
B7. What kinds of things would you want to know more about when it comes to this proposed optional time-of-use rate?

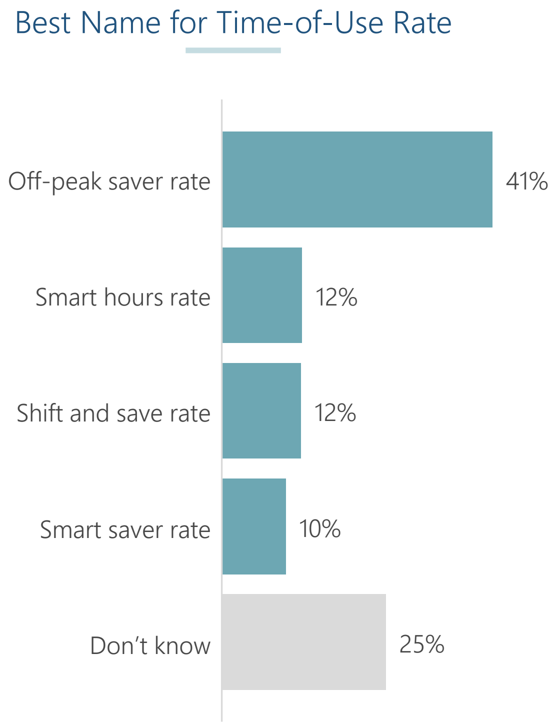
sentis

‘Off-Peak saver rate’ is the most popular name for TOU.

Customers show a clear preference for naming the TOU rate the ‘Off-peak saver rate’.

This preference may reflect a desire among customers to realize savings (i.e., lower bills) by using electricity during off-peak times.

However, as the TOU rate concept was presented in the survey, using electricity during the off-peak periods doesn’t produce ‘savings’ in the typical way in which this term is understood – as a reward for taking a certain action. Rather, using electricity during the off-peak helps the customer minimize the increase in their bills that will occur when they use electricity during the peak period.



Base: Total (838)
B6. Which of the following do you think is the best name for this time-of-use rate?


SUMMARY OF FINDINGS
Ability to Shift Use &
Likelihood of Choosing TOU
20

Customers are least likely to be able to shift their evening meals.

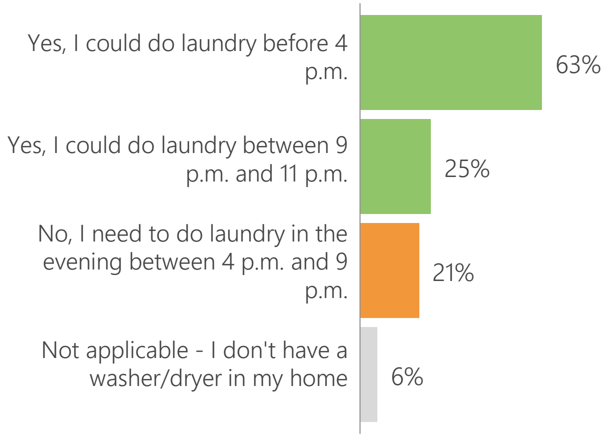
Customers generally demonstrate flexibility when it comes to how they could shift their dishwashing and laundry routines. Four-in-ten customers (41%) currently wash dishes during the peak period (see slide 10), but only 17% say that they need to run their dishwasher during this period. A notable percentage (37%) say they could run their dishwasher during the overnight credit period.

Just under half (47%) of customers currently do their laundry either before 4 p.m. or between 9 p.m. and 11 p.m. (see slide 10). However, three-quarters of customers (74%) say that they could do their laundry during these periods.

Customers demonstrate the least flexibility when it comes to shifting when they prepare evening meals – 88% currently prepare evening meals during the peak period – and three-quarters (75%) aren't able to shift outside of the peak period. This is why the TOU can create strong negative reactions among customers. In the qualitative follow-up part of the study customers were particularly likely to bring up the their inability to move their evening meal preparation time as the reason that the TOU won't work for their household.

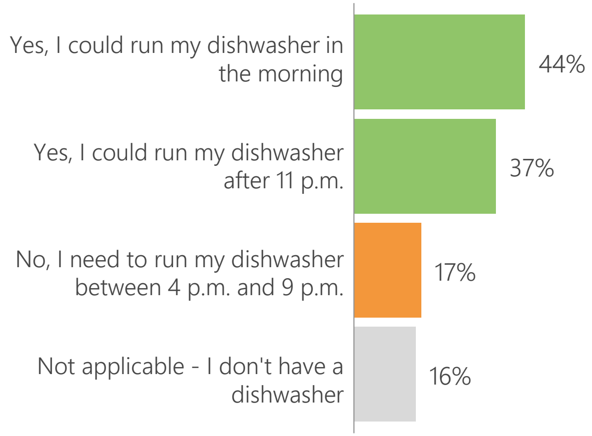
Laundry

74% could run during off-peak



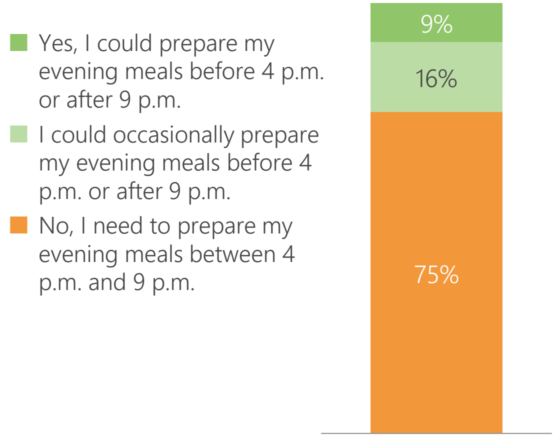
Dishwasher

67% could run during off-peak



Evening Meals

25% could prepare during off-peak



Base: Total (838)

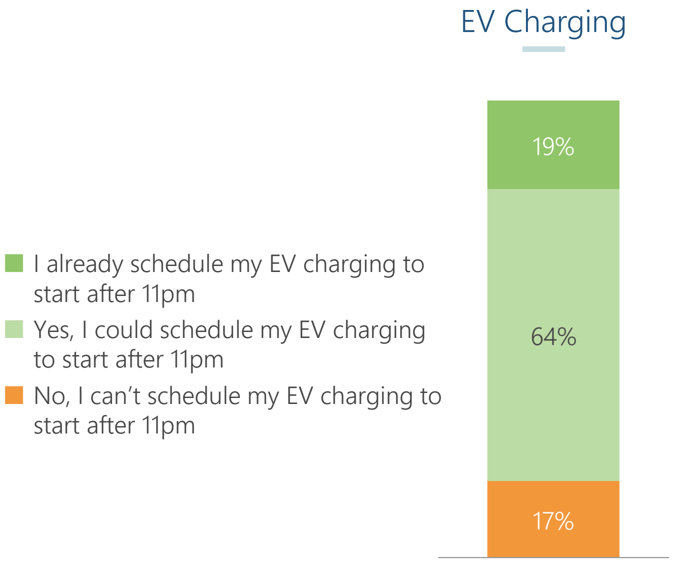
C1. Do you think you would be able to change the time that you do laundry, like shown in the above scenario? / C2. Do you think you could follow a dishwashing routine matching either of the different times as described in the above scenarios? / C3. Would you be able to change the time you prepare evening meals to before 4 p.m. or after 9 p.m.?

21

Most EV owners/orderers would be able to charge their EV after 11pm.

sentis

Only 17% of EV owners/orderers say they won't be able be able to charge their vehicle during the overnight credit period.



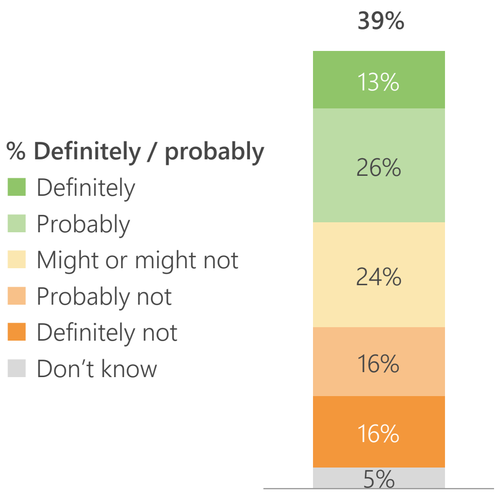
Base: EV owners and those who have ordered an EV (116)
C3b. Would you be able to schedule your home EV charging to start after 11p.m.?

39% of customers would choose to add the optional TOU rate.

Customers were given additional information about the savings they could potentially realize by shifting when they do laundry, dishes, or when they charge their EV (see Appendix). Customers remained divided – 39% said that they would either definitely or probably choose the TOU rate, while 32% said that they definitely or probably wouldn't choose it.

The two groups that are most likely to choose the TOU rate are EV owners/orderers and those who say they can switch their laundry and dishwashing to off-peak or overnight times.

Likelihood of Choosing TOU Rate



		EV Status			Ability to Shift	
	Total	Have / ordered EV	Interested in EV	Don't plan on getting EV	Could shift laundry & dishwasher	All Others
Base	838	116	415	307	504	334
Definitely / Probably (NET)	**39%**	**59%**	**39%**	**30%**	**56%**	**15%**
Definitely	13%	35%	12%	6%	21%	3%
Probably	26%	24%	28%	24%	36%	13%
Might or might not	24%	22%	24%	26%	28%	19%
Probably not	16%	11%	17%	17%	9%	26%
Definitely not	16%	7%	16%	22%	3%	34%
Don't know	5%	2%	5%	6%	4%	6%

Relatively higher than other subgroup(s)

Base: Total (838)
C4. After seeing these additional details, what's the likelihood you would choose to add this optional time-of-use rate?

Inability to avoid peak-time usage is the main reason customers are undecided or opposed to the TOU rate.

sentis

Opposition to the TOU rate is driven almost exclusively by customers anticipating that their bills with increase – whether this is stated directly (It will cost me more) or indirectly (I can't avoid peak time use, not practical to shift use). The follow-up qualitative part of the study shed additional light on why customers are unable to shift use. The following are the primary reasons customers give for not being able to shift: working outside the home during the day, having children that need to follow a set routine, being unable to take advantage of the overnight credit due to sleep schedule, not wanting to run appliances overnight due to noise or safety concerns and being part of a strata/apartment complex that prohibits the use of appliances during off-peak times or overnight.

Those who are undecided about the TOU rate are also concerned about the prospect of higher bills. However, they also want to know how the TOU will impact their bill.

Reason Customers Might or Might Not Choose TOU	
Base: among the 24% who might or might not choose TOU that left a comment	145
Circumstances / routine dictate our power use / can't avoid peak time use	29%
Need to know how it will impact my bill	21%
I want flexibility when I use electricity / don't want to be constrained	12%
More information / details necessary to decide	10%
Amount of savings isn't worth shifting use for / need bigger incentive	8%
It will cost me more	6%
I can't shift use because of living situation (e.g., apartment, tenants)	5%
Concerns about consumption / cost of specific appliances (e.g., A/C, heat pump)	5%

Reason Customers Probably or Definitely Would Not Choose TOU	
Base: among the 32% who probably or definitely would not choose TOU that left a comment	208
Circumstances / routine dictate our power use / can't avoid peak time use	35%
Don't like this concept / not fair / not practical for people to shift use	17%
It will cost me more	14%
Negative / cynical comment about BC Hydro	11%
I want flexibility when I use electricity / don't want to be constrained	11%
I can't shift use because of living situation (e.g., apartment, tenants)	10%
Amount of savings isn't worth shifting use for / need bigger incentive	8%

Showing mentions of 5% or more.
C5. Can you share with us why you [might or might not / probably would not / definitely would not] choose to add this optional time-of-use rate?

From qualitative follow-up research

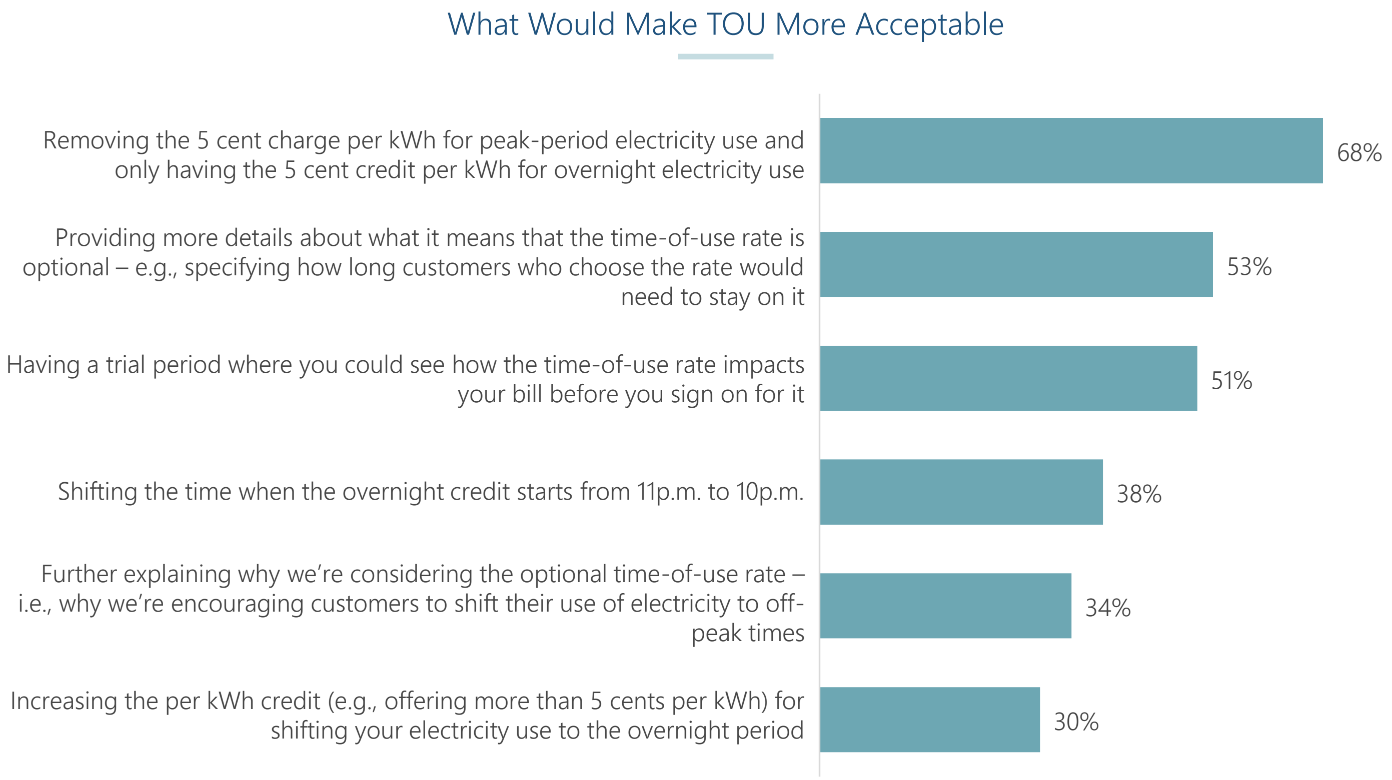
68% of those unlikely to add the TOU rate agreed that removing the peak charge would make them more likely consider.

In the qualitative follow-up part of the study customers who are unlikely to choose the TOU rate were asked if each of six potential changes/clarifications regarding the TOU rate would make them more likely to consider it.

Removing the peak charge is the change that would make these customers most likely to consider the TOU rate.

Providing more details on the optional nature of the rate and a trial period also make customers more likely to consider the TOU. This is consistent with the fact that the most common additional information customers want to know is how the TOU rate will impact their bill.

The fact that increasing the overnight credit ranks at the bottom of the list underscores that that this aspect of the TOU rate is simply not something these customers can conceive taking advantage of.



Among customers who somewhat / strongly disagreed that time-of-use would work for their household in B4b, and chose to participate in the follow-up survey (47).
G1c. Here are some things that other BC Hydro customers said would make them more likely to consider adding the optional time-of-use rate. We're interested in learning if any of these would make you more likely to consider adding it.

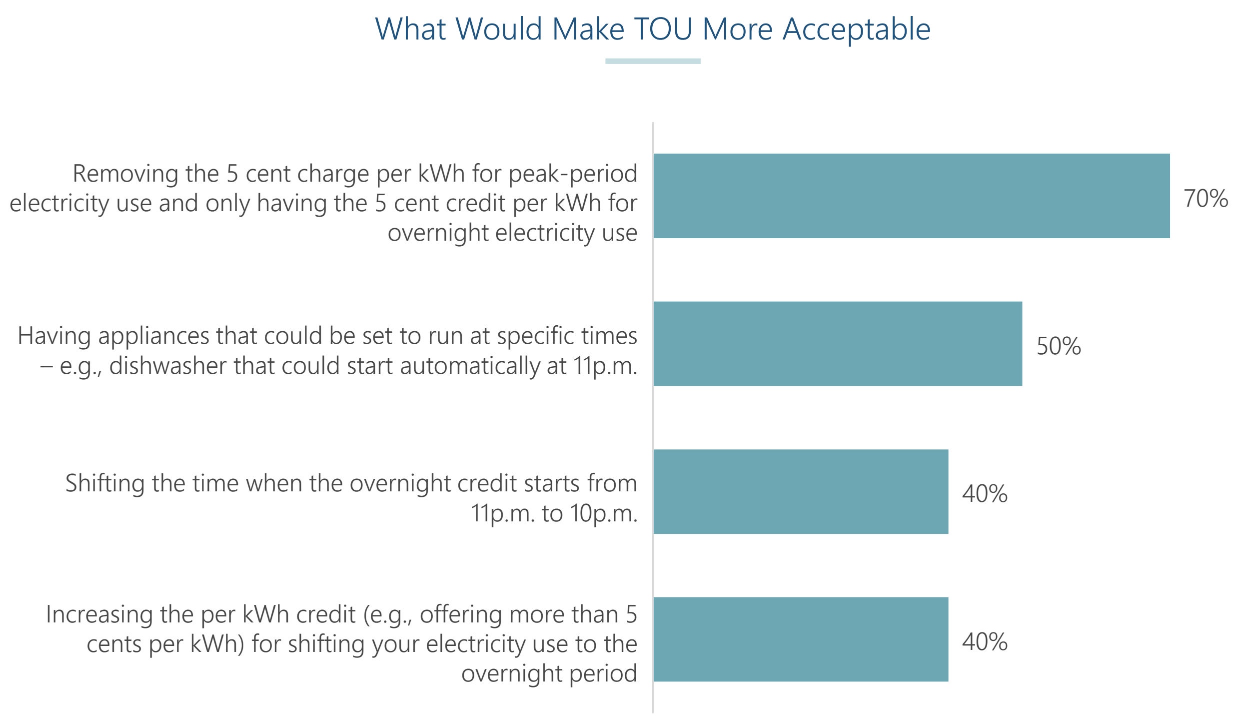
From qualitative follow-up research

sentis

Removing the peak charge has the most appeal, increasing the overnight credit has the least appeal.

In the qualitative follow-up part of the study customers who indicated that they could switch the time that they do their laundry or run their dishwasher but who said that they wouldn't be likely to choose the TOU rate were asked if each of four potential changes regarding the TOU rate would make them more likely to consider it.

Again, removing the peak charge is the change that would make these customers most likely to consider the TOU rate.



*Caution: small base (<30).
Among customers who are unlikely to sign up even though they can adjust either dishwasher or laundry and chose to participate in the follow-up survey (10)*.
G2c. Here are some things that other BC Hydro customers said would make them more likely to consider adding the optional time-of-use rate. We're interested in learning if any of these would make you more likely to consider adding it.

From qualitative follow-up research

sentis

VERBATIM COMMENTS

Group 1: Why TOU Wouldn't Work

"My primary issue is knowing what the actual cost consequence would be. It is possible it would result in savings - but without knowing for certain, I'm reluctant to commit to switching. The bulk of my electricity usage is during the day (as I retired person, I'm home most of the time). I could make a few usage changes fairly easily e.g., running the dishwasher at night and charging our PHEV during the 11 - 7 period only but I'm still not sure this would result in a net savings."

"I do not have an option to work from home and I am usually out at work from 7am until 6 or 7pm. I don't like to leave the dishwasher or laundry on while I am out in case of a water leak, and I don't stay up late so I have no option other than to do laundry in the evening. The dishwasher could go on at 9pm I guess. But cooking would certainly be during the peak period."

"I'm a single person in this household. I will not change my habits as time is worth more than a few pennies per week. My limited time is better spent working and earning money than worrying about when to do a load of laundry."

"We have children in our house. Between 4-9pm is when "we" as a household get home, have dinner etc. The increase would be exactly when we use the MOST power. It's by definition a harmful policy for anyone working a 9-5 style schedule."

"We live in a condo that has noise restrictions from 8am to 8pm, which includes running dishwashers, washing machines and vacuums. Since we work full-time and are out of the condo between 7am and 6pm, this means most of our usage would fall within the peak time and end up costing us more."

"The appliances we might want to use overnight (dishwasher and washer/dryer) keep our downstairs neighbours awake, so we can't run them during those hours. As we and they are both renters, we have no control over the quality of those appliances and are not in a position to replace them with quieter (or more energy-efficient) models."

Group 2: What Would Make TOU More Acceptable

"No, the time windows simply do not work for my family's schedule."

"I am not sure how we would change as we work during the day. Come home. Make dinner and all the rest of the chores during the time when you want to charge us more to use the electricity. Our household is already energy efficient. We use LED bulbs. Shut off lights, computers, televisions etc. when not in use. Dry some of the clothing outside in the summer and on racks in the winter in the house. We rarely go into the step 2 rate in a 2-month billing period cycle. Our appliances currently do NOT have timers to set them to come on at specific times. We would then have to spend thousands more dollars to change this and only save a little bit in the end…"

"No, unless society in general develops a work schedule that more evenly splits when people are at home/have time to do things, this sort of system will always disadvantage people with a regular 5-day work week."

"Only if the base rates were lowered to not create a large price increase from what current rates are to the peak demand time rates."

"Don't charge people who have absolutely no way to use electricity at night. Sure, give a deal to those who can use appliances at night, but don't punish people who can't."

"No, peak mealtimes align with our work schedules so without flexibility there the rest is irrelevant."

Note: Only showing a selection of comments
G1a.You mentioned that this time-of-use rate wouldn't work for your household. Could you tell us a bit more about why it wouldn't work? / G2a. Is there any way that the time-of-use rate could be changed to make you more likely to consider it?


SUMMARY OF FINDINGS
TOU Rate Scenario Preferences
28

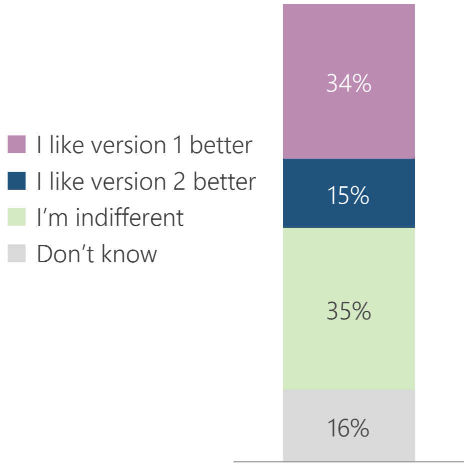
Given the choice, customers are twice as likely to opt for Version 1 over Version 2.*

sentis

Only 15% of customers would choose Version 2. Version 1 is the most preferred overall, as well as among EV owners/orderers and those customers who could shift the time that they do their laundry and run their dishwasher. The relative preference for Version 1 illustrates that more customers are focused on maximizing benefits (5 cent credit for off-peak use) than minimizing losses (3 cent charge for peak use).

Note, however, that a substantial percentage of customers (35%) are indifferent regarding the versions. Most of these customers would not choose to sign up for the TOU rate.

Version 1 vs. Version 2



		EV Status			Ability to Shift	
	Total	Have / ordered EV	Interested in EV	Don't plan on getting EV	Could shift laundry & dishwasher	All Others
Base	838	116	415	307	504	334
I like version 1 better (5 cent credit overnight, 5 cent charge during peak)	34%	53%	34%	26%	49%	12%
I like version 2 better (3 cent credit overnight, 3 cent charge during peak)	15%	13%	15%	16%	16%	14%
I'm indifferent	35%	24%	39%	34%	23%	52%
Don't know	16%	10%	12%	24%	11%	22%

*Please see the Appendix for how the versions were presented to customers.

Relatively higher than other subgroup(s)

Base: Total (838)

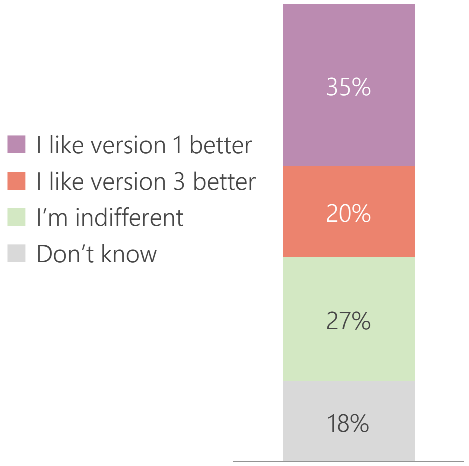
D1. What's your impression of optional time-of-use rate version 2 compared to optional time-of-use version 1 that we showed earlier?

sentis

Version 1 is also nearly twice as popular as version 3.

Version 1 is also the preferred choice when compared to Version 3, even though the scenario presented to customers shows Version 3 netting more savings than Version 1. Given that the vast majority of customers say that they have to use at least some electricity during the peak period, the 7 cent charge during this period likely dissuades them from choosing Version 3.

Version 1 vs. Version 3



		EV Status			Ability to Shift	
	Total	Have / ordered EV	Interested in EV	Don't plan on getting EV	Could shift laundry & dishwasher	All Others
Base	838	116	415	307	504	334
I like version 1 better (5 cent credit overnight, 5 cent charge during peak)	35%	46%	36%	29%	43%	25%
I like version 3 better (5 cent credit overnight, 1 cent credit between 9 p.m. and 11 p.m., 7 cent charge during peak)	20%	26%	20%	16%	27%	10%
I'm indifferent	27%	13%	31%	28%	17%	41%
Don't know	18%	15%	13%	26%	13%	24%

Relatively higher than other subgroup(s)

Base: Total (838)

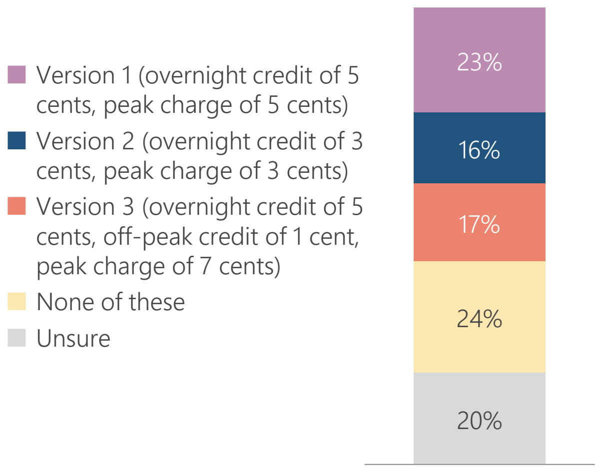
D2. What is your impression of the optional time-of-use version 3, compared to the optional time-of-use version 1?

There is a slight preference for Version 1. Versions 2 and 3 are equally popular.

sentis

When all three versions are presented to customers, customers still show a preference for Version 1, albeit less pronounced. This is because customers who previously selected either Version 2 or Version 3 when compared to Version 1, tend to retain their preference when comparing all three versions.

Most Appealing Version



		EV Status			Ability to Shift	
	Total	Have / ordered EV	Interested in EV	Don't plan on getting EV	Could shift laundry & dishwasher	All Others
Base	838	116	415	307	504	334
Version 1 (overnight credit of 5 cents, peak charge of 5 cents)	23%	33%	24%	17%	32%	10%
Version 2 (overnight credit of 3 cents, peak charge of 3 cents)	16%	17%	15%	16%	17%	14%
Version 3 (overnight credit of 5 cents, off-peak credit of 1 cent, peak charge of 7 cents)	17%	22%	17%	14%	24%	7%
None of these	24%	17%	24%	28%	10%	44%
Unsure	20%	11%	19%	25%	17%	24%

Relatively higher than other subgroup(s)

Base: Total (838)
D3. Of the optional time-of-use versions presented, which one do you find the most appealing?

Customers' version preferences are driven by what is reasonable for them to shift.

sentis

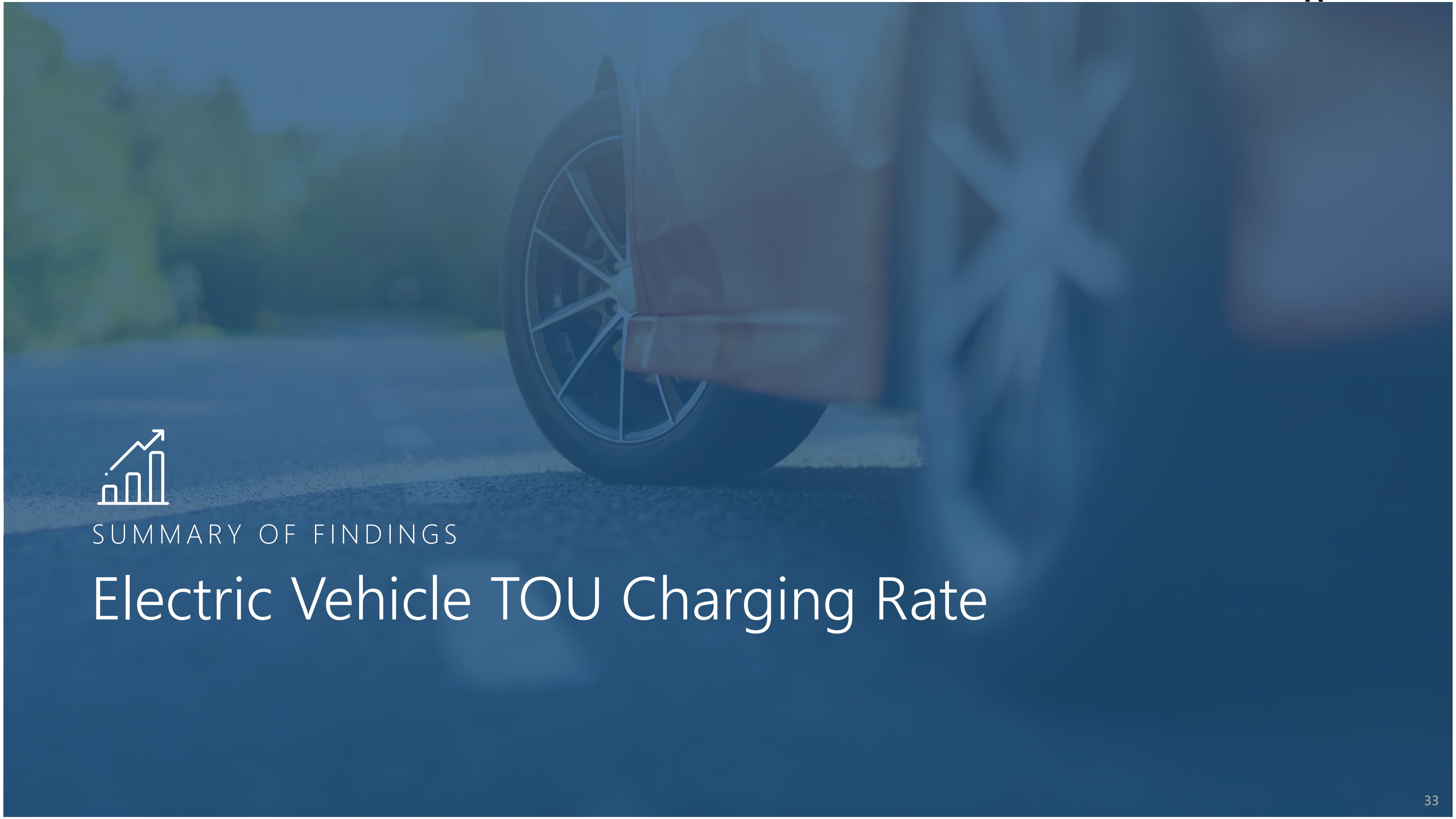
Customers who prefer Version 1 do so primarily because it could generate the most savings/smallest increases in bills, because it's simple to understand, and because it's less punitive than Version 3 (given that customers will need to use at least some electricity during the peak period). Customers who prefer Version 2 do so primarily because it's the least punitive version for peak time consumption and that it could generate the most savings/smallest increases in bills. Customers who prefer Version 3 are more squarely focused on the savings potential – presumable because they can shift a fair amount of their use away from the peak period.

Reasons for Preferring Version 1	
Base: among the 23% who prefer version 1 and left a comment	142
Could generate the most savings / lowest cost increases given what I currently do or can shift	37%
Simple to understand	29%
Less punitive than Version 3 / can't shift all use from peak	23%
Reasonable / good balance / trade-off between credits and charges	15%
Most flexible / fits my lifestyle, schedule	7%
Least punitive for peak time consumption / can't avoid it	3%

Reasons for Preferring Version 2	
Base: among the 16% who prefer version 2 and left a comment	84
Least punitive for peak time consumption / can't avoid it	35%
Could generate the most savings / lowest cost increases given what I currently do or can shift	31%
Reasonable / good balance / trade-off between credits and charges	14%
Less punitive than Version 3 / can't shift all use from peak	8%
Most flexible / fits my lifestyle, schedule	7%
Don't / hardly run appliances overnight	3%
Simple to understand	2%

Reasons for Preferring Version 3	
Base: among the 17% who prefer version 3 and left a comment	132
Could generate the most savings / lowest cost increases given what I currently do or can shift	69%
Most flexible / fits my lifestyle, schedule	15%
Reasonable / good balance / trade-off between credits and charges	5%
EV Savings	4%

Showing mentions of 2% or more
D4. Why do you prefer [D3 response]?


SUMMARY OF FINDINGS
Electric Vehicle TOU Charging Rate
33

59% of EV owners/orderers would choose the EV-charging rate over the TOU rate.

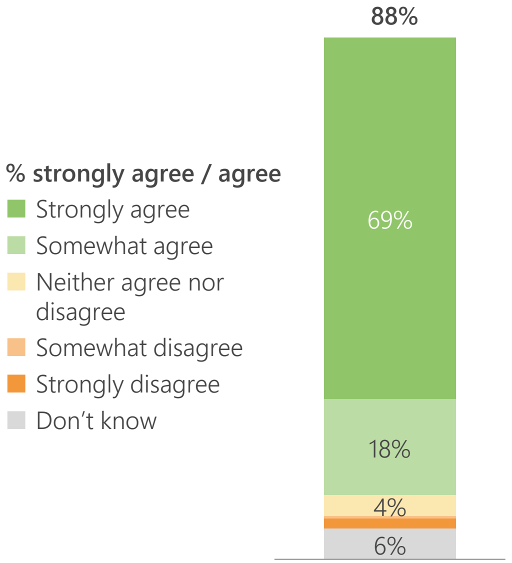
sentis

EV owners/orderers have a good understanding of the EV-only TOU rate.

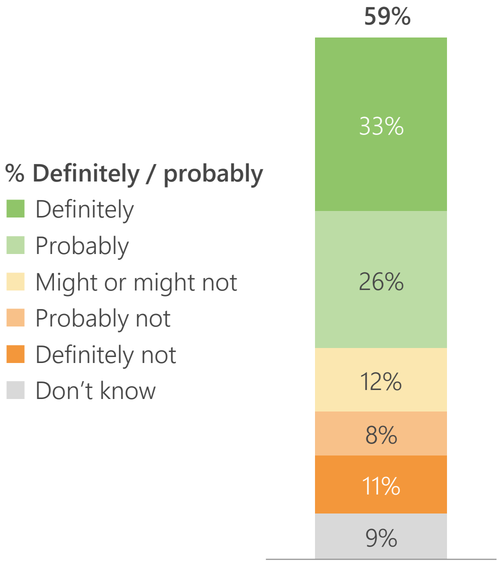
Six-in-ten of EV owners/orderers would choose this EV-only charging rate instead of the TOU rate for the home.

In the follow-up qualitative part of the study we learned that this group prefers the EV-only charging rate either because they can't change other aspects of their home electricity usage or that it would require greater discipline to reap the rewards of the TOU rate for the home. The EV-only charging TOU rate is simple to follow.

Understanding of Optional At-Home EV Charging Rate



Likelihood of Choosing EV Rate Over TOU Rate



Base: EV owners/orderers (116)

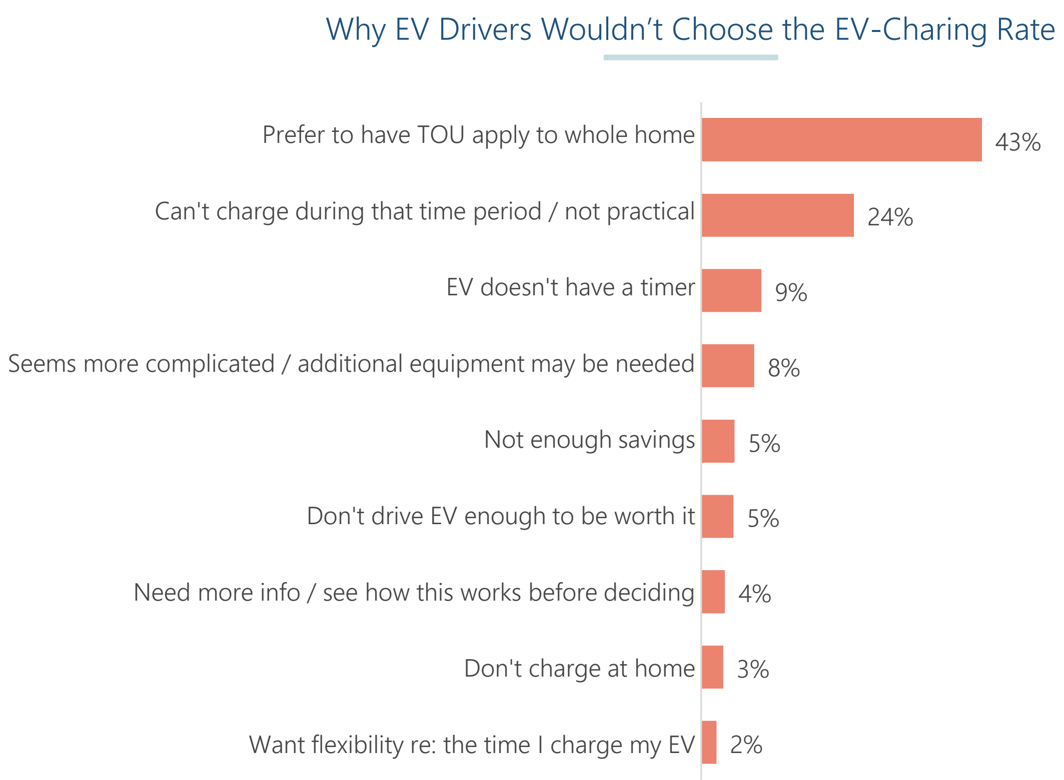
E4. Another rate option we're considering is for at-home EV charging specifically. That is, the optional time-of-use rate would be applied only to electricity used for charging your EV, and not to electricity you use in your home for other purposes. EV charging done between 11 p.m. and 7 a.m. would be credited 5 cents per kWh while charging between 4 p.m. and 9 p.m. would be charged an additional 5 cents per kWh. Please indicate your level of agreement with the following statement: I understand how this proposed optional time-of-use rate works. / E5. What is the likelihood you would choose this optional EV-charging rate instead of the optional time-of-use rate for the home?

EV owners/orderers who prefer the regular TOU rate would like the rates to apply to their whole home, and not just their EV.

sentis

The main reason that EV owners/orderers don't prefer the EV-only charging rate is that they want to benefit from the TOU applied to the whole home.

A secondary reason is that they can't charge during the overnight period.



Base: EV owners/orderers who might or might not, probably not or definitely not choose the EV rate over the TOU rate (36)
E5b. Can you share with us why this rate doesn't work for you?

Introducing additional information on second meters significantly reduces interest in the EV-charging rate

sentis

After learning that the EV-only charging rate requires a second meter that could cost "*up to a couple of thousand dollars or more*", interest in the EV-only charging rate plummets to 9%.

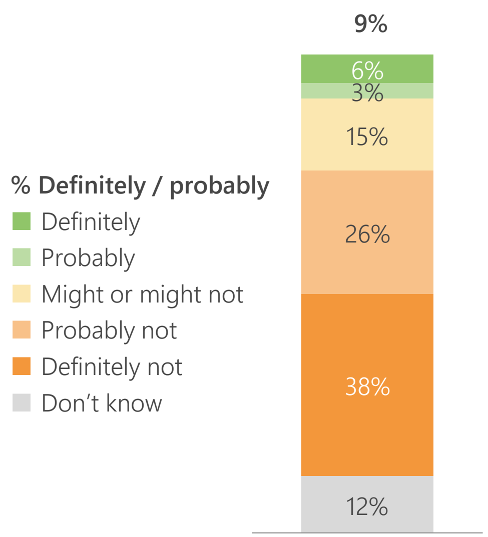
EV owners / orderers were presented with the following additional information about the eligibility for the EV Charging Rate and then asked to rate their likelihood of choosing the EV-charging rate instead of the optional time-of-use rate for the home.

"In the future, technology may become available that allows EV charging without a second electricity meter. However, for now, an EV-charging only rate requires a second meter installed on your property. The possible costs and requirements to be eligible for the rate are listed below:

For those with a second electricity meter already, there may be some added cost to reconfigure your meter base.

For those without a second electricity meter, the cost to purchase one is around $200, plus additional installation costs. Work may also be required to upgrade the electrical connection to your home before the meter can be installed. These costs could add up to a couple of thousand dollars, or more."

Likelihood of Choosing EV Rate Over TOU Rate After Additional Information



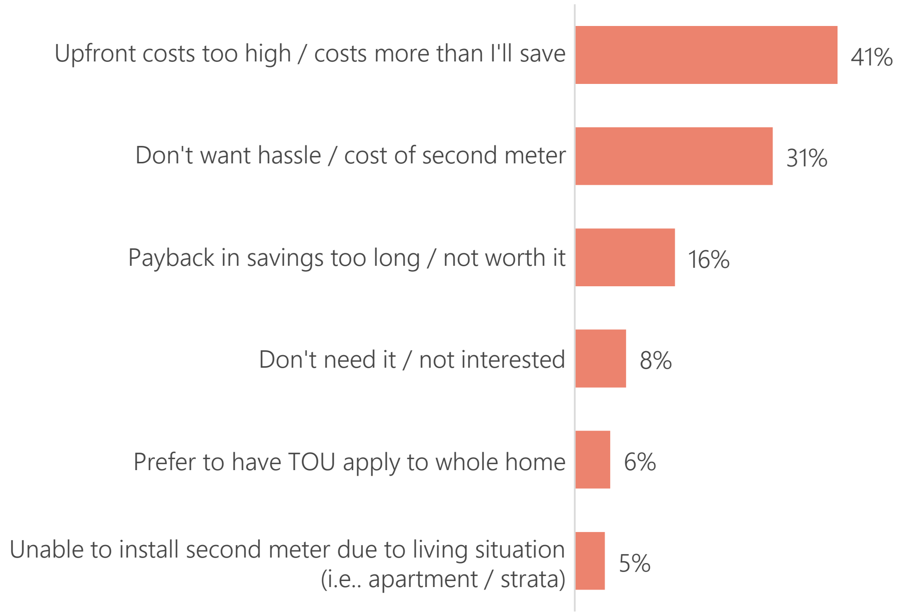
Base: EV owners/orderers (116)
E6. With this additional information about the eligibility requirements for this rate, what's the likelihood you would choose this EV-charging rate instead of the optional time-of-use rate for the home?

The cost and hassle of a second meter are not welcomed by EV owners/orderers.

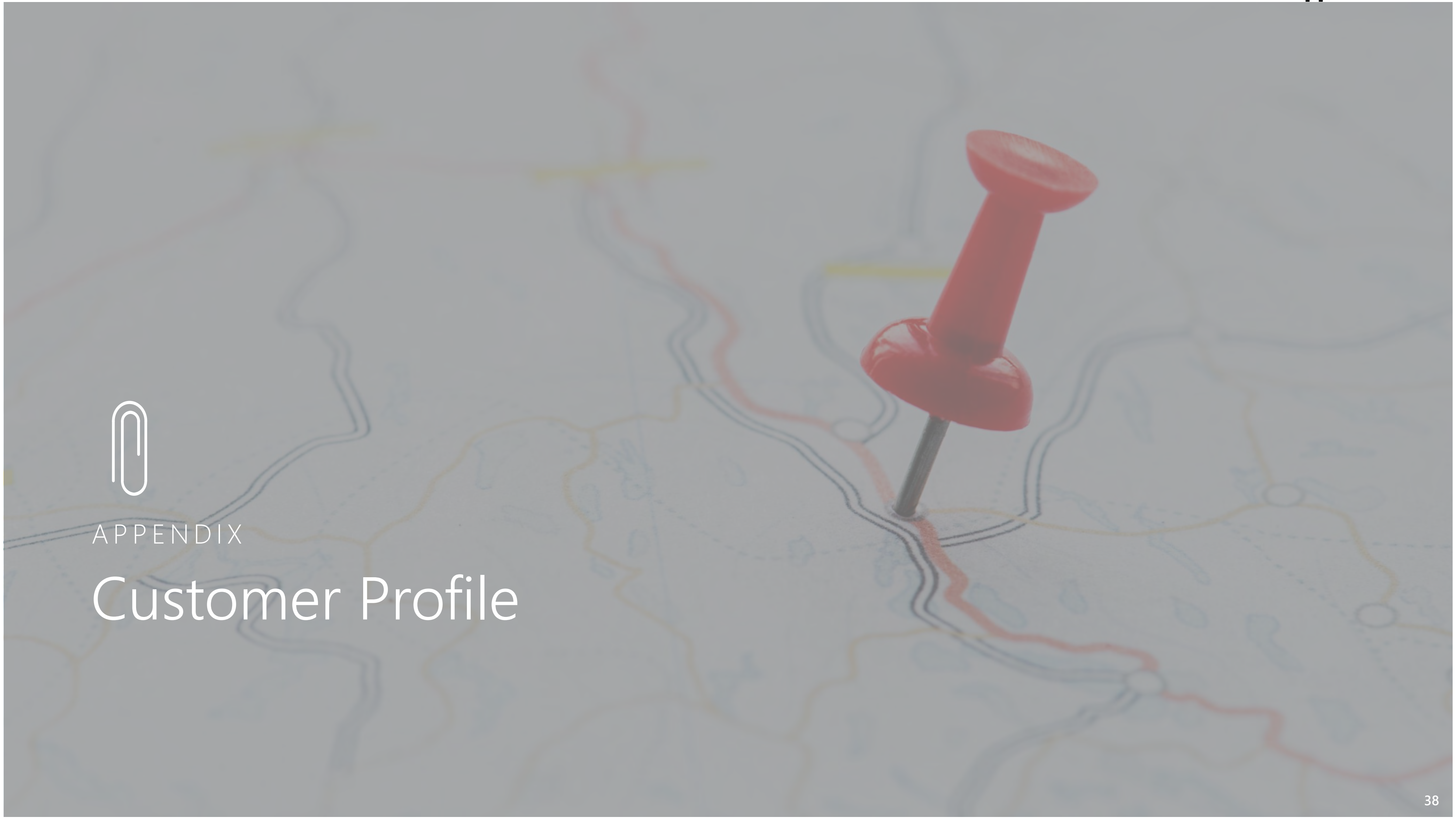
sentis

The main reason that the 64% of EV owners/orderers don't want to sign on to the EV-only charging rate is that the upfront costs are too high. They also don't want the hassle of having another meter to maintain.

Why EV-Only Rate Doesn't Work
(after additional information is presented)



Showing mentions of 5% or more.
Note: insufficient base to show why EV owners / orderers who definitely / probably / might or might not choose the EV-charging
Base: EV owners/orderers who probably or definitely would not choose the EV-charging rate after the additional information was shared (69)
E7. Can you share with us why you probably would not / definitely would not choose this EV-charging rate instead of the optional time-of-use rate?


APPENDIX
Customer Profile
38

sentis

RESPONDENT PROFILE

	Total	Lower Main.	Van. Island	South Interior	North
		Region			
Base	838	420	263	103	52
Region					
Lower Mainland	64%	100%	-	-	-
Vancouver Island / South Coast	21%	-	100%	-	-
Southern Interior	10%	-	-	100%	-
North	5%	-	-	-	100%
Age					
18-24	1%	1%	1%	0%	0%
25-34	17%	17%	13%	16%	24%
35-44	25%	26%	23%	21%	26%
45-54	17%	18%	15%	17%	16%
55-64	18%	18%	17%	20%	12%
65+	17%	15%	22%	20%	18%
Prefer not to say	6%	6%	9%	6%	3%
Gender					
Male	46%	48%	41%	46%	40%
Female	43%	43%	45%	41%	50%
Other	2%	2%	2%	2%	6%
Prefer not to say	9%	8%	11%	11%	3%

	Total	Lower Main.	Van. Island	South Interior	North
		Region			
Base	838	420	263	103	52
Household Income					
Under $20,000	2%	2%	2%	0%	8%
$20,000 to under $40,000	7%	5%	8%	6%	18%
$40,000 to under $60,000	9%	9%	9%	10%	3%
$60,000 to under $80,000	8%	7%	10%	6%	11%
$80,000 to under $100,000	11%	10%	9%	17%	14%
$100,000 to under $120,000	10%	11%	8%	10%	7%
$120,000 to under $140,000	4%	4%	7%	6%	0%
$140,000 to under $160,000	4%	4%	4%	1%	7%
$160,000 to under $180,000	4%	4%	3%	4%	0%
$180,000 to under $200,000	4%	4%	5%	4%	2%
$200,000 or more	11%	13%	7%	7%	4%
Prefer not to say	27%	27%	27%	29%	26%
Income Group					
Base	552	277	175	63	37
Low income	12%	10%	14%	6%	30%
Moderate income	48%	44%	52%	63%	53%
High income	40%	46%	35%	31%	17%

sentis

RESPONDENT PROFILE

	Total	Lower Main.	Van. Island	South Interior	North
		Region			
Base	838	420	263	103	52
Household Type					
Single-family detached home	51%	41%	66%	74%	66%
Duplex / triplex or similar	3%	3%	4%	3%	3%
Townhouse / rowhouse	13%	17%	6%	10%	6%
Apartment or condominium	30%	38%	20%	8%	11%
Mobile or modular home	2%	0%	2%	3%	14%
Other	1%	1%	1%	1%	0%
Household Size					
Base	730	365	232	84	49
1	23%	24%	23%	17%	25%
2	39%	37%	44%	44%	26%
3	14%	14%	13%	15%	10%
4	15%	15%	11%	19%	29%
5	5%	5%	4%	4%	4%
6	2%	2%	3%	2%	6%
7+	2%	3%	1%	0%	0%

	Total	Lower Main.	Van. Island	South Interior	North
		Region			
Base	838	420	263	103	52
Consumption Group					
Less than 5,000	29%	35%	20%	18%	18%
5,000 to < 8,500	25%	23%	24%	38%	27%
8,500 to < 13,000	22%	22%	21%	22%	24%
13,000 or more	24%	20%	35%	22%	31%
Own or Rent					
Own	78%	75%	80%	91%	79%
Rent	21%	24%	20%	9%	21%
Live with family but do not own the home	1%	1%	0%	0%	0%
Household Composition					
Base	730	365	232	84	49
1 Adult	23%	24%	23%	17%	25%
2 Adults, no children under 18	35%	34%	40%	42%	19%
Adult(s) with children under 18	30%	29%	30%	27%	47%
Three or more adults, no children under 18	12%	13%	7%	15%	9%

sentis

RESPONDENT PROFILE

	Total	Lower Main.	Van. Island	South Interior	North
		Region			
Base	838	420	263	103	52
Main Source for Heating Home & Water					
Electricity for both	38%	34%	60%	23%	33%
Electricity for home, natural gas for water	8%	9%	10%	3%	7%
Natural gas for both	30%	34%	12%	40%	28%
Natural gas for home, electricity for water	7%	6%	6%	15%	11%
Other	6%	4%	7%	16%	15%
Unsure	10%	14%	4%	2%	6%
Main Source of Water Heating					
Electricity	48%	40%	70%	44%	55%
Natural gas	39%	43%	23%	44%	37%
Wood	<1%	0%	<1%	1%	0%
Propane	2%	<1%	2%	9%	2%
Heating oil	0%	0%	0%	0%	0%
Other	2%	3%	<1%	1%	0%
Unsure	10%	14%	4%	2%	6%

	Total	Lower Main.	Van. Island	South Interior	North
		Region			
Base	838	420	263	103	52
Main Home Heating Source					
Electricity	56%	56%	74%	30%	44%
Natural gas	40%	43%	20%	56%	41%
Wood	2%	<1%	5%	7%	11%
Propane	1%	<1%	0%	5%	0%
Heating oil	<1%	0%	0%	1%	5%
Other	<1%	<1%	0%	0%	0%
Own Electric Vehicle					
Have EV or ordered one	15%	18%	13%	10%	0%
Interested in EV	51%	51%	58%	40%	37%
Don't plan on getting EV	35%	31%	29%	50%	63%
Own Heat Pump					
Have one	15%	10%	35%	13%	6%
Considering one	16%	14%	21%	11%	23%
Considered it but decided not to get one	12%	12%	11%	17%	18%
No	47%	52%	31%	54%	41%
Haven't heard of that before	9%	12%	2%	5%	12%


APPENDIX
Scenarios
During the survey, customers were presented with information about the TOU rate. The following slides showcase the content and format in which the information about TOU versions 1, 2 and 3 were presented. For each scenario, EV owners were provided additional information about EV charging.
42

sentis

VERSION 1

Question Text

C1. We'll now provide a bit more context on how this rate could work using a few possible scenarios related to how you use electricity. The below chart shows how you could potentially save by changing the time of day that you do certain energy-consuming behaviours. Note monthly and annual savings have been rounded.

Scenario	Potential Annual Savings -5 & +5 cents
You change the time that you do two loads of **laundry** from 7 p.m. to before 4 p.m., or between 9 p.m. and 11 p.m.	$24 ($2 per month)
You change the time that you run your ENERGY STAR® **dishwasher** each day from after you have dinner at 6 p.m. to after you have breakfast at 8 a.m. Or You change the time you run your ENERGY STAR® **dishwasher** each day from after dinner at 6 p.m. to before you go to bed at 11 p.m.	$13 ($1 per month) $25 ($2 per month)

Scenario	Potential Annual Savings -5 & +5 cents
You change the time that you do two loads of **laundry** from 7 p.m. to before 4 p.m., or between 9 p.m. and 11 p.m.	$24 ($2 per month)
You change the time that you run your ENERGY STAR® **dishwasher** each day from after you have dinner at 6 p.m. to after you have breakfast at 8 a.m. Or You change the time you run your ENERGY STAR® **dishwasher** each day from after dinner at 6 p.m. to before you go to bed at 11 p.m.	$13 ($1 per month) $25 ($2 per month)
Instead of plugging in your EV when you get home from work at 4:30 p.m. each day, you plug it in or schedule your EV to start charging after 11 p.m.	$243 ($20 per month)

sentis

VERSION 1 VS. VERSION 2

Question Text
D1. Now, here's a slightly different version of the time-of-use rate concept we just covered. The difference in the version below, which we'll call time-of-use rate version 2, is that the charge for using electricity during the peak period and the credit for electricity used during the off-peak period are each 3 cents per kWh, instead of 5 cents per kWh. Everything else is the same from the first version in terms of the example customer and average month's electricity usage. Note monthly and annual savings have been rounded.

	Potential Annual Savings	
Scenario	Version 1 -5 & +5 cents	Version 2 -3 & +3 cents
You change the time that you do two loads of **laundry** from 7 p.m. to before 4 p.m., or between 9 p.m. and 11 p.m.	$24 ($2 per month)	$14 ($1.17 per month)
You change the time that you run your ENERGY STAR® **dishwasher** each day from after you have dinner at 6 p.m. to after you have breakfast at 8 a.m. Or You change the time you run your ENERGY STAR® **dishwasher** each day from after dinner at 6 p.m. to before you go to bed at 11 p.m.	$13 ($1 per month) $25 ($2 per month)	$8 (67 cents per month) $15 ($1.25 per month)

	Potential Annual Savings	
Scenario	Version 1 -5 & +5 cents	Version 2 -3 & +3 cents
You change the time that you do two loads of **laundry** from 7 p.m. to before 4 p.m., or between 9 p.m. and 11 p.m.	$24 ($2 per month)	$14 ($1.17 per month)
You change the time that you run your ENERGY STAR® **dishwasher** each day from after you have dinner at 6 p.m. to after you have breakfast at 8 a.m. Or You change the time you run your ENERGY STAR® **dishwasher** each day from after dinner at 6 p.m. to before you go to bed at 11 p.m.	$13 ($1 per month) $25 ($2 per month)	$8 (67 cents per month) $15 ($1.25 per month)
Instead of plugging in your **EV** when you get home from work at 4:30 p.m. each day, you plug it in or schedule your EV to start charging after 11 p.m.	$243 ($20 per month)	$146 ($12.17 per month)

sentis

VERSION 1 VS. VERSION 3

Question Text

D2. Here's another version, which we'll call optional time-of-use rate version 3. Note that version 3 features three pricing periods instead of the two pricing periods in the other versions. Again, everything else from the example customer profile remains the same.

The details of version 3 are below:

- You receive a credit of 5 cents per kWh for electricity used between 11 p.m. to 7 a.m.
- You receive a credit of 1 cent per kWh for electricity used between 9 p.m. to 11 p.m.
- You are charged an additional 7 cents per kWh hour of electricity used between 4 p.m. and 9 p.m.

Note monthly and annual savings have been rounded.

	Potential Annual Savings	
Scenario	Version 1 -5 & +5 cents	Version 3 -5 / -1 / +7 cents
You change the time that you do two loads of **laundry** from 7 p.m. to before 4 p.m., or between 9 p.m. and 11 p.m.	$24 ($2 per month)	$38 ($3.17 per month)
You change the time that you run your ENERGY STAR® **dishwasher** each day from after you have dinner at 6 p.m. to after you have breakfast at 8 a.m. Or You change the time you run your ENERGY STAR® **dishwasher** each day from after dinner at 6 p.m. to before you go to bed at 11 p.m.	$13 ($1 per month) $25 ($2 per month)	$20 ($1.67 per month) $31 ($2.58 per month)

	Potential Annual Savings	
Scenario	Version 1 -5 & +5 cents	Version 3 -5 / -1 / +7 cents
You change the time that you do two loads of **laundry** from 7 p.m. to before 4 p.m., or between 9 p.m. and 11 p.m.	$24 ($2 per month)	$38 ($3.17 per month)
You change the time that you run your ENERGY STAR® **dishwasher** each day from after you have dinner at 6 p.m. to after you have breakfast at 8 a.m. Or You change the time you run your ENERGY STAR® **dishwasher** each day from after dinner at 6 p.m. to before you go to bed at 11 p.m.	$13 ($1 per month) $25 ($2 per month)	$20 ($1.67 per month) $31 ($2.58 per month)
Instead of plugging in your **EV** when you get home from work at 4:30 p.m. each day, you plug it in or schedule your EV to start charging after 11 p.m.	$243 ($20 per month)	$292 ($24.33 per month)

sentis

VERSION 1, 2 AND 3

Question Text
D3. Of the optional time-of-use versions presented, which one do you find the most appealing? Note monthly and annual savings have been rounded.

	Potential Annual Savings		
Scenario	Version 1 -5 & +5 cents	Version 2 -3 & +3 cents	Version 3 -5 / -1 / +7 cents
You change the time that you do two loads of **laundry** from 7 p.m. to before 4 p.m., or between 9 p.m. and 11 p.m.	$24 ($2 per month)	$14 ($1.17 per month)	$38 ($3.17 per month)
You change the time that you run your ENERGY STAR® **dishwasher** each day from after you have dinner at 6 p.m. to after you have breakfast at 8 a.m. Or You change the time you run your ENERGY STAR® **dishwasher** each day from after dinner at 6 p.m. to before you go to bed at 11 p.m.	$13 ($1 per month) $25 ($2 per month)	$8 (67 cents per month) $15 ($1.25 per month)	$20 ($1.67 per month) $31 ($2.58 per month)

	Potential Annual Savings		
Scenario	Version 1 -5 & +5 cents	Version 2 -3 & +3 cents	Version 3 -5 / -1 / +7 cents
You change the time that you do two loads of **laundry** from 7 p.m. to before 4 p.m., or between 9 p.m. and 11 p.m.	$24 ($2 per month)	$14 ($1.17 per month)	$38 ($3.17 per month)
You change the time that you run your ENERGY STAR® **dishwasher** each day from after you have dinner at 6 p.m. to after you have breakfast at 8 a.m. Or You change the time you run your ENERGY STAR® **dishwasher** each day from after dinner at 6 p.m. to before you go to bed at 11 p.m.	$13 ($1 per month) $25 ($2 per month)	$8 (67 cents per month) $15 ($1.25 per month)	$20 ($1.67 per month) $31 ($2.58 per month)
A customer typically plugs in their **EV** when they get home from work at 4:30 p.m. and keep it plugged in until their commute to work the next morning. By plugging in or scheduling the charging to being after 11 p.m.	$243 ($20 per month)	$146 ($12.17 per month)	$292 ($24.33 per month)

46

BC Hydro
Power smart

BC Hydro Optional Residential Time-of-Use Rate Application

Appendix D-7I

Digital Dialogue by UPWORDS

Understanding reactions to BC Hydro's proposed Rate Changes

Findings from Online Qualitative Research

August 2021

BC Hydro

upwords

INSIDE THIS FINAL REPORT

PROJECT DETAILS

upwords

3

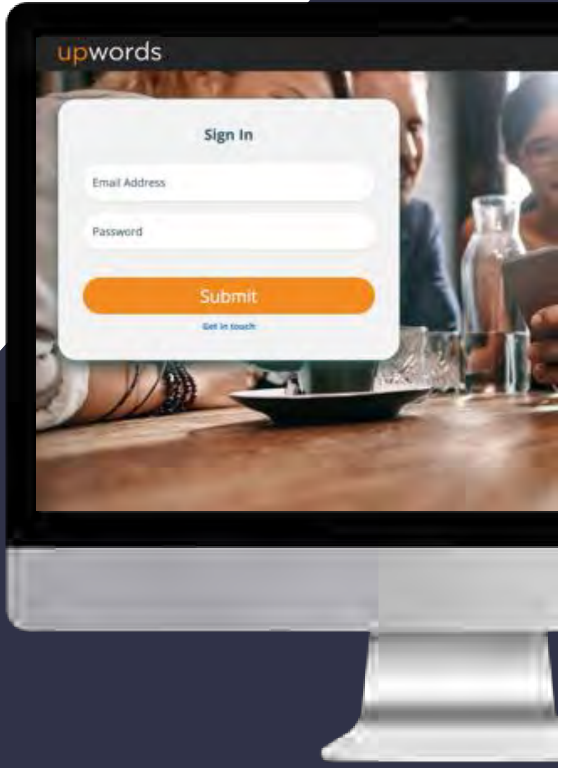
HOW WE WENT ABOUT IT
Project Details

2-day
Online
Discussion

OBJECTIVE: BC Hydro wanted to deeply understand customer perceptions and opinions on proposed alternatives to the current default electricity rate and voluntary time of use rate options.

2-day online discussion; ~90 minutes of activity/participant in total

- Participants logged in to the online discussion platform to complete their tasks
- Tasks were completed independently to eliminate social desirability bias and groupthink
- Professionally trained moderators from Upwords probed for clarity and added detail
- Stakeholders could log in to the platform to observe the discussion.



Part 1

- Considerations
- Current Stepped Rate
- Flat Rate – Description only
- Annual Usage Rate – Description only
- Flat Rate – hypothetical bill impact

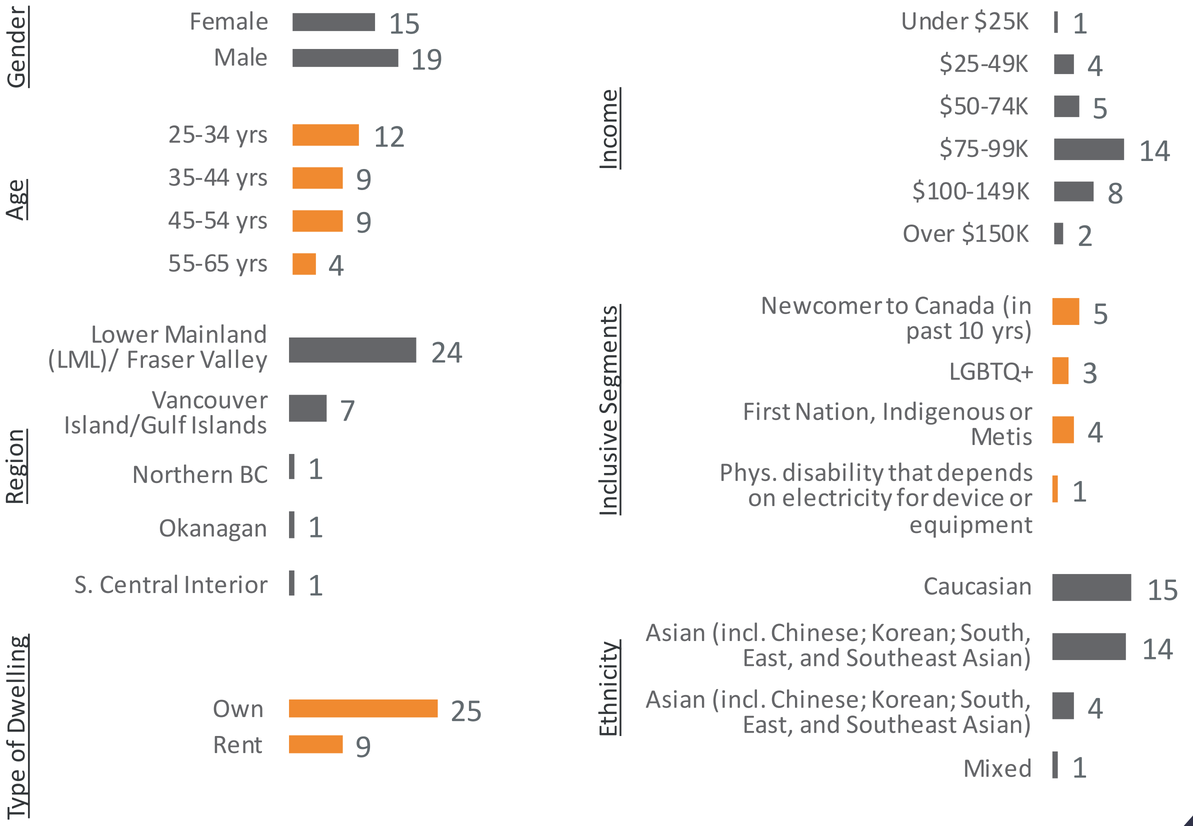
Part 2

- Annual Usage Rate – hypothetical bill impact
- Comparison of options
- Voluntary Opt-In Rates
  – Whole Home & Electric Vehicles

Hypothetical bill impacts were based on actual usage data, where possible

WHO WE TALKED TO: PARTICIPANT DETAILS

34 verified BC Hydro Customers completed this discussion.



HOW TO

INTERPRET THE FINDINGS

The findings of these interviews are qualitative in nature and cannot be projected to be statistically representative of the population.

They represent the views of a small group of BC Hydro customers across British Columbia.

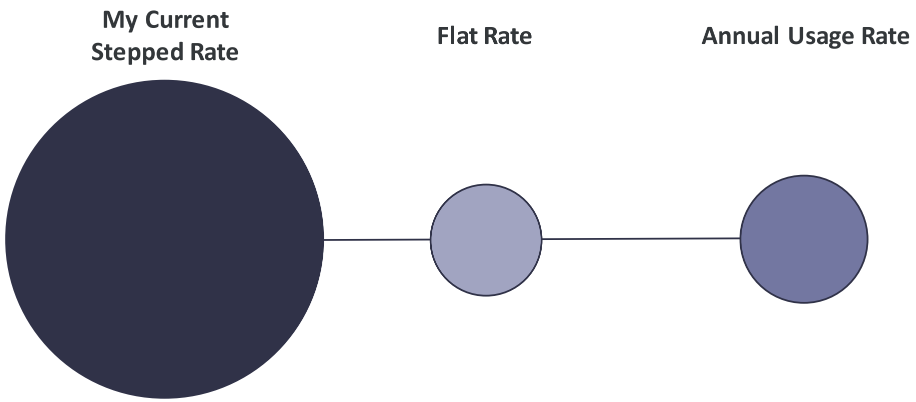
They are however valuable in providing **direction and insight** into the issues discussed.

INSIGHT SUMMARY

There is strong preference for Current Stepped Rate: preference for ANY option was typically rooted in financial considerations (lowest bill), as well as the perceived incentive for reducing energy usage

PRE (based on description only)

Q. Based on all three descriptions you just saw, which (if any) of these three options would you personally prefer? I prefer…

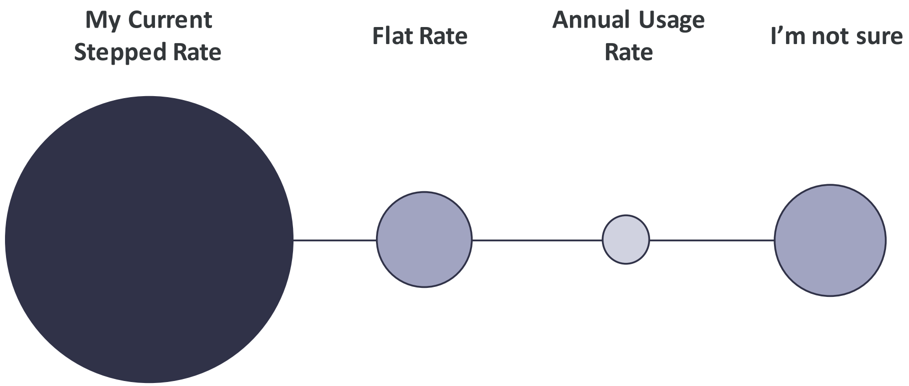


*I feel that the current model is more fair than the new options because **flat rate doesn't encourage [to] reduce consumption**.*
- Male, Lower Mainland, 35-44 years old

*The stepped rate option offers much more flexibility and **potential savings during low usage months.***
- Female, Greater Vancouver, 25-34 years old

POST (after seeing bill impact)

Q. Thinking of all of the options you've seen, and their hypothetical bill impacts for you, which do you personally feel would be preferable for you personally? I prefer…



*The stepped rate seems **more economical for my usage**, and I really like the fact that the **rate is going up if you use more energy**. For example, I think that if someone has several TVs on all day, their consumption is going to be much higher, and they are putting a strain on the system, and this should be reflected in their bill **to encourage a more mindful consumption.***
- Male, Metro Vancouver, 25-34 years old

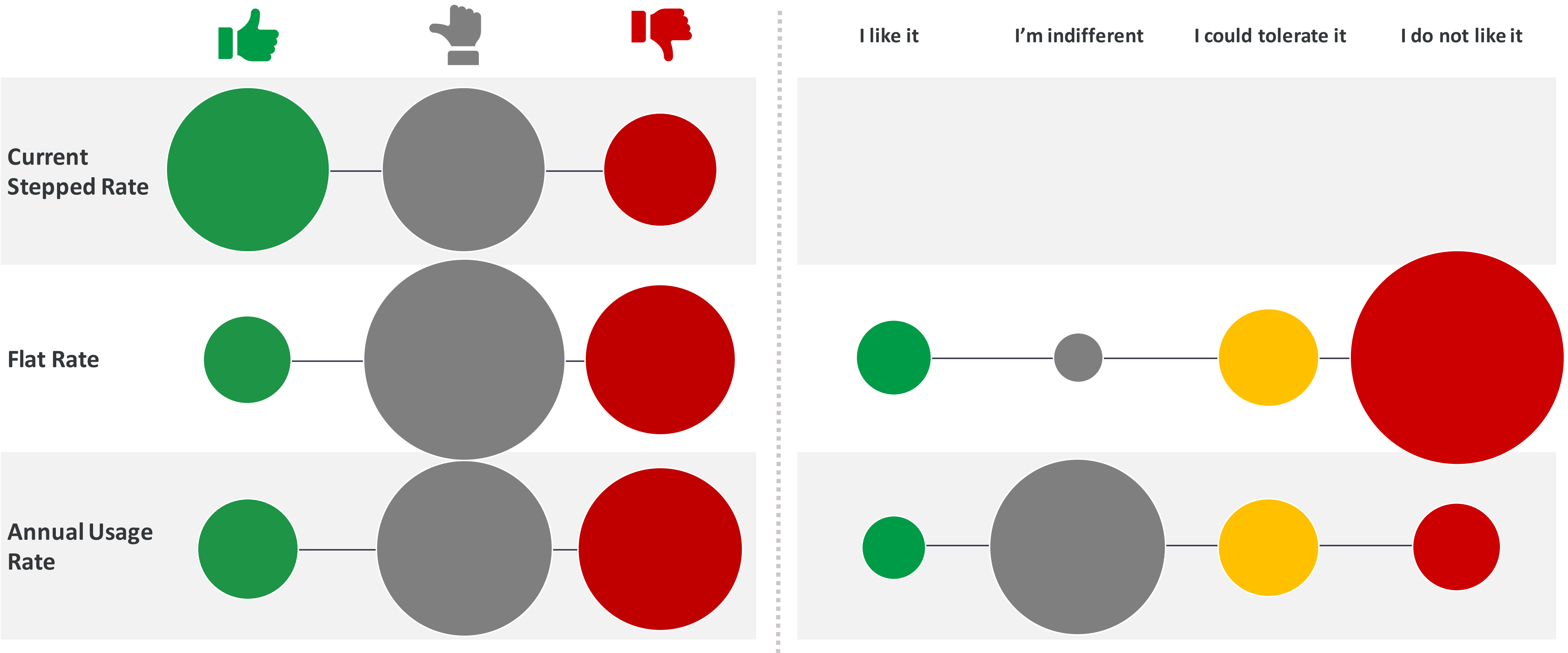
After seeing hypothetical bill impacts, Flat Rate had the greatest negative reaction

PRE (based on description only)

Q. How do you feel about (…)?

POST (after seeing bill impact)

Q. How do you feel about this option now that you see the actual impact for you?



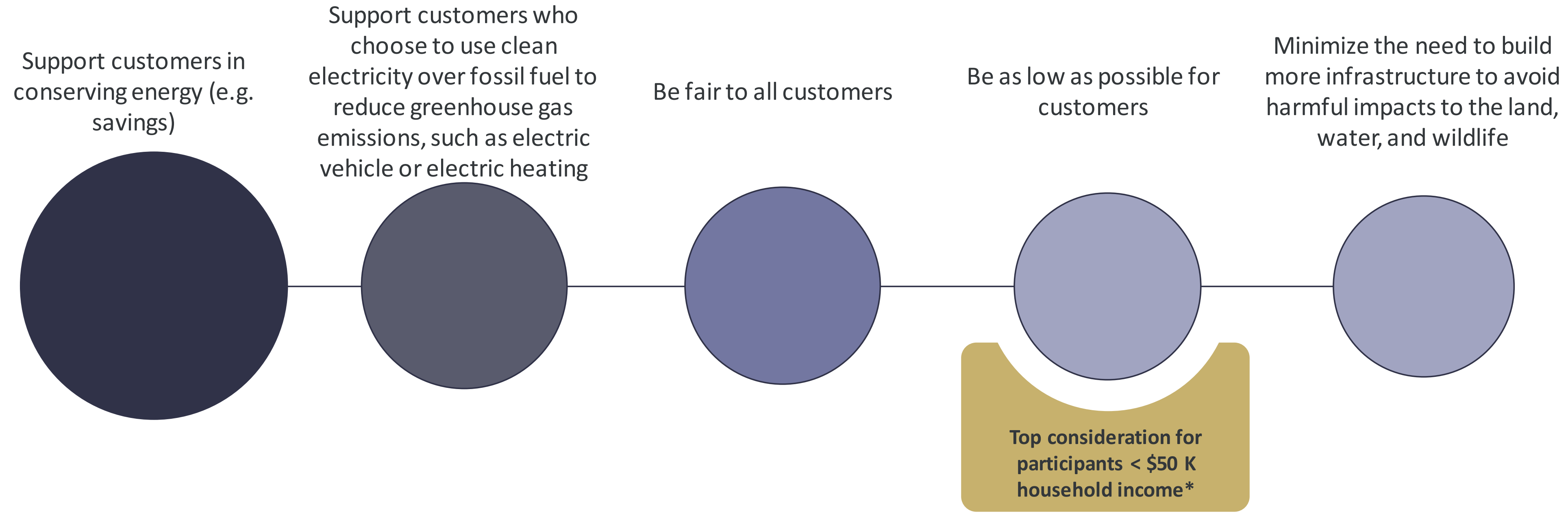
upwords

9

*Caution, all sample sizes are small!

Supporting conservation, clean energy use and fairness were the top ‘stated’ considerations; lower income participants were mainly interested in having a low bill

Q: Which, if any of these factors, do you think BC Hydro should consider when developing its electricity rates?

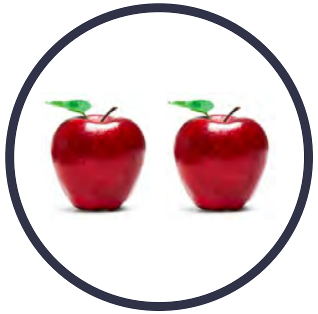


After seeing hypothetical bill impacts, nearly all chose the option that provided them personally with the lowest bill and/or encouraged conservation.

*Those who were low income were not necessarily low usage. Only 2 of the 6 who with <$ 50K household income were never in Step 2.

upwords

There were different definitions of "Fairness"



Sameness
Everyone is treated the same

Deservedness
Those who deserve more are given more

Need
Those who need more, are given more

Current Rate structure satisfied elements of sameness **AND** deservedness:

- same rates applied all
- those who conserve (deserve), stay in Step 1

upwords

[1] Source: https://www.psychologytoday.com/ca/blog/am-i-right/201205/its-not-fair-what-is-fairness

Positive reinforcements (through incentives) were more favourably received than negative motivation (avoiding 'punishment')

Incentives/ Rewards

- **Current Stepped Rate structure** rewards customers with lower rates for staying at Step 1

- With **Flat Rate**, households using *more* energy would seeing a decrease; most felt this **did not provide incentive** for conservation
- **Annual Usage** felt 'demotivating'; **little incentive to conserve** if impact not seen until next year

Penalties

- **Current Stepped Rate structure** - Step 2 is seen as a penalty especially for those who try hard but have factors out 'of their control' (rural location, old house, rental unit, larger family)
- **Annual Usage** – those in higher usage segments feel like they are 'penalized'

Current Stepped Rate felt fair to most but did not address the tension between conservation and electrification

Some picked up on the fact that as they further 'electrify' (right thing to do environmentally) it will push them into Step 2 more often.

Conservation Efforts

Increased Electrification/ Energy Dependency

"

I do believe that this two-step rate **can encourage electricity conservation**,

however …

we are going to be **more and more dependent on electricity**…. This is going to be especially true for households that switch to electric vehicles and heating over fossil fuels….
Perhaps if BC Hydro can either **increase the threshold before Step 2** is applied **or a discount if a household can prove that it has switched** to less greenhouse emitting technology (i.e. electric cars).
- Male, 35-44, Lower Mainland, Step 2, Rent, South Asian

upwords

While preferred over other options, there were some issues identified with Current Stepped Rate

Rural customers often have no access to natural gas, community water; no choice

Lower income customers with larger families are often in older homes; always in Step 2

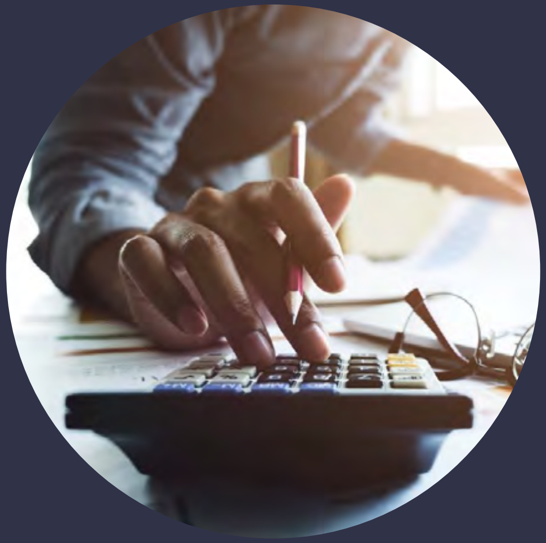
Step 1 is very hard to attain, some wish for additional Steps

Many are not aware of the Step system (especially those on equal billing), therefore no 'incentive' to stay in lower Step

"

*As a **rural area customer**, myself and many of my neighbors and friends do not have the luxury of natural gas heating, city water and sewer connections, and **MUST rely on electricity to provide these services from our own on-site sources**.*
*We can't pour a glass of water, flush the toilet or even water our gardens without consuming electricity directly… **we are always billed at tier 2.***
- Male, 45-54, Vancouver Island, Step 2

Flat Rate appeared to remove the incentive to use less



Flat Rate was seen as benefitting those who use more and “penalizing” those who use less (compared to Current Stepped Rate).
This felt “backwards”.

“

An increase of **over $100/year may not seem like a** lot to some, but it really is **when you're living with a lower income**.
I have never hit step two pricing, so I have kept the lower rate, I don't think it's fair to subject lower usage customer to higher rates while drastically dropping some bills with very high usage. **It just seems backwards to me; you are punishing the customers who have reduced their electricity use while rewarding those who have used excessively.**
- Female, 25-35, Greater Vancouver, Indigenous, LGBTQ+ Renter, Low Income

Annual Usage Rate goes against the principal of Present Bias (the human tendency to favour today over tomorrow)

*There is **little incentive** to "do better" month to month because **the reward is less immediate.** There would be no reflection in the monthly bills.*
- Samantha

Many questioned the usage segments:

- **low appears too low** for many to ever attain
- **high is extremely high** so many wonder who would ever use that much (encourages wastefulness)

Many felt the wide medium range could be further split (similar to how they wished for additional tiers in the Current Stepped Rate system).

*The **low rate is so low it would not encourage me to find ways to cut my usage by 80%** if I was sitting in the top end of medium usage. This directive and reward for low usage **would keep fossil fuel customers** as fossil fuel customers.*
- Male, 35-44, Vancouver Island, Indigenous, Step 2

<u>Annual Usage Rate</u> variation by housing type was liked by many who felt they would get a decrease and was 'unfair' to others

Hesitations around this idea related to the notion that **it lacked 'fairness'.** This was **especially true for customers who saw those living in single family dwellings as 'subsidizing'** the rates of those in **multi-family units.**

Charging different rates based on housing type **did not appear to have anything to do with usage or conservation, or how homes are built** (old apartment vs new condo = very different usage).

None considered that the differences might have to do with set up costs.

*I'm not into **being penalized** (charged more) **for working extremely hard and CHOOSING not to live in a densely populated area** and then being told **I will be subsidizing rates for people living in condensed multi unit dwellings**. I would consider this blatantly creating divide and almost playing favorites of regions or classes of people and not having 1 fair price per kwh for all. I am very against this model and would consider cutting as many ties from bc hydro as possible even if it means switching to fossil fuels for all available appliances.*
- Male, 35-44, Vancouver Island, Indigenous, Step 2

Whole Home Time of Use was clearly preferred over EV Time of Use as it was more broadly applicable

While preferred and appreciated in theory, many felt Whole Home Time of Use peak hours would be highly restrictive, especially for:

- Those with young kids
- Those working shifts
- People living in multi-unit housing

"

***Most working families** need to get sleep the structure noted above is **unrealistic** for any real savings as the lower rate is **only available when most working people would be unable** to take advantage of the off-peak times.*

- Male, 45-54, Vancouver Island, Step 2

The EV Time of Use rate only left a few feeling more likely to consider getting an EV in the future.

Most felt the upfront costs of the extra meter in addition to the investment to buy the EV were prohibitive.

Final thoughts:

<table>
<tr><th>Key Learning</th><th>Implications</th></tr>
<tr><td>BC Hydro has done a great job reinforcing the benefits of energy conservation. Therefore, the ideas that are strongest combine low rates for the customer with incentives for conservation.</td><td rowspan="2">Ensure future solutions have an element of reward or incentive that enables customers who choose to conserve and/or make ‘green’ choices feel like they will see an immediate personal benefit (in the present).</td></tr>
<tr><td>Positive reinforcement for reducing energy usage is well received.</td></tr>
<tr><td>Customers are very present focused. They think about their actions and want to see resulting bill impacts immediately.</td><td rowspan="3">Education will be critical. It will need to be simple, customer friendly, and easily accessible.

While many will not take the time to investigate and will just accept changes, ensure customers have the chance to understand the reasons why rates are changing, beyond how the new calculations work.

Many will tolerate small to moderate changes if they understand the rationale and feel it’s ”fair”.</td></tr>
<tr><td>Customers have a hard time connecting the dots around their energy usage in the future. They are thinking about conserving today and not thinking about how future electrification will result in an increase in (cleaner) electricity usage.</td></tr>
<tr><td>Many do not take the time to review details of their bill and many did not even know about the Current Stepped Rate system.</td></tr>
</table>

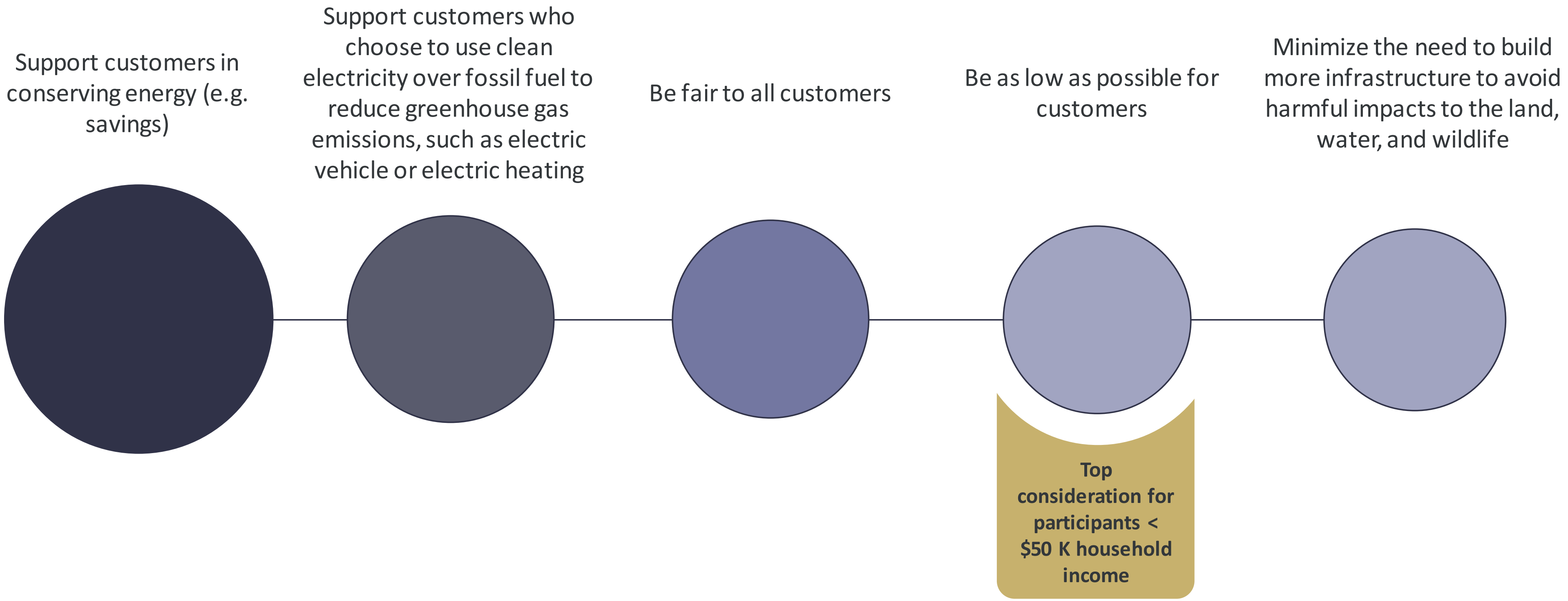
DETAILED FINDINGS

upwords

Considerations

All the considerations were important to many; with conservation support topping the list

Q: Which, if any of these factors, do you think BC Hydro should consider when developing its electricity rates?



*Those who were low income were not necessarily low usage. Only 2 of the 6 who with <$ 50K household income were never in Step 2.

upwords

Supporting customers in conserving or reducing fossil fuels was tied to the idea of "rewarding" customers with incentives for conservation

Supporting customers in conserving

- **Rewarding** customers with **incentives** for conservation would benefit everyone; reduces strain on the system, and provides cheaper rates for customers
- A couple acknowledged the **need for more practical support/incentives** (rebates or individual support/consultation) to reduce carbon footprint
- A couple agreed it was most important to start **consuming less first**, especially considering expected future increased electrification

Supporting customers in reducing fossil fuels (EV, Heat Pump)

- Some felt that BC Hydro **should provide incentives** (rate discounts, rebates) to encourage behaviours that reduce GHG emissions
- Some felt the options given (electric vehicle or electric heating) were **only feasible for a few**, due to external factors (renters, finances); a couple thought that their incentives should not be funded by others

Be fair for all

- We saw evidence of the three tenants of fairness[1] in participant responses:
- **Sameness:** Everyone is treated the same or gets the same rate; this includes ensuring some are not 'subsidising' others for items like EVs
- **Deservedness:** the more people use, the more they should pay
- **Need:** Those who need more (low income) should have help available

upwords

[1] *Source: https://www.psychologytoday.com/ca/blog/am-i-right/201205/its-not-fair-what-is-fairness*

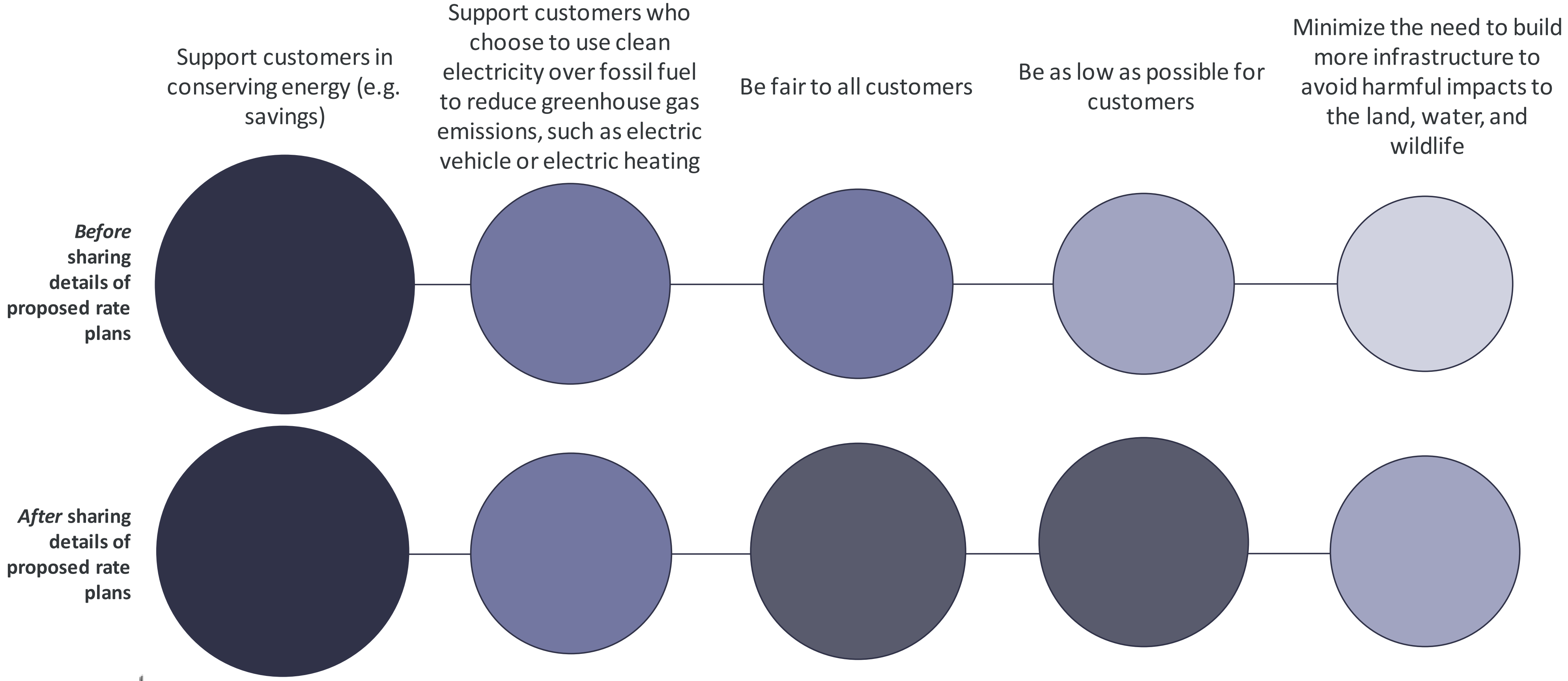
I see being fair to all customers focusing on every customer being charged on the same scale. Not classifying one type of customer (condo vs apartment vs detached house) differently resulting in a different rate scale or plan. Also, I feel incentives for financial support by BC Hydro for electric vehicles (providing discounted home charging hardware, etc.) should not be funded by rate payers who do not have electric vehicles.

- Male, 45-54, Lower Mainland, Chinese, Rent

upwords

Little changed when reviewing considerations AFTER sharing details of the proposed rate plans; fairness became slightly more important as some options were perceived as ‘punishment’

Q: Which, if any of these factors, do you think BC Hydro should consider when developing its electricity rates?



upwords

Current Stepped Rate

upwords

Current Stepped Rate – Stimulus Presented

Stimulus as presented

The Stepped Rate charges customers a lower rate up to a limit (or threshold) and a higher rate for all electricity used beyond the limit. To illustrate, the typical residential customer is charged the following:

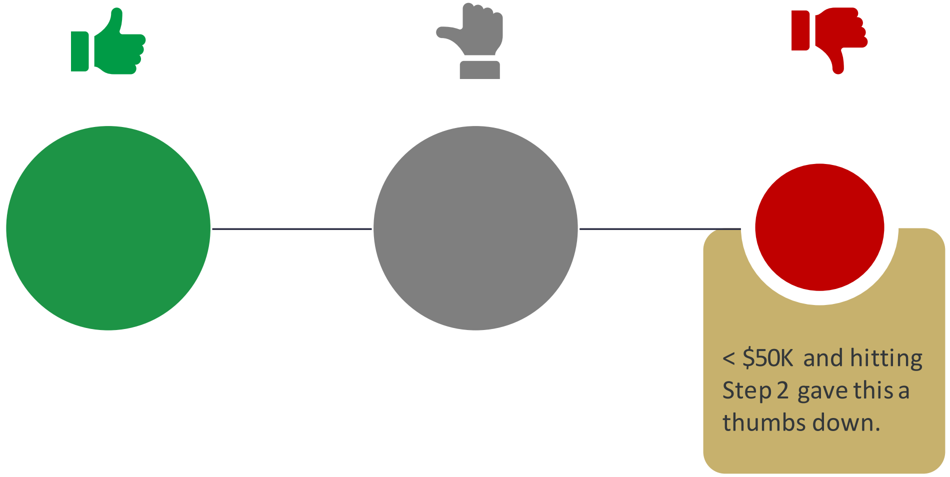
- Step 1 is 9.35 cents per kilowatt hour (kWh), up to a 1,350 kWh per two-month period
- Step 2 is 14.03 cents per kWh for usage above 1,350 kWh in the same period

In addition to the two-step electricity rate, BC Hydro bills also include a basic charge (20.80 cents per day or about $6.30 per month per account), which covers some of the costs related to customer service (billing, metering, call centre, etc.).

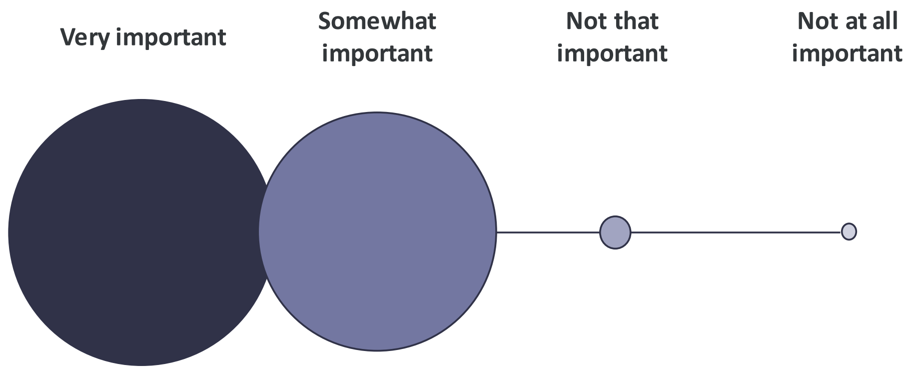
The Stepped Rate was designed to encourage electricity conservation, but this can be challenging for some customers due to factors like their home type and/or advancements in technology leading to an increased use of electricity.

There was moderate support for the Current Stepped Rate and most felt it’s important to have this info but it was new info to many

Q. What is your gut reaction to the idea of BC Hydro continuing to use Energy Conservation Programs as the first step of the Integrated Resource Plan (…)?



Q. How important is it for you to understand how your BC Hydro bill is calculated?



Q. Were you familiar with the description of the Stepped Rate before, or is it new information?

upwords

While they say it's important to know how their bill is calculated, many who were not aware of how the Current Stepped Rate works

“

In theory it is very important for me to know how it is calculated*, but I've* ***never bothered to examine it carefully*** *over all these years, so really it couldn't have been that important to me. I think a reason why it wasn't as important is I* ***don't really have a way to verify BC Hydro's billing and not that much incentive for additional electricity conservation*** *above my already conservative habits.*

- Male, 35-44, Lower Mainland, Chinese-Caucasian

“

I didn't really know about the Stepped Rate system until just today. That, so far, is the only "downside" that I've identified in the system, i.e. ***it only works as an incentive to the degree that people know about it, appreciate it, and are aware of the savings*** *they can gain by staying below that threshold, etc...*

- Male, 35-44, Lower Mainland, Step 2

upwords

Those who liked the Current Stepped Rate appreciated that it encourages conservation

What's Working

- ✓ **Encourages conservation;** there is an incentive/reward in place to save money on energy bills
  - Having a lower bill is a reward
  - Fair; those who use more pay more
  - Knowing about the Steps would help some pay more attention to usage
- ✓ **Transparency: In theory**, many found it important to know understand what they were paying for and how their bill was calculated
- ✓ Those who already knew about this **appreciated that this info could be found** on their bills

"*It seems **fair** how it is. If I **use more I pay more.***

- Male, 25-34, Greater Vancouver, Step 2

"*It seems like a **logical idea**, and I don't yet see many downsides. **Saving money on home energy bills is a major incentive** in our household for reducing our energy consumption: turning down the heat in winter and dressing more warmly at home; turning out lights, using efficient appliances, etc...*

- Male, 35-44, Lower Mainland, Step 2

Others felt "penalized" by Step 2; it seemed unfair if there were factors out of their control

Hesitations

- **Step 1 is unattainable.** Many felt they were not able to stay in Step 1 despite being conscious and conserving felt discouraging to some; Step 2 felt like a **penalty** to some due to circumstances out of their control (rural location, age of home, condo/apartment building, larger family)
- While it was important for many to know the breakdown, some acknowledged that the **rates were out of their control** and that they had **no way of verifying/disputing/changing charges on their bill** – some admitted they just paid their bill every month without looking further into their usage
- **Increases in energy use due to COVID** (work from home) make this system not as practical for many
- **Lack of awareness:** To many, this was new information, so it's not an incentive if people do not know about it. Some want to be able to check (for example on App) where they are at for usage – some don't know when they hit Step 2

I have had awareness of the stepped rate as I hit it every billing cycle. ***There is almost no way for my home*** *(especially through a pandemic and with technology advances)* ***to keep our usage below it.***
- Female, 25-34, Vancouver Island, Step 2

I am curious how many households in BC actually meet the Step 1 target monthly. We live in an ***older home with electric heating****, so we exceed the Step 1 target every month. Though intended as an incentive****, it is actually discouraging to see that despite our efforts, we never meet target****. But, we accept it. Financially, it makes more sense for us to spend an extra $1000 a year in Step 2 rates than to invest $5,000 or more to renovate our house for energy reduction.*
– Male, 55-65, Okanagan, Step 2

Flat Rate

upwords

Flat Rate - Stimulus Presented

Flat Rate - Description

This rate structure option would include just one rate for each kilowatt hour of electricity used and a basic charge . It would be a 'default' rate, which means it would be applied to all residential customers.

The rate amount would be in between the current Step 1 and Step 2 rates, and there would be no limit or threshold applied. This means customers would be charged for their electricity use at the same rate no matter how much they used.

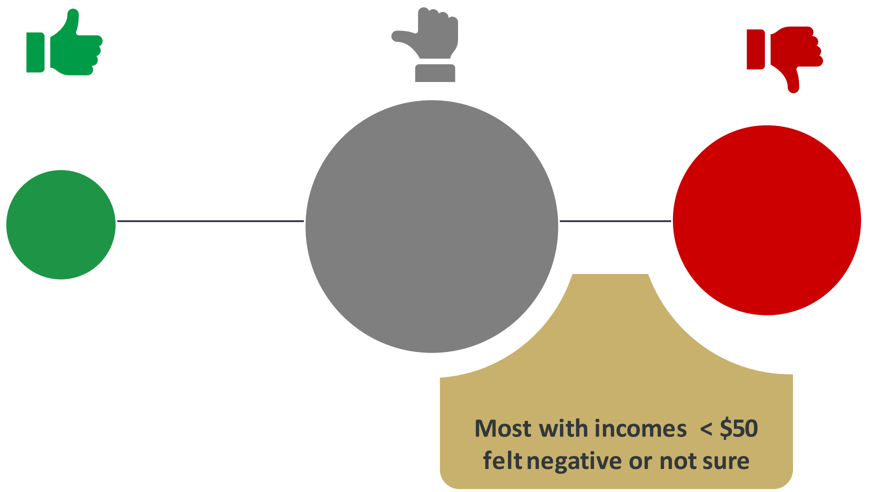
This approach would simplify how customers are billed and would make it easier to introduce new optional rates later on, such as rates for a specific use.

If introduced, a Flat Rate would affect some customers' bills compared to today: some might see increases, while others might see decreases.

Several utilities in Canada offer flat rates as their default offering and in B.C., FortisBC is currently transitioning to flat rates from the previous inclining, or conservation rate that was in place.

Reaction to the Flat Rate Description leaned neutral to negative

Q. What is your gut reaction to the idea of BC Hydro continuing to use Energy Conservation Programs as the first step of the Integrated Resource Plan (…)?



What's working

- Some found this **straightforward and simple** - everyone pays for what they consume
- A few liked that this **would remove the discouragement of failing to stay in Step 1**; which also meant potential savings on own bill
- A couple understood (without being aided) that this could **encourage switching from fossil fuel** to electric because they would not be bumped into Step 2

*I like the concept of flat rates. **If the rate is between Step 1 and Step 2, our household could potentially save** some money annually. The current stepped rate is discouraging, because the only time we ever achieved the Step 1 target was by going on holiday for 3 weeks.*
- Male, 55-65, Okanagan, Step 2

upwords

The main dislike of the Flat Rate description was that it appeared to **remove the incentive to use less**; it benefits those who use more and "penalizes" those who use less (compared to current)

Hesitations

- x Many commented that this system **would benefit those who consume more electricity as they would pay less**; those using less energy (not hitting Step 2 currently) would see an increase in their bill – some felt this was not incentivizing the right way, not giving an incentive to reduce consumption
- x For some, just seeing the description without the hypothetical bill impact left them feeling **unsure how it would affect their household or bill**
- x A few **misinterpreted** this to mean the same bill for everyone, paying the same amount no matter how much electricity used?

"*I have never approached the second-tier threshold. I suspect this means **my electricity rates will increase**. I'm **not in favor** of a flat rate per kilowatt hour of electricity. Also, wouldn't this **provide less incentive to reduce consumption of electricity**?*
- Male, 45-54, Lower Mainland, Chinese, Rent

"*It **penalize people who use less electricity** and discourage others to reduce electricity consumption.*
- Male, 34-44, Lower Mainland, Chinese, New Canadian, step 2

"*I view that customers who use more need to pay more. Why should customers who **use less have to pay an increase**?*
- Female, 45-54, Vancouver Island, Step 2,

"*The flat rate option is **more straightforward;** however, I am **concerned that I would be paying more** for my consumption. I think that the **Stepped Rate is actually more fair because if you consume more, you pay more**.*
- Male, 25-34, Metro Vancouver, New Canadian

Flat Rate - Stimulus Presented

Flat Rate - Hypothetical Usage Data

Here are some additional details for the first variation of the Flat rate scenario:

Basic charge: 20.80 cents per day

Energy charge: 11.22 cents per kWh

Now I have a second variation of this to show you: Here are some additional details for the second variation of the Flat rate scenario:

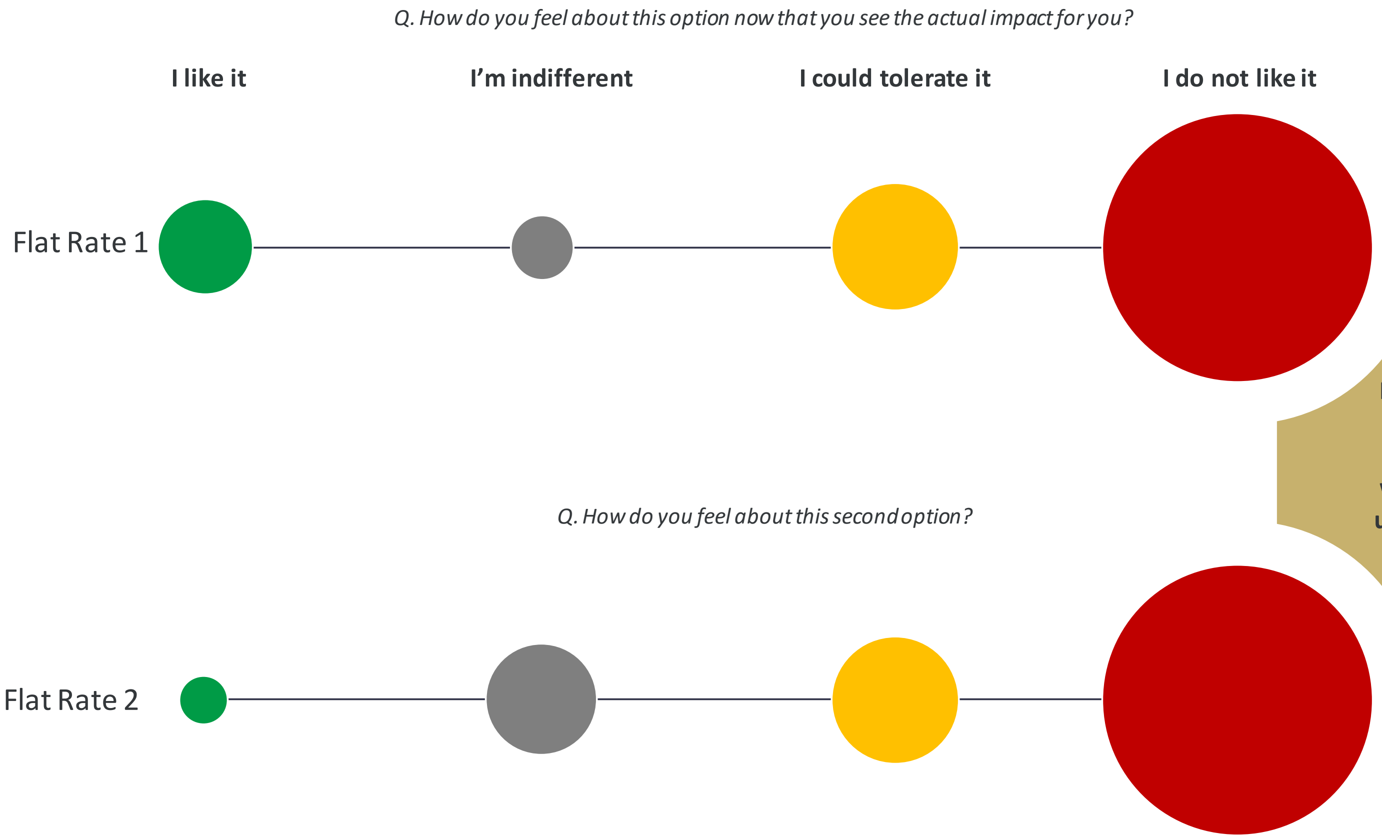
Basic charge: 31.20 cents per day

Energy charge: 10.83 cents per kWh

Many **did not like** the idea of a Flat Rate after seeing their hypothetical bill impact. The second option was less positively received than the first.

Preference

When asked preference for Flat Rate 1 or Flat Rate 2, the majority chose the cheaper option (typically Flat Rate 1) but many did not like either, in theory.



Most < $50 K did not like it or could tolerate it. Only one with relatively higher usage liked it due to a positive bill impact.

upwords

Those who liked the Flat Rate, typically saw their bill go down; those who did not like it felt there was **no incentive to conserve**

Reasons for ratings were typically the same for both options.

What's working

- ✓ **Potential savings** for own household (typically higher energy users)
- ✓ The **lower base rate and higher energy rate** (variation 1) **was preferred slightly** by a few who thought this would be more motivating to consume less
- ✓ A couple reasoned that this would be more fair if travelling and not using electricity at all (why pay a higher base rate if not home?)

Hesitations

- x **Increase in yearly charge compared to current rate**, especially for lower energy users
- x **No incentive** to conserve energy
- x Most **did not understand** that this would be **beneficial for switching to electricity over fossil fuels**
- x Indifference (about both variations of Flat Rate) was rooted in **similarity of numbers** – not enough change to impact perceptions either way

Questions about this idea included:

- What are the benefits/drawbacks to both options?
- How are the base rate and energy rate established? How do they come up with the numbers?
- Where is the extra money going? What is being supported by an increased basic charge?
- What's the difference between the 2 options? (own numbers are similar)

In their words …

When reading the question, even before pressing the respond button to see the financial details specific to me (estimated cost comparison), I thought "no". I feel this way for several reasons. 1) this provides less/no incentive for higher electricity users to conserve energy use. 2) obviously my rates go up. 3) less energy conservation directly results in more improvements to infrastructure which I do not want to pay for.

- Male, 45-54, Lower Mainland, Chinese, Rent

An increase of over $100/year may not seem like a lot to some, but it really is when you're living with a lower income. I have never hit step two pricing so I have kept the lower rate, I don't think it's fair to subject lower usage customer to higher rates while drastically dropping some bills with very high usage. It just seems backwards to me, you are punishing the customers who have reduced their electricity use while rewarding those who have used excessively

- Female, 25-35, Greater Vancouver, Indigenous, LGBTQ+ Renter, Low Income

I still do not like the flat rate option, and as I expected the bill is now higher… this is almost a $100 more, even though I am not using more electricity

– Male, 25-34, Metro Vancouver, New Canadian

upwords

Annual Usage Rate

upwords

Annual Usage Rate - Stimulus Presented

Annual Usage Rate - Description

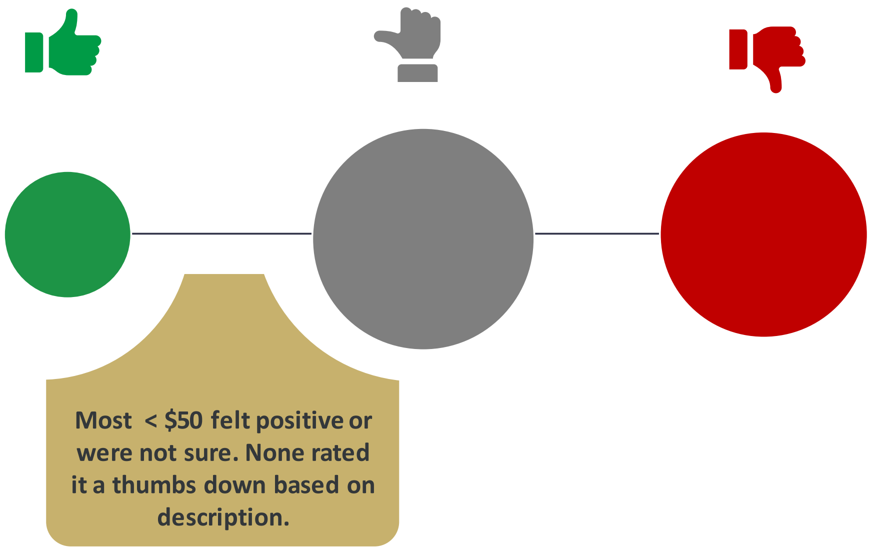
Similar to the Flat Rate, this structure includes one rate for each kilowatt hour of electricity used and a basic charge. However, the difference is that the rate is based on each customer's usage in the prior year. In other words, if this rate were introduced for 2022, the rate you would be charged in 2022 would be based on how much electricity you used in 2021

BC Hydro would divide customers into three segments based on their previous year's usage and each segment would be charged a specific rate. There would be no change to a customer's rate as long as their usage stays within the limit defined by their segment.

This concept would simplify how customers are charged for electricity and would make it easier to offer additional optional rates for specific uses.

Reaction to the Annual Usage Rate description leaned neutral to negative; those who liked it saw it as incentive to get better year over year

Q. What is your gut reaction to the idea of BC Hydro continuing to use Energy Conservation Programs as the first step of the Integrated Resource Plan (...)?



What's working

- Some saw this as an **incentive/challenge to be more conscious** about energy consumption knowing that it could lead to savings on bill the following year
- A few thought it was fair for the rate to reflect usage; those who use less will get a lower rate

> *I also would be interested in this it's like a competition style... I like to challenge myself to use less than the previous year and save money.*
> - Female, 25-34, Northern BC, Renter

Many were hesitant or disliked this idea because of fluctuations in their usage either due to weather or due to their own household composition

Hesitations

- x Some considered it **unfair to base a rate on previous year**
- x Does not consider how many people live in a household
- x Harsh penalty for those who just go over the threshold – they would have to pay for it a whole year
- x **Less or no incentive to conserve**:
  - Only motivating for those at the border between segments
  - Lives change (someone moves in or out): a year is too long to reflect changes, with the reward being less immediate
- x To a few, this was confusing as it felt **more complicated/complex than the Stepped Rate** – they did not understand all the ramifications of being charged based on previous year; harder to plan for household expenses

Questions about this idea included:

- What are the segments? What about unforeseen short-term spikes (weather, project; COVID caused a spike in energy consumption)? Is it tied to an address? What about change in ownership? What if you travel one year but not the next?

*Not a fan of this idea. **BC has extreme weather** plus having a young family our life is changing constantly… and our **conservative efforts may not be realized for a year** causing a loss in commitment due to lack of positive reinforcement... I feel there is too much of a disconnect from your actions.*

- Male, 45-54, Southern And Central Interior, Hong Kong, Step 2

*I dislike this idea because **people lives and needs change** from one year to the next. For example, if a family member leaves the household, you would still be paying the same rate. **It doesn't seem fair**.*

- Male, 25-34, Metro Vancouver, New Canadian

This option goes against the principal of present bias or immediate gratification. Customers want to see bill impacts immediately if they are actively conserving.

*There is **little incentive to "do better"** month to month because the reward is less immediate. There would be no reflection in the monthly bills.*

- Samantha

upwords

Annual Usage Rate - Stimulus Presented

Annual Usage Rate - Hypothetical Usage Data

The annual usage segments include:

Low: below 4,000 kWh per year

Medium: 4,000 to 50,000 kWh per year

High: over 50,000 kWh per year

LOW Users:

Because you fall into the low usage category (below 4,000 kWh per year), your costs under this rate scenario would be:

Basic Charge: 20.80 cents per day

Rate: 9.41 cents per kWh

MEDIUM Users:

Because you fall into the medium usage category (4,000 – 50,000 kWh per year), your costs under this scenario would be:

Basic Charge: 20.80 cents per day

Rate: 11.19 cents per kWh

Like yesterday, I have a variation of this to show you now. Here are some additional details:

Basic Charge: 31.20 cents per day

Rate: 10.86 cents per kWh

High Users:

Because you fall into the high usage category (over 50,000 kWh per year), your costs under this scenario would be:

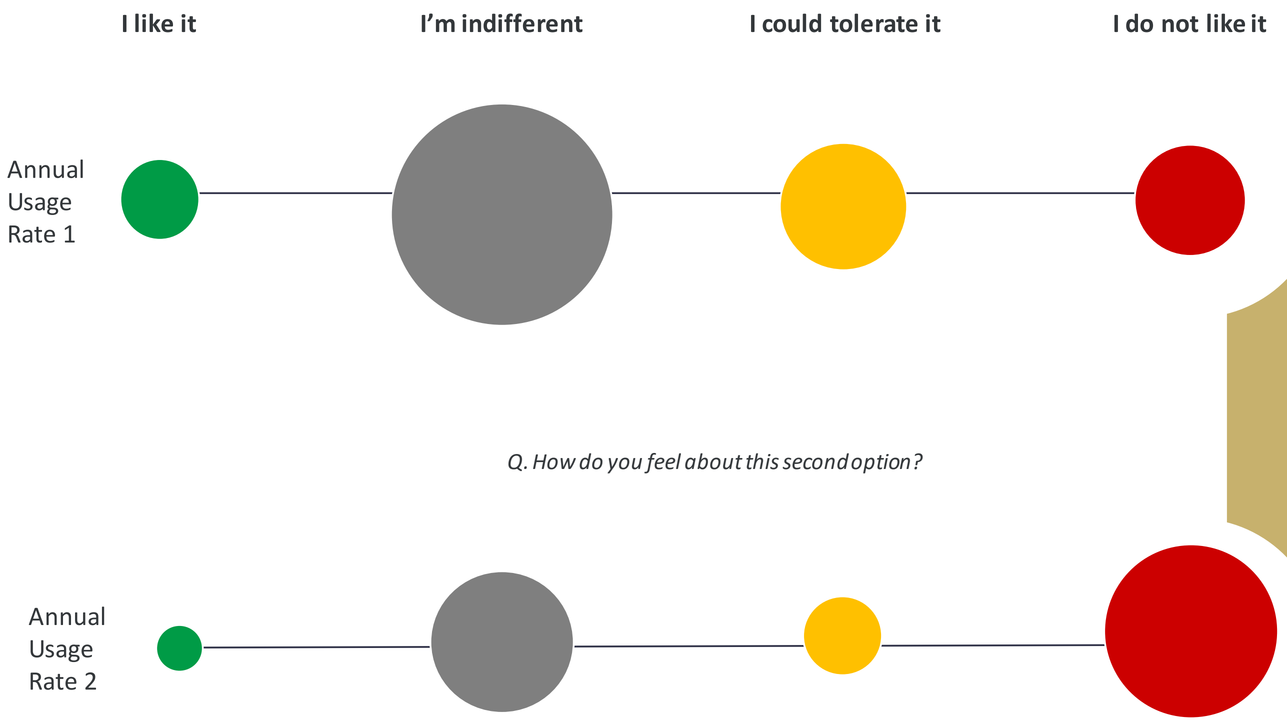
Basic Charge: 36.28 cents per day

Rate: 12.47 cents per kWh

There was not strong approval for Annual Usage Rate scenarios presented; many were indifferent or could tolerate it as bill impacts were minimal, especially for the first option

Preference: Participants were equally divided in their preference for Annual Usage Scenario 1 or Annual Usage Scenario 2; preference was mainly based on bill impacts.

Q. How do you feel about this option now that you see the actual impact for you?



Those < $50 were either indifferent or did not like it (for both options) due to bill impacts; this was a change from their more positive responses to the description.

Note that only "Medium" users were shown the second option

upwords

The few who liked the Annual Usage Rate felt it might encourage people to try to get into the lower segment or felt reassured that they would not get pushed into high

Reasons for ratings were typically the same for both options.

What's working

- ✓ A few liked that trying to stay in lower segment to save money would **encourage reduction of energy** usage
- ✓ The **higher base rate and lower energy rate** (variation 2) **was preferred slightly**; while this was simply the cheaper option out of the 2 for many, some reasoned that a lower energy charge would be better if using more energy (e.g., in winter months) or because it would have less impact on next year if travelling one year.
- ✓ A couple felt reassured that the medium range was wide enough that they would **never go into high**.

Hesitations

- x Many saw an **increase in yearly charge compared to current rate** (even if small)**,** causing dislike for both these rates
- x Indifference (about both variations) for many was rooted in **similarity of numbers** – not enough change to impact perceptions either way
- x **Segments are too wide**: impossible to get the lower or higher rate, would just remain in medium; desire for more/ different levels

Questions about this idea included:

- Want to see own kWh consumption in the calculation –where it would fall in the medium category
- What is the justification/basis for increasing the basic charge? What is the basic charge for?
- How did they come up with the segments?
- Does it lower average energy consumption throughout the population, reduce carbon emissions, …?
- Would need more than 2 years of usage/billing data to see how it affects own cost

In their words …

The low rate is so low it would not encourage me to find ways to cut my usage by 80% if I was sitting in the top end of medium usage. This directive and reward for low usage would keep fossil fuel customers as fossil fuel customers.

- Male, 35-44, Vancouver Island, Indigenous, Step 2

Because I live in a condo where hot water is covered by the strata, if the hydro bill for the condo increases substantially under this new system, then my strata fees will likely go up as well. Many apartments and condos have a similar setup where the hot water system is not in each unit and therefore provided by the building as a whole. This will disproportionally affect larger apartment complexes that are bumped into the higher segment solely because they have more units. So while the complex may be using less electricity PER UNIT, they may be paying more than a smaller building complex.

– Male, 35-44, Lower Mainland, Chinese-Caucasian

I would like to know 4000 to 50,000 is a big difference. How did Hydro come up with these segments. I think the segments could be changed.

- Female, 55-65, Lower Mainland, Step 2

upwords

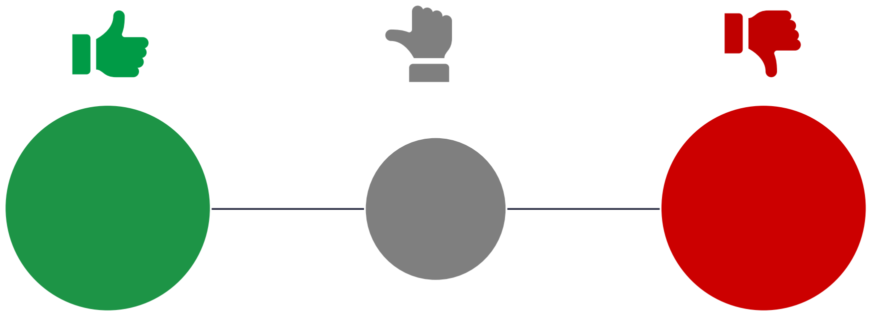
Annual Usage Rate – Housing Type - Stimulus Presented

Housing Type

With this rate option, a variation BC Hydro is also exploring is charging a rate based on your housing type (apartment, townhome, free standing house) rather than charging a rate based on how much you use (small, medium, high use). Apartment customers would have a lower rate as lower consumers in this scenario.

Many felt the variation where BC hydro charges a rate based on housing type was “unfair” as housing type was not indicative of usage or attempts at conservation

Q. How do you feel about this option?



Those < $50 were more likely to like this option as they tended to be renters in apartments and felt it would benefit them

What’s Working

✓ Some apartment dwellers/renters thought this would be beneficial for them personally

Hesitations

x **This felt unfair to people in freestanding homes;** it would not promote energy conservation, it just “penalizes” people in larger spaces even if they use less or try to conserve more.

x Some felt there were **certain considerations that went against this proposal**:
- Wealthy people can live in apartments/condos
- Condo/apartment doesn’t mean it’s worth less
- Depends on the way homes are built or energy efficiency, not on type of dwelling
- Everyone uses the same electricity, does not depend on type of home

x One participant felt like they would be **subsidizing** people living in condensed multi-unit dwellings, which would create divides or play favorites of regions and classes of people

upwords

In their words …

It penalize people living in larger space even if their electricity consumption is lower than those living in a smaller space.

- Male, 34-44, Lower Mainland, Chinese, New Canadian, step 2

I'm not into being penalized (charged more) for working extremely hard and CHOOSING not to live in a densely populated area and then being told I will be subsidizing rates for people living in condensed multi unit dwellings. I would consider this blatantly creating divide and almost playing favorites of regions or classes of people and not having 1 fair price per kwh for all. I am very against this model and would consider cutting as many ties from bc hydro as possible even if it means switching to fossil fuels for all available appliances.

- Male, 35-44, Vancouver Island, Indigenous, Step 2

I am an apartment owner so I would be interested in this option.

- Female, 25-34, Lower Mainland, Chinese

I don't like this rate option as my grandmother who lives in a apartment and has electric heat uses a ton of heat and her bills are way higher than mine in a 3-bedroom house so for her to have a lower rate than me someone who tries to save electricity I don't like.

- Female, 25-34, Northern BC, Renter

upwords

50

Comparing options

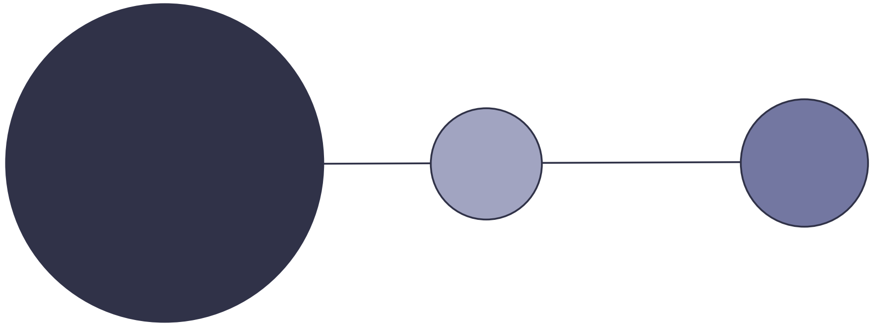
upwords

There was consistent preference for Current Rate; for most, preference for ANY option was rooted in financial considerations (lowest bill), as well as the perceived incentive for conservation

PRE (based on description only)

Q. Based on all three descriptions you just saw, which (if any) of these three options would you personally prefer?

I prefer my current Stepped Rate | Flat Rate | Annual Usage Rate



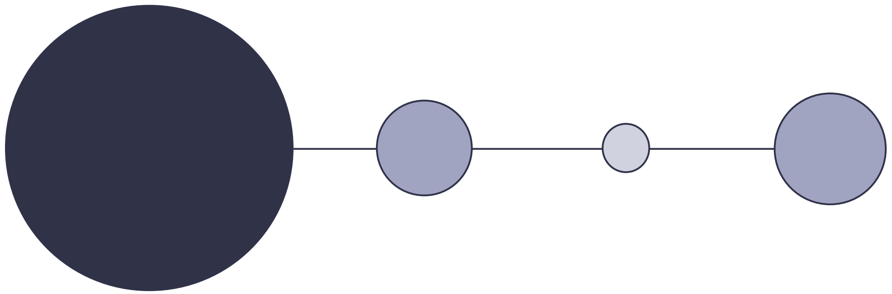
> *I feel that the current model is more fair than the new options because **flat rate doesn't encourage [to] reduce consumption**.*
> - Male, Lower Mainland, 35-44 years old

> *The stepped rate option offers much more flexibility and **potential savings during low usage months.***
> - Female, Greater Vancouver, 25-34 years old

POST (after seeing bill impact)

Q. Thinking of all of the options you've seen and their hypothetical bill impacts for you, which do you personally feel would be preferable for you personally?

I prefer my current Stepped Rate | Flat Rate | Annual Usage Rate | I'm not sure



> *The stepped rate seems **more economical for my usage**, and I really like the fact that the **rate is going up if you use more energy**. For example, I think that if someone has several TVs on all day, their consumption is going to be much higher and they are putting a strain on the system and this should be reflected in their bill **to encourage a more mindful consumption.***
> - Male, Metro Vancouver, 25-34 years old

For most, their preferred rates option did not drive interest in Heat Pumps;

Q. In what ways (if any) does your preferred rate scenario make a difference in the likelihood you'll get a heat pump?

More Likely (single mentions)

- Heat pump would have **immediate effect on winter bill** (compared to inefficient electrical baseboard heat) **under Flat Rate scenario** without being worried to be bumped up to next segment
- Would be easier to understand charges and weigh the pros and cons

Less Likely

- A couple had already looked into it and decided not to buy it (one went with an electric furnace instead)

Unsure/No Difference

- Those renting or living in an apartment or condo **do not have the option** to decide their heat source
- Some already had electric heat (baseboards, furnace) and **no plans to replace**
- A few felt they **did not know enough** about the potential savings of a heat pump, or did not even know what a heat pump was

Voluntary Opt In Rates

upwords

54

Voluntary Opt In Rates - Stimulus Presented

Whole Home

This concept is designed to enable customers to take advantage of a lower rate at times when there is lower demand for electricity. For example, this option would charge customers a lower rate for running their appliances (e.g. dishwasher, laundry, etc.) later in the evening, or charging an electric vehicle overnight. .

The high-demand time, which is known as "on-peak", would be defined as starting at 7:00am and lasting until 10:59pm. The lower-demand time, known as "off-peak", would be from 11:00pm until 6:59am.

This rate structure would apply to all customers. There would still be a basic charge, plus an on-peak rate and an off-peak rate. For example:

Basic charge	20.80 cents per day
On-peak	14 cents per kWh
Off-peak	6 cents per kWh

Unlike the current two-step rate, this concept is defined by time periods, rather than a usage threshold.

Second Option Times

Does your impression change if the "on-peak" and "off-peak" time ranges were defined instead as:

Off-peak (day)	7:00 to 16:00
On-peak	16:00 to 20:59
Off-peak (evening)	21:00 to 22:59
Overnight	23:00 to 6:59

NOTE: *while only a few mentioned it, this did not clarify if overnight was off-peak or on-peak or a separate rate altogether. If further testing is done, we recommend making this clearer.*

The concept of Whole Home Time of Use Rate was in general favourable, even though many felt the times were impractical and restrictive

What's working	Hesitations
✓ This **encourages energy use at lower demand times**, reducing strain on system	x Many found it **unrealistic, impractical or restrictive,** esp. for families with kids, night shift workers or those who live in multi-unit complexes: - does not fit with lifestyle; takes away the freedom to schedule - few utilize that time window (overnight), such as an Electric Vehicle or the dishwasher, wondering how much that would save them in the end
✓ **Lower cost and potential savings** were an appealing incentive/reward to some	x The **off-peak hours** (in the first option) **were too late** for many who felt they would have **little opportunity to take advantage of reduced rates** during off-peak times and therefore would be **paying more** with rates being higher than the current rate during on-peak times
✓ A few acknowledged that this would **be an incentive to Electric Vehicle owners** or could motivate the switch	x A few were worried about **sound pollution** in condo/apartment buildings at night
✓ Nearly all felt **the earlier off-peak option** would suit them better	

In their words …

I think this is an interesting scenario and I like it it would definitely encourage use during nonpeak times to lessen the work on the grid and prevent a overload.

- Female, 25-34, Northern BC, Renter

Weighing the cost versus trouble of doing "heavy usage tasks" after hours or before dawn, seems like more trouble than it's worth. I guess if it happens to work out for me than great, but I won't be timing my household duties to begin 11pm or end them before 7pm to save a few dollars, cents even I would imagine the difference would come to.

- Male, 25-34, Metro Vancouver, LGBTQ+, Low Income, Rent, Step 2

Unfortunately, who is really going to be doing their laundry during those times? Yes, charging a car overnight or running this dishwasher at bedtime would be fine but there are only a few things that can utilize that window.

- Female, 25-34, Vancouver Island, Step 2

Most working families need to get sleep the structure noted above is unrealistic for any real savings as the lower rate is only available when most working people would be unable to take advantage of the off peak times.

- Male, 45-54, Vancouver Island, Low Income, Step 2

Running appliance later in the evening is absolutely terrible idea. just cuz sound pollution in condo buildings is the worst

- Male, 25-34, Greater Vancouver, Step 2

Electric Vehicle - Stimulus Presented

Electric Vehicle

This concept is intended to meet the increasing electricity demand from the growing electric vehicle market. As more and more customers buy these vehicles and charge them at home, there is greater demand put on the electricity grid. By offering a specific rate for home charging, customers could choose to charge at lower-demand times and save money. The customer would be required to install a second BC Hydro meter (approximately $2,000 to $3,000) to ensure that the electric vehicle charging was correctly captured for billing.

In this concept, the charging rate would be applicable between 11:00pm and 6:59pm.

NOTE: This was presented as 11pm - 6:59 PM – only a few picked up on this. It likely should have said 6:59 am.

Electric Vehicle Time of Use Rate

What's Working	Hesitations
✓ Some appreciated that **the cost would be for individual user, not impacting all customers;** people without Electric Vehicles aren't subsidizing ✓ Opportunity to **save money** ✓ A couple thought this would **encourage the use of Electric Vehicles** by offering a more affordable way to charge – this in turn would help the environment ✓ A couple found it **helpful to keep track** of exact cost for charging thanks to the separate meter	x Many disliked the **up-front cost,** especially when considering the investment already required for an Electric Vehicle; they wondered how long it would take to offset the cost by savings from the lower charging rate, or wanted clarification about who pays – all consumers or EV owner? - A couple thought this should be paid by BC Hydro since they benefit x Some were **indifferent:** because they did not have an Electric Vehicle (or a vehicle at all) and/or were not planning on buying one x The allotted **charging time** (overnight) seemed problematic to a few who worried about losing flexibility and freedom or said it did not work for certain schedules (such as shift workers) x A few had **questions**: - What happens to the meter when someone moves? - Why is there a need for a second meter?

Interest in Electric Vehicle was not impacted

Q. In what ways (if any) does your preferred rate scenario make a difference in the likelihood you'll get a heat pump?

More Likely

- A couple recognized that **everyone will be driving Electric Vehicles** in the future as they are mandated by 2035; knowing about the opportunity to save charging costs **might impact to get one sooner**.
- **Overnight timing works perfect**

Less Likely

- **No Difference**: some said they were not planning on buying an Electric Vehicle and still don't (due to up-front costs or dislike for Electric Vehicles in general); others were already interested, and the special charging rate did not change anything to increase or decrease their interest further
- A few wanted **more information**: how long would it take to offset the cost of the additional meter? How much electricity consumption comes from charging an Electric Vehicle?

Unsure/No Difference

- **Additional cost of second meter** was a deterrent for a few, making it even more unaffordable
- One pointed out that it was impossible for them to take advantage of this offer since installing a second meter was **not an option in a condo building**

In their words …

The responsibility is put on the driver that chooses to drive [an] EV. I like that. I think heavy consideration must be given to those who are unable to comply because of i.e.; Condo living, existing underground accessibility, owners without assigned parking et al. This survey seems to be very urban centric. I hope that consideration is given to all the consumers and moving forward we are not penalizing the hard workers in remote and rural residents.

- Male, 45-54, Southern And Central Interior, Hong Kong, Step 2

I think electric vehicles are integral to our move away from fossil fuels. I think that owners should have access to affordable charging and that by making a small tweak to behaviour they could have the best of both worlds, lower costs while not driving up demand for power and the environmental impacts of that.

- Female, 35-44, Lower Mainland, Step 2

I don't think that changing the rate structure is going to influence whether I buy an electric vehicle or not. I do not have one right now, but I am considering it. I think overall buying an electric vehicle is better for the environment.

- Male, 55-65, Lower Mainland, South Asian, Step 2

Why does a second meter have to be installed. As long as the vehicle is charged in the off peak rates it would be captured in that rate. Or are you saying an electric vehicle would be charged a rate below the off peak hours.

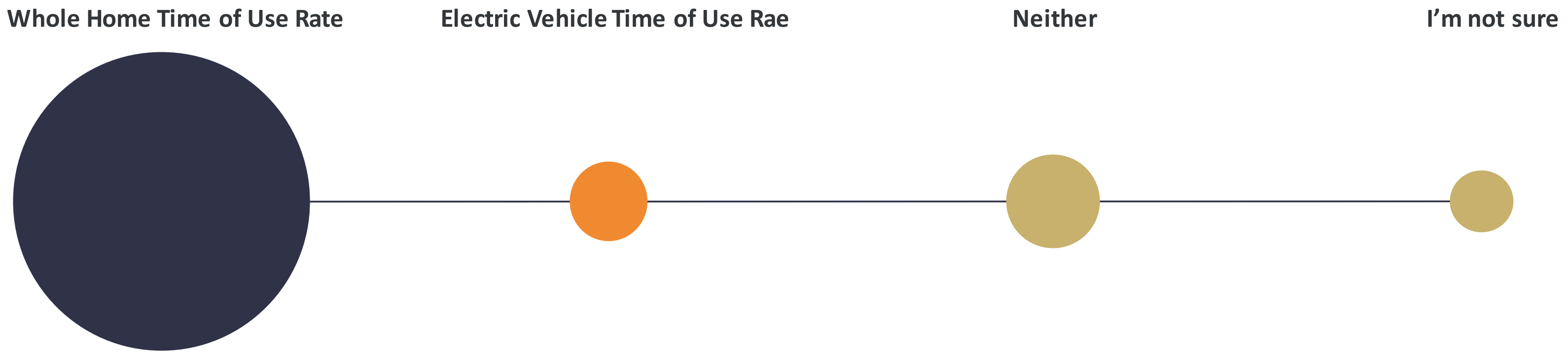
- Female, 55-65, Lower Mainland, Step 2

Right now, an electric vehicle is a substantial investment. Adding an additional meter surcharge adds to the cost of a machine that begins to devalue the moment it is driven. BC Hydro would have to demonstrate that the fuel savings would offset the meter cost.

- Male, 55-65, Okanagan, Step 2

Upon comparison the Whole Home Time of use Rate was preferred by the majority; it was more broadly applicable

Q. Which of these two options, if any, would you personally prefer?



Whole Home TOU Rate

- As long as times work with own schedule, this TOU rate seemed **more realistic/ applicable**
- A couple liked that this was **not limited to Electric Vehicle owners** – they could still take advantage of this option

Electric Vehicle TOU Rate

- A couple perceived this as **integral to move away from fossil fuel**: it supports people who choose to be more environmentally friendly
- Some thought this **did not apply to them** as they do not have an Electric Vehicle and were not planning on buying one

Neither/I'm not sure

- A couple would **need more off-peak times** in order to support either option;
- A couple felt they **lost flexibility** in energy usage – waiting for off peak times;

upwords


THANK YOU
Layla Shea
layla@upwords.ca
upwords

BC Hydro Optional Residential Time-of-Use Rate Application

Appendix D-7J

Focus Groups by Leger

Qualitative Report

Time of Use Focus Group Research

DATE JANUARY 2022

Table of Contents

Background & Research Objectives

Utilities across North America and globally have offered time-varying rates to customers for years and more recently, with the increase in electric vehicles and other technologies, have been introducing end-use time-of-use (TOU) rates. On this topic, BC Hydro is following up on the results of its recent Time of Use Survey regarding the home charging needs of Electric Vehicle (EV) drivers and non-drivers, and their willingness to shift to “off peak” periods at critical times of the year.

The utility wished to probe deeper into the survey results via qualitative research using online video chat focus groups. The groups explored with EV and non-EV drivers whether there is interest in an optional whole-home time-of-use rate now and in the future, as well as explored preferences and likelihood of participation in shifting to “off-peak” periods. If they were not interested in TOU rates, then questions would focus more on their level of understanding and reasons for disinterest. Specific topics explored in the focus groups included:

- **Attitudes around TOU rates** - why BC Hydro would want to implement them, and any confusion or uncertainty with TOU rates;
- **Thoughts on Whole Home TOU rates** – what appliances currently in the home that would enable usage at off-peak times, benefits to the user, any personal experience with TOU rates outside of BC, potential challenges, support needed from BC Hydro to utilize TOU rates, any seasonal preference (i.e. winter or weekdays only), what would make it appealing;
- **EV TOU rates only** – would it be of interest, any concerns, what would make it appealing;
- **EV charging** – when, at home or away from home, current cost to charge, how easy would it be to charge at off-peak times;
- **Current behaviour without an EV** – current spend on gasoline, anticipated behaviour if owned an EV (i.e. charge at home/away, drive more/less, would TOU appeal, any concerns; and,
- **Rates going forward** – better understanding of TOUs now, would behaviour change to utilize off peak times, any comments to BC Hydro about electricity rates.

Methodology

Online video chat focus groups with BC residents were conducted via the FOCUS video focus group software.

Groups were run on January 12 and 13, 2022.

Leger conducted four groups split as follows:

- Group 1 – 8 participants (EV owners who charge at home all the time)
- Group 2 – 8 participants (EV owners who charge at home or away)
- Group 3 – 8 participants (non-EV owners who are not interested in time of use fees)
- Group 4 – 8 participants (non-EV owners who are interested in time of use fees)

Mix of gender, age, BC region, homeowners/renters, and types of dwelling within each group.

Leger collaborated with BC Hydro on the recruitment screener. Participants were screened to not work in a market research/media/utility related role, must be a BC Hydro customer, and either EV owners or not. Participants received a $100 honourarium. In coordination with BC Hydro, the moderator guide was developed to ensure that the groups collected the pertinent information.

Online Video Chat Focus Group Limitations

Qualitative findings should be viewed as directional rather than statistically based; caution should be exercised when extrapolating the findings to British Columbia residents overall.

Online video chat focus group research is exploratory in nature and involves a limited number of participants. That said, the consistency of findings across these group sessions allows for key insights and conclusions to be derived from this research.


Key Findings

Key Findings

Overall, customers are interested in the Whole Home TOU rate. The general sentiment is that it will be an up-to-date alternative to the current two-step system, which many feel has been played out and should be discontinued. Most would at least opt in to try it out and see if it works for them, especially if it saves them money—if it doesn't, then they can return to the default rate. Introducing the concept of TOU to these customers has sparked more thinking around their electricity use habits—most would consider adjusting their use schedule for appliances, charging, etc. to take advantage of off-peak pricing.

Common themes discussed include integrating some flexibility in the offer (i.e. peak times, community usage vs whole province average, families vs single dwellers), support from BC Hydro to make the switch (information sharing with the customer and support for stratas) and generally treating this initiative as a partnership – residents helping BC Hydro level the load, BC Hydro crediting those who are putting in effort to make changes.

- Energy conservation is important to many and already integrated into their daily lives. Rationale for TOU rates is generally understood, with mixed reviews among those who had past experience.
- Many are interested in TOU rates, but peak hours and rates are highly criticized. Programming dishwashers and washing machines are easy to adjust, but some are not willing to stay up late to complete these chores. Heating the home is generally the largest electric expense; guidance on how to adjust this would be beneficial as well as sharing potential cost savings is likely to incentivize switching to TOU rates.
- Year-round TOU rates is preferred to seasonal, though some are interested in the weekday option and some can see benefit of seasonal TOU with usage much higher in the winter. Whole Home is preferred over EV TOU-only rates to encourage sustainable habits.
- EV owners typically charge at home and generally spend less on electricity than others spend on gasoline. EV drivers would charge overnight at the lower rate and can easily program their EV to do so.

Online Video Chat Focus Group Results

Leger

Energy conservation is important to many and already integrated into their daily lives.

Several participants have made efforts to conserve energy in their daily life, ranging from simple measures such as turning off lights, regulating thermostats, to running appliances overnight, purchasing electric vehicles, even renovating or custom-building homes with more energy efficient solutions. Overall, consciousness about energy consumption was there among most participants but varied in level of commitment. Many are open to trying TOU, especially if it's an opt-in program, to see if it benefits them.

«*I try to regulate my thermostat as much as possible. I'm very conscious of making sure my dishwasher is full before I run it, same thing for laundry that kind of stuff. Turning off lights.*» ***Female, Group 1***

«*I've spent the last 50 years conserving electricity so I haven't changed very much recently because I've already done it.* » ***Male, Group 1***

«*If they gave you the opportunity to opt in and opt out then that way you could experiment with it and see if it's better for you, if it would be beneficial. I would try it out if it doesn't work, then you opt out and you go back to where you're at. If you have that flexibility. I think the key for all of us here is flexibility. We don't all want to feel Hoodwinked into something we have no choice over, right?*» ***Male, Group 3***

«*I think it's beneficial for those of us that are really concerned about climate change and the consumption of electricity that we can actually do something on our part.* » ***Male, Group 1***

«*I seem to be the person who walks around the house turning off lights a lot of the time.*» ***Female, Group 2***

«*I do try to set my dishwasher to run in the evening, like late evening when I'm in bed and when I'm in whatever room I'm in, that's the only room that I light, all the rest of the lights are turned off.*» ***Female, Group 2***

«*We've switched most of our light bulbs over to LED.*» ***Female, Group 2***

Photo by lilartsy from Pexels

The rationale behind TOU rates is generally understood.

Participants appeared to understand the concept of electricity capacity and BC Hydro's rationale for proposing TOU rates. A couple shared their skeptical views with respect to selling power to other jurisdictions, but this was not a wide-spread concern.

«I can definitely see why this would be beneficial to them. I mean anytime you can shift the load around, I mean it's the same thing we're doing with the pandemic, right, flattening the curve, right that if you can drop cut the peak off and spread that out, I mean then we need less power generation, like the whole system.» ***Male, Group 4***

«I think this is, as a province, as a society where anything we can do to reduce the amount of electricity that we need to generate or to to reduce the infrastructure costs. All of that is on a global sense is really important.» ***Male, Group 4***

«I was thinking that it was to do with electric vehicles and just smoothing off that demand.» ***Female, Group 3***

«Generally I guess hydro would be interested in this to relieve the draw the demand on the grid so that they don't necessarily have to build another. Something like that. I imagine» ***Male, Group 1***

«Well, it's basically so they don't have to increase their capacity for the whole province. I think it's beneficial for those of us that are really concerned about climate change and the consumption of electricity that we can actually do something on our part. » ***Male, Group 1***

«Well, if I was going to be cynical, I would suggest that they want to free up capacity that can be exported to other jurisdictions at high rates in the United States, like California when it's required. So basically, I see this to a degree as an exercise by hydro to diminish demand. And I don't know that it's necessarily infrastructure related in this province where they can then export power to other parts of of the continent that may need it more and make lots of money doing it. That's the cynical side of what I have to say. They're not cynical side is maybe they just need more. They need to even out the demand usage.» ***Male, Group 3***

Photo by James Wheeler from Pexels

Mixed reviews among those who had experience with TOU rates in other jurisdictions.

Some had experiences with TOU rates most commonly in Ontario, while a few also came across them in France and England. There were mixed assessments of the Ontario experience, however, some proposed BC should follow the same peak hour times as Ontario, which would not be possible due to the different peak use times.

«In Ontario, what they have currently is the highest time of use rate is during sort of commercial working hours. So I think it varies based on the season, but it's usually between eight AM and 4 to 5 p.m. That's the highest rate. And then the medium rate is that time period of like 4 to 7 PM in the evening whenever he's getting home from school from work, making dinner, doing laundry. And then the cheap hours, as we always called them was the green time, which was after seven or eight PM until early the next morning. And so that would be when we would do our laundry, when we would put the dishwasher on, like maybe turn the heat up a little bit overnight so that we could take advantage of that sort of lower price.» ***Female, Group 3***

«Ontario's peak price was 17 cents per kilowatt opposed to the 25 cents that BC Hydro is suggesting. Also, it did have data in our bills in Ontario, which was very helpful because it meant that I could see if I run the dishwasher at 5:00, I would have spent this much, but because I ran it at 9:00, I saved this much.» ***Female, Group 3***

«I was actually surprised at the time of used scheduling and pricing having come from Ontario we had time of use and I mean, they went seven PM to seven AM for the low rate.» ***Male, Group 2***

«Well, certainly in the UK, they run a program called Economy seven for as long as I can remember. It basically does the same thing. It's cheap rate electricity overnight. And it's again it was used to to reduce the draw peak times and you know, offering an incentive to people to do that by offering the cheap rate electricity.» ***Male, Group 1***

«[In Ontario] we had the luxury of that. But I know that a lot of people in my circle don't because they were stay at home parents or lived in apartment buildings or whatever and had noise things. So it did end up costing them more. They did see their their bills go up when that came into the system.» ***Female, Group 3***

«[In Ontario] I'll get a text message and say they hooked it up to my A. C. In the house and a couple other things and they would get a message saying we're going to shut this off for two hours. And that's why you're getting a better rate. So if a bunch of homes could shut off certain items that are on the grid so they don't have to go to max. But I can override it, but if I override it, they were charging me $0.42 a kilowatt. So if you're willing to take a little bit of a hit once in a while to help them out when they're in need. I thought that was an interesting program.» ***Male, Group 2***

More are interested in TOU rates than not, but peak hours and rates are highly criticized.

Many participants feel the proposed $0.25/kwh rate during the peak hours of 4-9pm is too high. This objection was particularly strong among those who feel they have no choice but to use electricity during these hours, especially those who work during the day, work from home, and people with families.

«I was just surprised at the 4 to 9 o'clock for the max. And I think people will see 25 cents a kilowatt and just about have a heart attack because nobody's going to wait till 11 o'clock.» ***Male, Group 2***

«My initial reaction was 25 cents a kilowatt hour have they gone off their tree. It seems to me that if you're going to have a peak demand, it has to be something that isn't going to give you immediate sticker shock.» ***Male, Group 3***

«For kilowatt hour I think and um the rate at peak time is about 25c. So it's really punitive in lots of ways. So I would probably sign up for it, but I think there are probably a lot of people who might find it not an advantage.» ***Male, Group 4***

«In some ways you'd be punishing people who had kids and had, you know, a few options to because of their schedules and their work and what not, they wouldn't really have the option to be shifting the bulk of their electrical usage to 9:00 at night or after 11.» ***Male, Group 2***

«If the peak is just a bit higher than the daytime rate and that the evening is just a bit lower then I think people will still have the incentive to shift, but it takes a bit of that risk off.» ***Male, Group 4***

«I think everyone's consensus mostly was just not such a huge disparity between five cents and 25 cents, like something way less extreme, would be a bit more appealing.» ***Male, Group 3***

«The big spike rate between four and eight p.m. is a time where I don't have any control over my electricity usage like I'm going to peak there because that's when my kid comes home, that's when we cook dinner and that's when I actually need heat in our place.» ***Male, Group 3***

«The peak hours that they kind of talked about the 4-9, those would be my peak hours, I mean in our family and my kids are at school, my wife is home, but the rest of us are all out of the house. So are the electricity use? Not during those peak hours is minimal, but the kids come home, you do dinner do baths, do all those things that you can't do at a different time until the kids go to bed at 8:30. Um I would be screwed by this rate.» ***Male, Group 4***

«I'm currently working from home because of the pandemic, but also probably going forward because I think my office is going to end up being closed permanently. I am home, I use the same amount of electricity if it's 11 in the morning or 5 in the afternoon.» ***Male, Group 3***

Fixed peak hours and limited flexibility to adjust energy usage at home are key barriers with TOU rates.

Some wondered whether the peak hour period could be changed—when provided the information that it was indeed the time of peak electricity use in BC and therefore could not be changed, they were accepting of that fact. Some mentioned that they have no choice but to use electricity at peak times due to routines such as returning home from work and needing to heat the home, cooking dinner, and spending quality time with family—the high cost of electricity with TOU rates during peak hours is a "disincentive" to families. Some feel the high TOU rates during peak hours will hurt poor families, especially those who live in rental housing and may not have the choice of taking advantage of non-peak times.

«Makes it challenging if you're working a day job too, you know to avoid those peak hours.» ***Female, Group 1***

«Can we choose what time of the day that these are applicable to? Because for example, some people working night shifts, most of the time their day is their night.» ***Male, Group 1***

«If I put my washing on at 10:00, get it in the dryer and then go to bed. If I start my washing at 11:00, I'm not going to stay up until midnight to put it in the dryer.» ***Male, Group 2***

«In some ways it'd be punishing people who had kids and had few options because of their schedules and their work and what not, they wouldn't really have the option to be shifting the bulk of their electrical usage to 9:00 at night or after 11. » ***Male, Group 2***

«Let's say lower income folks probably don't have electric cars. I would propose that lower income folks probably are using baseboard heating, like the cheapest you can have. And I actually think this unduly punishes the people with low income that are using electric heat without the electric cars.» ***Male, Group 2***

«I like the concept, but there needs to be adjustment around the rate, 25 cents is way too high. And the times to make it more in line with the behavior that we want people to have because I really like the goal, which is going to be to offset move some of the energy consumption to different times of day, which is understandable and a very good goal to have. But it just needs to be more relatable to families in BC. That isn't so crazy as a four day, 4 to 9 p.m. 25 cents per kilowatt hour. That's when everyone comes home, I'm sure that is a peak time, but it covers so much of the evening and so much of the free time that people have together. Yeah, no one would ever, I don't think anyone would choose this purposefully at these rates.» ***Male, Group 2***

Leger

Heating the home generally the largest electric expense, guidance on how to adjust this would be beneficial.

The biggest electric expense for many is heating their homes, which many agree is not able to be pushed to off peak times easily, so there is skepticism that the new rate would in fact save them money. Some suggest they could think about how they would adjust heating their home, but perhaps this is an area where BC Hydro could offer some guidance on how to set thermostats to avoid the peak hours.

«The only way that I would be able to shift my usage to take advantage of these rates would be to be uncomfortably cold during the day. I'm not willing to sacrifice that.» ***Female, Group 3***

«I think what would save money is if there is a way to control the heating at home because that's what, especially in winter months, is eating a lot of energy, right?» ***Male, Group 1***

«I heat my house and it is by far the biggest electrical load in the system.» ***Male, Group 4***

«I don't want to go too in depth, but basically the heat's off in the house except for one room all day until my kid comes home Then we heat up the entire house and that's around four p.m. Then the heat turns off at nine PM because we're sleeping, which is like exactly the peak. I would consider and try to shift it, just crank the heat up at like 230 and just heat the house up to some crazy amount like 25°. And then after that initial peak where the house is warm, then reduce it down and that might actually save me money. My overall electric use would increase, but because of the time savings, I might actually save money so I could probably give it a try.» ***Male, Group 3***

«The fact that I now heat my house with a heat pump, I am not going to turn it off at any point during the day, it's far more comfortable in our house now at less cost.» ***Male, Group 4***

«Some people have already expressed if you know there's a big push to use electricity to heat your house, but you can't turn your furnace off for five hours right? Like that doesn't really work. And that heating is typically the most expensive part for someone's hydro bill? Right, so how do you how do you shift that load?» ***Male, Group 4***

14

Photo by Binyamin Mellish from Pexels

Showing potential savings likely to incentivize switching to TOU rates.

Many would like to see an online calculator to show potential cost savings if they opted for Whole Home TOU vs. the default rate. Some would prefer BC Hydro to show them in their bill or on paper directly what their potential savings are. Some feel a credit on their bill would be appropriate to acknowledge their effort to switch activities to off peak times.

«*I think that if you want to sell this to consumers, what you have to do is basically show them that moving to this system will be revenue neutral, but should they choose to move some of their kilowatt hour consumption to off peak times some sort of a credit can be issued against their bill or an incentive that way because right now, what I see here is a carrot and stick.*» ***Male, Group 3***

«*Any additional analytics related to my usage and consumption are always helpful. I know those tools exist online, but if BC Hydro integrated into the website which appliances used what amount of money and tips on how to how to save those who are always really helpful.*» ***Female, Group 4***

«*I would like some, some tools either online or in a phone call to help us compare rates to see which would serve best for us.*» ***Male, Group 4***

«*It would be pretty cool if Hydro actually said in your bill, we crunched your numbers for the last three months. If you go into this plan you would save 15%. They have the power to do it and that would be cool.*» ***Male, Group 3***

«*I'd like to have a tool or some kind of a comparator. I'd like an example of how it might affect me.*» ***Female, Group 2***

«*I want to see Plan A, B and C. You know, to get an idea what the rates are, What the times are they think goes with my schedule and my needs, do they fall into those parameters?*» ***Male, Group 2***

«*I would look at a suggestion from BC Hydro too, what they thought my best scenario over the last three years would be.*» ***Female, Group 4***

TOU a model that requires people to work together to achieve success.

Some believe BC Hydro cannot implement the new TOU rates without considering BC residents as partners in this initiative. If BC Hydro needs to spread out the demand on electricity, residents want to be given some sort of guarantee that their efforts will be rewarded. In some cases, landlords will need to work with their tenants to work within the TOU parameters. At the end of the day, it's about determining how can everyone work together to benefit from this new arrangement.

«I talked with a friend about it and he's got a house with two suites in it and he includes hydro in the rent. He says, I have no control over them now, they'll turn the heat up and open the window. And so he says, I can't encourage them to do that, let alone, do your laundry after 9:00 PM.» ***Male, Group 1***

«You're trying to create partnerships here. I think you're trying to make your consumers be a partner in your efforts as to reduce high peak demand times on your grid. You have to treat them like partners to do that right? If you want them to behave like partners, you have to treat them like partners.» ***Male, Group 1***

«I'd like to say that continuing to use these [focus groups] to connect with us and communicate with people is really important. I think that most people want to help the environment, we need information. I've been able to make decisions and under certain circumstances may be willing to, if we feel supported, be willing to pay more if that's necessary, if we are taken seriously, and are listened to and we feel like BC Hydro is being responsible and we trust the institutional level.» ***Male, Group 2***

«I want to know that my bill is going to cost me less after the year is over, because otherwise people are just going to fall back on when it's convenient. If there are no savings, why am I making the effort to set my dishwasher on delay?» ***Female, Group 2***

«It seems to me that the objective of such a program is to reduce or to even out load on the grid and is thus in BC Hydro's interest and they're trying to provide a carrot make it in my interest. So it seems reasonable that they might be able to offer me a guarantee that my electricity bill over the year would not be more than I was paying on the steps rate. I don't see any reason why they shouldn't offer that guarantee because that way they're putting their money where their mouth is.» ***Male, Group 2***

Photo by Cytonn Photography from Pexels

Apartment living may make a TOU plan more difficult to participate in; as well, non-EV owners tend to be less supportive.

People who don't have electric cars and/or feel they have only a limited number of appliances that they can apply to the non-peak hours pricing are less supportive of Whole Home TOU. People who live in rental apartments or strata units with noise restrictions particularly feel TOU rates may not necessarily work for them.

«One of the problems is it's okay we can program our dishwasher, our drying machine during the night, but in our building there is a bylaw that says that you are not allowed to use those appliances after some hours because you are making noise, you are disturbing other people. So additional thing that would be problematic in this sense is when you live in a building, you have to obey the by laws.» ***Female, Group 3***

«You know, if the problem is really about electric vehicles, then I don't understand why they don't just incentivize charging overnight rather than dis-incentivizing using electricity when we all need electricity.» ***Female, Group 3***

«'m not interested because all I have is a dishwasher and a washing machine that I could feasibly move to the nighttime, which makes up a very, very small proportion of my electricity bill.» ***Male, Group 3***

«There's no incentive for my landlord as he doesn't pay the bill to make the appliances more efficient to replace them. So that's one of the other struggles I'm kind of stuck with the inefficient appliances I have because I'm not going to fork out thousands of dollars to replace the furnace or the dishwasher or whatever.» ***Male, Group 4***

«I wondered also whether renters will have an option. So if the owner of the building or the flat decides that he wants to go with a variable rate, does the renter have an option or a choice or is it go with the unit because it might punish people who don't really have that choice.» ***Male, Group 4***

«I'm in a townhouse as well and our strata board are not very progressive. And so it would not be something that I could even contemplate doing if I wanted to, which is a shame. It would be really nice if municipalities or whatever would actually insist that strata's put some charging stations in, but that would not be feasible in my situation.» ***Female, Group 2***

«No, I don't see much advantage to it to many people because if you don't have an electric car then what's the benefit to me to get power cheap after 9:00.» ***Male, Group 1***

17

Photo by George Becker from Pexels

Year-round TOU rates are preferred to seasonal, though some are interested in seasonal/weekday option.

When asked whether they would prefer seasonal TOU (winter, weekdays only), the general sentiment among participants was they would still prefer having TOU all year-round – the thinking is that they would prefer not to have to change their habits for electricity (and any pre-programmed charging/appliance operation) by the changing of the season. This is a change in lifestyle overall that shouldn't vary throughout the year. However, some did say they would move activity to the weekend if that were an option or could see the benefit of a seasonal offering.

«If it is going to be offered, it has to be offered throughout the year. If not the same. It's a behavior right? It's your lifestyle, you have to program yourself to adapt to that.» **Male, Group 1**

«I definitely think that it would be counter intuitive to have it only for winter because a lot of people will just fall off the wagon.» **Male, Group 1**

«I'm not going to start laundry at 10 o'clock at night. And so for me, this option would not work whether it was weekends or whether it was winter season or winter weekdays.» **Female, Group 2**

«People with kids, their schedules during the week aren't very flexible. Whereas weekend you do have that flexibility. So I think that if you're going to go ahead with this kind of system, having it be also be like that on weekends is huge.» **Female, Group 1**

«I prefer to do it for the whole year. I'm charging my car all the year round, my furnace, the heat pump (it doubles as an air conditioner).» **Male, Group 2**

«That would be to my benefit. It would just be that habitual side of it for a year round option» **Female, Group 4**

«I don't have to pay attention I guess I just I sign up and then it works that way and I get into a habit and a routine.» **Male, Group 4**

«But the object of the exercise is to make people change some of their behaviors not to accommodate the behaviors that people already have.» **Male, Group 2**

«I definitely prefer year round.» **Male, Group 4**

«I could definitely do laundry at like 10 AM. On the weekend, but not necessarily 10 AM during the weekday.» **Female, Group 1**

«Seasonally sure you'll benefit a little better from it in the summer then you would in the winter but I wouldn't want it to be only available in one season and not available in another season. You have to get used to your change in your lifestyle. We're pretty much going to change it all year long.» **Male, Group 1**

«There's a big difference between winter and summer. A different pattern would be more beneficial to be agreed. We want to do something that is more convenient for summer and winter time.» **Male, Group 1**

Whole Home TOU generally preferred to sole EV TOU, and requiring a second charger is a key reason for this.

When given the choice of EV TOU versus Whole Home TOU for those with EVs and hoping to have an EV, overall, while there was some interest in EV TOU, there was still an overall preference for the Whole Home TOU. We note that EV TOU would require either a second electricity meter (level 1 or 2) or a networked or internet-connected charger to communicate with the BC Hydro billing system.

«I like the idea of the whole package because there are items in the house that use almost as much power as charging our car. You know the electric hot water tank with the size of the family we have we go through a lot of hot water so all of those I see all of the little things adding up to.» ***Male, Group 1***

«For my situation it would not be practical to spend the money for a second meter and the wiring associated with that.» ***Male, Group 2***

«Yes, [EV TOU] more interesting to me. I would definitely charge my car at different times to save money on my electrical vehicle. Yeah.» ***Female, Group 2***

«If I have to install some different Equipment, 2nd meter or different technology because you know, to be honest, the cost of running my electric vehicle is pretty economical and I worked it out that I saved seven cents a kilowatt hour around the year.» ***Male, Group 2***

«I've only ever had a level one charger. I am in a townhouse. My strata gave me nothing but problems when I tried to ask to put a level two, even though we have our own panels and everything.» ***Female, Group 2***

«I'm assuming that hydro somehow will have a connection to your wall charger separately from the rest of the house so they can offer electric car only option and if that were the case, yeah, I'd be interested in that because, like I said, the electric car is kind of one of the easiest ways to save money.» ***Male, Group 1***

«The time of use sounds very complicated. If you need a level two charger that connects to a smart meter or a separate meter, if you're using 110 with an internet connection. I mean it sounds it sounds almost undoable. You know, the complication of getting millions or thousands of homes configured to worked like that for EV I mean. I mean it sounds great to be able to get a cheaper rate on your EV, if you did it overnight, but if you went for the whole home package and you were paying six cents a kilowatt hour between nine PM and seven PM 4, 11 PM and seven PM, just set your EV up to charge, you know, after 11 o'clock at night.» ***Male, Group 2***

Dishwashers, washers and dryers are the main items identified as programmable for a Whole Home TOU plan.

In terms of the appliances that could be programmed to operate overnight, every group brought up dishwasher, washer, and dryer. Some also mentioned programmable thermostats and unique appliances like Instant Pots.

«*There are basically three appliances that you can use for time of use the dishwasher, the washing machine? The dryer after that.*» ***Male, Group 3***

«*I think the dishwasher is the only thing that I have the ability to set a timer on.*» ***Female, Group 3***

«*I think I've got um an instant pot. That's programmable and certainly I have a stove that has a self cleaning oven that's programmable. I don't use it very often, but I can definitely do it at night.*» ***Female, Group 2***

«*My dishwasher has a four hour delay setting so I can definitely put that on and have it run overnight and then likely throw a load of laundry in before I go to bed. Kind of use that overnight. So washer, washing machine probably not the dryer but the washing machine for sure. And my dishwasher.*» ***Female, Group 4***

«*Okay, so I have electric heating with a heat pump. There's nothing I can do about that. But of course the coldest time of day is during the night. So that's great. My car charging is easy to make that go at night, dishwashing and clothes washing.*» ***Male, Group 2***

«*As far as I know I have my dishwasher and my car are the only ones that I know of that I could charge. Maybe my well my computer would draw so little.*» ***Female, Group 2***

«*But we put in programmable thermostats on all of our baseboard heaters.*» ***Male, Group 3***

20

Photo by Castorly Stock from Pexels

EV owners typically charge at home and generally spend less on electricity than others spend on gasoline.

EV owners ranged from frequent to infrequent use, depending on their occupation status – some work at home or are retired (with much less vehicle use due to the pandemic), while others use their vehicles daily for commuting or other routines. Charging routines would be based on this use; more frequent users or those who make long trips would make use of external charging stations. In terms of home charging, some program their charging times while others have a regular, manual charging routine or leave their EVs plugged in. Monthly charging costs again varied depending on use, ranging from $10 to $50 per month, generally lower than gasoline costs which ranged from $40 to $125 monthly.

«I think having an electric car is like a really simple way to save money if you can charge at night because everybody can easily, you know, set their schedules. So, charges from midnight or whatever.» ***Male, Group 1***

«My wife uses [the EV] daily to get back and forth to work. So in the evening she gets home, she plugs it in. We've got the time set up already so that it charges at nighttime. If it needs to top up it does.» ***Male, Group 1***

«I'm probably about the lowest of the bunch. I only Maybe $10 [on EV per month]. I live really close to work and and shopping and stuff so.» ***Male, Group 2***

«I really liked it when they started charging at BC Hydro stations because when it was free, I'd often go and there'd be two or three people at two stations and I, you know, our cars only have a 150 kilometer limit. I needed to charge in order to be able to complete my errands and you know, people were just charging somewhere else for free rather than paying a bit to do it at home. So I was actually quite glad when they added a charge to it.» ***Male, Group 2***

«If BC Hydro could do something to make it really easy for apartment building owners to put charging stations into apartments, that would really help because I could go and connect in at night and do that, charging at night.» ***Female, Group 2***

«I'd say for me 40 to 50 [to charge EV per month].» ***Female, Group 2***

«We do all all are charging at home because you come home you plug in your car. The car itself has a schedule when it decides, you know, you can set it to charge whenever. We usually set a charge later in the night or in the middle of the night» ***Male, Group 1***

«It's way cheaper to charge at home than at a hydro fast charger.» ***Male, Group 1***

«We spend about $9 a month on our EV because it cost me about $2.50 to fully charge it, and we charge it about every 10 days.» ***Male, Group 1***

«I'm probably around 100 bucks a month [on gas] probably. I mean between to and from work and the kids and all their activities.» ***Male, Group 4***

Leger

Many are dissatisfied with the current two-step model.

Many are not pleased with the current two-step model. Some find it disincentivizes people to conserve energy once they break into the second tier. There is also unfair bias against families who simply have more people in the home, or people who live in colder climates and require more energy to heat their homes, who will never stay within the first tier. It leads some people to prefer the TOU rates over the current model.

«For me it's also about the choice I guess because once I go into step two I have no choice but to pay that rate right? Like there's nothing I can do to mitigate that price increase. Whereas with different time of use rates, I can at least have more control over when to use my appliances so that I can try to save more right? Because once I get step two I'm like, oh well whatever. You know I tried but if I'm going to be paying as much anyways might as well go all out and because there's no control of this stuff too right? Like it's it's been so cold in the last couple of weeks. » ***Female, Group 1***

«I m not a fan of the step one, step two personally. I feel like it's not fair to people that have families. I feel like single people never get into that step two and there's not really any incentive for me to make a huge difference if no matter what I do, I'm going to be into step two, you know, I'll just do what's convenient for me if I'm going to be charged. But I know I can set my timer on my dishwasher and I will set it till 11 or 12 at night and I can set my car to charge at non peak times. So I know that I would do that.» ***Male, Group 2***

«I personally never liked two tier billing when they brought it in 15 years ago. I thought it unduly penalized people that live in colder parts of the province. And given that we're all ratepayers in the same residential class, I didn't feel that that was appropriate at all. So this has the potential to be more equitable, but I don't see it as being particularly equitable in its current proposed form on the pdf you folks sent us.» ***Male, Group 3***

«I can echo some of the things we've heard already. I have to reinforce that the current stepped rate is not useful in the current context with the BC energy plan and our absolute need to reduce carbon emissions. It's punitive, it's the wrong thing. So very pleased that Hydro is looking at making some changes.» ***Male, Group 2***

«I think that the two step rate is counterproductive in terms of climate change. » ***Male, Group 2***

Leger

Final feedback included abolishing the current two step system, adjusting the proposed TOU rates and times…

At the end of the day, many are looking for the current system to be replaced, and generally there is buy-in on the TOU model. However, the peak hours and the rates are heavily criticized and many are concerned this would end up costing them more, especially in colder areas of the province and those with families. Implementing TOU rates year long would be preferred and perhaps looking at rates based more on community usage opposed to blanket rates.

«Two step program should be abolished sooner than later, it's not helping anyone. » ***Male, Group 1***

«The two step is past its best before date. It's not effective for what we need to accomplish in the current time framer, in the years they had. So the two step rate has got to go, that that would be the biggest message I could pass on.» ***Male, Group 2***

«It's penalizing big families too. I mean the two step, it cannot be sustained. When you have a family of six, you have to consume more and then you go to that 2nd step so quickly. I think that nobody ever takes that into account and they charge you. And it's not fair from my opinion.» ***Female, Group 3***

«The biggest thing for me is to narrow the time of use differences because I think really in rate design you want the cost to reflect to be reflected in the rates and the power doesn't cost 26 cents at peak and it probably cost more than five cents at night to produce. And having that narrower gap will still encourage people to shift, but it won't be punitive for people.» ***Male, Group 4***

«I think everyone's consensus mostly was just not such a huge disparity between five cents and 25 cents, like something way less extreme, be a bit more appealing.» ***Male, Group 3***

«It's got to be all year long. If they're going to bother with it every day all year.» ***Male, Group 1***

«I would consider time of use if the times were different.» ***Male, Group 3***

«I think that they're looking at sort of the average of the whole province. And part of the issue with that is that there is such a disparity of income all through the province as well as the disparity of a difference with weather patterns. And by looking at the province as a whole, they're going to end up pissing off somebody somewhere and if they look maybe more based on community needs that they may find that they have better reception.» ***Female, Group 3***

«I would say [two step] is penalizing folks that are using electricity for heat. » ***Male, Group 3***

…support from BC Hydro is needed to make the switch and incentives provided for those who do or already have made changes…

Those interested in making the switch to TOU would like guidance from BC Hydro as to the best way personally to adjust their usage (including renters with little autonomy), and reasonable time to adjust to the new ways. Some sort of financial compensation as an incentive to those who are making changes.

«We made the choice when we custom built our house to use electricity as the principal means by which to power it and heat it. And because we did that, I think that we have an expectation that whatever hydro does needs to be fair and equitable.» ***Male, Group 3***

«I think people can, I have a family, I know that we could definitely make some changes. Will it take time. Absolutely. It will and I have to adjust to some new normal things. I mean Surrey banned all bags as of November 1 and I didn't even know until I walked in one day without my reusable and they said there's no more bags, what would you like to do? So I think as long as hydro gave us time to adjust and suggestions on how to adjust different things. I think you could make it work but it's not going to be like overnight and it's not going to be as simple as I think they'd like it to be.» ***Female, Group 2***

«I think that there's got to be incentive for people who are trying to make changes.» ***Female, Group 2***

«I would love for BC Hydro to try to help me. I look at my bills not daily, but I probably look at them every week or so. I would love to see on my bills somewhere along the lines of did you know you spent $12 in electricity on Saturday between four and eight p.m. And I could actually think to myself, what did I do to for you know, something like that to make a customer a little more aware of when they're using so much electricity to maybe try to make changes. Those charts are not always easy to read and not everyone knows how to access them. So you put a couple of sentences on a bill.» ***Female, Group 2***

«My biggest thing again, just looking at myself would be to try and find a way to help people who are renting that can't make decisions about energy efficiencies in their house or the appliances they're using.» ***Male, Group 4***

…lastly, benefits of TOU rates are noticed (especially for EV drivers) and some skepticism exists around the new model.

Those who already have done all they can do to adjust their lifestyle to be more energy efficient are skeptical any changes would be doable for them. Some even go as far to suggest it would be better for them to store energy themselves in batteries to access at peak periods. Transparency is important as some are skeptical that Hydro has their best interest in mind. Lowered rates for overnight EV charging are recognized as are other benefits for running household appliances.

«I think even right now, I've done as much as I'm able to do within my lifestyle and schedule already to reduce the usage and I honestly can't see how I could accommodate doing anything differently to get out of using power between the peak periods. I'm doing as much as I can right now and like I say, I honestly can't see how I can make it any different any better.» ***Female, Group 2***

«I think one of the big advantages is for people who want to electrify and get away from fossil fuels. If you're going to switch to an EV, if you're going to switch from gas to a heat pump, you're going to be using more electricity, be more step two rates and the more that that can be balanced out more easier it is to integrate things into the grid and not penalize customers who do that.» ***Male, Group 4***

«I understand that maybe there can be a variance in terms of time of use billing, but 25 cents per kilowatt hour during the peak times and five cents for the low times strikes me almost as a subsidy to people that are going to be charging electric vehicles versus those that don't have electric vehicles.» ***Male, Group 3***

«Well the overnight overnight charge is nice and low at 5 cents, which is great for EV because that's something you can usually schedule. It's not so easy to do laundry in the middle of the night, but you can put your dishwasher on just before bed, which would help. That would run late.» ***Male, Group 1***

«I think BC Hydro exports power and I think they should make it really clear that if people are working to conserve power and take measures to conserve power that's not just so BC Hydro can export the power and make more money. I think that there's sort of a balance there. They are representative in in green power and people have to trust them and if they feel that really it's all about exporting energy and making more money than I think that trust will be eroded. So that has to be really clear.» ***Male, Group 4***

«That 25 cent rate is so high that it is just about cost effective to buy a bunch of batteries store the energy at the five cent rate and feed it back to yourself during the high period. That can't be what BC Hydro has in mind. So they really need to think about that.» ***Male, Group 2***


Appendix

Preliminary profiles of each focus group

EV Owners (both those who do almost all their charging at home and who charge at home and elsewhere, Groups 1 and 2)

- Passionate about their EVs and most appear committed to 'doing their part' to combat climate change.
- Quite knowledgeable about electricity use and home power needs—some monitor electricity use very closely.
- They are mostly homeowners and are able to choose times for when they can schedule appliance use and EV charging.
- Want to replace the current two-step rate model and prefer Whole Home TOU model vs EV only as it is more lifestyle driven.
- Concerned the peak time restrictions and cost will prohibit use of this method among families and those unable to make changes because of schedules.
- Want to know their efforts to reduce energy consumption are being recognized by BC Hydro.

Non-EV Owners not interested in TOU rates (Group 3)

- Seem to be more cynical about BC Hydro's motives behind proposing TOU rates (e.g. to facilitate exporting electricity elsewhere, helping subsidize EV owners).
- They are open to trying TOU if cost savings can be demonstrated vs. current or default rate structures.
- Most feel that $0.25/kwh during peak hours is too high and would hurt families and low income people.
- Some renters and apartment and condo dwellers in this group; renters don't have a choice in the appliances they have and others have noise restrictions at certain times of the day. Because of this, some feel they don't have the flexibility to make the TOU worthwhile to them.

Non-EV Owners interested in TOU rates (Group 4)

- Fairly similar to Group 3, but appear to be less cynical about BC Hydro's motives behind TOU.
- Open to trying TOU but looking for BC Hydro to work with them and offer support to implement changes.

Pre-Reading for Focus Groups

Participants were provided the following information to review before attending the focus groups.

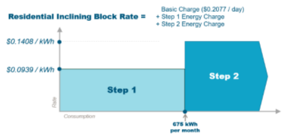
BC Hydro – Residential Rates Focus Groups

Topic: Optional Time-of-Use rates

Thanks for your upcoming participation in our virtual focus group session. We've put the following overview together to provide you some context for the session.

Introduction

As a residential customer, you're currently billed for the electricity you use based on a 2-step rate. This rate was introduced in 2008 to encourage energy conservation and has largely met those goals. We're currently investigating options to update the default residential rate in response to customers changing needs for electricity.

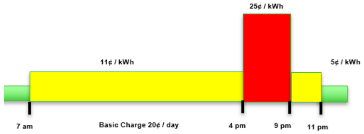


Electrification is on the rise

We're already planning and anticipating our province's future electricity needs as we've seen more customers choosing to drive electric vehicles or installing heat pumps in their homes. With this increased use in electricity, we anticipate the need to construct new facilities to meet the need for capacity within the electrical system. "Capacity" is the maximum sustainable amount of electricity that can be produced and delivered to meet the periods of highest demand for electricity. In B.C., these periods of high system demand occur in the winter, usually between 4 – 9 pm on weekdays.
Here's a short two-minute video that explains the concept of capacity.

The need for optional time-of-use rates

Time-of-Use rates can support electrification and promote the efficient use of the electrical system. By encouraging customers to shift their electricity use from periods of high system demand to lower demand periods (i.e. overnight), BC Hydro can defer costly system upgrades, resulting in lower long-term costs for all customers.



This figure provides illustrative pricing corresponding with periods of high, medium and low system demand. Customers that can shift the use of high consuming appliances like clothes washers/dryers and electric vehicle chargers from the peak period, can save money and help BC Hydro reduce future land and water impacts.

Could time-of-use rates work for you?

We've invited you and other customers to these sessions so we can learn more about your preferences when it comes to optional time-of-use rates. Questions such as:

- Why might they or might they not work for your household?
- If you opted in, what is the likelihood you'd continue this behaviour (shifting your electricity use to cheaper times of the day) all year long even if the time-of-use pricing is limited to a specific period (i.e. winter months).
- Does the pricing we're considering motivate you to participate and save?

We look forward to speaking with you soon!

OUR SERVICES

- **Leger**
  Marketing research and polling
- **Leger MetriCX**
  Strategic and operational customer experience consulting services
- **Leger Analytics (LEA)**
  Data modelling and analysis
- **Leger Opinion (LEO)**
  Panel management
- **Leger Communities**
  Online community management
- **Leger Digital**
  Digital strategy and user experience
- **International Research**
  Worldwide Independent Network (WIN)

600
EMPLOYEES

185
CONSULTANTS

8
OFFICES

MONTREAL | QUEBEC CITY | TORONTO | WINNIPEG
EDMONTON | CALGARY | VANCOUVER | PHILADELPHIA

OUR CREDENTIALS

Leger is a member of the Canadian Research Insights Council (CRIC), the industry association for the market/survey/insights research industry.

Leger is a member of ESOMAR (European Society for Opinion and Market Research), the global association of opinion polls and marketing research professionals. As such, Leger is committed to applying the international ICC/ESOMAR code of Market, Opinion and Social Research and Data Analytics.

Leger is also a member of the Insights Association, the American Association of Marketing Research Analytics.

BC Hydro Optional Residential Time-of-Use Rate Application

Appendix E

The Brattle Group – Capacity Savings Estimates in BC Hydro's 2021 IRP: An Independent Review

Capacity Savings Estimates in BC Hydro's 2021 IRP: An Independent Review

PREPARED BY
Ahmad Faruqui, Ph. D.
Principal Emeritus

PREPARED FOR
BC Hydro

FEBRUARY 22, 2022

Page 1 of 58

TABLE OF CONTENTS

Page 2 of 58

1. Introduction

Nature of engagement

BC Hydro filed its 2021 Integrated Resource Plan (IRP) with the British Columbia Utilities Commission (BCUC) on December 21, 2021. The 2021 IRP includes estimates of the capacity savings that BC Hydro expects to obtain from its demand response (DR) programs and time-varying rates.[1] Specifically, BC Hydro has estimated that a portfolio of DR programs and time-varying rates could provide 220 MW of capacity savings by 2030, and a portfolio of additional DR programs and rates that is specifically focused on electric vehicle (EV) charging could provide an additional 100 MW of capacity savings in 2030.[2]

BC Hydro retained me as an independent expert to review their methods for determining their capacity savings estimates. Specifically, BC Hydro asked that I address the following two questions:

1. Are the methodologies used to derive the estimated capacity savings reasonable?[3]
2. Are the resulting estimated capacity savings reasonable?

In my review, I worked with a team of experts at Brattle. We conducted a thorough review of BC Hydro's methodology, relying on primary source documents provided by BC Hydro. Those sources include the 2021 IRP and supporting technical appendices, studies and associated workpapers prepared for BC Hydro by consulting firms (including Brattle), and phone interviews with BC Hydro subject matter experts (SMEs) who were involved in the DR program and rates analysis. We conducted further research to develop support for the conclusions of my review. Appendix A includes a complete list of the sources I relied upon in my review.

Summary of expert qualifications

I am an energy economist whose consulting practice encompasses rate design, demand response, distributed energy resources, demand forecasting, decarbonization, electrification, energy efficiency, and load flexibility.

In my career, I have advised some 150 clients in 12 countries on 5 continents and appeared before regulatory bodies, governments, and legislative councils in Alberta, Arizona, Arkansas, California, Colorado, Connecticut, Delaware, District of Columbia, Egypt, the U.S. Federal Energy Regulatory Commission, Georgia, Illinois, Indiana, Iowa, Jamaica, Kansas, Kentucky, Michigan, Maryland, Minnesota,

1 As used here, "DR programs" includes direct control incentive programs (e.g., targeting electric space and water heating) and peak saver incentives. "Rates" includes time-of-use rates and critical peak pricing rates.

2 BC Hydro, 2021 Integrated Resource Plan, December 21, 2021, page 1-3. Note that the references are to fiscal year 2030.

3 Note that the capacity savings associated with energy efficiency programs and with the Industrial Load Curtailment Program were determined by BC Hydro to be outside the scope of my review.

Missouri, Nevada, New Brunswick, Nova Scotia, Ohio, Oklahoma, Ontario, Pennsylvania, the Philippines, Saudi Arabia, Texas, and Washington. I have presented at seminars on energy policy in 20 countries on 6 continents.

I have authored or coauthored more than 150 papers in peer-reviewed and trade journals and co-edited five books on industrial structural change, customer choice, and electricity pricing. My work has been cited in Bloomberg, Businessweek, The Economist, Forbes, and National Geographic, in addition to news outlets including the Los Angeles Times, The New York Times, San Francisco Chronicle, San Jose Mercury News, and the Washington Post. I have also appeared on Fox Business News and NPR.

I have taught economics at San Jose State University, the University of California, Davis, and the University of Karachi and delivered guest lectures at Carnegie Mellon, Harvard, Idaho, MIT, New York University, Northwestern, Rutgers, Stanford, UC Berkeley, and UC Davis.

A complete list of my qualifications is provided in Appendix B.

Summary of findings

My review of BC Hydro's methodology for estimating the capacity savings of its DR programs and time-varying rates identified seven distinct steps in the company's analysis. After reviewing each of the seven steps, I have concluded that BC Hydro's approach to those seven steps is reasonable and consistent with standard industry practices. In some areas, BC Hydro's analytical rigor significantly exceeds the industry norm. I also conclude that BC Hydro's capacity savings estimates are well supported and reasonable.

Where I offer recommendations for improving the analysis, my recommendations are refinements that could expand and enhance the usefulness of the study's conclusions to BC Hydro by adding further nuance and detail. I would not expect these refinements to necessarily alter BC Hydro's core findings. It goes without saying that any utility planning study can be improved as the industry's experience in this area advances. Given the growing importance of flexible demand and time-varying rates in the transition to a decarbonized economy, I believe BC Hydro's analysis will serve as a solid foundation for scaling up its demand response programs and rates.

2. Overview of BC Hydro's Methodology

I have distilled my understanding of BC Hydro's methodology for estimating the capacity savings of DR programs and rates into seven distinct analytical steps, as summarized in Table 1.

TABLE 1: OVERVIEW OF STEPS IN BC HYDRO'S METHODOLOGY FOR ESTIMATING CAPACITY SAVINGS

	Analysis Step	Comments
1	**Determine relevant DR programs and rates**	The "menu" of options included in the IRP is defined by program or rate type, and by deployment method (opt-in or opt-out).
2	**Establish customer eligibility**	The pool of customers eligible to participate in a DR program or rate will depend on whether they have the necessary technology (e.g., electric heating electric vehicle).
3	**Determine participation rate**	Not all eligible customers will choose to participate in a DR program or rate. This step determines the share of customers that are likely to enroll.
4	**Estimate per-participant impact**	Capacity savings will vary from one customer to the next, depending on their size and many other factors. This step establishes the average peak demand impact across participants in the DR program or rate.
5	**Account for participation "overlap"**	The standalone capacity savings of individual DR programs and rates are not always additive, because they may target load reductions from the same customer end-uses. This step reduces savings to account for that overlap.
6	**Adjust impacts for effective load carrying capability (ELCC)**	In this step, the capacity savings are derated to account for operational constraints that would prevent DR programs and rates from providing the same capacity value as a dispatchable generator.
7	**Adjust impacts to account for uncertainty**	Lastly, the capacity savings are adjusted (either up or down) to account for uncertainty in the assumptions underlying the capacity savings estimates.

Page 5 of 58

For each of the steps in Table 1, my report describes the details of BC Hydro's methodology, compares that methodology to my understanding of standard industry practices in other jurisdictions, and offers suggestions to refine the analysis in the future. Note that, while the steps in Table 1 are generally applicable to all DR programs and rates analyzed by BC Hydro, there are some differences in how the company evaluated DR programs and rates related to EVs. For that reason, I discuss the EV DR programs and rates in their own separate section of the report.

3. Selecting Programs and Rates

The first step in BC Hydro's estimation of capacity savings was to select the DR programs and rates to be considered in the analysis.

Methodology

BC Hydro analyzed direct control incentive programs targeting electric space and water heating and EV charging, peak saver incentives, time-of-use (TOU) rates, critical peak pricing rates, and an Industrial Load Curtailment Program.[4] My understanding is that BC Hydro selected these programs because they provide multiple participation options across all customer segments, and are feasible from an implementation standpoint.

Discussion

BC Hydro has selected a portfolio of DR and rates programs that span what I consider to be the most important options for a winter-peaking utility that is just beginning to go down the path of introducing DR offerings to its customers. The options include technology-based programs for deep and dependable load reductions, as well as behavioral options so that participation opportunities exist for all customers. The DR programs and rates analyzed by BC Hydro align with the programs that account for the vast majority of DR capacity savings identified in a recent Brattle study on the national potential for cost-effective load flexibility in the United States.[5]

As a refinement in future assessments of DR potential, BC Hydro may wish to consider analyzing variations of the DR programs the company has analyzed, in order to determine beneficial deployment and implementation strategies. For example, water heating load control can be implemented through advanced technology that provides real-time load flexibility, or through more basic technology (e.g., a timer) that provides daily load shifting. Each approach has its advantages and disadvantages.

---

4 Note that the capacity savings associated with energy efficiency programs and with the Industrial Load Curtailment Program were determined by BC Hydro to be outside the scope of my review.

5 Ryan Hledik, Ahmad Faruqui, Tony Lee, and John Higham, "The National Potential for Load Flexibility: Value and Market Potential through 2030," June 2019.

Page 6 of 58

As BC Hydro gains experience with DR programs, the company may also wish consider broadening the portfolio of options to include emerging load flexibility programs. For example, some utilities are starting to utilize the direct control of behind-the-meter batteries to provide demand response benefits.[6] This is still an emerging option and requires that there be sufficient battery adoption among customers in order for the program to have a meaningful impact, but may be worth exploring in future studies. Similarly, BC Hydro could consider the potential to use demand-side resources to provide system value through ancillary services and daily load shifting.

4. Customer Eligibility

Once BC Hydro defined the list of DR programs and rates considered for the IRP, the next step was to determine the portion of customers that would be eligible for each DR program or rate. For example, only customers with electric heating would be eligible for participation in an electric heating direct load control program. This eligibility estimate establishes the theoretical upper-bound on enrollment.

DR programs

Methodology

BC Hydro relied on its load forecast to establish the total customer count in each year of the planning horizon. The company then relied on a 2017 end-use survey to determine the share of the customer base equipped with electric heat or electric water heating, the two specific end-uses controlled by BC Hydro's proposed DR programs. BC Hydro then applied these shares from the end-use survey to the forecasted customer counts to arrive at estimates of the total eligible customer base for the space heating and water heating direct load control programs.

Discussion

BC Hydro's methodology for determining DR program eligibility is reasonable and consistent with standard industry practices. BC Hydro's approach accounts for future growth in the customer base. End-use studies are the most common resources for determining eligibility, and have the benefit of being tailored specifically to the utility's customer base (rather than relying on more general province-wide or national averages).

To refine these estimates in future planning studies, BC Hydro could consider updating the end-use study and allowing the annual end-use saturation estimates to change over the forecast horizon. I would not expect BC Hydro's use of a study from 2017 to result in significantly different findings than if the company had developed and used a more recent end-use study, given the gradual rate at which customers change their space and water heating fuel equipment, since these appliances are long lived.

[6] Green Mountain Power, Portland General Electric, and Duke Energy Florida are three examples of US utilities that have or will implement this concept.

Page 7 of 58

However, in future analyses, these adjustments would allow BC Hydro to account more precisely for a potential trend toward heat pump adoption, for example.

Time-varying Rates

Methodology

BC Hydro has already deployed smart meters across its service territory, so technology was not an eligibility constraint in the rates analysis. BC Hydro reviewed its rate schedules and identified those schedules that the company would consider as candidates for future time-varying rate offerings. Ultimately, customers on rate schedules accounting for approximately 85% of BC Hydro's customer base were considered eligible for the rate options. Examples of excluded rate schedules are street lighting (which is not metered) and small commercial customers (which were expected to demonstrate lower responsiveness to time-varying rates).

Discussion

BC Hydro considered the vast majority of its customer base to be eligible for time-varying rates, which is consistent with industry practices elsewhere. The exclusion of a small number of rate schedules is appropriate and avoids overstating the potential capacity savings of time-varying rates. In future analyses, BC Hydro could consider including small-to-medium sized commercial customers for time-varying rate offerings. While pilots have found very small commercial customers (i.e., those with peak demand less than 20 kW) to lack a significant degree of price responsiveness, slightly larger customers (e.g., with peak demand in the 50 kW to 100 kW range) have demonstrated price responsiveness.[7]

5. Standalone Participation Rates

After determining the share of customers eligible for each DR program and rate, BC Hydro then estimated the share of those customers that could plausibly enroll in the programs and rates. Participation in all of the programs and rates is optional and mostly opt-in. In some rates suites, BC Hydro considered the potential associated with opt-out deployment.[8] In this step, the participation rates are determined on a standalone basis for each program or rate. A later step in BC Hydro's analysis takes into account the possibility of "competition" between DR programs and rates.

7 Ahmad Faruqui, Jenny Palmer and Sanem Sergici, "The Untold Story: A Survey of C&I Dynamic Pricing Pilot Studies," Metering International, 2010.

8 Opt-in deployment means the customer must proactively enroll in the program or rate. Opt-out means the customer is defaulted on to the rate, with the option to revert to an alternative rate option.

Page 8 of 58

DR programs

Methodology

Base case participation estimates were developed for BC Hydro by Navigant (now Guidehouse), based on a review of utility experience deploying DR programs in other jurisdictions. The assumed participation rates range from 15% to 20%, depending on the DR program. BC Hydro reviewed these assumptions and adjusted them if needed based on the company's pilot experience. However, my understanding is that no adjustments were made to the DR programs that are within the scope of my analysis for this report.[9]

Program enrollment is assumed to grow to those steady-state participation levels over a five- to six-year deployment period, following an S-curve trajectory. Additionally, the base case adoption rates are adjusted to be consistent with higher customer incentive payment levels that are assumed in BC Hydro's "Demand Response Program B." BC Hydro assumed that a doubling of the incentive payment would result in a 25% increase in DR program enrollment, based Guidehouse's review of a 2017 DR potential study by Lawrence Berkeley National Lab (LBNL).[10]

Discussion

I consider the assumed participation rates of 15% to 20% to be reasonable for a utility like BC Hydro, which currently has limited experience with DR program deployment. Utilities in other jurisdictions have achieved enrollment rates that are greater than this. For example, Xcel Energy has achieved over 50% enrollment among eligible customers in its residential air-conditioning load control program in Minnesota. However, those cases typically apply to utilities that, like Xcel Energy, have a long history of offering DR programs and have reached those participation rates over many years. Additionally, those utilities typically are in summer peaking regions; there is less experience with DR programs targeting winter peaks, which warrants a conservative participation estimate. I recommend that BC Hydro monitor enrollment in its programs, and update these assumptions as the company gains program deployment experience.

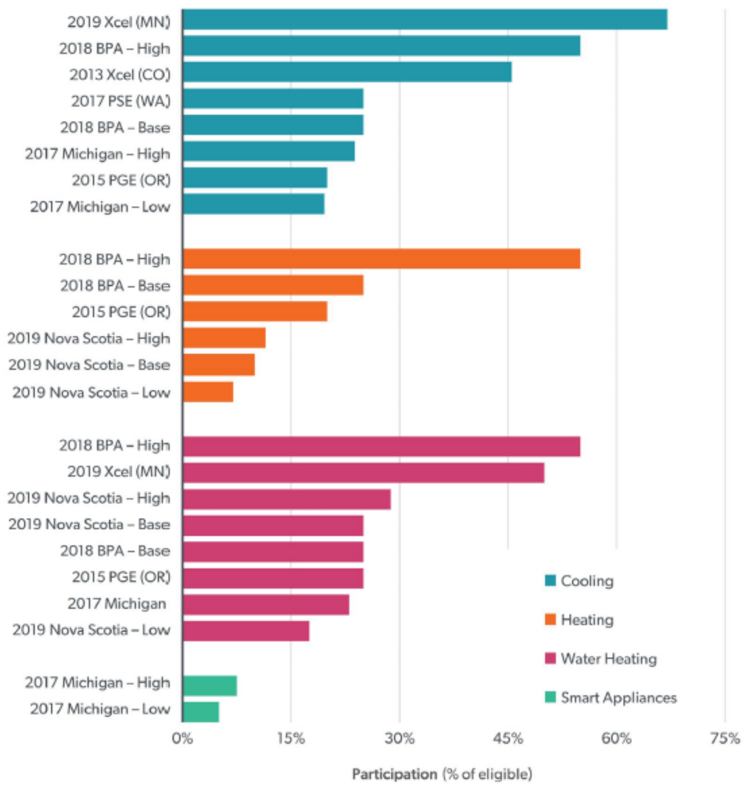
Figure 1 summarizes achievable residential DR program enrollment rates from studies in other jurisdictions, based on research that my Brattle colleagues and I recently conducted for the U.S. Department of Energy. BC Hydro's assumptions fall within the range of participation rates shown in the figure.

---

[9] An adjustment was made to the Interruptible Load Curtailment participation rate, which as noted earlier is outside the scope of my report.

[10] LBNL, "2025 California Demand Response Potential Study," prepared for the California Public Utilities Commission, 2017.

FIGURE 1: RESIDENTIAL DR PROGRAM ENROLLMENT ESTIMATES FROM STUDIES IN OTHER JURISDICTIONS



Source: U.S. Department of Energy, "A National Roadmap for Grid-Interactive Efficient Buildings," prepared by LBNL, The Brattle Group, Energy Solutions, and Wedgemere Group, May 2021.

BC Hydro's 5- to 6-year S-shaped participation ramp-up period is consistent with assumptions that I have used in similar studies for other utilities. BC Hydro's assumption that DR program enrollment will increase by 25% when participation incentives are doubled is at the low end of the range of sources that I have reviewed. Those sources, summarized in Table 2, suggest that enrollment could increase by nearly 50% when incentives are doubled. However, as with the base participation assumptions, I believe it is appropriate for BC Hydro to use a conservative assumption of 25% in this case, due to the limited experience with DR programs in the company's service territory and in winter peaking jurisdictions more broadly.

Page 10 of 58

TABLE 2: STUDIES ESTIMATING THE RELATIONSHIP BETWEEN INCENTIVES AND PARTICIPATION

Study	Methodology	Result
LBNL, "2025 California Demand Response Potential Study," 2017	Derived primarily from the impact evaluation of a 2009 PG&E **pilot** to test enrollment in a residential air-conditioning load control program at various incentive levels.	Doubling incentive leads to **25%** increase in DR enrollment (per Guidehouse review of the study findings)
Brattle, "DR Potential in Xcel Energy's Northern States Power Service Territory," 2014	Conducted **primary market research** (survey) to establish likelihood of Minnesota customer participation in DR programs at various incentive levels. Conducted regression analysis to establish relationship between change in incentive and change in likely enrollment.	Doubling incentive leads to **50%** increase in likely DR enrollment (residential)
BPA and Cadmus, "Demand Response Elasticities Analysis," 2018	**Analyzed 2010-2015 EIA-861 data** on utility-level DR capacity and incentives. Conducted regression analysis to establish class-level relationship between change in incentive and change in DR capacity.	Doubling of incentive leads to **50%** increase in DR capacity (residential)
GDS Associates and Nexant, "Energy Efficiency Potential Study for Pennsylvania," 2015	Conducted **primary market research** (survey) with residential customers in Pennsylvania to establish willingness to adopt EE measures. Survey results present EE equipment purchase likelihood as a function of incentive payment.	Doubling incentive leads to **~60%** increase in EE adoption (average across various technologies with different adoption rates; estimate for HVAC is ~60%)

Time-varying Rates

Methodology

I developed BC Hydro's enrollment assumptions for time-varying rates, with assistance from my Brattle colleagues. The base case enrollment assumptions are 15% for opt-in deployment, and between 73% and 95% for opt-out deployment (depending on customer class). I developed these estimates through analysis of U.S. Energy Information Administration data on existing utility time-of-use rate offerings and a review of utility evaluation reports on time-varying rate offerings.

Page 11 of 58

Discussion

The enrollment assumptions for time-varying rates that I provided to BC Hydro are consistent with the best available industry data and literature on the topic, and supported by my extensive experience designing and evaluating the rate offerings for utilities across North America and internationally. As with the DR program enrollment assumptions, I recommend that BC Hydro continue to monitor progress in the deployment of its time-varying rates, and update these assumptions as the company gains experience. The case of Arizona Public Service is noteworthy. It is a summer peaking utility with an extreme climate. It experiences more than a hundred days annually with temperatures in excess of a hundred degrees Fahrenheit. Over several decades, it has been able to achieve opt-in enrollment of more than half of its residential customers in time-varying rates.

6. Per-Participant Impacts

In this step, BC Hydro established an estimate of the average capacity savings per participant in the DR programs and rates. BC Hydro combined these per-participant impacts with the participation estimates to produce aggregate, system-level estimates of capacity savings.

DR programs

Methodology

Navigant developed BC Hydro's per-participant impact assumptions. The impacts are based on a review of estimates for similarly situated utilities in other jurisdictions, a review of BC Hydro's pilot experience, and Navigant's experience evaluating the impacts of DR programs. BC Hydro reviewed these assumptions and applied adjustments where applicable based on the company's expectations around program deployment. My understanding is that central space heat load control is the only program for which the impacts were subsequently adjusted (a 25% decrease), to account for an expectation that a portion of the participation load will be from heat pumps, which tend to have less operational flexibility and lower overall electricity demand than electric furnaces.

Discussion

The sources that BC Hydro relied upon to establish the per-participant impacts assumptions are credible, and they appear to be based on the experience of Western, often winter peaking, utilities. Given the limited experience with DR programs and time-varying rates in British Columbia, it is reasonable to rely on tailored impact estimates from other jurisdictions. In the absence of extensive BC Hydro-specific experience upon which to base the impact estimates, there will be some uncertainty in these assumptions. My familiarity with the literature on DR program impacts suggests that these impacts vary from one utility service territory to the next, depending on factors such as climate, customer behavior, building stock, and impact evaluation methods. In future analyses, I recommend that BC Hydro revise these assumptions as the utility gains experience with its DR programs, and as new relevant data becomes available from winter peaking utilities in other jurisdictions. In the meantime, BC Hydro's approach to accounting for uncertainty in the impacts appropriately addresses this range of possible future outcomes (as discussed further in Section 9 of this report).

Time-varying Rates

Methodology

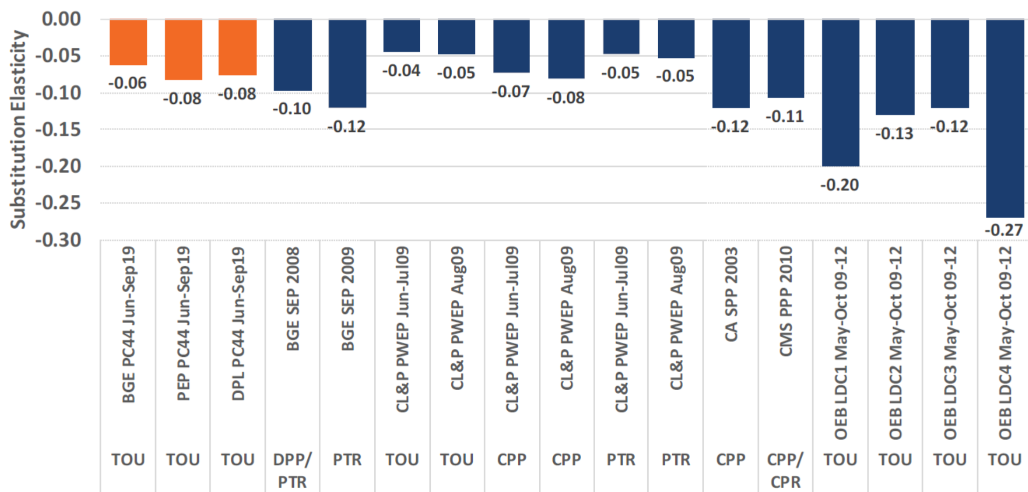
I helped BC Hydro develop the per-participant impact assumptions for the time-varying rates, with assistance from Brattle colleagues. Specifically, BC Hydro provided me with the company's assumed price elasticities of participants in the time-varying rate offerings, which I reviewed for reasonableness. Price elasticity is a measure of the extent to which customers will respond to price signals. In the context of BC Hydro's time-varying rates, the elasticity of substitution indicates the extent to which customers will shift their usage from higher price periods (i.e., peak periods) to lower priced periods (i.e., off-peak periods). BC Hydro combined these price elasticity estimates with assumed peak-to-off-peak price ratios in the time-varying rates to establish an estimate of capacity savings.

Discussion

The residential price elasticities assumed by BC Hydro are consistent with my experience evaluating time-varying rates, and with my understanding of the literature on the topic. Figure 2 summarizes price elasticity of substitution estimates from several recent studies, and BC Hydro's assumptions fall within this range. The literature on price elasticities for large customers is less conclusive, but BC Hydro has addressed this through the uncertainty analysis described in Section 9 of this report.

Page 13 of 58

FIGURE 2: PRICE ELASTICITY OF SUBSTITUTION ESTIMATES FROM TIME-VARYING RATES PILOTS



Sources and notes: Sanem Sergici et al., "PC44 Time of Use Pilots: Year One Evaluation," prepared for Maryland Joint Utilities, September 15, 2020. BGE - Baltimore Gas and Electric; PEP-Pepco Maryland; DPL-Delmarva Power & Light Maryland; CL&P- Eversource Energy; CA SPP – California's Statewide Pricing Pilot; CMS - CMS Energy (Michigan); OEB - Ontario Energy Board.

7. Participation Overlap Derate

In this step, BC Hydro adjusted the capacity savings estimates to account for potential "overlap" in capacity savings across DR programs and rates. This overlap can occur when a single customer is a potential participant in both a DR programs and a time-varying rate, which could target load reductions from the same end-use. BC Hydro's implemented adjustments to avoid attributing the load reduction benefits of that single customer's end-use to both the DR program and the time-varying rate.

For example, when offered in isolation, a hypothetical space heating direct load control program may provide 10 MW of peak demand reduction from 10,000 customers. A residential time-varying rate, also offered in isolation, may provide 20 MW from 50,000 customers. However, 5,000 of the participants may be interested in both the load control program and the rate. Both programs would likely provide load reductions from those participants' space heating, and it is important from a planning standpoint to avoid counting the same load reduction twice (as well as to avoid double payment for that load reduction).

Methodology

My understanding is that BC Hydro has derated the impacts of the DR programs to account for "retained potential". Retained potential is the capacity savings that is incremental to the impacts of time-varying rates. The adjustments are based on BC Hydro's judgement and understanding of program operations.

The derates are 10% for water heating load control and 50% for space heating load control. Peak saver impacts are not derated, as that program would be a mutually exclusive offering relative to the rates options.

Discussion

BC Hydro's decision to account for overlap is reasonable and consistent with established industry practices. It is common for utilities to establish a participation prioritization hierarchy in DR potential studies, and to adjust the capacity savings potential of programs that are progressively lower in the hierarchy. That is effectively what BC Hydro has done, by attributing full capacity savings to the time-varying rates and then de-rating the DR program capacity savings to account for overlap.

In future studies, I recommend that BC Hydro conduct market research to develop empirical support for the derates. For example, customers could be provided with a survey that tests their likelihood of adopting various DR programs and rates, both in isolation and in combination. Statistical analysis of the survey results would indicate the extent to which combined participation in competing programs is less than the sum of likely participation in the programs if offered in isolation. I recommend that BC Hydro then use this information to construct bottom-up support for the derate assumptions, categorizing customer participation across individual programs and multiple programs, so that there is transparent, segmented accounting for the participation assumptions. My understanding from conversations with BC Hydro is that the company has begun to conduct this type of analysis.

8. ELCC Adjustment

Capacity savings from DR programs and time-varying rates do not equate one-for-one to the capacity value of peaking generation that is available nearly around-the-clock. This is because DR programs have operational constraints, such as a limit on the number of load curtailment events that can be called per year, the timing of the window during which load is curtailed, and the ability to call consecutive events. DR programs and rates also can increase load before or after an event, which needs to be accounted for when assessing their overall impact on system load. In this step, BC Hydro adjusted the capacity savings of the DR programs and rates to account for these limitations. The share of maximum program capacity that counts as true capacity savings in the IRP is referred to as the "effective load carrying capability" (ELCC) of the programs and rates.[11]

Methodology

Appendix H of BC Hydro's IRP summarizes the company's methodology for estimating the ELCC of DR programs and rates. At a high level, BC Hydro determines how hourly system load would be impacted by the DR programs and rates, accounting for specific operational parameters of each DR program and

[11] These adjustments are not unique to DR programs and rates. BC Hydro develops ELCCs for other resources as well, such as wind and solar units.

rate. BC Hydro then calculates the extent to which that modified load shape could be increased without violating the company's 1-in-10 loss of load expectation (LOLE) criterion for maintaining resource adequacy. The ELCC is calculated by dividing the megawatts of allowable load increase by the maximum capacity of the DR programs and rates.

Additional relevant notes on BC Hydro's methodology:

- BC Hydro uses a 2017 weather normalized hourly system load shape, because 2017 was determined to be a broadly representative year from a weather and load shape standpoint.

- The operational parameters that are used to characterize the performance of the DR programs and rates include: number of interruption events (12 to 20 per year, dispatched optimally), duration of curtailment window (5 to 9 pm for DR programs and rates considered in my review), and post-event rebound (assumes all curtailed load reappears as an incremental increase beyond baseline load following the curtailment event).

- BC Hydro focuses the analysis on the capacity of DR programs and rates in 2030, as this is roughly the midpoint of the planning horizon.

Discussion

Derating the capacity savings of DR programs and rates is a standard step in robust utility planning studies. I have observed a variety of methods being used to develop these derates. In California, for example, the utilities develop availability factors based on steps laid out the Demand Response Cost-effectiveness Protocols.[12] Some utilities in other jurisdiction adopt modified versions of these factors, or apply judgement based reductions to capacity savings. An advantage of BC Hydro's approach is that it tailors the adjustments specifically to the company's system conditions.

BC Hydro's methodology is reasonable and conceptually similar to an approach that my Brattle colleagues and I have employed in our load flexibility analysis tool, LoadFlex.[13] In particular, accounting for a variety of operational parameters relative to an 8,760 hourly load shape provides a nuanced perspective on the capacity value of the DR programs and rates to the BC Hydro system. BC Hydro's use of a weather normalized load shape from a representative historical year is sufficient. As a future refinement to the analysis, BC Hydro may consider re-shaping the hourly profile to align with the company's expectations that peak demand will grow faster than energy demand; the 2017 load profile is likely less "peaky" than the company's load profile in future years, and may understate the ELCC of DR programs and rates as a result. Relatedly, focusing on 2030 capacity savings in this analysis likely understates the ELCC of the programs and rates prior to that period, and overstates the ELCC after 2030.

[12] CPUC Website: https://www.cpuc.ca.gov/industries-and-topics/electrical-energy/electric-costs/demand-response-dr/demand-response-cost-effectiveness.

[13] For more information about the LoadFlex tool, see Ryan Hledik, Ahmad Faruqui, Tony Lee, John Higham, "The National Potential for Load Flexibility: Value and Market Potential Through 2030," June 2019.

Page 16 of 58

This is because the ELCC declines as resources grow in size, and BC Hydro's DR programs and rates are expected to grow in size over the planning horizon. However, these are reasonable approximations to make in a study of this nature, and I would not expect them to dramatically affect the findings.

9. Accounting for Uncertainty

As with any forecast, there is uncertainty in the assumptions behind BC Hydro's estimates of capacity savings from the DR programs and rates. BC Hydro conducted analysis to account for this uncertainty, which resulted in adjustments to the capacity savings estimates and also contributed to an assessment of the downside risk that may arise from a system planning standpoint if the capacity savings do not materialize at the expected levels.

DR programs

Methodology

BC Hydro's methodology for addressing uncertainty is described in Appendix M of the IRP. First, BC Hydro staff determined plausible low and high estimates of capacity savings associated with the DR programs and rates, to supplement the base estimates described above. Those low and high estimates were based on BC Hydro subject matter expert judgement and informed by considerations regarding factors such as the plausibility of higher enrollment rates or technological breakthroughs. Then, BC Hydro established a probability distribution to encompass the low, base, and high estimates.

The distribution of results of the uncertainty analysis had two applications in BC Hydro's IRP. BC Hydro modified its base capacity savings estimates to reflect the mean of the distribution of possible outcomes. This modification could either moderately increase or decrease the base estimate, depending on the shape of the probability distribution. Additionally, BC Hydro used the analysis to inform its assessment of the risk that DR programs and rates could underperform relative to their expected capacity savings levels. Specifically, the company ran its IRP model assuming DR program and capacity savings only materialized at levels equating roughly to the 10^{th} percentile of the probability distribution, and determined what near term contingencies may be needed to address the shortfall.

Discussion

Based on my experience, BC Hydro's approach to assessing uncertainty in the capacity savings is advanced relative to standard industry practices. Utility IRPs that I am aware of often test low and high sensitivity cases around DR program and rates impacts, but rarely go as far as BC Hydro to assess the uncertainty probabilistically. BC Hydro's approach provides the company with a refined perspective on the role of DR programs and rates in resource planning decisions.

To further advance BC Hydro's robust approach to uncertainty assessment, the company could consider supplementing the subject matter experts' perspectives on plausible high and low cases with a review of what has been achieved by utilities in other jurisdictions. Doing so would add further nuance and support to those estimates. BC Hydro's use of the uncertainty analysis also could be expanded to provide commentary on the upside associated with DR programs and rates performing at a higher level than expected (e.g., reduced system imports or improved system reliability).

Time-varying Rates

Methodology

I helped BC Hydro develop the uncertainty-related assumptions for the time-varying rates, with assistance from Brattle colleagues. Specifically, I provided BC Hydro with low and high estimates of price elasticities and enrollment, which BC Hydro used to simulate capacity savings.

Discussion

The high and low price elasticity and enrollment assumptions that I provided to BC Hydro were based on a survey of the best available information on time-varying pricing rates. I maintain a database of the results of rates pilots and full scale deployments, and have conducted impact evaluations of many such studies across North America, and drew from that experience to develop these estimates.

10. EV DR Programs and Rates

Electric vehicles (EVs) are expected to introduce large increases in overall system load and peak demand requirements over the next several decades. This is particularly pertinent in British Columbia, as the government has passed a law that would require all new vehicles to be zero emissions by 2040.[14] Unlike other jurisdictions, where similar goals and targets are aspirational, British Columbia's requirements are legally binding. Given the importance of fully accounting for the capacity implications of this level of EV adoption, BC Hydro estimated the load impacts of future EV adoption, and the capacity savings associated with DR programs and rates that target that EV charging load.

Methodology

Similar to BC Hydro's approach to modeling the other DR programs and rates, EV program-related capacity savings were developed through a series of steps. First, BC Hydro developed a bottom-up forecast of EV market share using key drivers such as the capital-related costs of owning EVs (i.e., vehicle sale prices, government incentives) and variable operating costs as a function of distance driven, fuel efficiency, and relative fuel prices (electric vs gasoline). Next, the forecast of the annual total number of

[14] The ZEV Act stipulates percentage targets for new light-duty vehicle sales in B.C. that must have zero emissions, as follows: 10 per cent of sales by 2025, 30 per cent of sales by 2030, and 100 per cent of sales by 2040

EVs was calculated as the product of the EV market share and the total vehicle purchase forecast. BC Hydro developed three EV forecasts: Low, Reference, and High. Reference level forecasts were utilized to develop EV DR impacts.

Next, BC Hydro developed the EV DR program and rates enrollment estimates. EV DR programs and rates are still in a relatively nascent stage of development, but typically take the form of both “active” and “passive” management of the EV charging load. Active EV managed charging involves controlling the charging load of the EV through in-vehicle telemetry capabilities or through smart chargers. Passive EV managed charging involves applying a TOU rate specific to the EV’s charging load. BC Hydro developed three EV DR (managed charging) participation scenarios: i) 35% driver participation; ii) 50% driver participation and iii) 75% driver participation. BC Hydro found that the 50% participation level would be an important component of a portfolio of resources designed to relieve capacity constraints on the south coast of the Province. Accordingly, BC Hydro used the 50% participation level to develop the EV DR impacts for the IRP’s Base Resource Plan.

After forecasting EV adoption and establishing assumed customer participation in the EV DR programs and rates, the last step in BC Hydro’s analysis was to determine the expected capacity savings from participating customers. EV capacity savings are estimated based on a Monte Carlo model of electric vehicle charging behavior that forecasts the total annual electric vehicle load and the hourly demand of electric vehicle charging in the service territory over the IRP planning period. BC Hydro modeled the system load impact of a given percentage of EV customers participating in the EV DR programs, with a simulated delay in the time at which those customers start their vehicle charging until the off-peak period. BC Hydro assumed that approximately 75% to 90% of the peak period charging load of participating customers would be shifted out of the peak period.

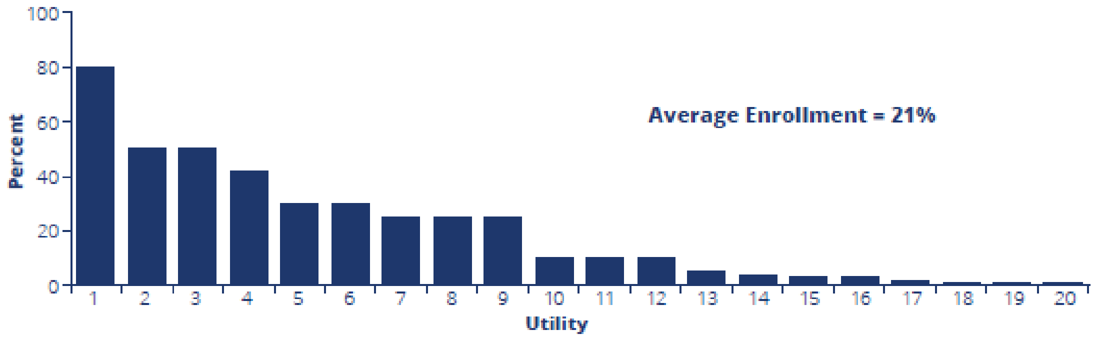
The same ELCC and uncertainty adjustments described earlier in this report were applied to the EV capacity savings estimates.

Discussion

Given the ambitious direction from the ZEV Act, BC Hydro assumes a significant number of EVs will be on the road as of 2030. BC Hydro’s assumption of 50% driver participation in EV charging DR programs and rates is ambitious, but I believe it is achievable based on a review of early experience with EV TOU rates in other jurisdictions. Figure 3 summarizes participation in EV TOU rates as identified in a study that my Brattle colleagues conducted in collaboration with the Smart Electric Power Alliance (SEPA) and Enel X. The figure shows that BC Hydro’s participation estimate is near the upper end of the range of enrollment rates that have been achieved, but is not outside that range. The SEPA study highlights a number of actions that can be taken by utilities to achieve the type of enrollment level being targeted by BC Hydro. Further, BC Hydro’s EV DR offerings include active and passive managed charging, which will cater to a broad range of EV customers, increasing the likelihood of participation.

Page 19 of 58

FIGURE 3: SHARE OF ELIGIBLE CUSTOMERS ENROLLED IN EV TIME-VARYING RATE



Source: Erika Myers, Jacob Hargrave, Richard Farinas, Ryan Hledik, and Lauren Burke, "Residential Electric Vehicle Rates That Work," prepared for the Smart Electric Power Alliance, November 2019.

BC Hydro also assumes that once the customers are enrolled in these programs and rates, 75% to 90% of peak period charging load will be shifted to other hours. The industry's early experience with EV DR programs and rates suggests that this assumption is ambitious but achievable given the flexible nature of the EV charging, especially for active managed EV charging programs. A pilot study in San Diego found that participants in TOU rates for EV charging provided peak usage reductions that are generally consistent with this range.[15]

There is relatively limited industry experience with EV DR programs and rates, and therefore less empirical support regarding achievable participation rates and capacity savings than for the more established DR programs and rates discussed earlier in this report. I recommend that BC Hydro continue to monitor and refine its EV DR program and rates assumptions as the company's and the industry's experience advances in this area.

[15] Nexant, "Final Evaluation for San Diego Gas & Electric's Plug-in Electric Vehicle TOU Pricing and Technology Study," prepared for San Diego Gas & Electric, February 20, 2014. The pilot found that EV owners shifted 73% to 84% of their charging to the super-off-peak period in response to peak-to-super-off-peak price ratios in the range of 2-to-1 to 4-to-1.

11. Conclusions

By combining the steps described above, BC Hydro arrives at its estimate of 220 MW of capacity savings from DR programs and rates targeting residential and commercial customers, and an additional 100 MW from DR programs and rates that specifically target home EV charging load. In this report, my team and I set out to address the following questions that were posed to me by BC Hydro:

1. Are the methodologies used to derive the estimated capacity savings reasonable?[16]
2. Are the resulting estimated capacity savings reasonable?

To assess the reasonableness of BC Hydro's capacity savings estimates, as well as BC Hydro's methodology for developing them, I relied on a variety of sources, including the BC Hydro's IRP, technical reports, and subject matter expert interviews. I benchmarked BC Hydro's approach against my understanding of approaches used to conduct similar studies by utilities in other jurisdictions across North America.

I have concluded that BC Hydro's approach to estimating the capacity savings is reasonable and broadly consistent with standard industry practices from other jurisdictions. The capacity savings estimates themselves are reasonable and well supported by BC Hydro's analysis. In some instances, such as the company's treatment of uncertainty, I believe BC Hydro's analytical rigor has significantly exceeded the industry norm.

In my report, I have noted some instances where BC Hydro's assumptions were reasonable but on the conservative end of the reasonableness spectrum. I feel this level of conservatism is appropriate for a utility in BC Hydro's position, given the company's (and Province's) relatively limited experience with demand response and time-varying rates thus far.

Given the industry's long history of experience with DR programs and time-varying rates, there is a variety of established utility practices for estimating capacity savings. A study by any utility in any jurisdiction, regardless of size, geography, ownership structure, or level of sophistication, is subject to resource and timeline constraints, and can be improved through further analysis. In this vein, my report identifies several opportunities for BC Hydro to refine its methods and continue to push the envelope as the company advances its understanding of DR programs and time-varying rates.

Ahmad Faruqui, Ph.D.
Principal Emeritus
February 22, 2022

[16] Note that the capacity savings associated with energy efficiency programs and with the Industrial Load Curtailment Program were determined by BC Hydro to be outside the scope of my review.

Page 21 of 58

Appendix A: BC Hydro Materials Relied Upon

1. BC Hydro, 2021 Integrated Resource Plan, December 21, 2021.
2. BC Hydro, "Demand Response Program Options for Brattle 20219423.xls".
3. BC Hydro, "Electric Vehicle Peak Reduction for Brattle Mar 12 2021 R2.xls"
4. The Brattle Group, "Estimating the Impact of New Time-Varying Rates for BC Hydro," memorandum to BC Hydro, July 14, 2020.
5. The Brattle Group, "Capturing the Uncertainty in Elasticity of Substitution and Customer Participation Rates in Time-Varying Rates," memorandum to BC Hydro, September 24, 2020.
6. De Zoysa, Sanjaya, and Alex Tu, BC Hydro subject matter expert interview (ELCC calculation), January 19, 2022.
7. Faruqui, Ahmad, "Modeling opt-out deployment of critical-peak pricing (CPP) in BC Hydro," memorandum to BC Hydro, January 24, 2021.
8. Hanlon, Kristen, BC Hydro subject matter expert interview (DR program impacts and participation), January 19, 2022.
9. Jubb, Anthea and Robert Zeni, BC Hydro subject matter expert interview (EV DR programs and rates), January 20, 2022.
10. Navigant, "Demand Response Potential for Assessment for BC Hydro," prepared for BC Hydro, March 28, 2018.
11. Navigant, "British Columbia Utilities Demand Response Potential Assessment," April 4, 2017.
12. Stumborg, Basil, BC Hydro subject matter expert interview (uncertainty analysis), January 21, 2022.

Page 22 of 58

Appendix B: Expert Qualifications

Dr. Faruqui provides expert advice and testimony on rate design, load flexibility, energy efficiency, demand response, distributed energy resources, demand forecasting, decarbonization, and electrification. He has worked for over 150 clients on five continents and appeared before regulatory bodies, governments, and legislative councils.

He has authored or coauthored more than 100 papers in peer-reviewed and trade journals and co-edited books on industrial structural change, customer choice, and electricity pricing. His work has been cited in *Bloomberg*, *Business Week*, *The Economist*, and *Forbes*, in addition to *The New York Times* and the *Washington Post*, and he has appeared on NPR and Fox Business News.

Dr. Faruqui has taught economics at San Jose State, UC Davis and the University of Karachi and delivered guest lectures at Carnegie Mellon, Harvard, Idaho, MIT, New York, Northwestern, Rutgers, Stanford, and UC Berkeley. He obtained an MA in Agriculture Economics and a PhD in Economics from UC Davis, and a BA and an MA in Economics from the University of Karachi.

EDUCATION

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

AREAS OF EXPERTISE

Expert witness

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

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

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

Innovative pricing

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

Regulatory strategy

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

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

Page 24 of 58

- **Design and evaluation of marketing programs**. He has helped generate ideas for new products and services, identified successful design characteristics through customer surveys and focus groups, and test-marketed new concepts through pilots and experiments.
- **Academic experience**. He has given lectures at the University of California, Berkeley, University of California, Davis, Harvard University, University of Idaho, Massachusetts Institute of Technology, Michigan State University, Northwestern University, University of San Francisco, Stanford University, University of Virginia, and University of Wisconsin-Madison. Additionally, he has led a variety of professional seminars and workshops on public utility economics around the world. Finally, he has taught economics at San Jose State University, University of California, Davis, and the University of Karachi.

EXPERIENCE

Innovative Pricing

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

Page 25 of 58

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

set of illustrative rates that were created for four customer classes using actual utility data. The work was reviewed by a national peer-review panel.

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

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

Demand Response

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

Page 28 of 58

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

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

Smart Grid Strategy

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

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

Demand Forecasting

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

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

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

Demand-Side Management

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

Page 32 of 58

organizations in a privatized energy market, and were designed to help develop U.S. AID's future funding agenda.

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

Advanced Technology Assessment

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

TESTIMONY

Arizona

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

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

Arkansas

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

California

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

Colorado

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

Page 34 of 58

Connecticut

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

District of Columbia

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

Georgia

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

Idaho

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

Illinois

- Direct testimony on rehearing before the Illinois Commerce Commission on behalf of Ameren Illinois Company, on the Smart Grid Advanced Metering Infrastructure Deployment Plan, Docket No. 12-0244, June 28, 2012.
- Testimony before the Illinois Commerce Commission on behalf of Commonwealth Edison Company regarding the evaluation of experimental residential real-time pricing program, 11-0546, April 2012.
- Rebuttal Testimony before the Illinois Commerce Commission on behalf of Commonwealth Edison Company in the matter of the Petition to Approve an Advanced Metering Infrastructure Pilot Program and Associated Tariffs, No. 09-0263, August 14, 2009.
- Prepared rebuttal testimony before the Illinois Commerce Commission on behalf of Commonwealth Edison, on the Advanced Metering Infrastructure Pilot Program, ICC Docket No. 06-0617, October 30, 2006.

Page 35 of 58

Indiana

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

Kansas

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

Louisiana

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

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

Maryland

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

Minnesota

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

Mississippi

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

Missouri

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

Montana

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

Nevada

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

New Mexico

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

Oklahoma

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

Page 38 of 58

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

Pennsylvania

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

Washington

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

REGULATORY APPEARANCES

Arkansas

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

Delaware

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

Kansas

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

Ohio

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

Texas

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

PUBLICATIONS

Books

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

Chapters in Books

- "Making the Most of the No Load Growth Business Environment," with Dian Grueneich. *Distributed Generation and Its Implications for the Utility Industry*. Ed. Fereidoon P. Sioshansi. Academic Press, 2014. 303-320.
- "*Arcturus*: An International Repository of Evidence on Dynamic Pricing," with Sanem Sergici. *Smart Grid Applications and Developments, Green Energy and Technology*. Ed. Daphne Mah, Ed. Peter Hills, Ed. Victor O. K. Li, Ed. Richard Balme. Springer, 2014. 59-74.
- "Will Energy Efficiency make a Difference," with Fereidoon P. Sioshansi and Gregory Wikler. *Energy Efficiency: Towards the end of demand growth*. Ed. Fereidoon P. Sioshansi. Academic Press, 2013. 3-50.
- "The Ethics of Dynamic Pricing." *Smart Grid: Integrating Renewable, Distributed & Efficient Energy*. Ed. Fereidoon P. Sioshansi. Academic Press, 2012. 61-83.
- "The Dynamics of New Construction Programs in the 90s: A Review of the North American Experience," with G.A. Wikler. *Proceedings of the 1992 Conference on New Construction Programs for Demand-Side Management*, May 1992.
- "Forecasting Commercial End-Use Consumption" (Chapter 7), "Industrial End-Use Forecasting" (Chapter 8), and "Review of Forecasting Software" (Appendix 2) in *Demand Forecasting in the Electric Utility Industry*. C.W. Gellings and P.E. Lilbum (eds.): The Fairmont Press, 1992.
- "Innovative Methods for Conducting End-Use Marketing and Load Research for Commercial Customers: Reconciling the Reconciled," with G.A. Wikler, T. Alereza, and S. Kidwell. *Proceedings of the Fifth National DSM Conference*. Boston, MA, September 1991.

Page 40 of 58

- "Time-of-Use Rates and the Modification of Electric Utility Load Shapes," with J. Robert Malko, *Challenges for Public Utility Regulation in the 1980s*, edited by H.M. Trebing, Michigan State University Public Utilities Papers, 1981.
- "Implementing Time-Of-Day Pricing of Electricity: Some Current Challenges and Activities," with J. Robert Malko, *Issues in Public Utility Pricing and Regulation*, edited by M. A. Crew, Lexington Books, 1980.

Technical Reports

- *Modernizing Distribution Rate Design,* with Ahmad Faruqui, Ryan Hledik and Lam Long, prepared for ATCO Ltd., March 13, 2020.
- *Analysis of Ontario's Full Scale Roll-out of TOU Rates – Final Study,* with Neil Lessem, Sanem Sergici, Dean Mountain, Frank Denton, Byron Spencer, and Chris King, prepared for Independent Electric System Operator, February 2016. http://www.ieso.ca/-/media/files/ieso/document-library/conservation-reports/final-analysis-of-ontarios-full-scale-roll-out-of-tou-rates.pdf
- *Quantifying the Amount and Economic Impacts of Missing Energy Efficiency in PJM's Load Forecast,* with Sanem Sergici and Kathleen Spees, prepared for The Sustainable FERC Project, September 2014.
- *Structure of Electricity Distribution Network Tariffs: Recovery of Residual Costs,* with Toby Brown, prepared for the Australian Energy Market Commission, August 2014.
- *Time-Varying and Dynamic Rate Design*, with Ryan Hledik and Jennifer Palmer, prepared for RAP, July 2012. https://www.raponline.org/wp-content/uploads/2016/05/rap-faruquihledikpalmer-timevaryingdynamicratedesign-2012-jul-23.pdf
- *The Costs and Benefits of Smart Meters for Residential Customers*, with Adam Cooper, Doug Mitarotonda, Judith Schwartz, and Lisa Wood, prepared for Institute for Electric Efficiency, July 2011. http://www.edisonfoundation.net/iee/Documents/IEE_BenefitsofSmartMeters_Final.pdf
- *Measurement and Verification Principles for Behavior-Based Efficiency Programs*, with Sanem Sergici, prepared for Opower, May 2011. http://files.brattle.com/files/8217_measurement_and_verification_principles_for_behavior-based_efficiency_programs_sergici_faruqui_may_2011.pdf
- *Methodological Approach for Estimating the Benefits and Costs of Smart Grid Demonstration Projects.* With R. Lee, S. Bossart, R. Hledik, C. Lamontagne, B. Renz, F. Small, D. Violette, and D. Walls. Pre-publication draft, prepared for the U. S. Department of Energy, Office of Electricity Delivery and Energy Reliability, the National Energy Technology Laboratory, and the Electric Power Research Institute. Oak Ridge, TN: Oak Ridge National Laboratory, November 28, 2009.

- *Moving Toward Utility-Scale Deployment of Dynamic Pricing in Mass Markets*. With Sanem Sergici and Lisa Wood. Institute for Electric Efficiency, June 2009.
- *Demand-Side Bidding in Wholesale Electricity Markets.* With Robert Earle. Australian Energy Market Commission, 2008. https://www.aemc.gov.au/sites/default/files/content/a2f43d16-f48f-4983-8776-9bc1dd71de65/Report-on-Demand-Side-Bidding-in-Wholesale-Electricity-Markets-by-The-Brattle-Group.pdf
- *Assessment of Achievable Potential for Energy Efficiency and Demand Response in the U.S. (2010-2030)*. With Ingrid Rohmund, Greg Wikler, Omar Siddiqui, and Rick Tempchin. American Council for an Energy-Efficient Economy, 2008.
- *Quantifying the Benefits of Dynamic Pricing in the Mass Market.* With Lisa Wood. Edison Electric Institute, January 2008.
- California Energy Commission. *2007 Integrated Energy Policy Report,* CEC-100-2007-008-CMF.
- *Applications of Dynamic Pricing in Developing and Emerging Economies.* Prepared for The World Bank, Washington, DC. May 2005.
- *Preventing Electrical Shocks: What Ontario—And Other Provinces—Should Learn About Smart Metering.* With Stephen S. George. C. D. Howe Institute Commentary, No. 210, April 2005.
- *Primer on Demand-Side Management*. Prepared for The World Bank, Washington, DC. March 21, 2005.
- *Electricity Pricing: Lessons from the Front.* With Dan Violette. White Paper based on the May 2003 AESP/EPRI Pricing Conference, Chicago, Illinois, EPRI Technical Update 1002223, December 2003.
- *Electric Technologies for Gas Compression*. Electric Power Research Institute, 1997.
- *Electrotechnologies for Multifamily Housing*. With Omar Siddiqui. EPRI TR-106442, Volumes 1 and 2. Electric Power Research Institute, September 1996.
- *Opportunities for Energy Efficiency in the Texas Industrial Sector*. Texas Sustainable Energy Development Council. With J. W. Zarnikau et al. June 1995.
- *Principles and Practice of Demand-Side Management*. With John H. Chamberlin. EPRI TR-102556. Palo Alto: Electric Power Research Institute, August 1993.
- *EPRI Urban Initiative*: *1992 Workshop Proceedings (Part I)*. The EPRI Community Initiative. With G.A. Wikler and R.H. Manson. TR-102394. Palo Alto: Electric Power Research Institute, May 1993.
- *Practical Applications of Forecasting Under Uncertainty*. With K.P. Seiden and C.A. Sabo.TR-102394. Palo Alto: Electric Power Research Institute, December 1992.

- *Improving the Marketing Infrastructure of Efficient Technologies*: A Case Study Approach. With S.S. Shaffer. EPRI TR- I 0 1 454. Palo Alto: Electric Power Research Institute, December 1992.
- *Customer Response to Rate Options*. With J. H. Chamberlin, S.S. Shaffer, K.P. Seiden, and S.A. Blanc. CU-7131. Palo Alto: Electric Power Research Institute (EPRI), January 1991.

Presentations

- "A Walk along the Rate Design Frontier," presented at a Noontime Talk at the Berkeley Lab, December 10, 2021.
- "Modernizing Tariffs Is No Longer an Option, It's an Imperative," presented to APPA Public Power Forward Virtual Summit, December 3, 2021.
- "Innovative Rate Design and Smart Charging of EVs," presented at Qevcon 2021 Qatar, November 17, 2021.
- "Putting Demand Back in the Equation: Customer Choice and Tariff Design: Opportunities in Mexico," presented at ROPEC 2021, November 11, 2021.
- "Assessing CPS Energy's Affordability," presented to CPS Energy, October 27, 2021.
- "Report by Brattle Economists Quantifies Impact of Customer-Driven Adoption of Decarbonization Technologies," prepared for Oracle, October 21, 2021.
- "Customer Choice and Tariff Design: Opportunities in Brazil," presented at Brazil Energy Frontiers "The Electricity Sector & New Global Frontiers, October 20, 2021.
- "PC44 Time of Use Pilots: End of Pilot Evaluation," prepared for Maryland Public Service Commission, October 4, 2021.
- "The Rate Design Imperative: Why the Status Quo is Not Viable," presented to 21st Century Energy Policy Development Task Force, Indiana, August 18, 2021.
- "The Rate Design Imperative: Why the Status Quo is Not Viable," presented to IEEE, July 27, 2021.
- "A Meditation on Rate Design: Lessons from the Past Four Decades," July 25, 2021.
- "Four D's are disrupting the Utility Business Model," presented at a Virtual Peaker and Brattle Webinar: The Intersection of Rate Design & DER Technology, June 8, 2021.
- "Electricity Ratemaking and Equitable Rate Design: A Survey of Best Practices," presented at the Clean Energy Leadership Institute, June 2, 2021.
- "Grid-Interactive Efficient Buildings Could Deliver Between $100 and $200 Billion in Savings to the US Power System, According to Department of Energy Report Coauthored by Brattle Consultants," prepared for the US Department of Energy and the Office of Energy Efficiency & Renewable Energy Building Technologies Office, May 21, 2021.

- "Best Practices in Tariff Design: A Global Survey," presented to NARUC Staff Subcommittees, April 5, 2021.
- "Engaging Customers to Decarbonize Consumption: A Conversation with Commissioner Tim Echols of Georgia," presented at Solar Energy, Electric Mobility, Decarbonization, and Georgia's Economy Virtual Seminar, April 1, 2021.
- "Brattle Experts Discuss Ways to Close the Gap between TOU Rate Pilot Testing and Deployment," published in The Electricity Journal, December 1, 2020.
- "Study by Brattle Economists Evaluates Time-of-Use (TOU) Pilots for Maryland Utilities," prepared for Maryland Joint Utilities, September 15, 2020.
- "Nova Scotia Utility and Review Board: Time-Varying Pricing Project Submission," prepared for the Nova Scotia Power, June 30, 2020.
- "Brattle Experts Provide an International Perspective on TOU Rates in Recent Article," published in Energy Regulation Quarterly, June 1, 2020.
- "The Five "Immortal Objections" to Time-of-Use Rates," presented to PLMA Load Management Dialogue, May 28, 2020.
- "Ahmad Faruqui Shares Six Key Reasons for California to Deploy Dynamic Pricing by 2030 in Utility Dive Op-ed," published in Utility Dive, May 19, 2020.
- "Stakeholder recommendations on rate design reform: Matter 357," presented to New Brunswick Energy and Utilities Board, May 12, 2020.
- "Six Reasons Why California Needs to Deploy Dynamic Pricing by 2030," April 20, 2020.
- "Moving from Pilots to Full-Scale Deployments of Time-of-Use Rates: Bridging the Chasm," presented to MI Power Grid: Energy Programs and Technology Pilots Stakeholder Meeting, April 16, 2020.
- "Moving Ahead with Time-Varying Rates (TVR): US and Global Perspectives," presented to NARUC Staff Subcommittee on Rate Design, April 6, 2020.
- "Brattle Economists Author Article on Tariff Reform," published in IEEE Power and Engineering Magazine (paywall), April 1, 2020.
- "Modernizing Distribution Rate Design," prepared for ATCO, March 13, 2020.
- "Demand on Demand," presented at AESP Annual Conference, February 20, 2020.
- "An Assessment of APS's New Bill Comparison Web Tool," prepared for Arizona Public Service, January 23, 2020.
- "Empirical Assessment of the Demand for Residential Solar Distributed Generation and the Impact of Electricity Rate Design Reform," presented to Rutgers University Center for Research in Regulated Industries, January 17, 2020.

Page 44 of 58

- "Assessment of APS's Bill Comparison Web Tool: Methodology and Findings," December 10, 2019.
- "Ahmad Faruqui Discussed Energy Efficiency Progress over the Last Decade with Public Utilities Fortnightly," published in Public Utilities Fortnightly, December 1, 2019.
- "Framework Proposed by Brattle and EPRI Provides a Regulatory Standard for Evaluating the Cost-Effectiveness of Electrification Programs," published by the American Bar Association, November 13, 2019.
- "A Survey of Residential Time-Of-Use (TOU) Rates," November 12, 2019.
- "Advancing the Practice of Rate Design," presented at the 40th PLMA Conference, November 6, 2019.
- "Ahmad Faruqui Authors Article on Customer Centricity in Utility Strategy," published in Public Utilities Fortnightly, November 1, 2019.
- "The Total Value Test (TVT) for Assessing Electrification Programs," presented to California Efficiency + Demand Management Council (CEDMC), October 24, 2019.
- "A Conversation about Customer Centricity," presented at Virtual Speaker Forum, October 21, 2019.
- "Encouraging Rooftop Solar without Creating Cross-Subsidies," presented to SMUD, April 30, 2019.
- "Post-Modern Rate Design: The 'Secret Sauce' in Customer Engagement," presented at the Entergy Regulatory Conference, April 9, 2019.
- "Valuing and Compensating Distributed Energy Resources in ERCOT," with Ira Shavel and Yingxia Yang, prepared for the Texas Clean Energy Coalition, March 28, 2019.
- "2040: A Pricing Odyssey," presented at the EEI Spring Rates and Regulatory Affairs Committee Meeting, March 25, 2019.
- "Reinventing Demand Response for the Age of Renewable Energy," with Ryan Hledik, December 14, 2018.
- "Enabling Grid Modernization through Alternative Rates and Alternative Regulation," with Sanem Sergici and William P. Zarakas, presented at the Energy Policy Roundtable in the PJM Footprint, November 29, 2018.
- "Modernizing Distribution Tariffs for Households," presented to the Energy Consumers Association in Sydney, Australia, November 9, 2018.
- "The State of Electric Vehicle Home Charging Rates," with Ryan Hledik and John Higham, presented to Colorado PUC, October 2018.
- "Rate Design to Enable Flexible Loads," with Mariko Geronimo Aydin, presented at APPA Business & Financial Conference 2018, September 18, 2018.

- "Customer-driven Rate Design is the Wave of the Future," presented at the Colorado Rural Electric Association Managers Association Meeting, September 10, 2018.
- "Understanding the Costs and Benefits of Electrification: Electrification Cost-Benefit Case Studies," presented at the Electric Power Research Institute (EPRI) Electrification 2018 International Conference & Exposition, August 23, 2018.
- "Do Load Shapes of PV Customers Differ From Other Customers?" with Walter Graf, Presented at the Center for Research in Regulated Industries (CRRI) 31st Annual Western Conference, June 28, 2018.
- "Tariffs of the Future for Gas Utilities," with Léa Grausz, Henna Trewn, and Cecile Bourbonnais, presented at the Center for Research in Regulated Industries (CRRI) 31st Annual Western Conference, June 28, 2018.
- "Collecting Allowed Revenues When Demand is Declining," with Henna Trewn and Léa Grausz, presented at the Center for Research in Regulated Industries (CRRI) 31st Annual Western Conference, June 28, 2018.
- "Incentivizing the Adoption of Gas-Fueled Emerging Technologies with Pricing Tools," with Léa Grausz, presented at the 27th World Gas Conference, June 25, 2018.
- "Estimating the Impact of Innovative Rate Designs," presented to Southern California Edison, June 7, 2018.
- "Rate Design 3.0 and The Efficient Pricing Frontier," presented at the EUCI 2018 Residential Demand Charges Conference, Nashville, TN, May 15, 2018.
- "Does Dynamic Pricing of Electricity Eliminate the Need for Demand Charges?" presented at the Harvard Electricity Policy Group's (HEPG) 89th Plenary Session, January 25, 2018.
- "Dynamic Pricing: What Can We Learn From Other Jurisdictions?" presented at the California Public Utilities Commission's (CPUC) Electric Rate Forum, December 12, 2017.
- "Demand Charges and Dynamic Pricing Are Complements, Not Substitutes," presented at the California Public Utilities Commission's (CPUC) Electric Rate Forum, December 11, 2017.
- "Dynamic Pricing Works in a Hot and Humid Climate: Evidence from Florida," with Sanem Sergici and Neil Lessem, presented at the International Energy Policy & Programme Evaluation Conference, November 2, 2017.
- "A Hybrid Model for Forecasting Electricity Sales and Peak Demand: A Case Study of TNB in Malaysia," with Sanem Sergici and Neil Lessem, presented at the International Energy Policy & Programme Evaluation Conference, November 2, 2017.
- "Workshop on Pricing Reforms," with Neil Lessem, Presented to Energy Networks Association (ENA), October 17, 2017.
- "A Walk on the Frontier of Rate Design," with Cody Warner, presented to the Western Farmers Electric Cooperative's Residential Demand Workshop, October 5, 2017.

Page 46 of 58

- "The Future of Tariff Reform: A Global Survey," with Léa Grausz and Hallie Cramer, presented to the Indiana Energy Association's (IEA) Annual Energy Conference, September 28, 2017.
- "Forecasting the Impact of DSM on Energy Sales," with Zhen Wang, presented to the Edison Electric Institute (EEI), September 14, 2017.
- "A Global Survey of Customer-centric Tariff Reforms," with Neil Lessem, presented to the Commerce Commission, Wellington, New Zealand, August 24, 2017.
- "The Public Benefits of Leasing Energy Efficient Equipment: A Utility Case Study," with Henna Trewn and Neil Lessem, presented at the Center for Research in Regulated Industries' (CRRI) 30th Annual Western Conference, June 30, 2017.
- "Estimating the Impact of DSM on Energy Sales Forecasts: A Survey of Utility Practices," with James Hall and Zhen Wang, presented at the Center for Research in Regulated Industries' (CRRI) 30th Annual Western Conference, June 29, 2017.
- "Moving Forward with Tariff Reform," presented during the EEI Webinar on Rate Design, April 6, 2017.
- "An Irreverent Take on Customer Research in Our Industry," presented at the EPRI Workshop: Understanding Customer Preferences for and Adoption of New Services and Technology, April 4, 2017.
- "The Tariffs of Tomorrow," presented at the University of California, Davis Energy Efficiency Center Seminar, January 11, 2017.
- "Residential Demand Charges, Distributional Effects and Energy Storage," with contributions from Ryan Hledik, presented during the Edison Electric Institute (EEI) Grid Talk Webinar, November 17, 2016.
- "Curating the Future of Rate Design," presented at the EUCI's Residential Demand Charges Conference, October 20, 2016.
- "Understanding Residential Customer Response to Demand Charges: Present and Future," with Sanem Sergici and Ryan Hledik, presented at EUCI's Residential Demand Charges Conference, October 20, 2016.
- "Technology's Role, Rates and Customers, 1985-2016," presented at the Wisconsin Public Utility Institute, August 16, 2016.
- "Dynamic Pricing & Demand Response," with Sanem Sergici, presented at IPU's 58th Annual Regulatory Studies Program: The Fundamentals Course, August 11, 2016.
- "Retail Costing and Pricing for Electricity," with Philip Q Hanser and Sanem Sergici, presented at IPU's 58th Annual Regulatory Studies Program: The Fundamentals Course, August 11, 2016.

- "Emerging Issues in Forecasting Energy Consumption," with Josephine Duh and Zhen Wang, Presented at the CRRI Western Conference 2016, June 24, 2016.
- "A Three-Year Impact Evaluation of TOU Rates in Ontario, Canada," with Neil Lessem, presented at the Center for Research in Regulated Industries (CRRI) 29th Annual Western Conference, June 23, 2016.
- "Capturing Smart Meter Enabled Benefits in System Wide Rollouts: June 23, 2016," presented at the Center for Research in Regulated Industries (CRRI) 29th Annual Western Conference, June 23, 2016.
- "Residential Rates for the Utility of the Future," presented at Grid Edge World Forum 2016, June 22, 2016.
- "Residential Rates for the Utility of the Future," presented to the Alternative Rate Design Stakeholder Process for Xcel Energy, May 13, 2016.
- "Modeling Customer Response to Xcel Energy's RD-TOU Rate," with Ryan Hledik, presented to Xcel Energy, April 21, 2016.
- "Residential Demand Charges: An Overview," presented at the EEI Rate Committee Meeting, March 15, 2016.
- "A Conversation about Standby Rates," presented to Standby Rate Working Group Michigan Public Service Commission, January 20, 2016.

Articles and Papers

- "Conceptual Discussion on a Potential Hidden Cross-Seasonal Storage: Cross-Seasonal Load Shift in Industrial Sectors," with Yingxia Yang and Jared DeFrain, *the Electricity Journal,* Volume 33, Issue 8, October 2020. https://www.sciencedirect.com/science/article/pii/S104061902030138X?dgcid=author
- "Alberta Commission Chair Retires and Reflects on Regulatory Career: A conversation with Mark Kolesar," *Public Utilities Fortnightly,* Volume 158, September 2020.
- "The Coming Transformation of the Electricity Sector: A conversation with Amory Lovins," *The Electricity Journal,* Volume 33, Issue 7, August – September 2020.
- https://www.sciencedirect.com/science/article/pii/S1040619020301196
- "The Tariffs of Tomorrow: Innovations in Rate Designs," with Cecile Bourbonnais, *IEEE Power and Energy Magazine*, Volume 18, Issue 3, May – June 2020.
- "Refocusing on the Consumer: Utilities regulation needs to prepare for the "prosumer" revolution," *Regulation,* March 2020.
- "Why Dynamic Pricing Gets Back Seat in California: A dialogue with Commissioner Mike Peevey," *Public Utilities Fortnightly*, March 2020.

- "Double Down on Efficiency," with Ralph Cavanagh, *Public Utilities Fortnightly*, December 2019.
- "A New Paradigm for Utilities: Electrification of the Transportation and Heating Sectors," with Ryan Hledik, Jürgen Weiss, Michael Hagerty and Long Lam, *American Asscociation Bar*, November 13, 2019.
- "Quantifying Net Energy Metering Subsidies," with Sanem Sergici, Yingxia Yang, and Maria Castañer, *The Electricity Journal*, Volume 32, Issue 8, October 2019.
- "Reducing electricity prices and establishing electricity markets in China: Dos and don'ts," with Yingxia Yang, *The Electricity Journal,* Volume 32, Issue 8, October 2019.
- "2040: A Pricing Odyssey: How to price electricity when the grid goes 100 percent green," *Public Utilities Fortnightly*, June 1, 2019.
- "Expanding Customer Choices in a Renewable Energy Future," with Mariko Geronimo Aydin, *Leadership in Rate Design*, May – June 2019.
- "Emerging Landscape of Residential Rates for EVs – Creative design ahead," with Ryan Hledik and John Higham, *Public Utility Fortnightly*, May 2019. https://www.fortnightly.com/fortnightly/2019/05/emerging-landscape-residential-rates-evs
- "Transitioning to Modern Residential Rate Designs," with Lea Grausz and Cecile Bourbonnais, *Public Utility Fortnightly*, January 2019. https://www.fortnightly.com/fortnightly/2019/01/transitioning-modern-residential-rate-designs
- "Status of Residential Time-of-Use Rates in the U.S.," with Ryan Hledik and Cody Warner, *Public Utilities Fortnightly*, November 1, 2018. https://www.fortnightly.com/fortnightly/2018/11/status-residential-time-use-rates-us
- "Net Metering FAQ – Rate design and subsidies," with Steve Mitnick, *Public Utilities Fortnightly,* October 2018. https://www.fortnightly.com/fortnightly/2018/10/net-metering-faq
- "Rate Design 3.0 – Future of Rate Design," *Public Utilities Fortnightly*, May 2018. https://www.fortnightly.com/fortnightly/2018/05/rate-design-30
- Book Review – 'Modernizing America's Electricity Infrastructure' by Mason Wilrich, *Public Utilities Fortnightly*, May 2018. https://www.fortnightly.com/fortnightly/2018/05/mason-willrichs-modernizing-americas-electricity-infrastructure
- "Do Load Shapes of PV Customers Differ?" with Walter Graf, *Public Utilities Fortnightly*, February 2018. https://www.fortnightly.com/fortnightly/2018/02/do-load-shapes-pv-customers-differ

- “Arcturus 2.0: A meta-analysis of time-varying rates for electricity,” with Sanem Sergici and Cody Warner, *The Electricity Journal*, 30:10, December 2017, pp. 64-72. https://www.sciencedirect.com/science/article/pii/S1040619017302750
- “Moving Forward with Tariff Reform,” with Mariko Geronimo Aydin, *Energy Regulation Quarterly*, Volume 5, Issue 4, December 2017. http://www.energyregulationquarterly.ca/articles/moving-forward-with-tariff-reform#sthash.ZADdmZ2h.D2l1yz9z.dpbs
- “Innovations in Pricing: Giving Customers What They Want,” *Electric Perspectives*, September/October 2017.
- “Moving Forward with Electricity Tariff Reform,” with Mariko Geronimo Aydin, *Regulation*, Fall 2017. https://object.cato.org/sites/cato.org/files/serials/files/regulation/2017/9/regulation-v40n3-5.pdf
- “Enhancing Customer-Centricity,” with Henna Trewn, *Public Utilities Fortnightly*, August 2017. https://www.fortnightly.com/fortnightly/2017/08/enhancing-customer-centricity
- “The Public Benefits of Leasing Energy Efficient Equipment,” with Neil Lessem and Henna Trewn, *The Electricity Journal*, 30:6, July 2017, pp. 8-16. http://www.sciencedirect.com/science/article/pii/S1040619017301513
- “Rethinking Customer Research in the Utility Industry,” with Henna Trewn, *Public Utilities Fortnightly*, July 2017. https://www.fortnightly.com/fortnightly/2017/07/rethinking-customer-research
- “Do Manufacturing Firms Relocate in Response to Rising Electric Rates?” with Sanem Sergici, *Energy Regulation Quarterly*, 5:2, June 2017. http://www.energyregulationquarterly.ca/articles/do-manufacturing-firms-relocate-in-response-to-rising-electric-rates#sthash.uLnrPMwh.dpbs
- “Dynamic Pricing Works in a Hot, Humid Climate,” with Neil Lessem and Sanem Sergici, *Public Utilities Fortnightly*, May 2017. https://www.fortnightly.com/fortnightly/2017/05/dynamic-pricing-works-hot-humid-climate
- “The impact of advanced metering infrastructure on energy conservation: A case study of two utilities,” with Kevin Arritt and Sanem Sergici, *The Electricity Journal*, 30:3, April 2017, pp. 56-63. http://www.sciencedirect.com/science/article/pii/S1040619017300726
- “The impact of AMI-enabled conservation voltage reduction on energy consumption and peak demand,” with Kevin Arritt and Sanem Sergici, *The Electricity Journal*, 30:2, March 2017, pp. 60-65. http://www.sciencedirect.com/science/article/pii/S1040619016302536
- “Overcoming the Over-Forecasting Bias of Pure Econometric Models: A utility case study,” with Josephine Duh and Ingrid Rohmund, *Electricity Policy*, February 2017.

Page 50 of 58

- "The Impact of Time-of-Use Rates in Ontario," with Neil Lessem, Sanem Sergici, and Dean Mountain, *Public Utilities Fortnightly*, February 2017. https://www.fortnightly.com/fortnightly/2017/02/impact-time-use-rates-ontario
- "Competing Perspectives on Demand Charges," with Ryan Hledik, *Public Utilities Fortnightly*, September 2016. https://www.fortnightly.com/fortnightly/2016/09/competing-perspectives-demand-charges
- "An Economist's Dilemma: To PV or Not to PV, That Is the Question," *Electricity Policy*, March 2016. http://files.brattle.com/files/5834_2016_to_pv_or_not_to_pv__faruqui14march2016.pdf
- "Response to King-Datta Re: Time-Varying Rates," *Public Utilities Fortnightly*, March 2016. https://www.fortnightly.com/fortnightly/2016/03/response-king-datta-re-time-varying-rates
- "Impact Measurement of Tariff Changes when Experimentation is not an Option – A case study of Ontario, Canada," with Sanem Sergici, Neil Lessem, and Dean Mountain, *Energy Economics*, 52, December 2015, pp. 39-48.
- "Efficient Tariff Structures for Distribution Network Services," with Toby Brown and Lea Grausz, *Economic Analysis and Policy*, 48, December 2015, pp. 139-149.
- "The Emergence of Organic Conservation," with Ryan Hledik and Wade Davis, *The Electricity Journal*, Volume 28, Issue 5, June 2015, pp. 48-58. http://www.sciencedirect.com/science/article/pii/S1040619015001074
- "The Paradox of Inclining Block Rates," with Ryan Hledik and Wade Davis, *Public Utilities Fortnightly*, April 2015. http://www.fortnightly.com/fortnightly/2015/04/paradox-inclining-block-rates
- "Smart By Default," with Ryan Hledik and Neil Lessem, *Public Utilities Fortnightly*, August 2014. http://www.fortnightly.com/fortnightly/2014/08/smart-default?page=0%2C0&authkey=e5b59c3e26805e2c6b9e469cb9c1855a9b0f18c67bbe7d8d4ca08a8abd39c54d
- "Quantile Regression for Peak Demand Forecasting," with Charlie Gibbons, SSRN, July 31, 2014. http://papers.ssrn.com/sol3/papers.cfm?abstract_id=2485657
- "Study Ontario for TOU Lessons," *Intelligent Utility*, April 1, 2014. http://www.intelligentutility.com/article/14/04/study-ontario-tou-lessons?quicktabs_11=1&quicktabs_6=2
- "Impact Measurement of Tariff Changes When Experimentation is Not an Option – a Case Study of Ontario, Canada," with Sanem Sergici, Neil Lessem, and Dean Mountain, SSRN, March 2014. http://ssrn.com/abstract=2411832
- Dynamic Pricing in a Moderate Climate: The Evidence from Connecticut," with Sanem Sergici and Lamine Akaba, *Energy Journal*, 35:1, pp. 137-160, January 2014.

Page 51 of 58

- "Charting the DSM Sales Slump," with Eric Schultz, *Spark*, September 2013. http://spark.fortnightly.com/fortnightly/charting-dsm-sales-slump
- "Arcturus: International Evidence on Dynamic Pricing," with Sanem Sergici, *The Electricity Journal*, 26:7, August/September 2013, pp. 55-65. http://www.sciencedirect.com/science/article/pii/S1040619013001656
- "Dynamic Pricing of Electricity for Residential Customers: The Evidence from Michigan," with Sanem Sergici and Lamine Akaba, *Energy Efficiency*, 6:3, August 2013, pp. 571–584.
- "Benchmarking your Rate Case," with Ryan Hledik, *Public Utility Fortnightly*, July 2013. http://www.fortnightly.com/fortnightly/2013/07/benchmarking-your-rate-case
- "Surviving Sub-One-Percent Growth," *Electricity Policy*, June 2013. http://files.brattle.com/files/6849_surviving_sub-one percent_growth_faruqui_electricity_policy_june_2013.pdf
- "Demand Growth and the New Normal," with Eric Shultz, *Public Utility Fortnightly*, December 2012. http://www.fortnightly.com/fortnightly/2012/12/demand-growth-and-new-normal?page=0%2C1&authkey=4a6cf0a67411ee5e7c2aee5da4616b72fde10e3fbe215164cd4e5dbd8e9d0c98
- "Energy Efficiency and Demand Response in 2020 – A Survey of Expert Opinion," with Doug Mitarotonda, March 2012. Available at SSRN: http://ssrn.com/abstract=2029150
- "Dynamic Pricing for Residential and Small C&I Customers," presented at the Ohio Public Utilities Commission Technical Workshop, March 28, 2012. https://emp.lbl.gov/sites/default/files/oh-techsupport-faruqui.pdf
- "The Discovery of Price Responsiveness – A Survey of Experiments Involving Dynamic Pricing of Electricity," with Jennifer Palmer, *Energy Delta Institute*, Vol.4, No. 1, April 2012. https://issuu.com/edi_quarterly/docs/edi2030_quarterly_1_april
- "Green Ovations: Innovations in Green Technologies," with Pritesh Gandhi, *Electric Energy T&D Magazine*, January-February 2012. https://electricenergyonline.com/energy/magazine/618/article/Green-Ovations-Innovations-in-Green-Technologies.htm
- "Dynamic Pricing of Electricity and its Discontents" with Jennifer Palmer, *Regulation*, Volume 34, Number 3, Fall 2011, pp. 16-22. http://files.brattle.com/files/6373_dynamic_pricing_of_electricity_and_its_discontents_faruqui_aug_3_2011.pdf
- "Smart Pricing, Smart Charging," with Ryan Hledik, Armando Levy, and Alan Madian, *Public Utility Fortnightly*, Volume 149, Number 10, October 2011.
- "The Energy Efficiency Imperative" with Ryan Hledik, *Middle East Economic Survey*, Vol LIV: No. 38, September 19, 2011.

- "Are LDCs and customers ready for dynamic prices?" with Jürgen Weiss, *Fortnightly's Spark*, August 25, 2011.
- "Dynamic pricing of electricity in the mid-Atlantic region: econometric results from the Baltimore gas and electric company experiment," with Sanem Sergici, *Journal of Regulatory Economics*, 40:1, August 2011, pp. 82-109.
- "Better Data, New Conclusions," with Lisa Wood, *Public Utilities Fortnightly*, March 2011, pp. 47-48.
- "Residential Dynamic Pricing and 'Energy Stamps,'" *Regulation*, Volume 33, No. 4, Winter 2010-2011, pp. 4-5. http://www.cato.org/pubs/regulation/regv33n4/v33n4.html
- "Dynamic Pricing and Low-Income Customers: Correcting misconceptions about load-management programs," with Lisa Wood, *Public Utilities Fortnightly*, November 2010, pp. 60-64. https://www.fortnightly.com/fortnightly/2010/11/dynamic-pricing-and-low-income-customers
- "The Untold Story: A Survey of C&I Dynamic Pricing Pilot Studies" with Jennifer Palmer and Sanem Sergici, *Metering International*, ISSN: 1025-8248, Issue: 3, 2010, p.104.
- "Household response to dynamic pricing of electricity–a survey of 15 experiments," with Sanem Sergici, *Journal of Regulatory Economics* (2010), 38:193-225.
- "Unlocking the €53 billion savings from smart meters in the EU: How increasing the adoption of dynamic tariffs could make or break the EU's smart grid investment," with Dan Harris and Ryan Hledik, *Energy Policy*, Volume 38, Issue 10, October 2010, pp. 6222-6231. http://www.sciencedirect.com/science/article/pii/S0301421510004738
- "Fostering economic demand response in the Midwest ISO," with Attila Hajos, Ryan Hledik, and Sam Newell, *Energy*, Volume 35, Issue 4, Special Demand Response Issue, April 2010, pp. 1544-1552. http://www.sciencedirect.com/science/article/pii/S0360544209004009
- "The impact of informational feedback on energy consumption – A survey of the experimental evidence," with Sanem Sergici and Ahmed Sharif, *Energy*, Volume 35, Issue 4, Special Demand Response Issue, April 2010, pp. 1598-1608. http://www.sciencedirect.com/science/article/pii/S0360544209003387
- "Dynamic tariffs are vital for smart meter success," with Dan Harris, *Utility Week*, March 10, 2010.
- "Rethinking Prices," with Ryan Hledik and Sanem Sergici, *Public Utilities Fortnightly*, January 2010, pp. 31-39. https://www.fortnightly.com/fortnightly/2010/01/rethinking-prices
- "Piloting the Smart Grid," with Ryan Hledik and Sanem Sergici, *The Electricity Journal*, Volume 22, Issue 7, August/September 2009, pp. 55-69. http://www.sciencedirect.com/science/article/pii/S1040619009001663

Page 53 of 58

- "Smart Grid Strategy: Quantifying Benefits," with Peter Fox-Penner and Ryan Hledik, *Public Utilities Fortnightly*, July 2009, pp. 32-37. https://www.fortnightly.com/fortnightly/2009/07/smart-grid-strategy-quantifying-benefits
- "The Power of Dynamic Pricing," with Ryan Hledik and John Tsoukalis, *The Electricity Journal*, April 2009, pp. 42-56. http://www.sciencedirect.com/science/article/pii/S1040619009000414
- "Transition to Dynamic Pricing," with Ryan Hledik, *Public Utilities Fortnightly*, March 2009, pp. 26-33. http://www.fortnightly.com/display_pdf.cfm?id=03012009_DynamicPricing.pdf
- "Ethanol 2.0," with Robert Earle, *Regulation*, Winter 2009. https://object.cato.org/sites/cato.org/files/serials/files/regulation/2008/11/v31n4-noted.pdf#page=1
- "Inclining Toward Efficiency," *Public Utilities Fortnightly*, August 2008, pp. 22-27. https://www.fortnightly.com/fortnightly/2008/08/inclining-toward-efficiency
- "California: Mandating Demand Response," with Jackalyne Pfannenstiel, *Public Utilities Fortnightly*, January 2008, pp. 48-53.
- "Avoiding Load Shedding by Smart Metering and Pricing," with Robert Earle, *Metering International*, Issue 1 2008, pp. 76-77.
- "The Power of 5 Percent," with Ryan Hledik, Sam Newell, and Hannes Pfeifenberger, *The Electricity Journal,* October 2007, pp. 68-77. http://www.sciencedirect.com/science/article/pii/S1040619007000991
- "Pricing Programs: Time-of-Use and Real Time," *Encyclopedia of Energy Engineering and Technology,* September 2007, pp. 1175-1183.
- "Breaking Out of the Bubble: Using demand response to mitigate rate shocks," *Public Utilities Fortnightly*, March 2007, pp. 46-48 and pp. 50-51. https://www.fortnightly.com/fortnightly/2007/03/demand-response-breaking-out-bubble
- "From Smart Metering to Smart Pricing," *Metering International,* Issue 1, 2007.
- "Demand Response and the Role of Regional Transmission Operators," with Robert Earle, *2006 Demand Response Application Service*, Electric Power Research Institute, 2006.
- "2050: A Pricing Odyssey," *The Electricity Journal,* October 2006. https://www.researchgate.net/publication/222677841_2050_A_Pricing_Odyssey
- "Demand Response and Advanced Metering," Regulation, Spring 2006. 29:1 24-27.
- "Reforming electricity pricing in the Middle East," with Robert Earle and Anees Azzouni, *Middle East Economic Survey (MEES)*, December 5, 2005.
- "Controlling the thirst for demand," with Robert Earle and Anees Azzouni, *Middle East Economic Digest (MEED),* December 2, 2005.

Page 54 of 58

- "California pricing experiment yields new insights on customer behavior," with Stephen S. George, *Electric Light & Power*, May/June 2005. http://www.elp.com/index/display/article-display/229131/articles/electric-light-power/volume-83/issue-3/departments/news/california-pricing-experiment-yields-new-insights-on-customer-behavior.html
- "Quantifying Customer Response to Dynamic Pricing," with Stephen S. George, *Electricity Journal*, May 2005.
- "Dynamic pricing for the mass market: California experiment," with Stephen S. George, *Public Utilities Fortnightly*, July 1, 2003, pp. 33-35.
- "Toward post-modern pricing," Guest Editorial, *The Electricity Journal*, July 2003.
- "Demise of PSE's TOU program imparts lessons," with Stephen S. George. *Electric Light & Power*, January 2003, pp.1 and15.
- "2003 Manifesto on the California Electricity Crisis," with William D. Bandt, Tom Campbell, Carl Danner, Harold Demsetz, Paul R. Kleindorfer, Robert Z. Lawrence, David Levine, Phil McLeod, Robert Michaels, Shmuel S. Oren, Jim Ratliff, John G. Riley, Richard Rumelt, Vernon L. Smith, Pablo Spiller, James Sweeney, David Teece, Philip Verleger, Mitch Wilk, and Oliver Williamson. May 2003. Posted on the AEI-Brookings Joint Center web site, at http://www.aei-brookings.org/publications/abstract.php?pid=341
- "Reforming pricing in retail markets," with Stephen S. George. *Electric Perspectives*, September/October 2002, pp. 20-21.
- "Pricing reform in developing countries*," Power Economics*, September 2002, pp. 13-15.
- "The barriers to real-time pricing: separating fact from fiction," with Melanie Mauldin, *Public Utilities Fortnightly*, July 15, 2002, pp. 30-40.
- "The value of dynamic pricing," with Stephen S. George, *The Electricity Journal*, July 2002, pp. 45-55.
- "The long view of demand-side management programs," with Gregory A. Wikler and Ingrid Bran, in *Markets, Pricing and Deregulation of Utilities*, Michael A. Crew and Joseph C. Schuh, editors, Kluwer Academic Publishers, 2002, pp. 53-68.
- "Time to get serious about time-of-use rates," with Stephen S. George, *Electric Light & Power*, February 2002, Volume 80, Number 2, pp. 1-8.
- "Getting out of the dark: Market based pricing can prevent future crises," with Hung-po Chao, Vic Niemeyer, Jeremy Platt, and Karl Stahlkopf, *Regulation*, Fall 2001, pp. 58-62.
- "Analyzing California's power crisis," with Hung-po Chao, Vic Niemeyer, Jeremy Platt, and Karl Stahlkopf, *The Energy Journal*, Vol. 22, No. 4, pp. 29-52.
- "Hedging Exposure to Volatile Retail Electricity Prices," with Bruce Chapman, Dan Hansen and Chris Holmes*, The Electricity Journal*, June 2001, pp. 33-38.

Page 55 of 58

- "California Syndrome," with Hung-po Chao, Vic Niemeyer, Jeremy Platt and Karl Stahlkopf, *Power Economics*, May 2001, Volume 5, Issue 5, pp. 24-27.
- "The choice not to buy: energy savings and policy alternatives for demand response," with Steve Braithwait, *Public Utilities Fortnightly*, March 15, 2001.
- "Tomorrow's Electric Distribution Companies," with K. P. Seiden, *Business Economics,* Vol. XXXVI, No. 1, January 2001, pp. 54-62.
- "Bundling Value-Added and Commodity Services in Retail Electricity Markets," with Kelly Eakin*, Electricity Journal*, December 2000.
- "Summer in San Diego," with Kelly Eakin, *Public Utilities Fortnightly*, September 15, 2000.
- "Fighting Price Wars," *Harvard Business Review*, May-June 2000.
- "When Will I See Profits?" *Public Utilities Fortnightly*, June 1, 2000.
- "Mitigating Price Volatility by Connecting Retail and Wholesale Markets," with Doug Caves and Kelly Eakin, *Electricity Journal*, April 2000.
- "The Brave New World of Customer Choice," with J. Robert Malko, appears in *Customer Choice: Finding Value in Retail Electricity Markets*, Public Utilities Report, 1999.
- "What's in Our Future?" with J. Robert Malko, appears in *Customer Choice: Finding Value in Retail Electricity Markets,* Public Utilities Report, 1999.
- "Creating Competitive Advantage by Strategic Listening," *Electricity Journal*, May 1997.
- "Competitor Analysis," *Competitive Utility*, November 1996.
- "Forecasting in a Competitive Environment: The Need for a New Paradigm," *Demand Forecasting for Electric Utilities*, Clark W. Gellings (ed.), 2nd edition, Fairmont Press, 1996.
- "Defining Customer Solutions through Electrotechnologies: A Case Study of Texas Utilities Electric," with Dallas Frandsen et al. *ACEEE 1995 Summer Study on Energy Efficiency in Industry*. ACEEE: Washington, D.C., 1995.
- "Opportunities for Energy Efficiency in the Texas Industrial Sector," *ACEEE 1995 Summer Proceedings*.
- "Study on Energy Efficiency in Industry," with Jay W. Zarnikau et al. *ACEEE*: Washington, D.C., 1995.
- "Promotion of Energy Efficiency through Environmental Compliance: Lessons Learned from a Southern California Case Study," with Peter F. Kyricopoulos and Ishtiaq Chisti. *ACEEE 1995 Summer Study on Energy Efficiency in Industry*. ACEEE: Washington, D.C., 1995.
- "ATLAS: A New Strategic Forecasting Tool," with John C. Parker et al. Proceedings: *Delivering Customer Value, 7th National Demand-Side Management Conference*. EPRI: Palo Alto, CA, June 1995.

Page 56 of 58

- "Emerging Technologies for the Industrial Sector," with Peter F. Kyricopoulos et al. *Proceedings: Delivering Customer Value, 7th National Demand-Side Management Conference*. EPRI: Palo Alto, CA, June 1995.
- "Estimating the Revenue Enhancement Potential of Electrotechnologies: A Case Study of Texas Utilities Electric," with Clyde S. King et al. *Proceedings: Delivering Customer Value, 7th National Demand-Side Management Conference. EPRI*: Palo Alto, CA, June 1995.
- "Modeling Customer Technology Competition in the Industrial Sector," *Proceedings of the 1995 Energy Efficiency and the Global Environment Conference*, Newport Beach, CA, February 1995.
- "DSM opportunities for India: A case study," with Ellen Rubinstein, Greg Wikler, and Susan Shaffer, *Utilities Policy*, Vol. 4, No. 4, October 1994, pp. 285-301.
- "Clouds in the Future of DSM," with G.A. Wikler and J.H. Chamberlin. *Electricity Journal*, July 1994.
- "The Changing Role of Forecasting in Electric Utilities," with C. Melendy and J. Bloom. *The Journal of Business Forecasting*, pp. 3-7, Winter 1993–94. Also appears as "IRP and Your Future Role as Forecaster." *Proceedings of the 9th Annual Electric Utility Forecasting Symposium. Electric Power Research Institute (EPRI).* San Diego, CA, September 1993.
- "Stalking the Industrial Sector: A Comparison of Cutting Edge Industrial Programs," with P.F. Kyricopoulos. *Proceedings of the 4CEEE 1994 Summer Study on Energy Efficiency in Buildings*. ACEEE: Washington, D.C., August 1994.
- "Econometric and End-Use Models: Is it Either/Or Both?" with K. Seiden and C. Melendy. *Proceedings of the 9th Annual Electric Utility Forecasting Symposium. Electric Power Research Institute (EPRI*). San Diego, CA, September 1993.
- "Savings from Efficient Electricity Use: A United States Case Study," with C.W. Gellings and S.S. Shaffer. *OPEC Review*, June 1993.
- "The Trade-Off Between All-Ratepayer Benefits and Rate Impacts: An Exploratory Study," *Proceedings of the 6th National DSM Conference*. With J.H. Chamberlin. Miami Beach, FL. March 1993.
- "The Potential for Energy Efficiency in Electric End-Use Technologies," with G.A. Wikler, K.P. Seiden, and C.W. Gellings. *IEEE Transactions on Power Systems*. Seattle, WA, July 1992.
- "Potential Energy Savings from Efficient Electric Technologies," with C.W. Gellings and K.P. Seiden. *Energy Policy*, pp. 217–230, April 1991.
- "Demand Forecasting Methodologies: An overview for electric utilities," with Thomas Kuczmowski and Peter Lilienthal, *Energy: The International Journal*, Volume 15, Issues 3-4, March-April 1990, pp. 285-296.

Page 57 of 58

- "The role of demand-side management in Pakistan's electric planning," *Energy Policy*, August 1989, pp. 382-395.
- "Pakistan's Economic Development in a Global Perspective: A profile of the first four decades, 1947-87," with J. Robert Malko, *Asian Profile*, Volume 16, No. 6, December 1988.
- "The Residential Demand for Electricity by Time-of-Use: A survey of twelve experiments with peak load pricing," with J. Robert Malko, *Energy: The International Journal*, Volume 8, Issue 10, October 1983, pp. 781-795.
- "Incorporating the Social Imperatives in Economic Structure: Pakistan in the years ahead," *The Journal of Economic Studies*, Volume 1, No. 1, Autumn 1974.

Page 58 of 58

BC Hydro Optional Residential Time-of-Use Rate Application

Appendix F

The Brattle Group – A Review of BC Hydro's Optional Residential TOU Rate

A Review of BC Hydro's Optional Residential TOU Rate

PREPARED BY

Ryan Hledik

Sanem Sergici

PREPARED FOR

BC Hydro

FEBRUARY 21, 2023

Brattle

Table of Contents

I. Introduction

Nature of Engagement

BC Hydro's 2021 Integrated Resource Plan (IRP) identified the introduction of an optional residential time-of-use (TOU) rate as a near-term action. Accordingly, BC Hydro developed a proposed TOU rate design which is intended to produce some of the overall capacity savings from time-varying rates and demand response programs described in the IRP. The Brattle Group served as an advisor to BC Hydro in developing elements of the TOU rate proposal.

In an engagement letter dated December 20, 2022, BC Hydro requested that Ryan Hledik and Sanem Sergici of The Brattle Group provide a report that comments on several elements of the TOU rate proposal. Specifically, BC Hydro asked us to address the following issues:

1. *Please discuss the considerations that should inform time-varying rate design elements and pricing, in particular, the considerations that should inform the price ratios between the peak and off-peak prices.*

2. *Please discuss the range of participation in optional residential time-of-use rates for customers without an electric vehicle and customers with an electric vehicle.*

3. *Please comment on whether any conservation impacts should be expected with a time-varying rate (i.e., customers reducing their total consumption rather than shifting consumption from the peak period to other periods).*

4. *Please discuss whether this type of time-varying charge/credit concept has been offered in other jurisdictions, particularly in combination with a default inclining block rate.*

5. *Please provide your assessment of the price ratios in BC Hydro's optional residential time-of-use rate proposal. As part of your assessment, please consider, and comment on, the validity of the price ratios considering BC Hydro's marginal costs, as set out in Appendix L of BC Hydro's 2021 Integrated Resource Plan Application.*[1]

6. *BC Hydro's optional residential time-of-use rate proposal has three pricing periods: a peak period, an off-peak period and an overnight period. For household consumption and for electric vehicle charging consumption that is shifted out of the peak period, please comment on what*

[1] https://docs.bcuc.com/Documents/Proceedings/2021/DOC_65194_B-1-BCH-IntegratedResourcePlan-Public.pdf.

portion should be expected to be shifted to the overnight period and what portion should be expected to be shifted to the off-peak period.

7. *Please provide your assessment of the potential average peak demand reduction per participant for household consumption and for electric vehicle consumption. BC Hydro plans to offer demand response programs alongside our proposed optional residential time-of-use rate. However, for your assessment, please assume that any incremental peak demand reduction associated with enabling technologies provided through these programs would be attributed to the demand response programs rather than the optional time-of-use rate.*

The remainder of our report is organized around those seven issues. To address the issues, as requested in BC Hydro's engagement letter, we reviewed the rate proposal as it is described in the company's Optional Residential TOU Rate Information Booklet[2], as well as additional data provided to us by the company. We also had clarifying conversations with BC Hydro staff. Our commentary on the issues is supported by a review of literature and data on TOU rate design, utility customer experience with TOU rates, and the load impacts of TOU rates. We supplemented this review with our own experience designing and evaluating TOU rates for utilities across North America and internationally.

Summary of Expert Qualifications

Ryan Hledik is a Brattle Principal whose consulting practice focuses on regulatory, planning, and economic matters related to emerging energy technologies and policies. His areas of expertise include retail rate design, distributed generation, load flexibility, electrification, energy efficiency, energy storage, and grid modernization.

Ryan has led studies and authored papers, articles, and regulatory filings on rate design issues such as the benefits of time-varying pricing, strategies for transitioning customers to innovative rate designs, the efficient pricing of electricity for customers with distributed generation, rate design practices for public electric vehicle ("EV") charging, designing pilots to test innovative retail rate concepts, rate designs for promoting the efficient use of battery storage, and the load impacts of inclining block rates.

Ryan's clients have included electric and gas utilities, state and federal regulatory commissions, power developers, independent system operators, government agencies, industry trade associations, technology firms, research institutions, and law firms. He has published more than 30 articles on electricity industry matters and has presented at industry events throughout North America as well as in Brazil, Belgium, Germany, Poland, South Korea, Saudi Arabia, the United Kingdom, and Vietnam. His research has been cited in *National Geographic*, *The New York Times* and *The Washington Post*, and in trade press such as GreenTech Media, Utility Dive, and Vox.

2 https://www.bchydro.com/content/dam/BCHydro/customer-portal/documents/corporate/regulatory-planning-documents/regulatory-matters/Optional-Residential-TOU-Workshop-November-2022-Info-Booklet.pdf.

Ryan received his M.S. in Management Science and Engineering from Stanford University, where he concentrated in Energy Economics and Policy. He received his B.S. in Applied Science from the University of Pennsylvania, with minors in Economics and Mathematics.

Sanem Sergici is a Brattle Principal and an energy economist with sixteen years of consulting and research experience. Sanem's consulting practice is focused on understanding customer adoption of and response to innovative rate designs and emerging technologies. She regularly assists her clients in matters related to rate design, electrification, grid modernization investments, emerging utility business models and alternative ratemaking mechanisms.

Sanem has been at the forefront of the design and impact analysis of innovative retail pricing, enabling technology, and behavior-based energy efficiency pilots and programs across North America over the past decade. She led numerous studies in these areas that were instrumental in regulatory approvals of grid modernization investments and smart rate offerings for electricity customers. She also regularly testifies on these topics, more recently on the design of cost-based rates for electric vehicles and commercial charging stations.

Sanem regularly publishes in academic and industry journals and presents at industry events. She received her PhD in Applied Economics from Northeastern University in the fields of applied econometrics and industrial organization. She received her MA in Economics from Northeastern University, and BS in Economics from Middle East Technical University (METU), Ankara, Turkey.

Ryan's and Sanem's detailed qualifications are provided in Appendix A.

II. Commentary on the Key Issues

In this section, we provide our commentary on each of the seven key issues identified in BC Hydro's engagement letter.

Issue 1: Considerations that should inform TOU rate design, particularly peak-to-off-peak price ratio

The overarching principle of TOU rate design is cost reflectivity. Specifically, TOU rates should be designed to reflect the utility's underlying cost structure. The TOU pricing periods (peak, off-peak, and overnight) divide the day into clusters of hours when costs are relatively higher or lower than the other hours. The prices in each period are then set to reflect the cost of serving customer load in those hours. A cost-reflective rate promotes economic efficiency and fairness by ensuring that customers are generally charged based on the true cost of their consumption behavior, with an opportunity to reduce their electricity bill by shifting usage to lower cost periods of the TOU rate.

However, TOU rate design also requires balancing the principle of cost reflectivity with other important considerations. A commonly cited and authoritative source on rate design principles is Dr. James Bonbright's "Principles of Public Utility Rates," published originally in 1961 and later updated in 1988.[3] Among the principles discussed by Dr. Bonbright are simplicity (ease of understanding), public acceptability (rate design features that appeal to potential participants), rate stability (minimizing sudden dramatic changes in customer bills), and revenue sufficiency (a rate that yields the utility's revenue requirement).

To balance the principle of cost reflectivity with these other objectives, it is typically necessary to depart from a purely cost-reflective rate design. This is particularly the case when setting the "price ratio" of a TOU rate. The "price ratio" is the ratio between the peak period price and either the off-peak or overnight period price. In our experience, if a utility's costs imply a very high cost-based price ratio, it is appropriate to consider limiting the price ratio to a level that mitigates the risk of extreme bill swings among participants. Similarly, if a utility's costs imply a very low cost-based price ratio, it is appropriate to increase the ratio to ensure that bill savings opportunities are meaningful enough to induce price response (particularly if the utility's cost profile is expected rise to support that price ratio in the long run). It is standard practice for utilities to use costs as a general guide for establishing price ratios, rather than as a strict determinant of the ratios.

Therefore, within reason, it is appropriate for the TOU price ratio to be guided by, but deviate from, the precise ratio implied by a literal interpretation of the utility's costs. Behavioral considerations must be accounted for in the rate's design, in order to ensure that the rate is attractive to potential participants and satisfies important criteria beyond cost reflectivity.

Issue 2: Range of participation rates in optional residential TOU rates

The level of enrollment in opt-in residential TOU rates achieved by utilities to-date varies widely. This variation in participation can be attributed to a variety of factors, such as attractiveness of the rate design, the degree of marketing or educational outreach, and the presence or absence of enabling technology such as advance metering infrastructure (AMI).

In cases where utilities have made a concerted effort to enroll residential customers in TOU rates, enrollment levels have been significantly higher. For example, more than half of Arizona Public Service's (APS) residential customers have voluntarily enrolled in an optional time-varying rate, though it has taken the utility decades to reach that level of enrollment. Generally, data from the U.S. Energy

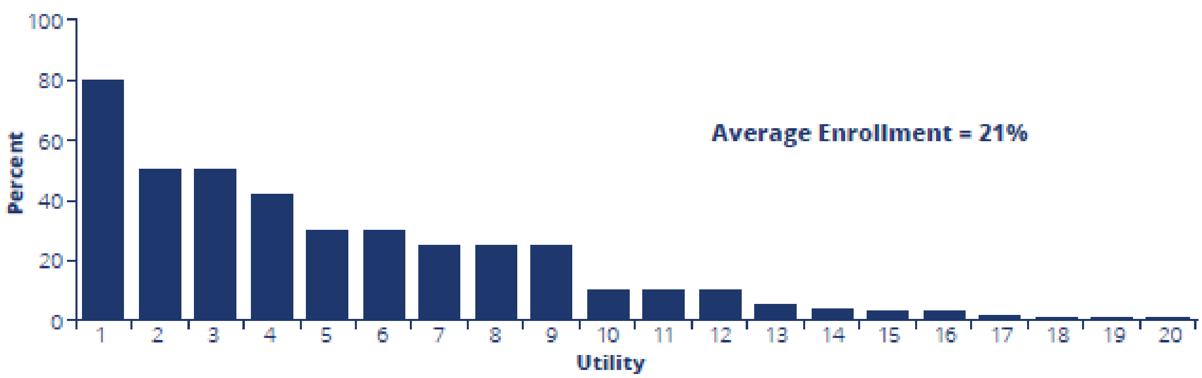
[3] James C. Bonbright, *Principles of Public Utility Rates*, (Columbia University Press: 1961) 1st Edition. Also, James C. Bonbright, Albert L. Danielsen, and David R. Kamerschen, *Principles of Public Utility Rates,* 2nd ed. (Arlington, VA: Public Utility Reports, 1988).

Information Administration indicates that some utilities offering opt-in residential TOU rates have been able to achieve participation rates ranging from 5% to 35%.[4]

BC Hydro assumes that 15% of customers who are expected to experience bill savings on the proposed TOU rate choose to enroll in it. Given that not all customers will benefit from the proposed rate, BC Hydro's assumed participation rate is approximately 8% when expressed as a percentage of the entire residential population (excluding those with an EV, which are addressed separately). BC Hydro's assumption is conservative in this sense, but still broadly consistent with the range of achievable participation rates in the studies noted above. We consider a steady state enrollment range of 5% to 35% to be reasonable as upper- and lower-bounds.

The information on TOU enrollment among customers with electric vehicles (EVs) is more limited, given that material levels of EV adoption have occurred only recently. According to a review of data on residential EV TOU rates conducted by Brattle and the Smart Electric Power Alliance (SEPA), existing enrollment in available EV TOU rates among eligible customers (i.e., those with an EV) has ranged from near-zero to roughly 80% across 20 utilities.[5] In the same study, a survey of EV owners with EnelX home chargers found that 48% of those customers outside of California were enrolled in a TOU rate, and 76% of those customers inside California were enrolled. This wide range of enrollment rates is attributable to factors such as the presence or absence of a dedicated TOU rate marketing budget, the magnitude of opportunity for significant participant bill savings, and the types of marketing channels used, among other factors. Figure 2 summarizes the range of observed residential EV TOU participation rates.

FIGURE 1: SHARE OF ELIGIBLE CUSTOMERS ENROLLED IN EV TIME-VARYING RATE



Source: Erika Myers, Jacob Hargrave, Richard Farinas, Ryan Hledik, and Lauren Burke, "Residential Electric Vehicle Rates That Work," prepared for the Smart Electric Power Alliance, November 2019.

4 U.S. Energy Information Administration Form 861 data, 2021. Accessed at https://www.eia.gov/electricity/data/eia861/.

5 Myers, Erika, Jacob Hargrave, Richard Farinas, Ryan Hledik, and Lauren Burke, "Residential Electric Vehicle Rates That Work," prepared for the Smart Electric Power Alliance, November 2019. https://sepapower.org/resource/residential-electric-vehicle-time-varying-rates-that-work-attributes-that-increase-enrollment/.

Given the direction from the ZEV Act, BC Hydro assumes a significant number of EVs will be on the road as of 2030. Our understanding is that BC Hydro assumes of 22% of all EV owners will be enrolled in a TOU rate in 2030.[6] That assumption is consistent with our review of early experience with EV TOU rates in other jurisdictions as described above. We consider a steady-state participation rate ranging from 15% to 40% of EV owners to be achievable upper- and lower-bounds in the long run, based on currently available data.

Issue 3: Conservation impacts of residential TOU rates

Virtually every empirical assessment of the load impacts of TOU rates has concluded that customers shift usage away from the peak period when enrolled in a TOU rate. However, the evidence on whether TOU rates result in an overall reduction in usage is inconclusive. Recent TOU pilots have quantitatively analyzed the conservation effect and concluded that it did not exist. In other words, in those studies, virtually all of the usage that was reduced during the peak period was shifted to the off-peak or overnight period. For example, Brattle's evaluation of the load impacts of Ontario's full-scale residential TOU rate transition did not identify any conservation effect.[7] Alternatively, some studies have identified a statistically significant "conservation effect" of TOU rates. For example, a survey of TOU offerings prior to 2005 identified a range of conservation effects which average to approximately 4% energy savings across the studies.[8]

As a general matter, given uncertainty regarding the TOU conservation effect, we consider BC Hydro's base assumption that there is no conservation effect to be reasonable. This is particularly true for customers with EVs, who simply would set their timers to charge during non-peak hours. Through conversations with BC Hydro we understand that the company also has analyzed the impact of a modest conservation effect for customers without EVs through sensitivity analysis, which we consider to be a reasonable approach given the uncertainty in the available information on this topic.

Issue 4: Precedent for BC Hydro's proposed charge/credit approach to implementing the TOU rate

BC Hydro is proposing to implement its TOU rate through a charge on usage during the peak period and a credit on usage during the overnight period. This approach allows BC Hydro to expose customers to

---

6 More specifically, BC Hydro assumes that 50% of EV customers will enroll in a TOU rate, with some exceptions (e.g., BC Hydro assumes customers in apartments with limited access to home EV charging will not enroll). The 22% estimate reported here is a share of the total residential population.

7 Neil Lessem, Ahmad Faruqui, Sanem Sergici, and Dean Mountain, "The Impact of Time-of-Use Rates in Ontario," *Public Utilities Fortnightly*, February 2017. https://www.brattle.com/wp-content/uploads/2017/10/7305_the_impact_of_time_of_use_rates_in_ontario.pdf.

8 Chris King and Dan Delurey, "Efficiency and Demand Response: Twins, Siblings, or Cousins?" Public Utilities Fortnightly, March 2005. http://assets.fiercemarkets.net/public/smartgridnews/sgnr_2007_12011.pdf.

the time-varying price signal while retaining the tiered structure of the underlying Residential Inclining Block (RIB) rate.[9]

The TOU rate design approach taken by the three investor-owned utilities (IOUs) in California is the most similar example to BC Hydro's proposed approach. All three California IOUs have transitioned their residential customers from an inclining block rate structure to TOU rates on an opt-out basis. To retain the inclining block structure of the existing rate, the California utilities also use charges and credits. However, they charge customers based on the TOU rate and then provide credits and charges for monthly usage falling within the various tiers of the inclining block rate. In other words, the California utilities use charges and credits to represent the price signals in the tiered rate, whereas BC Hydro uses charges and credits to represent the price signals of the peak and overnight periods in the TOU rate.

In our opinion, both BC Hydro's approach and the California utilities' approach are conceptually pragmatic and reasonable solutions to an important problem. When the existing rate has an inclining block structure, a large number of smaller-than-average customers benefit from the discounted first tier of the rate. If the proposed TOU rate does not retain that usage-based discount, a majority of the population is unlikely to experience bill savings by switching to the TOU rate. BC Hydro's proposed approach is an innovative way to overcome this challenge and improves the overall inclusiveness and customer attractiveness of the rate by providing virtually all customers with an opportunity to reduce their electricity bill once enrolled.

Issue 5: Assessment of the price ratios in BC Hydro's proposed TOU rate

BC Hydro has proposed to implement the TOU rate as a 5 cents/kWh charge on usage during the peak period, and a 5 cents/kWh credit on usage during the overnight period. This results in a peak-to-overnight price ratio of 3:1 when consuming in the first tier of the RIB rate[10], and 2.1:1 when consuming in the second tier of the RIB rate[11].

BC Hydro's proposed price ratios are generally supported by the utility's costs. In the overnight period, the 5 cents/kWh credit results in customers paying a price of 5.1 cents/kWh when in step 1 of the RIB rate. According to the company's 2021 Fully Allocated Cost of Service Study, BC Hydro's embedded

9 The RIB rate is BC Hydro's default rate for residential customers. It consists of a tiered rate structure with a lower energy charge for consumption up to a certain usage threshold and a higher energy charge for consumption beyond that usage threshold.

10 The first step price of the RIB is 10.1 cents/kWh. 10.1 cents/kWh + 5 cents/kWh peak charge = 15.1 cents/kWh effective peak price. 10.1 cents/kWh - 5 cents/kWh overnight period credit = 5.1 cents/kWh effective overnight price. 15.1 cents/kWh divided by 5.1 cents/kWh equals a price ratio of 3:1. These prices are consistent with the forecasted fiscal year 2025 RIB rate, as provided to us by BC Hydro.

11 The second step price of the RIB is 14.08 cents/kWh. 14.08 cents/kWh + 5 cents/kWh peak charge = 19.08 cents/kWh effective peak price. 14.08 cents/kWh - 5 cents/kWh overnight period credit = 9.08 cents/kWh effective overnight period price. 19.08 cents/kWh divided by 9.08 cents/kWh equals a price ratio of 2.1:1.

energy cost is approximately 4 cents/kWh, so the overnight period price generally aligns with this estimate of the minimum cost of serving residential load.

The 5 cents/kWh peak period charge was determined to maintain revenue neutrality (i.e., to produce incremental peak period revenue that offsets the revenue loss associated with the overnight period credit). By equalling the overnight period discount, the peak charge has the advantage of simplicity, which facilitates ease of understanding among participants.

BC Hydro's marginal costs are consistent with the proposed peak charge. According to Appendix L of the company's 2021 IRP, BC Hydro's long run marginal capacity cost is $109/kW-yr and its non-bulk transmission and distribution reference price is $65/kW-yr (in 2022 dollars).[12] Summing and dividing those costs by 1,825 peak period hours of the year and adding the company's marginal energy cost of $65/MWh produces peak period-related marginal costs of 16 cents/kWh. That marginal cost estimate falls within BC Hydro's implied peak period price of between 14.5 cents/kWh (step 1) and 19.08 cents/kWh (step 2).

From a behavioral standpoint, BC Hydro's proposed price ratios are sufficient for incentivizing TOU participants to shift usage away from the peak period. Generally, we consider a price ratio of at least 2:1 as being necessary in this regard. A milder price ratio introduces significant risk that customers will not respond to the TOU price signal, or will be disappointed by a lack of bill savings associated with shifting their usage.

Issue 6: Proportion of load likely shifted to off-peak and overnight periods of TOU rate

While there is extensive empirical evidence on the degree to which TOU participants shift their usage out of the peak period, we are not aware of data on the relative share of offsetting load building that occurs in the off-peak versus overnight periods. For non-EV owners, intuition suggests that some usage would be shifted to both periods. For example, programmable end-uses such as some washers, dryers, dishwashers, or pool pumps could be set to run during the overnight period, when the price is lowest. Other end-uses, such as air-conditioning, would need to be used during off-peak hours, to offset the impacts of load reductions during the peak period. Accordingly, BC Hydro assumes that, for non-EV owners, half of usage is shifted to the off-peak period and half is shifted to the overnight period. In the absence of empirical studies on the topic and based on the intuition described above, our opinion is that this is a reasonable assumption.

For EV owners BC Hydro assumes that, of the consumption shifted, 80% will be shifted to the overnight period and 20% will be shifted to the off-peak period. EV charging can be conveniently programmed to occur during the overnight period, so it is logical that a greater share of the shifted peak period usage would occur during the lowest-priced overnight period than for non-EV owners. At the same time, we

[12] We note that these are 2022 dollars and have not been escalated to a future year for the purposes of our analysis here.

would expect some portion of the shifted load to occur during the off-peak period, due to diversity in the driving patterns and associated charging needs of residential customers. For these reasons, our opinion is that BC Hydro's EV TOU load shifting assumptions described above are reasonable.

Issue 7: Expected per-participant peak demand reduction resulting from the TOU rate

The Brattle Group maintains a database of pricing offerings and peak demand reductions achieved in those offerings since 2010. We have published analysis of this database in three journal articles in 2010[13], 2013[14], and 2017[15]. We have continued to update the "Arcturus Database" over time, and as of the end of 2022, the database included 410 observations from 80 time-varying pricing pilots and full-scale offerings. Using the observations in this database, we estimated price response curves, which we refer to as "the Arc of Price Responsiveness". The Arc of Price Responsiveness returns an average peak demand reduction estimate for a given peak to off-peak (P/OP) price ratio, for various time-varying rates and availability of enabling technologies. The original Arc of Price Responsiveness estimated an average peak impact using the observations and relationships based on *all* of the pricing treatments in the database regardless of their enrollment mode (opt-in vs opt out) mainly to maximize the number of data points defining the relationship between peak impact and the P/OP price ratio. However, as more data points have been added to the database, it became possible to estimate different Arcs that account for different pricing treatments (i.e. TOU, CPP, etc.) and the enrollment mode (opt-in vs. opt-out). We are preparing to publish the results of Arcturus 3.0, which reports these updates and innovations that were implemented since the publication of prior studies.[16] We relied on this updated Arcturus 3.0 to assist BC Hydro in developing a more precise peak demand impact estimate based on the company's proposed opt-in TOU rate. This curve is reproduced below, in Figure 3.

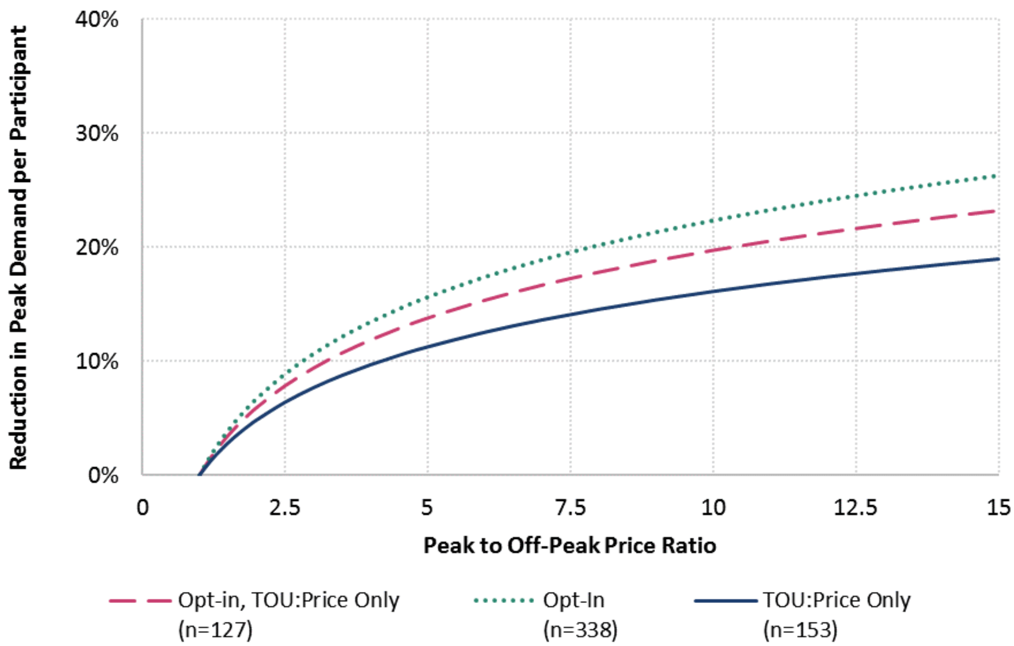
13 Ahmad Faruqui and Sanem Sergici, "Household response to dynamic pricing of electricity–a survey of 15 experiments," *Journal of Regulatory Economics* (2010), 38:193-225.

14 Ahmad Faruqui and Sanem Sergici, "Arcturus: International Evidence on Dynamic Pricing," *The Electricity Journal*, 26:7, August/September 2013, pp. 55-65

15 Ahmad Faruqui, Sanem Sergici and Cody Warner, "Arcturus 2.0: A meta-analysis of time-varying rates for electricity," *The Electricity Journal*, 30:10, December 2017, pp. 64-72.

16 Sanem Sergici, Ahmad Faruqui and Sylvia Tang, "Do Customers Respond to Time Varying Rates: A Preview of Arcturus 3.0," Brattle Working Paper, January 2023.

FIGURE 3: THE ARC OF PRICE RESPONSIVENESS BY OPT-IN AND TOU STATUS



Source: Sanem Sergici, Ahmad Faruqui and Sylvia Tang, "Do Customers Respond to Time Varying Rates: A Preview of Arcturus 3.0," Brattle Working Paper, January 2023.

For estimating the peak demand reduction for BC Hydro, we utilize the "Opt-in TOU Price Only" Arc. Based on the company's rate design, we estimate the peak demand reductions presented in Figure 4.

As discussed earlier, BC Hydro assumed that half of the load would be shifted to the off-peak period and the other half would be shifted to the overnight period, for non-EV owners. This implies that the customers respond to the peak/off-peak ratio half of the time and to the peak/overnight ratio the other half of the time. This assumption results in a blended impact of 6.5% for Tier 1, and 4.7% for Tier 2. On average, 61% of the consumption is in Step 1 and 39% of the consumption is in Step 2. Using these ratios in each consumption block, the weighted average is calculated as 5.8%. While this is our best point estimate of the peak impact, based on the range of observations in Arcturus we believe that impacts between 3% and 10% are plausible.

FIGURE 4: ESTIMATED PEAK DEMAND REDUCTIONS

	Price Ratio	Peak Period Consumption Reduction
Step 1 (Peak/Off-peak)	1.5	3.5%
Step 1 (Peak/Overnight)	3	9.4%
Step 1 Blended Impact (50/50)	N/A	**6.5%**
Step 2 (Peak/Off-peak)	1.4	2.9%
Step 2 (Peak/Overnight)	2.1	6.4%
Step 2 Blended Impact (50/50)	N/A	**4.7%**
Weighted Average Impact (Step 1 and Step 2)		**5.8%**

BC Hydro assumes that, on average, TOU participants with an EV will reduce their peak period EV charging load by approximately 75%. A pilot study in San Diego found that participants in TOU rates for EV charging provided peak usage reductions that are generally consistent with this range.[17] We generally consider 50% and 90% to be a reasonable range for EV charging load shifting, and BC Hydro's assumption falls into this range.

III. Conclusions

BC Hydro requested that we address seven issues related to their proposed optional residential TOU rate. Those issues spanned TOU rate design principles, customer participation in TOU rates, the conservation impact of TOU rates, a credit/charge approach to implementing TOU rates, TOU price ratios, participant load shifting behavior, and estimates of participant peak demand reductions.

The basis for our responses to those seven issues was a review of the literature on the topics, supplemented with our combined three decades of hands-on experience designing and evaluating residential TOU rates throughout North America. We reviewed BC Hydro's description of its residential TOU rate proposal in its November 2022 information booklet and had clarifying discussions with BC Hydro staff.

[17] Nexant, "Final Evaluation for San Diego Gas & Electric's Plug-in Electric Vehicle TOU Pricing and Technology Study," prepared for San Diego Gas & Electric, February 20, 2014. The pilot found that EV owners shifted 73% to 84% of their charging to the super-off-peak period in response to peak-to-super-off-peak price ratios in the range of 2-to-1 to 4-to-1.

We concluded that BC Hydro's proposed TOU design is consistent with successful industry rate design practices and effectively balances key ratemaking criteria. In particular, the company's proposed credit- and charge-based approach to implementing the TOU is an innovative approach to increase the appeal of a TOU rate for customers currently enrolled in an inclining block rate. Further, our review indicates that BC Hydro's assumptions about the potential participation in and load impacts of TOU rates are reasonable and consistent with the available empirical evidence on the subject.

Appendix A – Brattle Resumes

Ryan M. Hledik

PRINCIPAL

San Francisco +1.415.217.1000 Ryan.Hledik@brattle.com

Mr. Hledik specializes in regulatory and planning matters related to emerging energy technologies.

Mr. Hledik has consulted for more than 80 clients across 35 states and nine countries. He has supported his clients in matters related to energy storage, load flexibility, distributed generation, electrification, retail tariff design, energy efficiency, and grid modernization.

Mr. Hledik's work has been cited in regulatory decisions establishing procurement targets for distributed energy resources, authorizing billions of dollars in smart metering investments, and approving the introduction of innovative rate designs. He is a recognized voice in debates on how to price electricity for customers with distributed generation. He coauthored Saudi Arabia's first demand-side management (DSM) plan, and the Federal Energy Regulatory Commission's landmark study, *A National Assessment of Demand Response Potential*.

Mr. Hledik has published more than 30 articles on electricity matters and has presented at industry events throughout the United States as well as in Brazil, Belgium, Canada, Germany, Poland, South Korea, Saudi Arabia, the United Kingdom, and Vietnam. His research on the "grid edge" has been cited by *Forbes, National Geographic, The New York Times,* and *The Washington Post*, and in trade press such as *GreenTech Media*, *Utility Dive*, and *Vox*.

Mr. Hledik received his M.S. in Management Science and Engineering from Stanford University, where he concentrated in Energy Economics and Policy. He received his B.S. in Applied Science from the University of Pennsylvania, with minors in Economics and Mathematics. Prior to joining Brattle, Mr. Hledik was a Research Assistant with Stanford's Energy Modeling Forum and a Research Analyst with Charles River Associates.

AREAS OF EXPERTISE

- Electrification
- Load Flexibility, Demand Response, and Energy Efficiency
- Innovative Retail Electricity Pricing

- Energy Storage
- Grid Modernization
- Model Development

EDUCATION

- **Stanford University**
  MS in Management Science & Engineering
- **The University of Pennsylvania**
  BS in Applied Science

PROFESSIONAL EXPERIENCE

- **The Brattle Group (2006–Present)**
  Principal (2015–Present)
  Senior Associate (2009–2014)
  Associate (2006–2009)
- **Stanford Energy Modeling Forum (2005)**
  Research Assistant
- **Charles River Associates (2002–2005)**
  Research Analyst

TESTIMONY AND REGULATORY FILINGS

- Before the Public Service Commission of the District of Columbia, direct testimony filed on behalf of Pepco, on the issue of a benefit-cost analysis of Pepco's Climate Solutions Plan Phase I Application, Formal Case No. 1167, December 2022.
- Before the Missouri Public Service Commission, surrebuttal testimony filed on behalf of Evergy Missouri (West and Metro), on the issue of a proposed subscription pricing program, Case No. ER-2022-0130, August 2022.
- Before the Colorado Public Utilities Commission, "Xcel Energy Colorado Demand Response Study: Opportunities in 2030," report filed on behalf of Xcel Energy in Proceeding No. 22A-0309EG, June 2022 (with A. Ramakrishnan, K. Peters, R. Nelson, and X. Bartone).
- Before the Missouri Public Service Commission, direct testimony filed on behalf of Evergy Missouri (West and Metro), on the issue of a proposed subscription pricing program, Case No. ER-2022-0130, January 2022.

- Before the Public Service Commission of the District of Columbia, "Pepco's Climate Solutions 5-Year Action Plan: Benefits and Costs," report filed on behalf of Pepco in Formal Case No. 1167, January 2022 (with S. Sergici, M. Hagerty, M. Witkin, J. Olszewski, and S. Ganjam).
- Before the Public Service Commission of the District of Columbia, "An Assessment of Electrification Impacts on the Pepco DC System," report filed on behalf of Pepco in Formal Case No. 1167, August 27, 2021 (with S. Sergici, M. Hagerty, and J. Olszewski)
- Before the Alberta Utilities Commission, "Modernizing Distribution Rate Design," report filed on behalf of ATCO in *Distribution Inquiry – Combined Module (2 and 3)*, Proceeding ID 24116, March 13, 2020 (with A. Faruqui and L. Lam)
- Before the Arizona Corporation Commission, "An Assessment of APS's New Bill Comparison Web Tool," report filed on behalf of APS in *Arizona Public Service Company's (APS) Rate Review and Examination*, Docket No. E-01345A-19-0003, January 15, 2020 (with A. Faruqui and C. Bourbonnais)
- Before the Nova Scotia Utility and Review Board, "An Assessment of Nova Scotia Power's Proposed Extra Large Industrial Active Demand Control Tariff," expert report filed on behalf of NS Power *In the Matter of an Application by Nova Scotia Power Incorporated for Approval of an Extra Large Industrial Active Demand Control (ELIADC) Tariff, Under Which Port Hawkesbury Paper LP Will Take Electric Service From NS Power*, Matter No. M09420, September 26, 2019 (with A. Faruqui).
- Before the Public Utilities Commission of Nevada, direct testimony filed on behalf of Solar Partners XI ("Arevia"), Joint Application of Nevada Power Company d/b/a NV Energy and Sierra Pacific Power Company d/b/a NV Energy for approval of the third amendment to its 2018 Joint Integrated Resource Plan to update and modify the renewable portion of the Supply-Side Plan and the Transmission Action Plan, Docket No. 19-06039, Aug 26, 2019
- Before the Minnesota Public Utilities Commission, "The Potential for Load Flexibility in Northern States Power's Service Territory," report filed on behalf of Xcel Energy in *2020-2034 Upper Midwest Integrated Resource Plan*, Docket No. E002/RP-19-368, June 2019 (with A. Faruqui, P. Donohoo-Vallett, and T. Lee)
- Before the New Mexico Public Regulation Commission, "The Value of Energy Storage to the PNM System," report filed on behalf of Public Service Company of New Mexico *In the matter of Public Service Company of New Mexico's Consolidated Application for Approvals for the Abandonment, Financing, and Resource Replacement for San Juan Generating Station Pursuant to the Energy Transition Act*, Case No. 19-00195-UT, August 4, 2019 (with J. Pfeifenberger, J. Chang, P. Ruiz, and J. Cohen)
- Before the Public Utilities Commission of Nevada, "The Economic Potential for Energy Storage in Nevada," report filed on behalf of the Public Utilities Commission of Nevada and the Nevada Governor's Office of Energy, *Investigation and Rulemaking to Implement Senate Bill 204 (2017)*,

Docket No. 17-07014, October 1, 2018 (with J. Chang, R. Lueken, J. Pfeifenberger, J. Imon Pedtke, and J. Vollen)

- Before the Oregon Public Utilities Commission, "Demand Response Market Research: Portland General Electric, 2016 to 2035," report filed on behalf of Portland General Electric *In the Matter of Portland General Electric Company, 2016 Integrated Resource Plan*, Docket No. LC 66, November 15, 2016 (with A. Faruqui and L. Bressan)
- Before the Oregon Public Utilities Commission, "An Assessment of PGE's Demand Response Potential," report filed on behalf of Portland General Electric *In the Matter of Portland General Electric Company, 2013 Integrated Resource Plan*, Docket No. LC 56, March 2014 (with A. Faruqui)
- Before the Federal Energy Regulatory Commission, Affidavit on Behalf of Comverge Regarding PJM's Proposed Tariff Revisions Regarding Demand Response Capacity Market Participation Requirements. Docket No. ER13-2108-000, August 22, 2013 (with A. Faruqui)

SELECTED CONSULTING EXPERIENCE

Electrification

- For Pepco, assessed the benefits and costs of the company's Climate Solutions Plan. The Plan consists of 62 demand-side initiatives, including large energy efficiency, building electrification, and transportation electrification portfolios. The analysis quantified the energy system and environmental benefits of the programs and evaluated the target scale of the impact of the programs. Led a series of stakeholder workshops on the study findings and methodology. The final report was filed with the DC PSC.
- For Pepco, led the development of a study to analyze the peak demand impacts of achieving Washington, DC's decarbonization goals through electrification. The study included analysis of a portfolio of advanced energy efficiency and load flexibility measures to mitigate peak demand growth, and concluded that the projected peak demand growth rates would remain within the historical range experienced by the utility.
- For a west coast utility, estimated the change in energy use attributable to adopters of new technologies, including electric heating, electric vehicles, and rooftop solar PV. The analysis contributed to the utility's broader assessment of the energy affordability of technology adoption.
- For an east coast utility, was part of a team that analyzed how various retail rate designs would impact the economics of heat pump ownership. Constructed customer load profiles and assessed bill impacts.

- For a car manufacturer, assessed market opportunities for enabling EV managed charging and vehicle-to-grid. Surveyed market participants, estimated revenue potential, and conducted strategic market entry assessment.
- With the Smart Electric Power Alliance (SEPA), coauthored a paper on time-varying rates for home electric vehicle (EV) charging. The report is based on a survey of current utility rate offerings and identifies practices that are related to high enrollment in the rates.
- For the Electric Power Research Institute (EPRI), developed a survey and associated discrete choice modeling experiment to better understand drivers of EV adoption. The survey results were used to develop EV adoption models and resulting forecasts for several electric utilities.
- For EEI, developed a whitepaper to assess options and experience with rate design for fast-charging infrastructure to support adoption of electric vehicles. The whitepaper, titled "Facilitating Electric Vehicle Fast Charging Deployment," was published in October 2018.
- For EPRI, developed a framework for evaluating the cost-effectiveness of new electrification initiatives. The framework built upon cost-effectiveness tests used to evaluate demand-side management (DSM) programs. The report was published in August 2019.

Load Flexibility, Demand Response & Energy Efficiency

- For Xcel Colorado, assessed the cost-effective potential for new load flexibility programs in 2030. The study included benchmarking Xcel Colorado's existing demand response portfolio, assessing the seasonal need for new load flexibility programs, and quantifying the potential benefits and costs of the expanded portfolio.
- For private equity firm, assessed the revenue potential of a meter data disaggregation firm, with a focus on the market value of innovative behavioral energy efficiency and demand response programs that would be enabled by providing customers with real-time, appliance-level usage information.
- With LBNL, developed a whitepaper on emerging models for making load flexibility a win-win for both utilities and consumers.
- For a building equipment manufacturer, provided an overview of market opportunities for developing a demand response business.
- For the Alliance to Save Energy, developed the content for an interactive website designed to provide a variety of industry stakeholders with information about the value of load flexibility.

- For a large Canadian utility, served as an advisor on the utility's load flexibility assumptions in its integrated resource plan.
- For Oracle, assessed the potential for "consumer action pathways" to play a key role in reducing national carbon emissions. The customer action pathway consisted of energy efficiency, electrification, rooftop solar PV, and load flexibility.
- For PGE, participated in a team developing the utility's 2021 DER potential study. The study informed PGE's integrated resource plan and distribution resource plan.
- For a utility in the Upper Midwest, conducted a load flexibility study to inform the strategic development of the utility's demand-side resources.
- For an East Coast IOU, conducted analysis to forecast how the utility's load would increase if aggressive decarbonization goals are met through electrification, and to determine the extent to which energy efficiency and load flexibility measures could mitigate that load growth, highlighting the key role that load flexibility will play in facilitating the decarbonization transition.
- For a DER software developer, estimated the potential market value of residential load flexibility offerings across five utilities. The analysis highlighted that the load flexibility value proposition varies significantly depending on system and market conditions. The final report is a key input to the company's load flexibility business case. Subsequent work involved conducting a workshop for the company's staff on valuing load flexibility.
- For an investment firm considering an investment in a demand response aggregator, provided an outlook on DR market opportunities and an overview of the current state of DR in the US.
- For the US Department of Energy, developed a national roadmap for grid-interactive efficient buildings (GEBs). The engagement involved modeling the national potential for GEBs, as well as research and stakeholder engagement to identify barriers to GEB deployment, as well as opportunities for overcoming the barriers. The release of the roadmap was announced by the Secretary of Energy in May 2021.
- For the US Department of Energy, led a study to assess the relative benefits of energy efficiency, load flexibility, and electrification technologies for buildings under a variety of decarbonization scenarios. The study included analysis of more than 80 demand-side measures for 25 regions across the U.S., and included evaluation of the cost-effectiveness of the measures.
- For Lawrence Berkeley National Lab (LBNL), led a study to assess the extent to which various policy and technology developments could increase cost-effective energy

efficiency deployment potential. The study involves simulation of a representative Southeastern US utility using Brattle's resource planning model, GridSIM.

- For an Asian utility deploying its first demand response programs, provided research on current practices by utilities and third party aggregators with DR offerings in ISO and non-ISO markets. The research was used as input to the utility's DR strategy development initiative.
- For a natural gas distribution utility, leading a study to assess the market potential for demand response programs. The first-of-its-kind study assesses opportunities to utilize demand response as an alternative to developing gas distribution infrastructure. The study will serve as input to the utility's resource planning process.
- For Xcel Energy, led a study to assess opportunities for load flexibility in its Northern States Power service territory. The study looked beyond conventional DR options to evaluate the potential for emerging programs (e.g., EV charging control, behavioral DR) while considering new value streams (e.g. ancillary services, off-peak load building, around-the-clock load flexibility). The study utilized Brattle's LoadFlex model and is based on a detailed survey of DR programs and pilot projects deployed around the US. The study was filed with the Minnesota PUC and results were be used as inputs to Xcel Energy's integrated resource plan in the Upper Midwest
- For EPRI, conducted a study to explore methods for incorporating DERs into integrated resource planning. A unique feature of this study was the use of Brattle's capacity expansion model, GridSIM, to quantitatively illustrate the implications of various DER modeling techniques. In the first phases of the engagement, we assessed the implications of different approaches to modeling energy efficiency (EE) and demand response (DR), such as the advantages and disadvantages of modeling these resources on the "supply side" versus the "demand side" of the model. The current phase of the project focuses on electric vehicles (EVs) and rooftop solar, and includes a review of techniques for forecasting adoption of these technologies, as well as modeling the resource impacts of growth in EV adoption.
- For Xcel Energy, conducted a first-of-its-kind study to assess the extent to which "organic conservation" (also known as naturally occurring energy efficiency) was affecting electricity sales. Surveyed industry contacts about trends in organic conservation. Conducted a quantitative assessment of the impact of organic conservation for three end-use case studies using data from the US Energy Information Administration and Xcel Energy.

- Contributed to a study for the Texas Clean Energy Coalition to determine role of demand response, energy efficiency, and combined heat and power in future energy scenarios in Texas. Developed a feasible portfolio of EE and DR measures, including costs and performance characteristics. The programs were then fed into a suite of resource planning models to determine the impacts of EE and DR on ERCOT prices and system operations. The final report was highly publicized and presented to stakeholders and policymakers throughout the state.
- For EnerNOC, developed a whitepaper on valuing DR in international markets. Provided guidelines for quantifying the value of DR and presented three international case studies to illustrate how those calculations vary across markets.
- For a large power developer, assessed the energy efficiency aspects of the US Environmental Protection Agency's (EPA's) Clean Air Act, section 111(d). Specifically, analyzed the extent to which the energy efficiency targets that were established in the proposed policy were reasonable and achievable, and whether the EPA had represented energy efficiency correctly in its modeling scenarios.
- For the Kingdom of Saudi Arabia's energy regulator (ECRA), worked with a team of consultants to develop the nation's first demand-side management (DSM) plan. Participated in an introductory workshop with key stakeholders and conducted a series of in-country interviews to gather more detailed information. Coauthored an extensive study on the potential impacts and cost-effectiveness of a full range of DSM measures in Saudi Arabia. Worked with the team to develop policy recommendations and a ten-year plan for rolling out DSM measures across the country.
- For a national team of energy stakeholders in the Kingdom of Saudi Arabia, assessed the potential for broader adoption of combined heat and power (CHP). Developed a model to predict CHP potential by industry and technology type for a range of policy scenarios. Assessed barriers to adoption.
- For the Federal Energy Regulatory Commission (FERC), managed a team of contractors that developed the National Action Plan for Demand Response. The report defined a blueprint for maximizing the amount of cost-effective demand response (DR) that can be achieved in the United States. Led the development of a model that can be used to quantify the potential impacts and benefits of a variety of demand response and smart grid portfolios. Results were filed with US Congress in June 2010.
- For FERC, developed a state-by-state assessment of the potential for DR. The analysis used a bottom-up approach to quantify economic and achievable potentials individually for each of the 50 states, and to characterize the existing level of DR in each state.

Additionally, the work involved a comprehensive survey and analysis of existing literature on DR barriers at the wholesale and retail levels, as well as policy options for addressing these barriers. Results were filed with US Congress in June 2009 in a report titled A National Assessment of Demand Response Potential. Coauthored the document and managed its development across a team of subcontractors.

- For the California Energy Commission (CEC), coauthored two whitepapers on demand response and the potential for the CEC to exercise its load management authority to further increase demand response efforts in the state. The whitepapers were the impetus for two CEC-sponsored workshops involving the California utilities, regulators, consumer advocates, and other stakeholders. The whitepapers contributed to the CEC's 2007 Integrated Energy Policy Report and have resulted in a formal proceeding on the CEC's load management authority.
- For one of California's investor-owned utilities, developed recommendations for a forward-looking demand response strategy. Conducted a series of interviews with internal stakeholders and helped to lead two workshops to create a common understanding across the company regarding the value proposition of demand response, and ways in which it can be used to address key challenges facing the utility.
- Served as the lead architect of the Demand Response Impact and Value Estimation (DRIVE) model for assessing the hourly system impacts of portfolios of smart grid programs over a 20-year forecast horizon. The model simulates hourly system dispatch for 13 regions of the United States, both before and after a user-specified deployment of smart grid programs. The model is available on the FERC website.
- For Lawrence Berkeley National Laboratory (LBNL), updated the assumptions in FERC's 2009 A National Assessment of Demand Response Potential to reflect more recent industry developments. The results of that update were used as inputs to the Western Electricity Coordinating Council's (WECC's) transmission planning activities.
- For Portland General Electric, developed a bottom-up assessment of the peak demand reductions that could be achieved through and expanded offering of DR programs. Tailored the analysis to the specific market conditions that are unique to the Pacific Northwest and PGE's service territory. Reviewed studies on the ability of DR to integrate renewable energy resources into the grid. The study was first conducted in 2009 and then updated in 2012 and again in 2015. The 2015 update included a number of emerging DR options, such as bring-your-own-thermostat, behavioral DR, electric vehicle load control, and smart water heating programs.

- For Xcel Energy's Colorado and Minnesota service territories, conducted a bottom-up assessment of the potential impacts of DR programs. In Colorado, the study included an assessment of the cost-effectiveness of the DR options and results were filed with the Colorado PUC. In Minnesota, the study included the development of DR supply curves, which are inputs to Xcel Energy's integrated resource planning process.
- For the Midwest Independent System Operator (MISO), Bonneville Power Administration (BPA), and one of the largest power generation companies in the US, developed regional forecasts of the potential impacts of demand response and energy efficiency programs. Forecasts included a bottom-up assessment of existing demand response programs and a detailed projection of the achievable potential peak savings for each of these programs. The studies also included an assessment of the costs associated with the peak savings. The forecasts were used as inputs to the ISO's full-scale transmission expansion modeling effort and to enhance the market modeling efforts of BPA and the power generation company.
- For a large Southern utility, assessed policies, standards, and rules/regulations addressing the development and implementation of energy efficiency programs and renewable energy resources by utilities. Analysis included an assessment of the pros and cons of various energy efficiency incentive mechanisms such as the Save-a-Watt model and California's shared savings model. Assessed the political influence and collaboration potential of the utility's stakeholders as part of the strategy formulation process.
- For a large Independent System Operator (ISO), coauthored a whitepaper assessing the status of the region's achievement of its demand response potential. The paper included an assessment of the barriers to achieving the demand response potential, followed by policy and market design recommendations for addressing the barriers. The results were presented at the ISO's annual board meeting.
- For a large ISO, coauthored a whitepaper summarizing the current state of third party access to smart meter data. The paper reviewed existing policies in states that have already explored this issue, and drew parallels to other industries that have dealt with similar problems.
- For Comverge, developed an estimate of the potential benefits of offering an expanded residential direct load control program in the ComEd service territory. The assessment included quantification of avoided resource costs and a qualitative description of additional potential benefits, such as improved reliability and emissions reductions.

Innovative retail electricity Pricing

- For an eastern US utility, assessed the impact that various retail rate designs would have on the economics of residential electric heating relative to gas heat.
- For Lawrence Berkeley National Lab, contributed to a report on rate design for a power system with variable renewable energy resources. The report is intended to be filed with US Congress.
- For a large Midwestern utility, developed a proposal for a subscription pricing plan. The proposal included innovative features to promote energy efficiency and clean energy adoption.
- For a large Midwestern utility, contributed to the development of the utility's rate modernization plan. The project involved developing and analyzing TOU rate design proposals.
- For APS, conducted a review of the utility's online bill comparison tool. Results, summarizing Brattle's assessment of the accuracy of the tool, were filed with the Arizona Corporation Commission (ACC).
- For a Western utility, benchmarked the utility's operating costs and services against a relevant sample of comparison utilities in order to identify areas of relative strength, as well as growth opportunities.
- For Nova Scotia Power, reviewed and assessed a load flexibility tariff that the utility proposed for its largest customer. Co-authored an expert report summarizing the findings, which was filed with the Nova Scotia Utility and Review Board.
- For a Midwestern utility assessed the extent to which various distribution rate design options were cost reflective and aligned with the utility's underling cost of service.
- For Abradee, the trade association for the Brazilian distribution utilities, developed two whitepapers. The first paper addressed international stakeholder perspectives on emerging distribution tariff designs. The second paper summarized opportunities and risks associated with new utility services.
- For Vector, a distribution utility in New Zealand, evaluated the relative advantages and disadvantages of a variety of new distribution tariff designs that the utility was considering. Conducted analysis of customer bill impacts and estimated likely demand response from the new tariff offerings, in addition to establishing other rate evaluation metrics.

- For NorthWestern Energy, provided regulatory support for the utility's proposal to create a new rate class for customers with distributed generation and to introduce three-part rates for those customers.
- For Arizona Public Service, provided regulatory support and analysis in a proceeding to determine if the utility's commission-approved rate increase had been appropriately implemented.
- For Westar Energy, supported the utility's proposal to create a separate rate class for residential customers with distributed generation, and to introduce a three-part rate for those customers.
- For Idaho Power, supported the utility's proposal to create a separate rate class for residential customers with distributed generation. Included an analysis of the extent to which behind-the-meter storage would impact the load shapes of customers with rooftop solar and reduce their energy exports to the grid.
- For Commonwealth Edison, contributed to the development of a pilot that would test customer acceptance of a prepayment metering program. Work involved identifying pilot objectives, developing experimental design, and establishing appropriate sample size.
- For Citizens Advice, the largest consumer organization in Great Britain, led a study on the value of time-varying rates. The study included detailed power system modeling to quantify the monetary value time-varying rates in terms of avoided system costs. The study also included primary and secondary market research to identify the features of time-varying rate offerings that are most appealing to customers. The final report has informed ongoing dialogue in Great Britain around how to best capture value from the nation's ongoing smart metering rollout.
- For the US Department of Energy (DOE), coauthored a whitepaper on methods for unbundling and pricing distribution services in an environment of high distributed energy resource (DER) market penetration. The report identified the various services that are provided by the utility to DER customers, the discrete services provided by DER customers to the utility, and various frameworks for packaging and pricing these services. The report included an assessment of the advantages and disadvantages of each pricing framework from the perspective of both the utility and its customers.
- For a clean energy organization, developed a whitepaper on residential demand charges, their impact on low-income customers, and the potential opportunities that they would create for behind-the-meter energy storage.

- For the Edison Electric Institute (EEI), researched stakeholder perspectives on residential demand charges. Conducted interviews with nine consumer advocates to better understand their views on the advantages and disadvantages of demand charges relative to other rate design options. Findings were summarized in a *Public Utilities Fortnightly* article.
- For Georgia Power, developed a model to simulate likely customer response to demand charges (e.g., load shifting and/or changes in overall consumption). The model assumptions are based on a review of price elasticity studies as well as three pricing pilots involving residential demand charges. Also surveyed recent utility experience with residential demand charges and established a list of "lessons learned" from this experience.
- For Westar Energy, assessed the extent to which a new three-part rate (with a fixed charge, a demand charge, and a variable charge) would impact customer bills. Simulated the impact on owners of distributed generation (DG) and assessed the extent to which rate increases associated with sales reductions due to DG adoption would be reduced by introducing the new rate. Estimated likely customer rate switching behavior that would result from the introduction of the new options and the impact that this would have on utility revenue.
- Assisted a large Southwestern US utility in establishing its vision for the ideal residential rate. Established key principles for ratemaking and evaluated a comprehensive range of rate designs against these principles, particularly as they relate to fairness and equity in an environment of rapidly growing solar PV adoption. Provided strategic recommendations for transitioning to the ideal rate design.
- For a large Midwestern utility, assessed the bill impacts of a rollout of mandatory residential demand charges. The assessment included a particular focus on the impacts on low-income customers using estimates of household-level income data obtained through a market data firm and validated with public data from the US Census.
- For Citizens Advice, led a study on distribution network tariff design. The report includes insights from interviews with industry stakeholders, a survey of tariff reform activity in other countries, and detailed modeling of the distribution of bill impacts from the new tariff designs for more than 14,000 British customers. The simulations account for likely consumer response to the tariffs.
- For Xcel Energy, contributed to rebuttal testimony in support of the utility's proposal to eventually introduce three-part rates for residential customers. Addressed points in intervenor testimony regarding the efficacy of residential demand charges.

- For a large Midwestern utility, simulated likely customer response to a three-part rate. Developed three different approaches to estimating the impacts. Results were provided in context of the utility's rates proceeding.
- For Salt River Project (SRP), conducted an assessment of the utility's rate proposal for residential DG customers. The proposal was a mandatory, revenue neutral three-part rate with a tiered demand charge. Analysis culminated in the development of a whitepaper that was presented to SRP's Board. The rate proposal was approved by the Board.
- Assisted PGE in the design of a dynamic pricing pilot. Provided pilot design and evaluation assistance to test a number of under-researched issues, such as the impact of behavioral DR and differences in customer response when rates are offered on an opt-in versus an opt-out basis.
- For more than 15 utilities and other organizations across North America, designed dynamic pricing rates such as time-of-use (TOU), critical peak pricing (CPP), peak time rebates (PTR), and real-time pricing (RTP). Simulated the likely impact of the rates on utility load shapes and customer bills. Conducted cost-effectiveness analysis of offering these rates to the mass market. Recently, these studies have been conducted in Arizona, California, Connecticut, the District of Columbia, Delaware, Florida, Hawaii, Idaho, Illinois, Kansas, Maryland, Michigan, Missouri, New Jersey, North Carolina, Oregon, and Pennsylvania. Several of the analyses served as input to AMI business cases. The analyses also included a review of other demand-side options such as direct load control and energy efficiency.
- For the three California investor-owned utilities (IOUs), assessed the likely impact of residential rate reform on consumption. Analyzed the extent to which rate design changes (e.g., a reduction in the price differential between tiers of the inclining block rate, the introduction of a monthly customer charge, or a reduction in the low-income discount) would affect conservation. Drafted expert testimony that was submitted to the California Public Utilities Commission.
- For a large Southwestern utility, benchmarked the utility's projected retail rate against those of other utilities. Reviewed utility resource plans to estimate each utility's retail rate trajectory. Compared the utilities across a variety of rate drivers, such as reserve margin, fuel mix, load growth, load factor, renewables investment requirements, and demand-side activities. Provided strategic recommendations for addressing these drivers of future rate growth.

- For PacifiCorp, assessed the likely impacts of new rate designs on customer behavior. Projected likely adoption of the new rate offerings based on a survey of enrollment rates in other jurisdictions. Extrapolated the customer-level impacts to system-level impacts. Analysis was a key element of the utility's DSM potential study.
- For a large Western utility, evaluated the degree to which the introductions of new optional residential rate options would affect the utility's revenue. Developed a model to simulate customer switching behavior between the rate options. Provide strategic advice for transitioning from the current rate offering to a new paradigm of rate choice.
- For the Regulatory Assistance Project (RAP), coauthored a whitepaper on issues and emerging best practices in dynamic pricing rate design and deployment. The paper's audience was international regulators and rate analysts in regions that are exploring the potential benefits of AMI and innovative retail pricing.
- For multiple US utilities, helped design pilot programs for testing the impact of dynamic pricing rates and enabling technologies such as smart thermostats and in-home energy information displays. Contributions to pilot design included designing and selecting the appropriate treatments and providing general recommendations for ensuring the statistical validity of the results.
- For China Light & Power, provided guidance on dynamic pricing pilot design. Also evaluated the utility's methodology for calculating customer baseline consumption when determining rebate payments for a peak time rebate program.
- For the Ontario Energy Board (OEB), developed recommendations for improving the effectiveness of the province's mandatory residential TOU rate. Coauthored a whitepaper benchmarking the rate's design and deployment against best practices, and provided suggestions for improving certain elements. Co-presented the findings at a stakeholder workshop in Ontario.
- For Commonwealth Edison, contributed to the design of the first opt-out residential dynamic pricing pilot. Reviewed rate designs and simulated expected bill impacts across a representative sample of customers. Developed estimates of the potential value of an opt-out deployment of peak time rebates.
- For the Demand Response Research Center (DRRC), coauthored a whitepaper on leading issues in rate design. Developed a set of dynamic rates that were used in a workshop to guide California decision makers through the process of designing dynamic rates. Results were cited in a landmark ruling making dynamic pricing the default rate offering in California.

- For Xcel Energy, contributed to expert testimony supporting a filing proposing new inclining block rate (IBR) designs. The rates were designed to provide incentives for Xcel's customers to conserve energy. Developed a model for simulating customer response to the new rate designs and the resulting impact on Xcel's sales.
- For a large North American utility, developed estimates of the likely impact of moving from an inclining block rate structure to a time-of-use rate structure. Simulated the impact on overall energy consumption and peak demand under a range of rate design and price elasticity scenarios.
- For a large Southeastern utility, assessed the costs of the utility's green pricing program. Benchmarked the costs against those of similar programs offered by other utilities. Analyzed differences across programs and provided an assessment of the utility's costs, which was presented to the regulatory commission.

Energy Storage

- For a large Southeastern utility, conducted an assessment of two proposed battery projects. The study included identification and analysis of additional value streams not considered by the utility, and analysis of battery cycling strategies to optimize revenue while accounting for degradation effects.
- For a private investor, assessed the revenue potential for new storage assets in ERCOT. The analysis included estimation of the revenue impact associated with delayed market entry of competing assets as well as the risks associated with overbuilding of storage.
- For a large international energy company, evaluated the revenue potential of an investment in three US battery storage developers. The company ultimately made large investments in two of the three companies.
- For a large US renewables developer, assisted the company in its entry into the utility-scale storage business by evaluating storage and solar-plus-storage revenue potential in various organized wholesale markets in the US.
- For a large Southeastern utility, led a study to assess long-term opportunities for deploying storage to meet a large legislative requirement. The study focused on opportunities for emerging long-duration storage technologies.
- For Arevia, the developer of a large solar-plus-storage project in Nevada, provided regulatory testimony on the costs and benefits of the proposed project. The project, which was the largest solar-plus-storage project in the United States, was approved by the Public Utilities Commission of Nevada in December 2019.

- Served on the Energy Storage Association's Technical Advisory Council. Responsibilities included technical advice, providing input to the organization's research agenda, and developing whitepapers on emerging issues in the storage industry.
- For the ESA, organized and led a two-day seminar on emerging industry practices for incorporating energy storage into utility resource planning. Developed content and program, focused on issues such as storage costs and benefits, modeling and valuation techniques, the current state of energy storage in utility IRPs, and the interface between bulk system and distribution resource planning.
- For Public Service Company of New Mexico (PNM), led analysis of the value that new energy storage developments could provide to the utility's system. The analysis focused specifically on the benefits of standalone, utility-scale battery storage deployments. Results were summarized in a report titled, "The Value of Energy Storage to the PNM System," which was attached to a regulatory filing by PNM in June 2019.
- For the Public Utilities Commission of Nevada and the Nevada Governor's Office of Energy, led a study to estimate the statewide potential for cost-effective energy storage deployment. The analysis involved detailed modeling of the Western US power system and included an assessment of both utility scale and behind-the-meter storage. Results were published in a report titled, "The Economic Potential for Energy Storage in Nevada." The study has contributed to a regulatory proceeding to establish an energy storage procurement target for the state.
- For Dominion Energy, provided an assessment of the opportunities available for deploying energy storage pilots. The analysis began with a screening analysis to identify most attractive pilot options based on net economic benefits as well as other practical considerations such as implementation time, technical feasibility, consistency with state policies, and repeatability. Based on the findings of the screening analysis, a detailed assessment of specific solar-plus-storage and standalone storage projects estimated the benefits and costs of each project under a range of market price scenarios, technology configurations, and operational strategies. The proposed pilots were approved by the Virginia State Corporation Commission (SCC).
- For a large solar and storage developer, provided due diligence support for a potential investment in a solar-plus-storage facility in California. The analysis estimated revenue potential for the project under a range of price forecasts, technology configurations, and battery dispatch scenarios.
- For an international investor in power assets, analyzed the revenue opportunities and risks for standalone storage projects in California, Ontario (Canada), and New York. In

addition to detailed revenue forecasts, the analysis included a review of wholesale market participation opportunities, state policies and incentives, and trends in market fundamentals.

- For an energy storage developer, provided an outlook of revenue opportunities in Ontario, Canada. The analysis included an assessment of near-term revenue potential and commentary on the likely impact of regulatory and market developments on that potential.
- For a large Midwestern utility, contributed to the development of a model that forecasts behind-the-meter storage adoption and its impact on utility revenues and costs, electricity rates, system peak demand, and other key metrics.
- For a battery technology manufacturer, reviewed the impacts that PJM rule changes for participation in the frequency regulation market had on the battery's performance.
- For EOS, a battery storage developer, assessed the "stacked value" of a battery in the California market. The valuation included a detailed assessment of market prices and was based on realistic modeling of the battery's ability to simultaneously capture multiple value streams. The study also included an assessment of barriers to capturing this value, and recommendations regarding retail tariff design features that could address the barriers.
- For an environmental advocacy group (NRDC) and consortium of utilities (NRECA), estimated the costs and benefits of using controllable hot water heaters as "thermal batteries." Evaluated several control strategies, including daily energy arbitrage, peak shaving, and fast-response controllers capable of providing ancillary services. The study was covered by *The Washington Post* and in industry trade press.
- For a battery manufacturer, assessed the potential benefits that could be realized by deploying their technology in PJM and NYISO. Developed a dispatch model to simulate the technology's optimal operation in wholesale energy and ancillary services markets. Also quantified the value of avoided generation capacity and transmission and distribution capacity costs, as well as the reliability value if deploying the battery behind the meter. Assessed the ability of various stakeholders (ratepayers, utilities, third parties) to capture the value.

Grid Modernization

- For Enchanted Rock, a developer of microgrids, assessed the economic, resilience, and GHG impacts of a variety of microgrid options, including natural gas, renewable natural gas, and solar-plus-storage, as well as "hybrid" microgrids that combine these options.

- For Entergy, provided regulatory support for the company's proposal to roll out smart meters. Support included analysis of the energy efficiency and demand response benefits that would be enabled by the rollout.
- For a large British energy supplier, conducted an assessment of the national smart metering program. Identified risks that have emerged since the program's inception. Developed recommendations for plausible paths forward to mitigate the risks and increase the likelihood of the program's success. Research involved a detailed review of the BEIS smart metering Impact Assessment (IA), including modifications to the IA based on alternative future smart metering adoption and TOU uptake scenarios.
- For the US Department of Energy, served as a member of a Technical Advisory Group to review the activities of recipients of federal stimulus funding for consumer behavior studies. Reviewed smart grid pilot designs and provided guidance to improve their likelihood of success. Participated in regular meetings with the utilities on behalf of the US DOE to monitor progress.
- Served as lead architect of Brattle's *iGrid* model for assessing the costs and benefits of smart grid deployment strategies over a long-term (i.e., 50-year) forecast horizon. The model was used to evaluate seven distinct smart grid programs and technologies (e.g., dynamic pricing, energy storage, plug-in hybrid electric vehicles) against seven key metrics of value (e.g., avoided resource costs, improved reliability).
- Supported an expert witness in litigation regarding a contractual dispute between two smart grid companies. Assessed the likely market size for a new smart grid product using top-down and bottom-up modeling approaches. Drafted expert testimony.
- For the five Vietnamese distribution utilities, developed a 10-year roadmap for smart grid deployment across the country. The project began with a series of in-country stakeholder interviews and an initial assessment of the state of the Vietnamese grid. This information was used to develop preliminary recommendations for smart grid investment, which was presented and discussed during a one-day workshop with industry stakeholders. Feedback was incorporated into a final report titled *Vietnam's 10-year Smart Grid Roadmap*. The project was funded by the World Bank.
- For a firm investing in emerging energy technologies, developed an overview of key smart grid market developments. Topics included new non-traditional entrants to the utilities space, factors driving the decline in utility sales growth, and emerging regulatory constructs that could lead to new investment opportunities.
- For Pepco Holdings, established a universal list of metrics through which to track the impact of their smart grid rollout. Reviewed existing metric reporting requirements and

proposed additional metrics that would be useful to report in future regulatory proceedings.

- For a smart grid technology startup, provided strategic advice on how to design a smart grid pilot that would best demonstrate the value of their products. Authored a whitepaper summarizing key recommendations and assisted the company in effectively articulating the full value proposition of their integrated approach to home energy management.
- For Oak Ridge National Lab (ORNL) and the Electric Power Research Institute (EPRI), contributed to a report for evaluating the cost-effectiveness of smart grid investments. The report was published under the title *Methodological Approach for Estimating the Benefits and Costs of Smart Grid Demonstration Projects*.
- For the Connecticut Department of Energy and Environmental Protection (DEEP), contributed to the state's annual Integrated Resource Plan (IRP). Developed a chapter on emerging technologies (such as AMI, energy storage, and advanced waste-to-energy) and their potential future role in the state's mix of energy resources.

Wholesale Electricty Markets

- For a large Canadian utility, developed long-run projections of marginal energy and capacity prices under a variety of scenarios (which were defined by different assumptions about fuel prices, demand, carbon prices, etc.). To help explain trends in the prices, these forecasts were accompanied by scenario-specific detail about capacity additions and retirements, emissions, unit dispatch, and other outputs.
- Developed energy and capacity price forecasts under a range of market conditions to assist a large investor-owned utility in developing a strategy related to the decision to potentially retire a nuclear generating facility.
- Worked with an ISO to integrate demand response into its resource adequacy requirements. Reviewed existing utility demand response programs to identify those that would meet resource adequacy criteria. Developed a forecast of the potential for new demand response for the ISO's planning purposes.
- For a large transmission company, contributed to analysis using Brattle's Regional Capacity Model (RECAP) model to assess the value that new transmission lines would have from the perspective of bringing more renewables into the power market. The model quantified the impact of an increased market penetration of wind generation on system costs.

- For projects with multiple utilities, developed wholesale electricity price forecasts for regions across the United States using commercially licensed linear optimization models. Model forecasts were driven by assumptions about the outlook of fossil fuel prices and regional electricity demand levels, among other variables. Forecasts were developed using multiple data sources to create a range of price forecasts encompassing the varying assumptions established in the industry. Researched the inputs, set up and calibrated the model, and analyzed the resulting forecasts.
- For power marketers in California during the Western Energy Crisis, analyzed historical hourly California electricity bid data to quantify the potential economic impacts of the bidding strategies on regional electricity markets. Analysis included bids into the ISO's day ahead and real-time energy markets and ancillary services markets, as well as the California PX markets.

Model Development

- For the New York Department of Public Service (DPS), contributed to a model that will illustrate the impact of the state's Renewing the Energy Vision (REV) policy on utility financials. The analysis includes pricing structures for customers with distributed energy resources (DERs) as key inputs. The model can be used to assess the impacts of a range of DER market penetration scenarios on utilities, rates, and bills.
- Lead developer of the Regional Capacity Model (RECAP), an optimization model for forecasting the mix of generating capacity necessary to meet US electricity demand. The model closely calibrates to Annual Energy Outlook forecasts and was used in a whitepaper for the Edison Electric Institute to quantify the amount of generation and transmission capital investment that could be avoided through demand-side management.
- Worked with a team to develop a linear optimization model for forecasting the economic impact of various emission control policies. The model has been used to provide strategic emissions compliance advice to large electric utilities and for forecasting generator-specific environmental decisions.
- Created a tool for determining the optimal dispatch of energy storage technologies against given price series (energy and ancillary service markets), subject to the device's specific operating constraints. The tool was used to develop an economic valuation of a pumped storage plant in New England and to assess the potential value of a large-scale battery for a technology manufacturer.

- Developed a general equilibrium model for forecasting trends in international natural gas markets. The model was used in a study on the potential impacts of liquefied natural gas (LNG) adoption in the United States.
- Participated as a Research Assistant with Stanford University's Energy Modeling Forum (EMF). Presented an overview of participating models for an EMF study on issues in international natural gas markets.

Energy Asset Valuation

- For an infrastructure investment fund, provided due diligence support on potential fuel cell project investments in New York. Analysis included a forecast of potential project revenues and an assessment of regulatory risks facing the project.
- For NRECA and NRDC, assessed the costs and benefits of rooftop versus community solar in the context of zero net energy building policy. The study considered different solar PV configurations and market scenarios.
- For a foreign investor, assessed the likely future value of an investment in a new gas-fired combined cycle power plant in Western Pennsylvania. Projected gas, energy, and capacity prices under a range of plausible scenarios. Simulated the dispatch of the unit against these hourly price series to estimate potential earnings. Benchmarked the results against the performance of comparable units in the region.
- For one of the largest electricity consumers in the United States, conducted due diligence on the potential purchase of a large gas-fired combined cycle plan. Determined how a purchase of the plant would affect the firm’s energy portfolio. Used EPRI’s Energy Book System (EBS) to estimate the plant’s energy value given uncertainty in future electricity and fuel prices. Researched capacity and ancillary services markets to assess the plant’s potential for providing additional value in those areas. Investigated California LMP studies to determine whether the plant would have a price advantage or disadvantage due to transmission constraints when California transitioned to the MRTU market structure. Supplemented the LMP analysis with independent forecasts of nodal market prices in California using a large-scale production cost model. Analyzed the plant’s historical operations using publicly available data to determine how it was dispatched against market prices and to identify any additional synergistic benefits that might be achieved if the firm were to own the plant.

Mergers & Acquisitions

- Conducted a detailed audit of the FERC merger filing between Duke Energy and Progress Energy, which created the largest regulated utility in the United States. Updated data in the market power assessment and estimated new Herfindahl-Hirschman Indices (HHI). Explored new mitigation strategies that would alleviate screen failures that arose from the update.

- For several large electric utility mergers, aided electric utilities and their counsel in FERC regulatory filings. Performed analyses to measure the impacts on market concentration of proposed mergers between large electric utilities in the United States. Utilized a proprietary linear optimization model to calculate market shares before and after the mergers and suggested divestitures that would minimize the potential impacts of the mergers.

ARTICLES & PUBLICATIONS

- "Load Flexibility: Market Potential and Opportunities in the United States," with Tony Lee, *Variable Generation, Flexible Demand*, edited by Fereidoon Sioshansi, Academic Press, p. 195-210 (2021).
- "Avoiding Blackouts in California Through Load Flexibility," with Ahmad Faruqui, *Utility Dive* Op-Ed (September 14, 2020)
- "A New Paradigm for Utilities: Electrification of the Transportation and Heating Sectors," with Ahmad Faruqui, Jurgen Weiss, J. Michael Hagerty, and Long Lam, *American Bar Association's Energy Infrastructure, Siting and Reliability Newsletter* (November 13, 2019)
- "Emerging Landscape of Residential Rates for EVs: Creative Design Ahead," with John Higham and Ahmad Faruqui, *Public Utilities Fortnightly* (May 2019)
- "Two Paths for Advancing the Smart Metering Programme," *Utility Week* (December 2018)
- "Status of Residential Time-of-Use Rates in the US: Progress Comes Slowly," with Cody Warner and Ahmad Faruqui, *Public Utilities Fortnightly* (November 2018)
- "Storage-Oriented Rate Design: Stacked Benefits or the Next Death Spiral?" with Jake Zahniser-Word and Jesse Cohen, *The Electricity Journal* (October 2018)
- "Nothing Worth Having Comes Easy: Capturing the Stacked Benefits of Energy Storage," *RTO Insider* (December 19, 2017)
- "The Electrification Accelerator: Understanding the Implications of Autonomous Vehicles for Electric Utilities," with Jurgen Weiss, Roger Lueken, Tony Lee, and Will Gorman, *The Electricity Journal* (December 2017)
- "The Distributional Impacts of Demand Charges," with Gus Greenstein, *The Electricity Journal* (July 2016)

- "Competing Perspectives on Demand Charges," with Ahmad Faruqui, *Public Utilities Fortnightly* (September 2016)
- "Trends and Emerging Opportunities in Demand Response," with Lucas Bressan and Ahmad Faruqui, *Recursos Energeticos Distribuidos* (May 2016)
- "Understanding the UK's Potential for Demand Response," with Jurgen Weiss and Serena Hesmondhalgh, *Utility Week* (December 12, 2015)
- "The Emergence of Organic Conservation," with Ahmad Faruqui and Wade Davis, *The Electricity Journal* (June 2015)
- "The Paradox of Inclining Block Rates," with Ahmad Faruqui and Wade Davis, *Public Utilities Fortnightly* (April 2015)
- "Rediscovering Residential Demand Charges," *The Electricity Journal* (August/September 2014)
- "Smart by Default," with Ahmad Faruqui and Neil Lessem, *Public Utilities Fortnightly* (August 2014)
- "Analytical Frameworks to Incorporate Demand Response in Long-Term Resource Planning," with Andy Satchwell, *Utilities Policy* (March 2014)
- "Benchmarking Your Rate Case," with Ahmad Faruqui, *Public Utilities Fortnightly* (July 2013)
- "Drivers of Demand Response Adoption: Past, Present, and Future," with Kelly Smith, *Public Utilities Fortnightly* (January 2012)
- "Smart Pricing, Smart Charging," with Ahmad Faruqui, Armando Levy, and Alan Madian, *Public Utilities Fortnightly* (October 2011)
- "The Energy Efficiency Imperative," with Ahmad Faruqui, *Middle East Economic Survey* (September 2011)
- "Unlocking the €53 Billion Savings from Smart Meters in the EU: How increasing the adoption of dynamic tariffs could make or break the EU's smart grid investment," with Ahmad Faruqui and Dan Harris, *Energy Policy* (October 2010)
- "Rethinking Prices," with Ahmad Faruqui and Sanem Sergici, *Public Utilities Fortnightly* (January 2010)
- "Fostering Economic Demand Response in the Midwest ISO," with Ahmad Faruqui, Attila Hajos, and Sam Newell, *Energy Journal,* Special Issue on Demand Response Resources (October 2009)
- "Piloting the Smart Grid," with Ahmad Faruqui and Sanem Sergici, *The Electricity Journal* (August 2009)
- "Smart Grid Strategy: Quantifying Benefits," with Ahmad Faruqui and Peter Fox-Penner, *Public Utilities Fortnightly* (July 2009)

- "How Green is the Smart Grid?" *The Electricity Journal* (April 2009)
- "The Power of Dynamic Pricing," with Ahmad Faruqui and John Tsoukalis, *The Electricity Journal* (April 2009)
- "Transitioning to Dynamic Pricing," with Ahmad Faruqui, *Public Utilities Fortnightly* (March 2009)
- "The Power of Five Percent," with Ahmad Faruqui, Samuel A. Newell, and Johannes P. Pfeifenberger, *The Electricity Journal* (October 2007)

SELECTED WHITEPAPERS AND REPORTS

- "Making Grid-interactive Efficient Buildings a 'Win' for Both Customers and Utilities," with Andrew Satchwell, prepared for 2022 ACEEE Summer Study on Energy Efficiency in Buildings proceedings, August 2022.
- "Valuing Residential Energy Efficiency: Analysis for a Prototypical Southeastern Utility," with Andrew Satchwell, Oleksandr Kuzura, Oluwatobi Adekanye, and Chioke B Harris, prepared for Lawrence Berkeley National Lab (July 2022).
- "The Customer Action Pathway to National Decarbonization," with Sanem Sergici, Michael Hagerty, Ahmad Faruqui, and Kate Peters, prepared for Oracle (September 2021)
- "A National Roadmap for Grid-Interactive Efficient Buildings," with LBNL, Energy Solutions, and Wedgemere Group, prepared for the U.S. Department of Energy (May 2021).
- "Decarbonized Resilience: Assessing Alternatives to Diesel Backup Power," with Peter Fox-Penner, Roger Lueken, Tony Lee, and Jesse Cohen, prepared for Enchanted Rock, LLC (June 2020)
- "FixedBill+: Making Rate Design Innovation Work for Consumers, Electricity Providers, and the Environment," with Peter Fox-Penner and Andy Lubershane, The Brattle Group and Energy Impact Partners Working Paper (June 2020)
- "Identifying Likely Electric Vehicle Adopters," with Dan McFadden, Kenneth Train, Armando Levy, Jurgen Weiss, and Nicole Irwin, prepared for the Electric Power Research Institute (December 2019)
- "Solar-Plus-Storage: The Future Market for Hybrid Resources," with Roger Lueken, Judy Chang, Hannes Pfeifenberger, Jesse Cohen, and John Imon Pedtke (December 2019)
- "Residential Electric Vehicle Rates That Work," with Erika H. Myers, Jacob Hargrave, Richard Farinas, and Lauren Burke, prepared for the Smart Electric Power Alliance (November 2019)
- "The Total Value Test: A Framework for Evaluating the Cost-Effectiveness of Efficient Electrification," with Ahmad Faruqui, Michael Hagerty, and John Higham, prepared for the Electric Power Research Institute, August 2019)

- “The National Potential for Load Flexibility: Value and Market Potential Through 2030,” with Ahmad Faruqui, Tony Lee, and John Higham, The Brattle Group Report (June 2019)
- “Two Paths for Advancing Great Britain’s Smart Metering Programme,” with Pinar Bagci and Saurab Chhachhi, The Brattle Group Whitepaper (December 2018)
- “Facilitating Electric Vehicle Fast Charging Deployment,” with Jurgen Weiss, prepared for the Edison Electric Institute (October 2018)
- “Stacked Benefits: Comprehensively Valuing Battery Storage in California,” with Roger Lueken, Colin McIntyre, and Heidi Bishop, prepared for EOS Energy Storage (September 2017).
- “The Value of TOU Tariffs in Great Britain: Insights for Decision-makers,” with Will Gorman and Nicole Irwin, prepared for Citizens Advice (July 2017)
- “Beyond Zero Net Energy? Alternative Approaches to Enhance Consumer and Environmental Outcomes,” prepared for the National Rural Electric Cooperative Association (NRECA) and the Natural Resources Defense Council (NRDC) (June 2018)
- “Electrification: Emerging Opportunities for Utility Growth,” with Jurgen Weiss, Michael Hagerty, and Will Gorman, The Brattle Group Whitepaper (January 2017)
- “Distribution System Pricing with Distributed Energy Resources,” with Jim Lazar, prepared for Lawrence Berkeley National Laboratory’s Future Electric Utility Regulation series (May 2016)
- “The Tariff Transition: Considerations for Domestic Distribution Tariff Redesign in Great Britain,” with Ahmad Faruqui, Jürgen Weiss, Toby Brown, and Nicole Irwin, prepared for Citizens Advice (April 2016)
- “The Hidden Battery: Opportunities in Electric Water Heating,” with Judy Chang and Roger Lueken, prepared for the National Rural Electric Cooperative Association (NRECA), the Natural Resources Defense Council (NRDC), and the Peak Load Management Alliance (PLMA) (January 2016)
- “An Evaluation of SRP’s Electric Rate Proposal for Residential Customers with Distributed Generation,” with Ahmad Faruqui, prepared for Salt River Project (January 5, 2015)
- “Valuing Demand Response: International Best Practices, Case Studies, and Applications,” prepared for EnerNOC (January 2015)
- “Exploring Natural Gas and Renewables in ERCOT, Part III: The Role of Demand Response, Energy Efficiency, and Combined Heat & Power,” prepared for The Texas Clean Energy Coalition (May 29, 2014)
- “Demand Response Market Potential in Xcel Energy’s Northern States Power Service Territory,” with YouGov America, prepared for Xcel Energy (April 2014)

- "Incorporating Demand Response Into Western Interconnection Transmission Planning," with Andy Satchwell, Glen Barbose, Ahmad Faruqui, and Charles Goldman, LBNL Report, (July 2013)
- "Estimating Xcel Energy's Public Service Company of Colorado Territory Demand Response Market Potential," with YouGov America, prepared for Xcel Energy (June 2013)
- "Time-Varying and Dynamic Rate Design," with Ahmad Faruqui and Jenny Palmer, prepared for the Regulatory Assistance Project (July 2012)
- "Vietnam's 10-year Smart Grid Roadmap," prepared for Northern Power Corporation and The World Bank (December 2011)
- "Bringing Demand Side Management to the Kingdom of Saudi Arabia," with Global Energy Partners and PacWest Consulting Partners, prepared for ECRA (May 2011)
- "National Action Plan on Demand Response," with GMMB, Customer Performance Group, and Definitive Insights, prepared for the Federal Energy Regulatory Commission (June 2010)
- "A National Assessment of Demand Response Potential," with Freeman, Sullivan & Co. and Global Energy Partners, prepared for the Federal Energy Regulatory Commission (June 2009)
- "Assessment of Achievable Potential from Energy Efficiency and Demand Response Programs in the U.S.," with Global Energy Partners, prepared for the Electric Power Research Institute (January 2009)
- "Transforming America's Power Industry: The Investment Challenge," prepared for the Edison Electric Institute (November 2008)
- "Rethinking Rate Design: A Survey of Leading Issues Facing California's Utilities and Regulators," prepared for the Demand Response Research Center, Lawrence Berkeley National Laboratory (August 2007)
- "California's Next Generation of Load Management Standards," prepared for the California Energy Commission (May 2007)
- "The State of Demand Response in California," prepared for the California Energy Commission (April 2007)

PRESENTATIONS & SPEAKING ENGAGEMENTS

- "Yoga for the Decarbonized Power Grid," presentation at 2022 NARUC Annual Meeting, New Orleans, LA, November 15, 2022.
- "The National Potential for Load Flexibility," presentation at Connecticut DEEP Technical Session on Active Demand Response, November 3, 2022.
- "Making Grid-interactive Efficient Buildings a 'Win' for Both Customers and Utilities," 2022 ACEEE Summer Study on Energy Efficiency in Buildings (August 22, 2022).

- “Achieving Reliable Decarbonization: The Role of Energy Efficiency and Load Flexibility,” PLMA Dialogue (August 11, 2022).
- “Achieving the ‘Other’ Washington’s Decarbonization Goals with Energy Efficiency and Load Flexibility,” Efficiency Exchange 2022 (April 15).
- “The Energy Future Is Smart: Grid-Interactive Efficient Buildings,” panel at Los Angeles Better Buildings Challenge (LABBC) webinar (July 29, 2021)
- “A National Roadmap for Grid-Interactive Efficient Buildings,” presentation at Grid Forward’s “Building the Decarbonized Grid” summit (June 9, 2021)
- “Flexibility: The New Grid Zeitgeist,” panel at Microgrid 2020 Global Conference (November 18, 2020)
- “How Pricing is Playing a Greater Role in Grid Transitions,” panel at Peak Load Management Alliance (PLMA) 2020 Fall Conference (November 10, 2020)
- “The National Potential for Load Flexibility,” Rocky Mountain Utility Exchange, Keynote Session (September 30, 2020)
- “Load Flexibility: Yoga for the Power Grid,” SEPA Virtual Grid Evolution Summit (August 12, 2020)
- “The Potential for Load Flexibility,” Washington Utilities and Transportation Commission Workshop on Demand Response Potential and Target Setting (June 8, 2020)
- “The National Potential for Load Flexibility,” 2020 ASHRAE Virtual Conference (June 5, 2020)
- “Electric Vehicle Managed Charging: Considerations for an Emerging Opportunity,” NARUC EV Working Group Meeting (April 28, 2020)
- “The National Potential for Load Flexibility,” panel at NARUC 2020 Winter Policy Summit, Washington, DC (February 20, 2020)
- Participant, “Demand Flexibility and Control,” panel at North America Smart Energy Week, Salt Lake City, Utah (September 24, 2019)
- Participant, “Load Flexibility Potential in US by 2030,” PLMA Dialogue with Rich Barone, (September 5, 2019)
- Participant, “Transportation Electrification: Smart Strategies to Manage New Electric Vehicle Loads,” panel at the SEPA Grid Evolution Summit, Washington, DC (July 29, 2019)
- “The Potential for Load Flexibility in Northern States Power’s Service Territory,” Peak Load Management Alliance (PLMA) 2019 Spring Conference, Minneapolis, MN (May 14, 2019)
- “Incorporating DERs into Resource Planning: Energy Efficiency,” with Sanem Sergici and DL Oates, EPRI Winter 2019 Advisors Meeting, Tucson, Arizona (February 26, 2019)

- "Determining Optimal Storage Deployment Levels: Insights from Nevada," with Roger Lueken, Energy Storage Association Webinar (December 11, 2018)
- "Behind-the-Meter Storage: Stacked Benefits or the Next Death Spiral?" EEI Strategic Issues Roundtable, Pittsburgh, PA (October 12, 2018)
- "The Value of TOU Tariffs in Great Britain," Citizens Advice Public Workshop, London, UK (July 10, 2017)
- "The Hidden Battery," 3rd Annual Ancillary Services and DR Management Forum, Frankfurt, Germany (May 11, 2017)
- "The Hidden Battery," Smart Energy Summit, Brussels, Belgium (April 6, 2017)
- "Distribution System Pricing With Distributed Energy Resources," LBNL Future Electric Utility Regulation Series Webinar (May 31, 2016)
- "The Emergence of Residential Demand Charges," 2016 EEI Rate Analysts Meeting, Baltimore, MD (May 23, 2016)
- "Electricity Pricing for the Consumer of the Future," International Congress of Energy Science and Industry, Energi@21, Poznan, Poland (May 11, 2016)
- "Community Storage Initiative and Hidden Battery Report," PLMA Dialogue with Keith Dennis (March 24, 2016)
- "A Path Forward for Residential Demand Charges," 2015 NASUCA Annual Meeting, Austin, TX (November 10, 2015)
- "The National Landscape of Residential Rate Reform," 2015 SNL Utility Regulation Conference, Washington, DC (December 10, 2015)
- "The Top 10 Questions about Residential Demand Charges," EUCI Residential Demand Charges Symposium, Los Angeles, CA (August 31, 2015)
- "Residential Rate Design: Emerging Issues," EEI WebTalks webinar (August 27, 2015)
- "The Top 10 Questions about Residential Demand Charges," EUCI Residential Demand Charges Symposium, Denver, CO (May 14, 2015)
- "Rolling out Residential Demand Charges," EUCI Residential Demand Charges Symposium Pre-Conference Workshop, Denver, CO (May 13, 2015)
- "Residential Demand Charges: An Emerging Opportunity in Rate Design," EUCI webcast (December 16, 2014)
- "Residential Demand Charges: A Rate Design Revolution?" Center for Research in Regulated Industries 27th Annual Western Conference, Monterey, CA (June 26, 2014)

- “Rediscovering Residential Demand Charges,” 2014 EEI Rate and Regulatory Analysts Meeting, San Francisco, CA (May 20, 2014)
- “The New Direction of Home Energy Management,” 2014 Comverge Utility Conference, New Orleans, LA (May 7, 2014)
- “Surviving Sub-One Percent Growth,” 2014 Institute for Regulatory Policy Studies Conference, Springfield, IL (April 16, 2014)
- Panelist, Wharton Energy Conference, Smart Grid Panel, Philadelphia, PA (November 8, 2013)
- “The Smart Grid and the Future of Demand Response,” presented at Energy Central webinar titled “Integrated Demand Response - How Utilities Leverage Data for Intelligent Decisions” (September 18, 2013)
- “Analytical Frameworks to Incorporate Demand Response in Long-term Resource Planning,” with Andy Satchwell, CRRI Western Conference (June 21, 2013)
- “The Future of Rate Design,” EEI Rate Analysts Meeting, Orlando, Florida (May 21, 2013)
- “Demand Response: Lessons Learned from Across the Border,” presented at the CAMPUT Energy Regulation Course, Kingston, Ontario (August 1, 2012)
- “The Current State of US Demand Response,” presented as moderator at Energy Bar Association Annual Event, Washington, DC (April 26, 2012)
- “Vietnam’s 10-year Smart Grid Roadmap,” presented at World Bank stakeholder workshop in Hanoi (December 8, 2011)
- “Bringing DSM to the Kingdom of Saudi Arabia,” presented at AESP webinar (October 13, 2011)
- “Dynamic Pricing Pilots: Past, Present, and Future,” presented at EEI Rate Analysts Meeting (May 17, 2011)
- “Inclining Block Rates – Are They a Good or Bad Thing?” presented at an EEI webinar (August 5, 2010)
- “Do Customers Respond to Dynamic Pricing?” presented at the Brookings Institution Behavior Insights for Smart Grid Policy Workshop, Washington, DC (July 28, 2010)
- “Innovative Pricing for a Smarter Grid,” presented at TechConnect 2010 (June 24, 2010)
- “The Geography of Demand Response,” presented at the 2010 Southern California Edison Demand Response Forum (June 3, 2010)
- “Fairness and Equity in Dynamic Pricing,” presented at the 2010 EEI Rate Analysts Meeting (May 18, 2010)
- “A National Assessment of Demand Response Potential,” presented at an AESP webinar (October 15, 2009)

- "A National Assessment of Demand Response Potential," presented at the ALCA 2009 Fall Meeting, Los Angeles, CA (October 8, 2009)
- "How Green is the Smart Grid?" presented at an EUCI webinar (July 23, 2009)
- "Sizing up the Smart Grid," presented at the ConnectivityWeek GridWise Expo, San Jose, CA (June 11, 2009)
- "Integrating Dynamic Pricing and Inclining Block Rates," presented at the Stanford Energy & Feedback Workshop, Palo Alto, CA (September 5, 2008)
- "Evaluating Alternative Dynamic Pricing Designs," presented at the CRRI 21st Annual Western Conference, Monterey, CA (June 19, 2008)
- "The Coming Wave of Price-Based Demand Response," presented at the ConnectivityWeek DR Expo, San Jose, CA (May 22, 2008)

PRESS MENTIONS

- "Demand Response: A win-win solution to climate and energy price crises," Joe Lo, *Climate Change News* (October 5, 2022)
- "NextEra's 'game changing' Real Zero emissions goal spurs questions about hydrogen, demand-side management," Herman Trabish, *Utility Dive* (August 3, 2022)
- "The Big Picture on Emerging Technologies: Virtual Power Plants Advance in California," Herman Trabish, *California Current* (February 14, 2022)
- "State of the Electric Utility 2021: Despite sharp drop, cost remains key obstacle to more storage, some say," Kavya Balaraman, *Utility Dive* (April 1, 2021)
- "Solar panels and batteries on your home could help prevent the next grid disaster," Alejandra Borunda, *National Geographic* (February 25, 2021)
- "2021 Outlook: The DER boom continues, driving a 'reimagining' of the distribution system," Herman Trabish, *Utility Dive* (January 12, 2021.)
- "Two barriers to utility and customer savings with flexible loads and how regulators can help," Herman Trabish, *Utility Dive* (January 6, 2021)
- "California Considers Landmark Appliance Rule to Ease Grid Demand," Emily C. Dooley, *Bloomberg Law* (October 23, 2020)
- "Demand Response Failed California 20 Years Ago; the State's Recent Outages may have Redeemed it," Herman Trabish, *Utility Dive* (September 28, 2020)
- "Smart Meters Giving Missouri Customers Incentive to Save Energy During Peaks," Karen Uhlenhuth, *Energy News Network* (September 28, 2020)

- “Tesla Promises Cars that Connect to the Grid, even if Elon Musk Doesn’t Really Want Them to,” Justine Calma, *The Verge* (September 23, 2020)
- “Virtual Power Plants are Coming to California Apartment Buildings,” Justine Calma, *The Verge* (August 27, 2020)
- “Momentum Grows for Piloting Netflix-like Fixed Subscription Rates, but not Everyone's on Board,” Herman Trabish, *Utility Dive* (July 7, 2020)
- “Battery Energy Storage is Getting Cheaper, but How Much Deployment is too Much?” Herman Trabish, *Utility Dive* (June 30, 2020)
- “Tesla's Ex-storage Chief on Trump, Musk and the 'Holy Grail’,” David Iaconangelo, *E&E News* (May 15, 2020)
- “Calif. Inks Largest U.S. Battery Purchase in History,” David Iaconangelo, *E&E News* (May 5, 2020)
- “Biding One’s Utility Time,” Chuck Ross, *Electrical Contractor Magazine* (March 2020)
- “Want Cheaper Electricity? Xcel Energy Wants to Help – if You’re Willing to do Your Laundry at 2 a.m.,” Mark Jaffe, *Colorado Sun* (February 20, 2020)
- “Time-of-Use Electricity Rates May Hit Vulnerable Groups Harder, Study Finds,” Maria Gallucci, *IEEE Spectrum* (December 16, 2019)
- “EV-specific rates are the gateway to direct load management, SEPA report finds,” Robert Walton, *Utility Dive* (November 14, 2019)
- “A Utah Housing Development is Just the Start of Sonnen’s US Solar Ambitions,” Wolfgang Kerler, *The Verge* (August 28, 2019)
- “Renewables' Variability Sends Wary Utilities from Traditional DR to DER and Load Flexibility,” Herman K. Trabish, *Utility Dive* (August 14, 2019)
- “Using Electricity at Different Times of Day Could Save Us Millions of Dollars,” David Roberts, *Vox* (August 7, 2019)
- “Rise of Net Zero Energy Homes Could Boost Utility-Led Community Solar,” Herman K. Trabish, *Utility Dive* (July 19, 2018)
- “Stacking Energy Storage Values to Make Batteries More Profitable: Brattle Report,” *MicroGrid Knowledge*, September 18, 2017)
- “Brattle: Regulatory Barriers Prevent Stacking of Battery Benefits,” Peter Maloney, *Utility Dive* (September 13, 2017)
- “Batteries Hold Value in Various Applications: Study,” *MW Daily* (September 12, 2017)
- “Utilities in hot water: Realizing the benefits of grid-integrated water heaters,” Herman K. Trabish, *Utility Dive* (June 20, 2017)

- "ComEd jumps on the demand charge train with new Illinois proposal," Peter Maloney, *Utility Dive* (May 9, 2016)
- "Your home water heater may soon double as a battery," Chris Mooney, *The Washington Post* (February 24, 2016)
- "Move over, fixed fees—utilities see demand charges as revenue cure," Kari Lydersen, *Midwest Energy News* (December 2, 2015)
- "Using Telecom Tech, eCurv Looks to Lower Energy Bills, Raise Money," Thomas Miller, *Xconomy* (May 4, 2015)
- "Questions swirl around possible rates under a Boulder utility," Erica Meltzer, *Daily Camera* (January 31, 2015)
- "After SONGS: Forecasting the fate of demand response in California," Lisa Weinzimer, *Utility Dive* (March 21, 2014)
- "A National 'Smart Grid' Remains a Vision with Many Gaps," Peter Behr, *The New York Times* (October 22, 2009)

Sanem Sergici

PRINCIPAL

Boston, MA +1.617.864.7900 Sanem.Sergici@brattle.com

Dr. Sanem Sergici is a Principal in The Brattle Group's Boston, MA office specializing in innovative retail rate design and economic analysis of distributed energy resources (DERs). She regularly assists her clients in matters related to electrification, grid modernization investments, emerging utility business models and alternative ratemaking mechanisms.

Dr. Sergici has been at the forefront of the design and impact analysis of innovative retail pricing, enabling technology, and behavior-based energy efficiency pilots and programs across North America. She led numerous studies in these areas that were instrumental in regulatory approvals of grid modernization investments and smart rate offerings for electricity customers. She also has significant expertise in resource planning, development of load forecasting models and energy litigation.

Dr. Sergici regularly publishes in academic and industry journals and presents at industry events. She was recently featured in Public Utility Fortnightly Magazine's "Fortnightly Under 40 2019" list. She received her PhD in Applied Economics from Northeastern University in the fields of applied econometrics and industrial organization. She received her MA in Economics from Northeastern University, and BS in Economics from Middle East Technical University (METU), Ankara, Turkey.

AREAS OF EXPERTISE

- Innovative Retail Electricity Pricing
- Grid Modernization
- Electrification
- Distributed Energy Resources
- Resource Planning

EXPERT TESTIMONY AND REGULATORY FILINGS

Filed testimony before the Washington Utilities and Transportation Commission in the Matter of Puget Sound Energy General Rate Case. Docket UE-220066 and Docket-UG220067, January 31, 2022.

Testimony before the State of New Hampshire Public Utilities Commission, Docket No. DE 21-078, In the matter of Electric Make Ready and Demand Charge Alternative Proposals, on behalf of the New Hampshire Department of Energy, February 28, 2022.

Testimony before the State of New Hampshire Public Utilities Commission, Docket No. DE 20-170, In the matter of Electric Distribution Utilities Electric Vehicle Time of Use Rates, on behalf of the New Hampshire Department of Energy, October 13, 2021.

Report filed before the Public Service Commission of the District of Columbia, “An Assessment of Electrification Impacts on the Pepco DC System,” on behalf of Pepco in Formal Case No. 1167, August 27, 2021 (with R. Hledik, M. Hagerty, and J. Olszewski)

Testimony before the Nova Scotia Utility and Review Board in the Matter of The Public Utilities Act, R. S. N. S. 1989, c380, as amended and Application by Nova Scotia Power Incorporated for Approval of Time-Varying Pricing Tariff Application - M09777, May 17, 2021.

Filed rebuttal evidence before the Nova Scotia Utility and Review Board in the Matter of The Public Utilities Act, R. S. N. S. 1989, c380, as amended and Time-Varying Pricing Tariff Application - M09777, April 22, 2021.

Filed direct evidence before the Nova Scotia Utility and Review Board in the Matter of The Public Utilities Act, R. S. N. S. 1989, c380, as amended and Time-Varying Pricing Tariff Application - M09777, November 30, 2020.

Testimony before the State of New Hampshire Public Utilities Commission, Docket No. DE 19-057, Distribution Service Rate Case, on behalf of the Staff of the New Hampshire Public Utility Commission on rate design studies, December 20, 2019.

Testimony before the State of New Hampshire Public Utilities Commission, Docket No. DE 19-064, Distribution Service Rate Case, on behalf of the Staff of the New Hampshire Public Utility Commission on rate design studies, December 6, 2019.

SELECTED CONSULTING EXPERIENCE

Utility Regulatory and Business Models

- Assisted the New York Department of Public Service to develop a comprehensive financial model of a representative (downstate) New York utility capable of demonstrating the impacts of REV initiatives upon utility financial performance. Our modeling effort included developing plausible incentive regulation frameworks, new incentive mechanisms, and potential platform frameworks, services and futures.
- Development of Performance Incentive Metrics for the Joint Utilities of New York. The Brattle Group worked with the New York PSC Staff and, subsequently, with the State's six investor owned electric utilities (Joint Utilities) in analyzing the feasibility and impacts associated with proposed earnings sharing mechanisms (EAMs), primarily the EAMs associated with load factor and system efficiency.
- Assisted a North American Utility with development of a short-term and long-term regulatory strategy to enable their 2030 Vision. Brattle team interviewed the executive team; identified consensus views and disagreements on alternative business models and regulatory models. Developed straw proposals for two potential regulatory models one focused on enabling shorter-term outcomes, and the other focused on enabling Company's longer-term vision.
- Assisted Pepco D.C. as they develop a multi-year rate plan and various traditional and emerging performance incentive metrics to be filed in their upcoming rate case. Brattle team developed and facilitated workshops to introduce Pepco's MYRP proposal to the stakeholders and assisted Pepco with incorporating stakeholder input to the final proposal.
- Assisted a Canadian Utility with a critical assessment of their custom incentive ratemaking model and discussed how it compares with other forms of PBR. We presented a jurisdictional scan of the PBR implementations across North America and Europe, and assessed pros and cons of each approach. We also advised them on currently proposed "Distributed Utility Models" and assess pros and cons of each model; reviewed "Alternative Regulatory Models" that were developed to ensure that utilities can coexist with the DERs and continue to maintain healthy balance sheets.
- For a Canadian electric utility, reviewed and summarized alternative regulatory frameworks and incentive models that would support a sustainable energy efficiency business. Investigated the pros and cons of these models, identified the implications of each model for the utility, and

made a recommendation based on our findings. Utility will discuss the recommended approach with the regulator and seek an approval.

- For a large Canadian electric utility, assisted with the development of an alternative proposal to their current performance based regulation (PBR) framework. Examined and benchmarked several examples of performance based regulation schemes in place for other utilities, and advised on an enhanced PBR mechanism.

Innovative Rate Design and Impact Evaluation Studies

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

- Heat Pump Operating Cost Gap Analysis. For a gas and electric distribution utility in New York, Brattle analyzed the operating cost gap between heat pumps and gas heating and evaluated various available electric rate design options to reduce heat pump operating costs. The study included estimation of the electric load impacts of electrification of a small sample of the utility's residential customers based on their historical gas usage, followed by calculation of their hypothetical future electricity bills under various rate structures. The utility is using insights from this study to appropriately size heat pump incentives and to mitigate the heat pump affordability barrier by marketing a beneficial rate structure to customers.
- Technical Advisor to OEB on the New RPP Pilots. A Brattle team led by Dr. Sergici has developed a Technical Manual to guide the design and impact evaluation of new RPP pilots. Dr. Sergici has been closely working with the OEB RPP team as they oversee the implementation of these pilots in accordance with the guidelines
- Undertook impact Evaluation of Ontario's Time-of-Use Rates on Behalf of Ontario Power Authority. A Brattle team led by Dr. Sergici provided an impact evaluation of Ontario's province-wide roll-out of Time-of-Use (TOU) rates for its residential and general service customers on behalf of Ontario Power Authority. Brattle acquired hourly load data from the IESO and the LDCs, aggregated it for the pricing periods that correspond to the TOU rate, reinterpreted the full-scale deployment as a natural experiment, and analyzed it using econometric methods for three consecutive years.
- Undertook a retail rate benchmarking study for a large southwestern utility. Our team, led by Dr. Sergici, reviewed utility resource plans to estimate each utility's retail rate trajectory. We compared the utilities across a variety of rate drivers, such as reserve margin, fuel mix, load growth, load factor, renewables investment requirements, and demand-side activities, and provided strategic recommendations for addressing these drivers of future rate growth.
- Undertook an extensive review of the rate designs and methodologies used by other jurisdictions/countries for a large Canadian Utility. We reviewed the rates that are currently offered by a large Canadian utility and compared them with best industry practices from around the globe. As a result of our analysis, we identify some near term and long term alternative rate design options for our client, which can help them to manage revenue risks and volatility due to the effects of disruptive threats, and at the same time to increase innovation and affordability in the rate options presented to the customers.
- Assisted Pepco Holdings, Inc. to evaluate the effectiveness of the AMI-enabled energy managements tools (EMTs) in reducing per capita energy use. Led a team of four researchers to compile and process data for four of the PHI jurisdictions; identify relevant control groups and

methodology for impact evaluation and undertake an econometric analysis to quantify the EMT impact.

- Assisted an industry-leading provider of integrated demand response, energy efficiency, and customer engagement solutions in the design of and M&V plan for a behavioral demand response program. The plan included a detailed section on sampling selection for statistically valid and detectable program impact results.
- Prepared a comprehensive blueprint document for measuring the impacts of Baltimore Gas and Electric Company's Smart Grid Customer Programs. BGE has started deploying smart meters to all of its residential customers in Spring of 2012 and is scheduled to complete the deployment over a three-year period. BGE developed a full-scale program, "Smart Energy Manager (SEM)" program, to meet a central objective of the Smart Grid Initiative - customer education and engagement in a Smart Grid environment. The blueprint documented the design elements of the SEM program and introducing the approaches that will be used to measure the impacts of different SEM tools once the program is in the field and sufficient data are collected.
- Measurement and evaluation for in-home displays, home energy controllers, smart appliances and alternative rates for FPL. Carried out a 2-year impact evaluation of a dynamic and enabling technology pilot program. Used econometric methods to estimate the changes in load shapes, changes in peak demand, and changes in energy consumption for three different treatments. The results of this study were shared with Department of Energy as to fulfill the data reporting requirements of FPL's Smart Grid Investment Grant.
- Pricing and technology pilot design and interim impact evaluation for Commonwealth Edison Company (ComEd). Assisted ComEd in the design of an ambitious pilot program that included approximately 25 different treatment cells. The pilot, which is the first "opt-out" pilot program of its kind, involved 8,000 customers and tested the impact of dynamic prices with and without customer education, informational feedback through basic and advanced feedback devices, and other enabling technologies in the summer of 2010. Conducted an interim impact evaluation study preceding the formal impact evaluation of the study, which is planned to be completed by the end of 2011.
- Pricing and technology pilot design and impact evaluation for Consumers Energy. Designed Consumers Energy's pricing and technology pilot and conducted the impact evaluation study after the pilot was completed in September 2010. The pilot tested critical peak pricing (CPP) and peak time rebates (PTR) in conjunction with information treatment and technology. The pilot also tested the potential "Hawthorne bias" for a group of control group customers who were aware of their involvement in the pilot.

- Member of a Technical Advisory Group (TAG), which was formed by Department of Energy (DOE) and Lawrence Berkeley National Laboratory (LBNL). Reviewed and provided feedback on the experimental designs of the utilities that were awarded Smart Grid Investment Grant projects and participated in periodic project review meetings with utilities to review and provide feedback on the interim results as they implement their projects. As part of this assignment, authored a guidance document that discussed different impact evaluation methods, which can be selected by the utilities. This document was shared with the utilities and other TAG members.
- For an Independent System Operator (ISO), designed, managed and analyzed a market research to help improve participation in retail electricity products that encourage price-responsive demand (PRD). The research determined customer preferences for various time-based pricing products that would help define PRD products that may be developed in the ISO for each customer class. ISO will use the results of this research to assist in modifying wholesale market design to better support such PRD products.
- Assisted a client in conceptually developing a new product that would increase customer participation and performance in energy efficiency (EE) and demand response (DR) programs. Developed Total Resource Cost (TRC) tests for a few targeted EE and DR programs, and modeled the benefits and costs with and without the client's new product offering
- Co-authored a whitepaper reviewing the results from five recent pilot and full-scale programs that investigated low-income customer price-responsiveness to dynamic prices. The core finding of the whitepaper is that low income customers are responsive to dynamic rates and that many such customers can benefit even without shifting load.
- For a large California utility, conducted an econometric analysis, which investigated the role of weather conditions, smart meter installations, and electricity rate increases, among other control variables, in explaining the changes in the monthly usages and bills of a group of complaining customers. Estimated pooled regressions using a panel dataset, as well as individual customer regressions for more than 1,000 customers.
- Assisted an Illinois electric utility in the assessment of alternative baseline calculation for implementing peak time rebate (PTR) programs. Under a PTR program, participants receive a cash rebate for each kWh of load that they reduce below their baseline usage during the event hours. This requires establishment of a baseline load from which the reductions can be computed. The analysis involved simulating baselines for more than 2,000 customers using five alternative methodologies for several event days. Identified and recommended the baseline calculation methodology that yielded the most accurate baseline for individual customers, through the use of MAPE and RMSE statistics.

- Evaluated the Plan-It Wise Energy program (PWEP) of Connecticut Light and Power (CL&P) Company. PWEP tested the impacts of critical peak pricing (CPP), peak time rebates (PTR), and time of use (TOU) rates on the consumption behaviors of residential and small commercial customers. Each rate design was tested with high and low price variation as well as with and without enabling technologies. Conducted an econometric analysis to determine weather dependent substitution and daily price elasticities and subsequently quantified demand and energy impacts for each of the treatments tested in the PWEP. Developed optimal rate designs to be adopted in a full deployment scenario.
- For Baltimore Gas and Electric Company, assisted in the preparation of direct and rebuttal expert testimonies before the Maryland Public Service Commission, that explain the design and results of 2008 and 2009 Smart Energy Pricing (SEP) pilots.
- Evaluated the Smart Energy Pricing (SEP) pilot program of Baltimore Gas and Electric Company for three consecutive years. The pilot was designed to quantify the impacts of critical peak pricing (CPP) and peak time rebates (PTR) on residential customer consumption patterns. Conducted an econometric analysis to estimate demand systems and predict substitution and daily price elasticities for participating customers. Using the parameters of the demand equations, quantified demand, energy, and bill impacts associated with the programs. Impacts of the socio-demographic characteristics of the participants as well as their ownership of enabling technologies were separately identified on the demand response of the program participants.
- Co-authored a business practice manual for forecasting price responsive demand (PRD) in Midwest ISO. The draft manual introduces different methodologies for measuring and incorporating PRD into forecast LSE requirement for LSEs that are at different stages of rolling-out their out their dynamic pricing programs. The draft manual also proposes methodologies for the verification of the forecasted demand net of PRD for long term planning purposes.
- Assisted in the development of an affidavit that evaluates the implications of PJM's proposed revisions to the Operating Agreement (OA) on barriers to participation in PJM's Economic and Emergency Load Response programs.
- Co-authored a whitepaper on "Moving Toward Utility-Scale Deployment of Dynamic Pricing in Mass Markets" for Institute for Electric Efficiency. Whitepaper is intended to help facilitate nationwide progress toward the deployment of dynamic pricing of electricity by summarizing information that may assist utilities and regulators who are assessing the business case for advanced metering infrastructure (AMI).
- Assisted a New York utility in benchmarking their existing Demand Response (DR) portfolio to the best practice in U.S. and recommended improvements in their planned DR portfolio. Also

assisted the utility in quantifying costs and benefits of pilot programs proposed in their DR filing before the State of New York Public Service Commission.

- Assisted an electric utility in developing a residential pricing pilot program that tests inclining-block rate (IBR) structure. More specifically, designed several revenue neutral IBR alternatives and quantified load reduction and bill impacts from these IBR rates.
- Assisted an electric utility in their dynamic rate design efforts. Conducted impact analyses of converting from a flat rate design to alternative dynamic rate designs for each of the five major customer rate classes of the utility. Developed models that allow simulation of energy, demand, and bill impacts by season, day type and time period for an average customer from each of customer classes.
- Simulated the potential demand response of an Illinois utility's residential customers enrolled in real time prices. Results of this simulation were used in recent Midwest ISO Supply Adequacy Working Group (SAWG) meeting to facilitate conversation about price responsive demand in the region. Simulations were run for different scenarios including historic versus spiky real-time prices; peak versus uniform allocation of capacity charges; and with and without enabling technologies.
- Designed a survey on Long-run Drivers of U.S. Energy Efficiency and Demand Response Potential on behalf of EPRI and EEI. Conducted statistical analyses to examine the survey responses, which were turned in by more than 300 power industry leaders and academic experts. Using the outcomes from this survey, assisted in the development of future scenarios to model energy efficiency and demand response impact through 2030.
- Assisted in the preparation of an EEI report that quantifies the benefits to consumers and utilities of dynamic pricing. Undertook a comprehensive review of the dynamic pricing programs across the U.S. and elsewhere. Also implemented price response simulations to quantify the likely peak demand reductions that would realize under alternative dynamic pricing schemes.

Distributed Energy Resources and Grid Modernization

- Development of an Econometric Based EV Forecast for Baltimore Gas and Electric Company. The Brattle Team has compiled a comprehensive repository of national EV adoption related data and estimated an econometric model to explain the drivers of US EV sales, using data from 50 states, from 2011-2019. BGE had expressed a strong preference for a model that relates drivers of EV adoption to sales and did not want to use top down forecasts or a diffusion models due to their inflexibility to update assumptions. With the econometric model, it was possible to develop various forecasts depending on federal, state and utility incentives; different battery cost trajectories; alternative EV TOU rates; utility owned charging infrastructure among many other drivers. This econometric model was also supplemented by another system-dynamics based module that captured the supply side drivers of EV sales such as increasing model availability, charging infrastructure and improved R&D activities. Brattle team developed alternative EV sales scenarios for BGE's service territory and analyzed the impacts of EV load (under managed and unmanaged scenarios) on utility ratemaking, infrastructure investments and other financial metrics.

- For a U.S. utility, reviewed the utility's benefit cost assessment model used to evaluate distributed energy resources for alignment with commission orders and staff guidance. The assessment identified areas for refinement, including increasing the temporal and geographic granularity of the model. As part of the review, the Brattle team provided insights into potential misalignments between the valuation of transmission and distribution investment deferral within the model, customer value, and system value. The Brattle team rebuilt the model from the ground-up to allow for intuitive use and ensure that assumptions are clearly articulated and well-documented.
- For PGE, led the Brattle team developing EV potential as part of PGE's 2021 DER potential study. Developed light, medium and heavy duty vehicle forecasts through 2040, and quantified the peak, energy and EV charging infrastructure implications of these EV forecasts.
- For Pepco DC, conducted analysis to forecast how the utility's load would increase if aggressive decarbonization goals are met through electrification, and to determine the extent to which energy efficiency and load flexibility measures could mitigate that load growth, highlighting the key role that load flexibility will play in facilitating the decarbonization transition.
- For SRP, developed an updated EV adoption forecast for their territory to inform the potential scale of the managed charging program, analyzed the system-level benefits of managed EV charging to inform the level of customer incentives, including energy and capacity cost savings, and reviewed the design of their pilot study
- For a DER software developer, estimated the potential market value of residential load flexibility offerings across five utilities. The analysis highlighted that the load flexibility value proposition varies significantly depending on system and market conditions. The final report is a key input to the company's load flexibility business case.
- For a large east-coast utility, reviewed benefit cost framework and model data to evaluate non-pipe options. The review included treatment of geographic differences in marginal costs due to pipeline access, and the Brattle team rebuilt the model from the ground-up to allow for intuitive use.
- System Dynamics Modeling of DER Adoption and Utility Business Impacts. Led the development of Brattle's Corporate Risk Integrated Strategy Platform (CRISP) model and assisted utility clients

with the implementation of this model. CRISP is based on System Dynamics approach, which creates simulations based on dynamic feedbacks between utility policies and customer behavior, providing a new perspective on how much and how fast the "utility of the future" must evolve. The focus of these modeling efforts was to help utilities anticipate and accommodate distributed energy resources (DERs) as they become more economical and more widely adapted by retail electricity customers, and to evaluate the sustainability of their traditional cost-of-service business model in the face of such trends.

- For EPRI, conducted a study to explore methods for incorporating DERs into integrated resource planning. A unique feature of this study was the use of Brattle's capacity expansion model, GridSIM, to quantitatively illustrate the implications of various DER modeling techniques. In the first phases of the engagement, we assessed the implications of different approaches to modeling energy efficiency (EE) and demand response (DR), such as the advantages and disadvantages of modeling these resources on the "supply side" versus the "demand side" of the model. The current phase of the project focuses on electric vehicles (EVs) and rooftop solar, and includes a review of techniques for forecasting adoption of these technologies, as well as modeling the resource impacts of growth in EV adoption.
- Estimated NEM cross-subsidies using data from sixteen utilities. Used cost-of-service methodology to compare NEM customers costs on the system vs. revenue collection from these customers using company COS studies, and supplementing it by publicly available data on solar PV production profiles, installed DG capacity by utility and system load profiles.
- Wrote a comprehensive report for National Electrical Manufacturer's Association (NEMA) that reviews most recently approved 10 major grid modernization projects. Report discusses business cases and cost recovery mechanisms for each of these projects and documents how grid modernization technologies have benefitted customers and utilities.
- Analyzed the impacts of electric utility infrastructure investment on system reliability and resiliency for a Northeastern Utility, following major weather events. Primary area of analysis involved estimation of economic value of investments to customers using value of lost load (VOLL) metrics for electric system investments.
- Assisted Pepco Holdings, Inc. to analyze the Phase I of its Conservation Voltage Reduction (CVR) program in its Maryland Service Territory. First of its kind, this econometric study compares consumption of the treatment and control groups before and after the implementation of CVR. More specifically, a regression analysis was conducted to compare the usage levels of treatment and control group customers to determine whether the CVR treatment resulted in statistically significant conservation and peak demand impacts. The analysis accounts for exogenous factors

such as weather, calendar and seasonality impacts as well as utility energy and demand savings programs.

Decarbonization Policy and Resource Planning

- For New Jersey Board of Public Utilities, conducted a comprehensive electric and gas consumer total energy cost impact study to assess the energy burden for customers across several customer classes across all major gas and electric utilities in the state. Estimated the impacts of clean energy policies on different customer segments (e.g. customers adopting electric vehicles vs. customers with a gasoline car). Study identified equity implications, including impacts on low-income consumers and consumers with delayed electrification relative to others. The study can be accessed here.
- For Oracle Utilities, estimated the reduction in greenhouse gas (GHG) emissions that could occur by 2030 and 2050 if customer adoption of GHG-reducing technologies, including energy efficiency, rooftop solar, electric vehicles, and electric heat pumps, rises to an aggressive and achievable level.
- For a large Canadian utility, serving as an advisor on the utility's load flexibility assumptions in its integrated resource plan
- Evaluated how policy reforms could increase access and decrease costs of C&I renewable procurement for the REBA Institute, a group representing commercial and industrial (C&I) customers in the United States, through utility subscription programs, power purchase agreements, and third-party retailer providers. The report finds that there is much potential to increase C&I procurement and costs, but the policy pathway to enable these results is dependent on state characteristics. The report finds that introducing supply choice has the greatest potential to increase access but presents uncertainty regarding costs, and that utility subscription programs can present significant near-term opportunities.
- Currently assisting New York City's Mayor's Office of Sustainability to evaluate how a carbon trading scheme would impact the costs and benefits of implementing Local Law 97, an ambitious building-sector decarbonization law that mandates 80% emission reductions by 2050. In collaboration with larger consulting team, Brattle team is evaluating building segment data regarding the size and energy use of buildings covered by LL97, reviewing and modeling efficiency and electrification emission abatement retrofits, modeling building owner decision making to comply with the law, and is designing carbon trading policy to ensure the program meets the needs of the city government, environmental justice community, and ultimately lowers societal costs.
- Led the Brattle team that assisted the New York City Mayor's Office of Sustainability with the development of New York City's Roadmap to 80 x 50. The Brattle team analyzed the change in energy-sector greenhouse gas (GHG) emissions resulting from more than six future scenarios.

These scenarios explored the impacts of aggressive energy efficiency efforts, off-shore wind, and the continuance of low natural gas prices on the emissions footprint of New York City. The analysis shows that in order to reach 80 x 50, New York City will need to achieve a significant portion of its GHG reductions as a result of a dramatic shift towards a renewables-based grid. This shift towards renewables must overcome the anticipated retirement of nuclear facilities prior to 2050 and will be supported by the implementation of New York State's Clean Energy Standard and the declining cost of renewable energy.

- Conducted a study involving "solar to solar" comparison of equal amounts of residential- and utility-scale PV solar deployed in Xcel Energy Colorado's Service Area. Calculated costs and benefits of each of these two different but equally sized solar options, i.e., avoided energy, capacity and distribution network costs and others. The study found carbon reductions were greater on utility scale systems because the solar energy per MW is much higher on utility-scale due to better placement and tracking capability.
- Advised Nova Scotia Power Inc. on the reasonableness of the DSM scenarios and strategies that are being modeled in their Integrated Resource Plan (IRP). This effort also involved advising the Company on a variety of DSM issues and building up a model that quantifies the rate impacts for program participants and non-participants based on the selected DSM scenario.
- Coauthored the State's Annual Integrated Resource Plan (IRP) for the Connecticut Department of Energy and Environmental Protection (DEEP). This effort involved development of scenarios and strategies for an electric system to meet long-range electric demand while considering the growth of renewable energy, energy efficiency, other demand-side resources. Led the development of demand side management and emerging technology resource strategies and analyses involving these resources.
- Developed a model to assess the prudence of an electric utility's power procurement strategy in comparison to several other alternative options. As a result of this model, she assessed whether it is prudent to recover the congestion and loss costs associated with utility's chosen strategy from ratepayers in a state regulatory proceeding.
- Assisted in preparation of a marginal cost study for an integrated electric utility. The study estimated the incremental costs to the utility of serving additional demand and customer by time period, sub-region, and customer class. The costs were identified as energy, capacity and customer related for generation, transmission, and distribution systems of the utility.
- Assisted in developing an integrated resource plan for major electric utilities. Contributed to the design of future scenarios against which the resource solutions were evaluated. Designed scenarios were driven by external factors including fuel prices, load growth, generation

technology capital costs, and changes in environmental regulations. Forecasted the inputs series for the resource planning model consistent with each of the designed scenarios.

Demand Forecasting

- For an Asian utility considering an investment on a generation plant in PJM, we have reviewed, replicated, and developed alternative load forecasts using PJM's 2017 update. We have determined several uncertainty factors that are not fully captured in PJM's forecasting framework and developed "low load" and "high load" scenarios after accounting for these factors.
- For an electric utility in the Southeast, reviewed load forecasting models for residential and commercial customer classes. Assessed the accuracy and validity of the models by reviewing the historic and forecast period inputs to the model; model specification; in-sample and out-of-sample accuracy statistics; and incorporation of DSM impacts to the model, among many others. Also conducted an analysis using the U.S. Energy Information Administration's Annual Energy Outlook (AEO) data to determine the forecast errors during pre and post-recession periods.
- Developed a blueprint for integrating energy efficiency program impacts into the load forecasts for a Canadian Utility. This effort involved estimating the future impact of energy efficiency programs to be included in the load forecasts and developing price elasticity estimates that can be used to forecast the impact of the future changes in the price of electricity.
- Developed a load forecasting model for the pumping load of California State Water Project. Identified the main drivers of pumping load in major pumping stations. Through Monte Carlo simulations, quantified the uncertainty around load forecasts.
- Assisted in the preparation of testimony that evaluates the reasonableness of Florida Power and Light Co.'s total customer and monthly net energy for load (NEL) forecasting models. In addition to evaluating the methodology, also reviewed the reasonableness of the inputs used in the historic and forecast periods and assessed the soundness of ex-post adjustments made to the forecasts.
- Assisted PJM in the evaluation of its models for forecasting peak demand and re-estimated new models to validate recommendations. Predicted forecasting errors of the existing models and helped improving the forecast methodology by introducing the state-of-the art estimation techniques. Individual models were developed for 18 transmission zones as well as a model for the entire PJM system.
- Assisted a large utility in New York in understanding the decline in electric sales during the recent past and attributed the decline to a change in customer expectations of future income,

based on declining consumer confidence that has been created by the lingering economic recession.

- Reviewed the structure of the Tennessee Valley Authority's energy sales forecasting models by sector, assessed the magnitudes of the price elasticities and the model specifications used to generate them, analyzed the ability of the models to generate a baseline forecast that could serve as a point of reference when evaluating the likely impacts and cost-effectiveness of a wide range of new energy efficiency and demand response programs.
- Developed a demand forecast model for one of the world's largest steam system operators. Estimated regression models to predict the price elasticities and switching behavior of different consumer classes. Also helped in the development of a model to forecast the impact of alternative steam tariffs on the consumption and switching patterns of consumers.

Energy Litigation and Market Power Analysis

- For the California Parties, provided Brattle witness with litigation support and testimony regarding manipulation of electric power and natural gas prices in the western U.S. during 2000-01. The proceeding, before the Federal Energy Regulatory Commission involved Enron, Dynegy, Mirant, Reliant, Williams, Powerex and many other suppliers in the U.S. and Canada.
- Part of a Brattle team that analyzed the impacts of a merger, involving FirstEnergy and West Penn Power, on competition in retail electricity markets on behalf of Brattle testifying expert Mr. Frank Graves. Both companies owned electric distribution companies, transmission assets, generation resources, and retail electricity providers in several Mid-Atlantic States. The analysis involved assessment of whether the increased market share in wholesale energy markets affects retail competition, the number of suppliers in retail electricity markets, the ease of entry and exit to provide electricity to retail customers directly or through default service procurements, and the potential for abusing affiliate relationships with the electric distribution company to favor the retail electricity provider affiliate.
- Assisted in preparing affidavit before the Federal Energy Regulatory Commission examining whether the proposed acquisition of a power plant by an electric utility would lead to anti-competitive effects on wholesale market competition. In addition to performing market power tests required by FERC, directed an analysis that investigates the historical electric trading patterns between the acquiring utility and the other parties in the relevant geographical market. FERC agreed with the conclusion of the affidavit and authorized the transaction.
- Assisted in the development of testimony before the Postal Rate Commission involving calculation of mail processing variabilities and data quality issues. Addressed the endogeneity problems in the estimation of the variabilities using the instrumental variables approach.

TECHNICAL AND EXPERT REPORTS

- *PC44 Time of Use Pilots: Year One Evaluation*, with Ahmad Faruqui, Nicholas E. Powers, Sai Shetty, and Jingchen Jiang, prepared for Maryland Joint Utilities (September 15, 2020)
- *Nova Scotia Utility and Review Board: Time-Varying Pricing Project Submission*, with Ahmad Faruqui, prepared for the Nova Scotia Power (June 30, 2020)
- *Getting to 20 Million EVs by 2030: Opportunities for the Electricity Industry in Preparing for an EV Future*, with Michael Hagerty and Long Lam, published by The Brattle Group, Inc. (June 2020)
- *Renewable Energy Policy Pathways*, with Judy Chang, Kasparas Spokas, Maria Castaner, and Peter Jones, prepared in collaboration with the REBA Institute (May 2020)
- *Gross Avoidable Cost Rates for Existing Generation and Net Cost of New Entry for New Energy Efficiency*, with Samuel A. Newell, Michael Hagerty, Evan Cohen, Sang H. Gang, John Wroble, and Patrick S. Daou, prepared for PJM (March 17, 2020)
- *Energy Efficiency Administrator Models: Relative Strengths and Impact on Energy Efficiency Program Success,* with Nicole Irwin, prepared for Uplight (November 2019)
- *Incorporating Distributed Energy Resources into Resource Planning: Energy Efficiency*, with Ryan Hledik, D.L. Oates, Tony Lee, and Jill Moraski, prepared for EPRI (May 2019)
- *Status of DSM Cost Recovery and Incentive Mechanisms,* with Ahmad Faruqui, Elaine Cunha, and John Higham, prepared for Baltimore Gas & Electric (February 20, 2019)
- *Exploring the Use of Alternative Regulatory Mechanisms to Establish New Base Rates: Response to PC51 Request for Comments*, W. Zarakas, S. Sergici, P. Donohoo-Vallett, and N. Irwin, prepared for Joint Utilities of Maryland and filed in support of comments in PC51 for the Maryland Public Utilities Commission (March 29, 2019)
- *U.S. Alternative Regulatory Mechanisms: Scope, Status and Future,* with William Zarakas and Pearl Donohoo-Vallett, prepared for Baltimore Gas & Electric, Delmarva Power & Light and Pepco (February 19, 2019)
- *A Review of Pay for Performance (P4P) Programs and M&V 2.0*, with Heidi Bishop and Ahmad Faruqui, prepared for Commonwealth Edison (July 20, 2018)
- *Reviewing the Business Case and Cost Recovery for Grid Modernization Investments,* with Michelle Li and Rebecca Carroll, prepared for National Electrical Manufacturers Association (NEM) (2018)
- *Pepco Maryland In-Home Display Pilot Analysis*, with Ahmad Faruqui, prepared for Pepco (June 2017)

- *80x50 Energy Sector Model Assumptions and Results,* with Michael Kline and Pearl Donohoo-Vallett, prepared for the Mayor's Office of Sustainability (January 4, 2017)
- *Impact Evaluation of Pepco District of Columbia's Portfolio of Energy Management Tools,* with Ahmad Faruqui and Kevin Arritt, prepared for Pepco District of Columbia (October 2016)
- *Impact Evaluation of Delmarva Maryland's Portfolio of Energy Management Tools,* with Ahmad Faruqui and Kevin Arritt, prepared for Delmarva Maryland (April 2016)
- *Impact Evaluation of Pepco Maryland's Portfolio of Energy Management Tools,* with Ahmad Faruqui and Kevin Arritt, prepared for Pepco Maryland (January 2016)
- *Impact Evaluation of Pepco Maryland's Phase I Conservation Voltage Reduction (CVR) Program,* with Ahmad Faruqui and Kevin Arritt, prepared for Pepco Maryland (July 2015)
- *Analysis of Ontario's Full Scale Roll-out of TOU Rates – Final Study,* with Neil Lessem, Ahmad Faruqui, Dean Mountain, Frank Denton, Byron Spencer, and Chris King, prepared for Independent Electric System Operator (February 2016)
  http://www.ieso.ca/Documents/reports/Final-Analysis-of- Ontarios-Full-Scale-Roll-Out-of-TOU-Rates.pdf
- *Comparative Generation Costs of Utility-Scale and Residential Scale PV in Xcel Energy Colorado's Service Area,* with Bruce Tsuchida, Bob Mudge, Will Gorman, Peter Fox-Penner and Jens Schoene (EnernNex), prepared for First Solar (July 2015)
- *Quantifying the Amount and Economic Impacts of Missing Energy Efficiency in PJM's Load Forecast,* with Ahmad Faruqui and Kathleen Spees, prepared for The Sustainable FERC Project (September 2014)
- *Assessment of Load Factor as a System Efficiency Earning Adjustment Mechanism*, with William Zarakas, Kevin Arritt, and David Kwok, prepared for The Joint Utilities of New York (February 2017)
- *Expert Declaration in a Patent Dispute Case involving a Demand Response Product* (July 2014)
- *Measurement and Verification Principles for Behavior-Based Efficiency Programs,* with Ahmad Faruqui, prepared for Opower (May 2011)
  http://opower.com/uploads/library/file/10/brattle_mv_principles.pdf
- *Moving Toward Utility-Scale Deployment of Dynamic Pricing in Mass Markets,* with Ahmad Faruqui and Lisa Wood, IEE Whitepaper (June 2009)
- *The Impact of Dynamic Pricing on Low Income Customers,* with Ahmad Faruqui and Jennifer Palmer, IEE Whitepaper (June 2010)

ARTICLES & PUBLICATIONS

- "Bridging the Chasm between Pilots and Full-Scale Deployment of Time-of-Use Rates," *The Electricity Journal*, Volume 33, Issue 10 (December 2020)
- "Top Performing States in Energy Efficiency: Top States' Secret Sauce," *Public Utilities Fortnightly* (March 2020)
- "Quantifying Net Energy Metering Subsidies," with Yingxia Yang, Maria Castaner, and Ahmad Faruqui, *The Electricity Journal*, Volume 32, Issue 8 (October 2019)
- "Arcturus 2.0: A Meta-analysis of Time-varying Rates for Electricity," with Ahmad Faruqui and Cody Warner, *The Electricity Journal*, Volume 30, Issue 10 (December 2017)
- "Do Manufacturing Firms Relocate in Response to Rising Electric Rates?" with Ahmad Faruqui, *Energy Regulation Quarterly*, Volume 5, Issue 2 (June 2017)
- "Dynamic Pricing Works in a Hot, Humid Climate," with Ahmad Faruqui and Neil Lessem, *Public Utilities Fortnightly* (May 2017)
- "The impact of AMI-enabled conservation voltage reduction on energy consumption and peak demand," with Kevin Arritt and Sanem Sergici, *The Electricity Journal*, 30:2, pp. 60-65 (March 2017) http://www.sciencedirect.com/science/article/pii/S1040619016302536
- "Integration of residential PV and its implications for current and future residential electricity demand in the United States," with Derya Eryilmaz, *The Electricity Journal*, 29, 41-52 (2016)
- "Impact Measurement of Tariff Changes when Experimentation is not an Option – A case study of Ontario, Canada," with Neil Lessem and Dean Mountain, *Energy Economics*, 52, pp. 39-48 (December 2015)
- "Utility Investments in Resiliency: Balancing Benefits with Cost in an Uncertain Environment," with William Zarakas, *et al*., *The Electricity Journal*, Volume 27, Issue 5 (June 2014)
- "Low Voltage Resiliency Insurance: Ensuring Critical Service Continuity during Major Power Outages," with William Zarakas and Frank Graves, *Public Utilities Fortnightly* (September 2013)
- "Arcturus: International Evidence on Dynamic Pricing," with Ahmad Faruqui, *The Electricity Journal*, 26:7, pp. 55-65 (August/September 2013)
- "Dynamic Pricing of Electricity for Residential Customers: The Evidence from Michigan," by Ahmad Faruqui, Sanem Sergici and Lamine Akaba, *Energy Efficiency*, 6:3, pp. 571–584 (August 2013)
- "Dynamic Pricing of Electricity in the Mid-Atlantic Region: Econometric Results from the Baltimore Gas and Electric Company Experiment," with Ahmad Faruqui, *Journal of Regulatory Economics*, 40(1), pp. 82–109 (2011)

- "The Untold Story of: A Survey of C&I Dynamic Pricing Pilot Studies," with Ahmad Faruqui and Jenny Palmer, *Metering International*, Issue 3 (2010)
- Divestiture policy and operating efficiency in U.S. electric power distribution," with John E. Kwoka, Jr., and Michael Pollitt, *Journal of Regulatory Economics* (June 2010)
- "Household Response to Dynamic Pricing of Electricity – A Survey of the Experimental Evidence," with Ahmad Faruqui, *Journal of Regulatory Economics* (October 2010)
- "Rethinking Prices," with Ahmad Faruqui and Ryan Hledik, *Public Utilities Fortnightly* (January 2010)
- "Piloting the Smart Grid," with Ahmad Faruqui and Ryan Hledik, *The Electricity Journal* (August/September 2009)
- "The Impact of Informational Feedback on Energy Consumption - A Survey of the Experimental Evidence," with Ahmad Faruqui and Ahmed Sharif, *Energy-The International Journal* (August 2009)
- "Three Essays on U.S. Electricity Restructuring," Unpublished Ph.D. Thesis, Northeastern University (August 2008)

PRESENTATIONS & SPEAKING ENGAGMENTS

- "A New Approach to Strategic Planning in a High Distributed Resource Environment: Distributed Solar as a Case Study," Next-Gen Smart Grid Virtual Summit (December 9, 2020)
- "What Explains the Success of Top Performing States in Energy Efficiency?" NRRI Webinar (August 19, 2020)
- "A Blueprint to Pilot Design: Best Practices and Lessons Learned," MI Power Grid: Energy Programs and Technology Pilots Stakeholder Meeting (April 30, 2020)
- "Policies in Support of Customers' Purchase of Renewable Energy," NARUC Annual Meeting & Education Conference (November 18, 2019)
- "Rate Reform in Evolving Energy Marketplace," EUCI Residential Demand Charges/TOU Summit (May 30, 2019)
- "Grid Modernization: Policy, Market Trends and Directions Forward," 4th Annual Grid Modernization Forum, Chicago, IL (May 21, 2019)
- "Accelerating the Renewable Energy Transformation: Role of Green Power Tariffs and Blockchain," EUCI Southeast Clean Power Summit (February 25, 2019)
- "The Case for Alternative Regulation and Unintended Consequences of Net Energy Metering," 46th Annual PURC Conference, Gainesville, FL (February 21, 2019)

- “Reviewing Grid Modernization Investments: Summary of Recent Methods and Projects,” National Electrical Manufacturers Association (NEMA) (December 4, 2018)
- “Enabling Grid Modernization Through Alternative Rates and Alternative Regulation,” Energy Policy Roundtable in the PJM Footprint (November 29, 2018)
- “Return of Pay-for-Performance Stronger with M&V 2.0,” BECC Conference, Innovations in Models, Metrics, and Customer Choice, Washington DC (October 2018)
- “Rate Design in a High DER Environment,” MEDSIS Rate Design Workshop, Washington DC, (September 2018)
- “Demand Response for Natural Gas Distribution,” Center for Research in Regulated Industries (CRRI) 31st Annual Western Conference, Monterey CA (June 2018)
- “Status of Restructuring: Wholesale and Retail Markets,” National Conference of State Legislatures Workshop, "Electricity Markets and State Challenges," Indianapolis IN (June 2018)
- “Dynamic Pricing Works in a Hot and Humid Climate: Evidence from Florida,” International Energy Policy & Programme Evaluation Conference, Bangkok Thailand (November 2017)
- “Understanding Residential Customer Response to Demand Charges: Present and Future,” EUCI Residential Demand Charges Conference, Chicago IL (October 2016)
- “Utility Leaders Workshop: An Evolving Utility Business Model for the Caribbean,” Caribbean Renewable Energy Forum, Miami FL (October 2016)
- “Impact of Residential PV Penetration on Load Growth Expectations,” AEIC Western Load Research Conference, September 2016.
- “Moving away from Flat Rates,” Smart Grid Consumer Collaborative, Chicago, IL (September 2016)
- “Residential Demand Charges: An Overview,” EUCI Demand Charge Conference, Phoenix AZ (June 2016)
- “Conservation Voltage Reduction Econometric Impact Analysis,” AESP Spring Conference, Washington DC (May 2016)
- “Caribbean Utility 2.0 Workshop- Economics, Tariffs and Implementation: The Challenge of Integrating Renewable Resources and After Engineering Solutions,” co-hosted and presented at the Caribbean Renewable Energy Forum, Miami FL (October 2015)
- “Dispelling Common Residential DR Myths,” eSource Conference (October 2015)
- “Low Income Customers and Time Varying Pricing: Issues, Concerns, and Opportunities,” NYU School Law’s Forum on New York REV and the Role of Time Varying Pricing (March 2015)

- "Dynamic Pricing: Transitioning from Experiments to Full Scale Deployments," EDF Demand Response Workshop, Paris, France (July 2014) and Governors Association's Michigan Retreat on Peak Shaving to Reduce Wasted Energy (August 2014)
- "Impact Evaluation of TOU Rates when Experimentation is not Option: A Case Study of Ontario, Canada," 2014 Smart Grid Virtual Summit, Boston (June 2014)
- "Residential Demand Response Opportunities," Opower Webinar Series, Boston (June 2014)
- "Impact Evaluation of TOU Rates when Experimentation is not Option: A Case Study of Ontario, Canada," 33rd Annual Eastern CRRI Conference (May 2014)
- "The Arc of Price Responsiveness—Consistency of Results Across Time-Varying Pricing Studies," Chartwell Webinar, Boston (May 2013)
- "Evaluation of Baltimore Gas and Electric Company's Smart Energy Pricing Program," 9th International Industrial Organization Conference, Boston, MA (April 2011)
- "Dynamic Pricing: What Have We Learned?" Electricity Markets Initiative Conference, Harrisburg, PA (April 2011)
- "Do Smart Rates Short Change Customers," Demand Resource Coordinating Committee Webinar (December 2010)
- "Opening Remarks and Session Chair of Day 1," FRA Conference on Customer Engagement in a Smart Grid World, San Francisco, CA (December 2010)
- "The Impact of Informational Feedback on Energy Consumption," 2010 National Town Meeting on Demand Response and Smart Grid (June 2010)
- "The Impact of In-Home Displays on Energy Consumption," Colorado Public Service Commission (June 2010)
- "Does Dynamic Pricing Work in the Mid-Atlantic Region: Econometric Analysis of Experimental Data," Center for Research in Regulated Industries (CRRI) 29th Annual Eastern Conference (May 2010)
- "Distributed Generation in a Smart Grid Environment," panel speaker at the Center for Research in Regulated Industries (CRRI) 29th Annual Eastern Conference (May 2010)
- "Power of Information Feedback: A Survey of Experimental Evidence," Peak Load Management Alliance (PLMA) Webinar (April 2010)
- "Customer Response to Dynamic Pricing - A Long Term Vision," 2009 NASUCA Mid- Year Meeting, Boston (June 2009)
- "BGE's Smart Energy Pricing Pilot Summer 2008 Impact Evaluation," Association of Edison Illuminating Companies (AECI) Conference, Florida (May 2009)

- "California and Maryland - Are They Poles Apart?," Western Load Research Association Conference, Atlanta (March 2009)
- “Experimental Design Considerations in Evaluating the Smart Grid," Smart Grid Information Session Massachusetts DPU (December 2008)
- “Divestiture, Vertical Integration, and Efficiency: An Exploratory Analysis of Electric Power Distribution,” 4th International Industrial Organization Conference, Boston, Massachusetts (2006)

BC Hydro Optional Residential Time-of-Use Rate Application

Appendix G

Cost of Service Assessment

Table of Contents

List of Tables

1 Introduction

In this Appendix, BC Hydro assesses cost recovery for the proposed Optional Residential TOU Rate using BC Hydro's Fully Allocated Cost of Service (**FACOS**) methodology to compare the estimated revenue to cost ratios of the Optional Residential TOU Rate to the Residential rate class.

The Optional Residential TOU Rate is an "add-on" rate that applies year-round and every day of the year (i.e., weekdays, weekends, and holidays). Participating customers will still be billed for their total electricity usage during a billing period at their existing Residential rate.[1] They will then receive a 5-cent credit for each kWh of electricity consumed during the Overnight period (11 p.m. to 7 a.m.) and a 5-cent additional charge for each kWh of electricity consumed during the On-Peak period (4 p.m. to 9 p.m.). No credit or additional charge will be applied to consumption during the Off-Peak period (9 p.m. to 11 p.m. and 7 a.m. to 4 p.m.).

BC Hydro set the Optional Residential TOU Rate to collect, on average, the same amount of revenue, assuming customers who enrol in the Optional Residential TOU Rate do not shift their consumption from the On-Peak period. This was done by applying a credit for every kWh consumed during the Overnight period and an additional charge, of the same amount, for every kWh consumed during the On-Peak period. This approach works because, on average, Rate Schedule 1101 (**RS 1101 or RIB Rate**) customers consume the same amount of electricity, approximately 26% each, during these two periods each year.

[1] Most of BC Hydro's Residential customers living in the integrated service area take service under Rate Schedule (**RS**) 1101, the Residential inclining block rate (**RIB Rate**), and a small number of farm customers take service under RS 1151 Exempt Residential Service rate (**Flat Rate**).

BC Hydro used the Fiscal 2020 Fully Allocated Cost of Service (**FACOS**) Study[2] [3], to calculate and compare the forecast revenue to cost ratios of Optional Residential TOU Rate participants and all customers in the Residential rate class. Our cost of service assessment concludes that the proposed Optional Residential TOU Rate will result in lower revenue to cost ratios than the Residential class revenue to cost ratios in the near and mid-term; however, over the long term (i.e., by fiscal 2035 (Year 11)), the forecast revenue to cost ratio of the Optional Residential TOU Rate participants is expected to be similar to all Residential rate class customers at 93.1%. After fiscal 2035 the forecast revenue to cost ratio of the Optional Residential TOU Rate is expected to exceed that of the Residential rate class, reaching 94.5% by fiscal 2039 (Year 15).

This Appendix is structured as follows:

- Section 2 summarizes BC Hydro's FACOS methodology;
- Section 3 explains how we forecast the revenue we expect to collect from Optional Residential TOU Rate participants;
- Section 4 explains how we estimate the cost of providing service to Optional Residential TOU Rate participants; and,
- Section 5 presents the forecast revenue to cost ratios for the Reference Case, and the low-end and high-end sensitivities.

2 BC Hydro's Fully Allocated Cost of Service Studies

BC Hydro uses our FACOS studies to assess the extent to which a rate recovers the cost of providing service and to assess the potential for cost shifting to other groups of

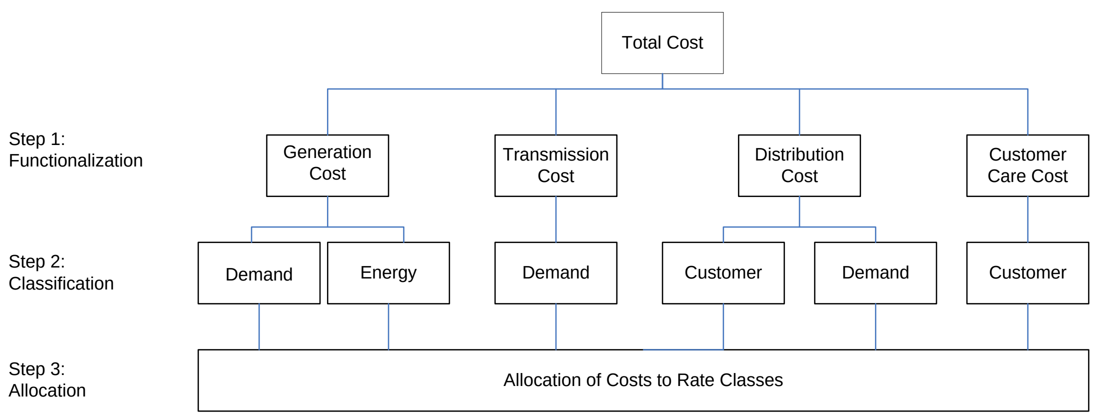
[2] BC Hydro's Fiscal 2020 FACOS was filed with the BCUC on February 11, 2021: https://www.bchydro.com/content/dam/BCHydro/customer-portal/documents/corporate/regulatory-planning-documents/regulatory-filings/facos/00-2021-02-11-bchydro-facos-f2020.pdf

[3] The Fiscal 2021 FACOS, filed with the BCUC on February 11, 2022, was not used for this cost-of-service study due to the impact of public health orders related to the COVID-19 pandemic on energy sales to customer classes.

ratepayers. A rate that generally recovers the cost of providing service does not result in cost shifting to other groups of ratepayers and is considered to result in the fair allocation of costs and the avoidance of undue discrimination between groups of customers.[4] In this cost of service assessment, we used our FACOS methodology to calculate and compare the revenue collected from the Optional Residential TOU Rate participants to the costs of providing service to these customers and summarized this information through forecast revenue to cost ratios.

Under the FACOS methodology, a cost is directly assigned to a customer class, if it can be attributed to that specific customer class. All historical accounting costs associated with delivering electricity services that cannot be directly assigned to a customer class, such as operating and capital-related expenses in a fiscal year, are "functionalized", "classified", and "allocated" to individual customer classes according to cost causation criteria. This three-step process is summarized in Figure G–1 below.

Figure G–1 Methodology of Cost-of-Service Study



As shown in Figure G–1 above, costs are first functionalized into four functions: Generation, Transmission, Distribution, and Customer Care. This means that costs are grouped by the function (i.e., Generation, Transmission, Distribution and Customer Care) and facilities that they are associated with.

[4] Refer to sections 2.2.2 and 4.7.1 for discussion on the Bonbright rate design criteria.

In the second step, costs are classified as:

- **Energy-related Costs (¢/kWh):** costs that vary with the amount of energy provided;
- **Demand-related Costs ($/kW-year):** costs that vary with the kilowatt demand imposed by the customer; and,
- **Customer-related Costs ($/account-year):** costs that are directly related to the number of customers served.

This means that the functionalized costs are classified based on the components of utility service being provided (i.e., energy costs, demand costs, or customer costs). Table G-1 below provides the Summary of Costs by Classification for the Fiscal 2020 FACOS.[5]

Table G-1 Summary of Costs by Classification (Schedule 4.1 of the Fiscal 2020 FACOS in $ Million)

Rate Class	Energy Related Costs	Generation Demand Related Costs	Transmission Demand Related Costs	Distribution Demand Related Costs	Total Demand Related Costs	Customer Related Costs	Total
Residential	712.3	352.9	485.9	522.8	1,361.6	251.9	2,325.7
GS Under 35 kW	157.8	62.7	86.3	106.2	255.1	37.9	450.9
MGS < 150 kW	136.0	49.0	67.5	78.7	195.2	15.0	346.2
LGS > 150 kW	439.3	148.0	203.7	186.6	538.3	9.4	987.0
Irrigation	2.9	0.1	0.1	4.5	4.7	0.8	8.3
Street Lighting, BCH	1.8	1.0	1.4	1.6	4.0	5.3	11.0
Street Lighting, Cust	6.6	3.3	4.6	5.2	13.1	1.6	21.3
Transmission	539.0	162.8	224.1	0.0	386.8	2.3	928.2
Total	1,995.7	779.8	1,073.5	905.5	2,758.8	324.1	5,078.6

[5] The Fiscal 2021 FACOS, filed with the BCUC on February 11, 2022, was not used for this cost-of-service study due to the impact of public health orders related to the COVID-19 pandemic on energy sales to customer classes.

Finally, in the third step, costs are allocated to rate classes based on Commission approved allocation factors (e.g., proportion of energy, coincident peak, non-coincident peak, or number of Customers).[6]

Table G–2 below provides the factors or "cost allocators" BC Hydro uses to allocate Energy-related, Generation demand-related, Transmission demand-related, Distribution demand-related, and Customer-related costs to individual customer rate classes.

Table G–2 Cost Allocators of Classified Costs

Classified Cost	Cost Allocator
Energy-related Cost	Proportion of total energy
Generation Demand-related Cost	Coincident Peak[7] Factor
Transmission Demand-related Cost	Coincident Peak Factor
Distribution Demand-related Cost	Non-Coincident Peak[8] Factor
Customer-related Cost	90% number of bills, 10% revenue

Using these allocation factors:

- The energy-related costs allocated to a rate class of customers is calculated as:

$$Energy - related\ Cost\ of\ Class$$

$$= Total\ Energyrelated\ Cost\ \times Proportion\ of\ Total\ Energy$$

$$= Total\ Energy - related\ Cost\ \times \frac{Energy\ Consumption\ of\ Class}{Total\ Energy\ Consumption}$$

$$= \frac{Total\ Energy - related\ Cost}{Total\ Energy\ Consumption} \times Energy\ Consumption\ of\ Class$$

6 Approved by the Commission in the BC Hydro's 2016 Cost of Service and Rate Class Segmentation Negotiated Settlement Agreement https://docs.bcuc.com/Documents/Proceedings/2016/DOC_46087_04-11-2016_COS-Negotiated-Settlement-Agreement.pdf.

7 Coincident Peak (also referred to as **four coincident peak** or **4CP**) is the average monthly peak demand of a customer class at the time of the system's peak demand for four winter months.

8 Non-Coincident Peak (**NCP**) is the peak demand of a customer class regardless of the time of occurrence during a year.

$$= Unit\ Energy\ Cost \times Energy\ Consumption\ of\ Class$$

- The Generation, Transmission and Distribution demand-related costs allocated to an individual customer class or customer group are estimated as unit cost of peak demand times the coincident peak or non-coincident peak of the customer class; and,
- The amount of Customer-related cost allocated to a customer class is the total Customer-related cost times the Customer-related cost allocator of the customer class.

Based on the Fiscal 2020 FACOS, the unit cost of Energy-related, Generation demand-related, Transmission demand-related, Distribution demand-related, and Customer-related costs of the Residential customer class in fiscal 2020 were estimated. These estimates are provided in Table G-3 below.

Table G-3 Unit Cost of Residential Class (in Fiscal 2020$)

Classified Cost Item	Unit Cost
Energy-related Cost	$0.0396 / kWh
Generation Demand-related Cost	$102.56 / kW-year
Transmission Demand-related Cost	$141.19 / kW-year
Distribution Demand-related Cost	$116.9 / kW-year
Customer-related Cost	$135.15 / account-year

After costs are determined based on the above FACOS methodology, the revenues received from each customer class or customer group are divided by the sum of allocated costs to determine the revenue to cost ratio of the customer class or customer group. Revenue to cost ratios provide estimates of how revenues from electricity sales to classes of customers compare to BC Hydro’s associated embedded cost of serving that class of customers.

As discussed in section 4.5.2.1 of Chapter 4, in BC Hydro's Fiscal 2020 FACOS Study,[9] the revenue to cost ratio of the Residential rate class was approximately 93%. A comparable revenue to cost ratio for the Optional Residential TOU Rate would provide reasonable certainty that the rate will have the same level of cost recovery as the Residential rate class, and therefore, will not result in cost shifting between customer classes.

3 Forecast Revenue of the Optional Residential TOU Rate

As discussed in section 4.3 of Chapter 4, BC Hydro developed Reference Case and low-end and high-end sensitivity assumptions for the Optional Residential TOU Rate. These assumptions were used to estimate the revenue from Optional Residential TOU Rate participants through the following three step process:

- **Step 1 - Forecast Participants:** forecast the number of participants with electric vehicles and without electric vehicles on the Optional Residential TOU Rate;
- **Step 2 – Forecast Consumption:** forecast the shift (i.e., to other periods) and reduction (i.e., conservation) in household usage and electric vehicle charging consumption during the On-Peak period by participants in the Optional Residential TOU Rate; and,
- **Step 3 – Forecast Revenue:** estimate revenue from participants if billed under the Optional Residential TOU Rate.

[9] Refer to: www.bchydro.com/content/dam/BCHydro/customer-portal/documents/corporate/regulatory-planning-documents/regulatory-filings/facos/00-2021-02-11-bchydro-facos-f2020.pdf. The Fiscal 2020 Fully Allocated Cost of Service Study was selected as a reference to avoid considering time-limited impacts from the COVID-19 pandemic.

3.1 Step 1 - Forecast Participants

Table G-4 below provides the estimated number of participants by fiscal year under the assumptions set out in the Reference Case, and the low-end and high-end sensitivities.[10]

Table G-4 Optional Residential TOU Rate - Participation Forecast

Fiscal Year	Total Number of Residential Customers	Reference Case Participation Forecast		Low-End Sensitivity Participation Forecast		High-End Sensitivity Participation Forecast	
		No EV	With EV	No EV	With EV	No EV	With EV
F2024	1,937,455	0	0	0	0	0	0
F2025	1,963,798	14,077	6,306	7,941	4,250	61,736	11,437
F2026	1,988,250	41,596	20,519	23,467	13,829	182,430	37,216
F2027	2,010,571	81,251	44,616	45,837	30,070	356,342	80,923
F2028	2,032,932	118,472	74,486	66,836	50,202	519,586	135,099
F2029	2,055,293	120,960	95,163	68,239	64,138	530,496	172,604
F2030	2,077,609	122,464	119,051	69,088	80,237	537,093	215,931
F2031	2,099,100	116,848	142,750	65,919	96,209	512,461	258,914
F2032	2,122,192	110,629	168,847	62,411	113,799	485,189	306,251
F2033	2,145,284	103,729	197,463	58,519	133,087	454,926	358,154
F2034	2,168,376	96,195	228,755	54,268	154,177	421,883	414,909
F2035	2,191,468	87,935	262,745	49,608	177,085	385,657	476,559
F2036	2,214,560	78,856	299,464	44,487	201,833	345,842	543,158
F2037	2,237,652	69,854	338,683	39,408	228,265	306,362	614,293
F2038	2,260,744	60,984	379,876	34,404	256,028	267,458	689,005
F2039	2,283,836	52,295	422,036	29,502	284,444	229,351	765,476

3.2 Step 2 - Forecast Consumption

As set out in section 3.1 above, participants on the Optional Residential TOU Rate are categorized as:

[10] As discussed further in section 4.3 of Chapter 4, BC Hydro assumes a six-year S-shaped participation ramp up.

- Participants without an electric vehicle; and,
- Participants with an electric vehicle.

The average annual consumption of the customers without an electric vehicle who can achieve bill savings on the Optional Residential TOU Rate is 11,348 kWh.

The average annual consumption of customers with an electric vehicle that can achieve bill savings on the Optional Residential TOU Rate, excluding customers in apartments, is 14,684 kWh.[11]

Table G-5, Table G-6, and Table G-7 below provide the breakdown of this annual average consumption by energy charge (i.e., Step 1 or Step 2) and by period (i.e., On-Peak, Off-Peak, Overnight) using the assumptions set out in the Reference Case, and the low-end and high-end sensitivities.[12]

Table G-5 Reference Case Participant Average Annual Consumption Breakdown[13]

	Participant with No Electric Vehicle		Participant with An Electric Vehicle	
	Pre-shift Consumption (kWh)	Post-shift Consumption (kWh)	Pre-shift Consumption (kWh)	Post-shift Consumption (kWh)
Total Consumption	11,348	11,348	14,684	14,684
RIB Rate				
Step 1	7,695	7,695	8,018	8,018
Step 2	3,653	3,653	6,666	6,666
Optional Residential TOU Rate				
On-Peak	2,932	2,785	4,001	3,067
Off-Peak	5,444	5,517	7,033	7,264
Overnight	2,972	3,046	3,649	4,352

11 The average consumption of participants with electric vehicles is higher due to the exclusion of apartments as well as the inclusion of electric vehicle charging load. Section 4.3.5.1 of Chapter 4 provides further details on the assumptions used for average electric vehicle charging load.

12 The average annual consumption is different in each case due to the different participation and consumption shifting assumptions in the Reference Case and in the low-end and high-end sensitivities.

13 Numbers may not add up to Total Consumption due to rounding.

Table G-6 Low-End Sensitivity Participant Average Annual Consumption Breakdown[14]

	Participant with No Electric Vehicle		Participant with An Electric Vehicle	
	Pre-shift Consumption (kWh)	**Post-shift Consumption (kWh)**	**Pre-shift Consumption (kWh)**	**Post-shift Consumption (kWh)**
Total Consumption	11,475	11,357	15,022	14,894
RIB Rate				
Step 1	7,695	7,691	8,012	8,019
Step 2	3,780	3,665	7,010	6,875
Optional Residential TOU Rate				
On-Peak	2,964	2,757	4,093	3,339
Off-Peak	5,505	5,549	7,195	7,348
Overnight	3,006	3,050	3,733	4,208

Table G-7 High-End Sensitivity Participant Average Annual Consumption Breakdown[15]

	Participant with No Electric Vehicle		Participant with An Electric Vehicle	
	Pre-shift Consumption (kWh)	**Post-shift Consumption (kWh)**	**Pre-shift Consumption (kWh)**	**Post-shift Consumption (kWh)**
Total Consumption	11,016	11,016	14,747	14,747
RIB Rate				
Step 1	7,660	7,660	8,018	8,018
Step 2	3,355	3,355	6,729	6,729
Optional Residential TOU Rate				
On-Peak	2,846	2,561	4,019	2,774
Off-Peak	5,284	5,427	7,063	7,401
Overnight	2,885	3,028	3,665	4,572

14 Ibid.

15 Ibid.

3.3 Step 3 - Forecast Revenue

As set out in section 3.1 above, participants on the Optional Residential TOU Rate are categorized as:

- Participants without an electric vehicle; and,
- Participants with an electric vehicle.

As set out in section 3.2 above, the average annual consumption for these two categories of participants can be broken down by energy charge (i.e., Step 1 or Step 2) and by period (i.e., On-Peak, Off-Peak, Overnight) using the assumptions set out in the Reference Case, and the low-end and high-end sensitivities.

To estimate revenue from participants in the Optional Residential TOU, BC Hydro applied the forecast rates shown in Table G-8 below to the participation and consumption forecasts set out in sections 3.1 and 3.2 above.

Table G-8 Forecast RIB Rate and Optional Residential TOU Rate Charges[16]

Fiscal Year	Forecast General Rate Change	RIB Rate			Optional Residential TOU Rate[17]	
		Step 1 ¢/kWh	Step 2 ¢/kWh	Basic ¢/Day	Credit ¢/kWh	Charge ¢/kWh
F2024	0.97%	9.68	14.08	21.10	5.00	5.00
F2025	2.18%	10.10	14.08	21.56	5.00	5.00
F2026	4.89%	10.59	14.77	22.61	5.00	5.00
F2027	0.11%	10.60	14.78	22.63	5.00	5.00
F2028	1.30%	10.74	14.98	22.92	5.00	5.00
F2029	0.12%	10.75	14.99	22.95	5.00	5.00
F2030	-0.61%	10.69	14.90	22.81	5.00	5.00

16 Fiscal 2024 and fiscal 2025 rates assume the Commission approves BC Hydro's Fiscal 2023 to Fiscal 2025 Revenue Requirements Application and that the Fiscal 2023 Residential Pricing Principles are extended for fiscal 2024 and fiscal 2025. Fiscal 2026 to fiscal 2030 rates are based on BC Hydro's rate forecast provided to the Commission in our response to BCUC IR 1.1.1 in BC Hydro's Fiscal 2023 to Fiscal 2025 Revenue Requirements Application proceeding. An assumed annual increase of 2% is applied to rates from fiscal 2031 to fiscal 2039.

17 As explained in section 4.2.2 in Chapter 4, BC Hydro proposes to that the 5-cent credit and additional charge stay consistent and not be escalated by the general rate increase each year to support customer understanding.

Fiscal Year	Forecast General Rate Change	RIB Rate			Optional Residential TOU Rate[17]	
		Step 1 ¢/kWh	Step 2 ¢/kWh	Basic ¢/Day	Credit ¢/kWh	Charge ¢/kWh
F2031	2.00%	10.90	15.20	23.27	5.00	5.00
F2032	2.00%	11.12	15.51	23.74	5.00	5.00
F2033	2.00%	11.34	15.82	24.21	5.00	5.00
F2034	2.00%	11.57	16.13	24.69	5.00	5.00
F2035	2.00%	11.80	16.45	25.18	5.00	5.00
F2036	2.00%	12.04	16.78	25.68	5.00	5.00
F2037	2.00%	12.28	17.12	26.19	5.00	5.00
F2038	2.00%	12.52	17.46	26.71	5.00	5.00
F2039	2.00%	12.77	17.81	27.24	5.00	5.00

Table G-9, Table G-10, and Table G-11 below provide the forecast revenue from participants using the assumptions set out in the Reference Case and the low-end and high-end sensitivities, respectively.

Table G-9 Reference Case Participant Revenue Forecast

Fiscal Year	RIB Rate			Optional Residential TOU Rate		Total Revenue ($)
	Step 1 Revenue ($)	Step 2 Revenue ($)	Basic Revenue ($)	Credit Revenue ($)	Charge Revenue ($)	
F2024	0	0	0	0	0	0
F2025	16,042,680	13,158,473	1,604,102	(3,515,995)	2,927,200	30,216,460
F2026	51,324,790	42,640,262	5,127,499	(10,799,940)	8,938,918	97,231,530
F2027	104,219,468	87,851,845	10,401,450	(22,082,754)	18,156,083	198,546,092
F2028	162,060,496	139,178,813	16,153,115	(34,251,486)	27,919,858	311,060,795
F2029	182,140,906	161,377,069	18,114,002	(39,130,120)	31,437,189	353,939,046
F2030	202,737,371	184,944,365	20,118,737	(44,557,801)	35,310,023	398,552,695
F2031	222,795,148	209,540,573	22,057,556	(48,859,976)	38,162,332	443,695,632
F2032	245,197,041	237,184,413	24,221,541	(53,592,351)	41,298,572	494,309,217
F2033	270,101,473	268,112,070	26,625,663	(58,769,076)	44,726,163	550,796,293
F2034	297,821,622	302,686,044	29,300,372	(64,431,590)	48,475,828	613,852,276
F2035	328,436,468	341,059,188	32,252,842	(70,570,783)	52,538,235	683,715,949
F2036	362,032,367	383,397,777	35,490,926	(77,179,240)	56,905,187	760,647,017
F2037	399,373,612	430,194,217	39,092,147	(84,343,367)	61,666,146	845,982,755

Fiscal Year	RIB Rate			Optional Residential TOU Rate		Total Revenue ($)
	Step 1 Revenue ($)	Step 2 Revenue ($)	Basic Revenue ($)	Credit Revenue ($)	Charge Revenue ($)	
F2038	440,172,193	481,090,744	43,028,703	(91,957,082)	66,748,116	939,082,675
F2039	483,612,094	535,117,557	47,221,465	(99,808,944)	72,003,713	1,038,145,886

Table G-10 Low-End Sensitivity Participant Revenue Forecast

Fiscal Year	RIB Rate			Optional Residential TOU Rate		Total Revenue ($)
	Step 1 Revenue ($)	Step 2 Revenue ($)	Basic Revenue ($)	Credit Revenue ($)	Charge Revenue ($)	
F2024	0	0	0	0	0	0
F2025	9,608,789	8,212,368	959,450	(2,105,341)	1,804,152	18,479,417
F2026	30,861,313	26,743,955	3,078,672	(6,488,538)	5,543,312	59,738,714
F2027	62,947,787	55,404,599	6,272,890	(13,317,426)	11,338,210	122,646,059
F2028	98,453,098	88,381,362	9,797,601	(20,755,665)	17,593,465	193,469,861
F2029	111,749,736	103,625,257	11,095,003	(23,901,744)	20,113,249	222,681,501
F2030	125,564,048	119,951,823	12,439,098	(27,418,298)	22,917,631	253,454,303
F2031	139,381,904	137,277,658	13,775,770	(30,295,459)	25,147,056	285,286,930
F2032	154,854,635	156,780,339	15,271,732	(33,461,247)	27,599,764	321,045,223
F2033	172,099,355	178,631,471	16,938,119	(36,925,611)	30,282,888	361,026,222
F2034	191,325,381	203,080,923	18,795,278	(40,714,540)	33,217,501	405,704,543
F2035	212,600,557	230,246,681	20,849,515	(44,823,548)	36,399,179	455,272,383
F2036	235,998,801	260,256,920	23,107,703	(49,249,263)	39,824,362	509,938,523
F2037	261,946,502	293,384,439	25,613,133	(54,035,841)	43,536,583	570,444,816
F2038	290,245,687	329,378,221	28,346,676	(59,113,751)	47,481,199	636,338,032
F2039	320,341,761	367,560,998	31,254,542	(64,344,701)	51,548,969	706,361,569

Table G-11 High-End Sensitivity Participant Revenue Forecast

Fiscal Year	RIB Rate			Optional Residential TOU Rate		Total Revenue ($)
	Step 1 Revenue ($)	Step 2 Revenue ($)	Basic Revenue ($)	Credit Revenue ($)	Charge Revenue ($)	
F2024	0	0	0	0	0	0

Fiscal Year	RIB Rate			Optional Residential TOU Rate		Total Revenue ($)
	Step 1 Revenue ($)	Step 2 Revenue ($)	Basic Revenue ($)	Credit Revenue ($)	Charge Revenue ($)	
F2025	57,013,991	40,000,249	5,758,688	(11,960,425)	9,492,271	100,304,774
F2026	179,619,049	127,378,957	18,131,343	(36,124,751)	28,523,984	317,528,582
F2027	358,232,806	257,269,768	36,135,031	(72,443,658)	56,857,405	636,051,353
F2028	543,864,050	397,240,936	54,805,655	(109,540,603)	85,276,736	971,646,774
F2029	585,843,265	441,047,011	58,929,234	(119,765,284)	91,875,841	1,057,930,068
F2030	624,802,677	485,103,499	62,728,567	(130,667,918)	98,730,200	1,140,697,026
F2031	654,301,087	526,207,161	65,542,379	(136,764,166)	101,537,601	1,210,824,063
F2032	686,362,956	571,930,111	68,592,215	(143,456,032)	104,610,849	1,288,040,098
F2033	720,999,687	622,543,508	71,877,088	(150,738,866)	107,934,422	1,372,615,839
F2034	758,783,390	678,713,884	75,452,634	(158,709,739)	111,574,801	1,465,814,971
F2035	799,545,749	740,545,172	79,300,048	(167,317,899)	115,486,704	1,567,559,774
F2036	843,101,938	808,145,895	83,398,729	(176,513,940)	119,625,387	1,677,758,008
F2037	892,860,395	883,571,464	88,095,672	(186,797,459)	124,436,036	1,802,166,109
F2038	948,416,180	966,230,953	93,352,467	(197,985,815)	129,816,574	1,939,830,360
F2039	1,008,419,320	1,054,428,228	99,038,841	(209,697,037)	135,543,262	2,087,732,615

4 Forecast Costs of the Optional Residential TOU Rate

The Reference Case and low-end and high-end sensitivity assumptions were used to estimate the cost to provide service to Optional Residential TOU Rate participants through the following three step process:

- **Step 1 – Estimate Implementation Costs:** costs associated with implementing the Optional Residential TOU Rate are directly assigned to participants in the Optional Residential TOU Rate. These costs are assumed to be the same in the Reference Case and in the low-end and high-end sensitivities;
- **Step 2 – Calculate Coincident and Non-Coincident Peak Demands:** the coincident peak and non-coincident peak of Optional Residential TOU Rate participants are calculated; and,

- **Step 3 – Estimate Cost of Service:** The cost to provide service to Optional Residential TOU Rate participants is estimated by applying the forecast customer-related cost, energy-related cost, generation, and transmission demand-related cost and distribution demand-related costs to the forecast participation, consumption and coincident and non-coincident peak estimates.

4.1 Step 1 – Estimate Implementation Costs

As outlined in section 4.8.4 of Chapter 4, BC Hydro will incur incremental technology, operations and customer education and communication costs to implement the Optional Residential TOU Rate. The implementation costs are not expected to vary much based on participation or customer response. Therefore, these costs are assumed to be the same in the Reference Case and in the low-end and high-end sensitivities. Table G-12 below provides the estimated implementation costs for the Optional Residential TOU Rate.

Table G-12 Estimated Implementation Costs

Fiscal Year	Estimated Technology Costs ($)	Estimated Operations Costs ($)	Estimated Customer Education and Communications Costs ($)	Estimated Total Implementation Costs ($)
F2024	0	104,604	0	104,604
F2025	1,082,093	1,472,638	63,493	2,618,224
F2026	2,164,186	1,308,731	159,861	3,632,778
F2027	2,164,186	1,568,700	265,274	3,998,160
F2028	2,164,186	2,031,637	367,407	4,563,229
F2029	2,164,186	2,035,214	429,699	4,629,099
F2030	1,082,093	2,092,353	485,699	3,660,145
F2031	0	2,166,390	540,699	2,707,089
F2032	0	2,206,441	595,699	2,802,140
F2033	0	2,410,268	650,699	3,060,967
F2034	0	2,471,496	695,699	3,167,196
F2035	0	2,540,112	740,699	3,280,811
F2036	0	2,616,009	785,699	3,401,708

Fiscal Year	Estimated Technology Costs ($)	Estimated Operations Costs ($)	Estimated Customer Education and Communications Costs ($)	Estimated Total Implementation Costs ($)
F2037	0	2,698,411	830,699	3,529,110
F2038	0	2,785,546	875,699	3,661,245
F2039	0	2,874,056	920,699	3,794,755

4.2 Step 2 - Calculate Coincident and Non-Coincident Peak Demands of Optional Residential TOU Rate Participants

As explained in section 2 above, Generation and Transmission demand-related costs are calculated based on the coincident peak factor. Distribution demand-related costs are calculated based on the non-coincident peak factor. Accordingly, to estimate demand-related costs for participants on the Optional Residential TOU Rate, BC Hydro first calculated the household consumption coincident and non-coincident peak demands for participants, using the assumptions set out in the Reference Case and the low-end and high-end sensitivities. This is shown in Table G-13 below.

Table G-13 Peak Demand Reduction of Household Consumption

Input	Reference Case	Low-End Sensitivity	High-End Sensitivity
Load Shifting (%)	5	3	10
Load Reduction (%)	0	4[18]	0
Customers with No Electric Vehicle			
Average Coincident Peak Demand (kW)	2.54	2.56	2.46
Estimated Average Coincident Peak Demand Reduction (kW)	0.127	0.176	0.246
Average Non-Coincident Peak Demand (kW)	3.15	3.18	3.03
Estimated Average Non-Coincident Peak Demand Reduction (kW)	0.157	0.219	0.303

[18] BC Hydro assumes 4% load reduction (i.e., energy conservation) in the low-end sensitivity. When combined with the load shifting assumption, this causes a greater average peak demand reduction than the Reference Case even though the load shifting assumption is higher in the Reference Case.

Input	Reference Case	Low-End Sensitivity	High-End Sensitivity
Customers with Electric Vehicle			
Average Coincident Peak Demand (kW)	2.64	2.70	2.67
Estimated Average Coincident Peak Demand Reduction (kW)	0.132	0.186	0.267
Average Non-Coincident Peak Demand (kW)	3.20	3.28	3.22
Estimated Average Non-Coincident Peak Demand Reduction (kW)	0.160	0.226	0.322

As explained in section 4.3.5.2 of Chapter 4, BC Hydro estimated the capacity savings associated with electric vehicle charging load based on the assumptions set out in the Reference Case and the low-end and high-end sensitivities. These estimates are shown in Table G-14 below.

Table G-14 Peak Demand Reduction per Electric Vehicle

Input	Reference Case	Low-End Sensitivity	High-End Sensitivity
Load Shifting %	75	50	90
Average Coincident Peak Demand (kW)	1.17	1.17	1.17
Estimated Average Coincident Peak Demand Reduction (kW)	0.88	0.59	1.05
Average Non-Coincident Peak Demand (kW)	1.54	1.54	1.54
Estimated Average Non-Coincident Peak Demand Reduction (kW)	1.16	0.77	1.39

For participants with an electric vehicle on the Optional Residential TOU Rate, the electric vehicle charging coincident and non-coincident peak demands are added to the household consumption coincident and non-coincident peak demands to estimate the total demand reduction for participants with an electric vehicle.

4.3 Step 3 – Estimate Cost of Service

BC Hydro estimated the embedded costs of Residential customers based on The Fiscal 2020 FACOS Study results provided in Table G-3 above. The forecast Customer-related cost, Energy-related cost, Generation, and Transmission demand-related cost and Distribution demand-related cost were escalated by the forecast annual general rate increases. This is shown in Table G-15 below.

Table G-15 Forecast Residential Embedded Costs

Fiscal Year	Forecast General Rate Change	Customer-Related Cost per Account-year ($/account)	Energy-Related Cost per kWh at Meter interface (¢/kWh)	Generation and Transmission Demand-Related Cost per 4CP at Meter interface ($/kW-year)	Distribution Demand-Related Cost per NCP at Meter Interface ($/kW-year)
F2020		135.15	3.96	243.76	116.90
F2021	-1.62%	132.96	3.89	239.81	115.01
F2022	1.00%	134.29	3.93	242.20	116.16
F2023	0.62%	135.12	3.96	243.71	116.88
F2024	0.97%	136.43	4.00	246.07	118.01
F2025	2.18%	139.40	4.08	251.43	120.58
F2026	4.89%	146.22	4.28	263.73	126.48
F2027	0.11%	146.38	4.29	264.02	126.62
F2028	1.30%	148.28	4.34	267.45	128.27
F2029	0.12%	148.46	4.35	267.77	128.42
F2030	-0.61%	147.56	4.32	266.14	127.64
F2031	2.00%	150.51	4.41	271.46	130.19
F2032	2.00%	153.52	4.50	276.89	132.79
F2033	2.00%	156.59	4.59	282.43	135.45
F2034	2.00%	159.72	4.68	288.08	138.16
F2035	2.00%	162.91	4.77	293.84	140.92
F2036	2.00%	166.17	4.87	299.72	143.74
F2037	2.00%	169.50	4.96	305.71	146.62
F2038	2.00%	172.88	5.06	311.82	149.55
F2039	2.00%	176.34	5.17	318.06	152.54

Based on the forecast participant, consumption, and coincident and non-coincident peak demand shifting estimates outlined in the sections above, we estimated the total embedded costs for Optional Residential TOU Rate participants under the Reference Case and the low-end and high-end sensitivities. This is shown in Table G-16, Table G-17, and Table G-18 below, respectively:

Table G-16 Reference Case Estimated Embedded Costs

Fiscal Year	Customer-Related Cost ($)	Energy-Related Cost ($)	Generation and Transmission Demand-Related Cost ($)	Distribution Demand-Related Cost ($)	Total Embedded Cost ($)
F2024	0	0	0	0	0
F2025	2,841,394	10,303,390	12,976,937	7,674,486	33,796,207
F2026	9,082,491	33,120,696	41,615,186	24,602,923	108,421,297
F2027	18,424,397	67,621,922	84,733,244	50,075,580	220,855,143
F2028	28,612,491	105,896,851	132,225,994	78,104,848	344,840,184
F2029	32,085,868	120,454,604	149,508,686	88,240,700	390,289,858
F2030	35,636,916	135,618,067	167,380,474	98,710,900	437,346,356
F2031	39,071,202	150,862,083	185,083,459	109,059,437	484,076,180
F2032	42,904,333	167,937,845	204,886,781	120,633,401	536,362,360
F2033	47,162,827	186,977,910	226,937,871	133,518,406	594,597,013
F2034	51,900,617	208,214,049	251,509,231	147,874,038	659,497,935
F2035	57,130,415	231,722,528	278,680,733	163,746,226	731,279,903
F2036	62,866,129	257,586,488	308,539,555	181,185,110	810,177,282
F2037	69,245,078	286,257,796	341,679,524	200,543,873	897,726,270
F2038	76,218,018	317,516,232	377,845,611	221,673,495	993,253,356
F2039	83,644,781	350,750,567	416,323,200	244,155,818	1,094,874,366

Table G-17 Low-End Sensitivity Estimated Embedded Costs

Fiscal Year	Customer-Related Cost ($)	Energy-Related Cost ($)	Generation and Transmission Demand-Related Cost ($)	Distribution Demand-Related Cost ($)	Total Embedded Cost ($)
F2024	0	0	0	0	0
F2025	1,699,502	6,267,246	8,078,575	4,796,857	20,842,180
F2026	5,453,343	20,235,631	26,077,952	15,482,871	67,249,797
F2027	11,111,356	41,522,543	53,496,636	31,758,127	137,888,662

Fiscal Year	Customer-Related Cost ($)	Energy-Related Cost ($)	Generation and Transmission Demand-Related Cost ($)	Distribution Demand-Related Cost ($)	Total Embedded Cost ($)
F2028	17,354,781	65,443,666	84,287,793	50,029,927	217,116,167
F2029	19,652,908	75,241,386	96,853,019	57,474,301	249,221,614
F2030	22,033,743	85,562,424	110,082,219	65,310,195	282,988,581
F2031	24,401,430	96,174,687	123,670,330	73,354,953	317,601,401
F2032	27,051,272	108,087,447	138,922,188	82,384,351	356,445,258
F2033	30,002,992	121,397,829	155,961,804	92,471,719	399,834,345
F2034	33,292,633	136,262,940	174,990,519	103,736,304	448,282,396
F2035	36,931,364	152,744,431	196,086,808	116,224,449	501,987,053
F2036	40,931,360	170,909,366	219,336,042	129,986,567	561,163,334
F2037	45,369,302	191,009,280	245,063,970	145,216,470	626,659,022
F2038	50,211,308	212,891,321	273,074,918	161,798,320	697,975,867
F2039	55,362,096	236,134,811	302,829,986	179,413,000	773,739,893

1 **Table G-18 High-End Sensitivity Estimated Embedded**
2 **Costs**

Fiscal Year	Customer-Related Cost ($)	Energy-Related Cost ($)	Generation and Transmission Demand-Related Cost ($)	Distribution Demand-Related Cost ($)	Total Embedded Cost ($)
F2024	0	0	0	0	0
F2025	10,200,534	34,655,693	41,630,793	24,518,970	111,005,990
F2026	32,116,586	109,575,210	131,309,989	77,316,718	350,318,504
F2027	64,007,052	219,472,347	262,251,833	154,369,511	700,100,742
F2028	97,078,881	335,130,578	398,904,274	234,710,127	1,065,823,861
F2029	104,383,099	364,810,180	431,189,449	253,514,724	1,153,897,452
F2030	111,112,970	393,341,248	461,539,053	271,144,657	1,237,137,928
F2031	116,097,159	417,190,122	485,399,471	284,898,754	1,303,585,506
F2032	121,499,423	443,415,227	511,452,514	299,902,925	1,376,270,089
F2033	127,318,017	472,099,811	539,736,439	316,175,850	1,455,330,117
F2034	133,651,487	503,668,523	570,699,149	333,977,445	1,541,996,603
F2035	140,466,525	538,083,439	604,242,992	353,246,946	1,636,039,902
F2036	147,726,640	575,301,292	640,260,105	373,917,337	1,737,205,374
F2037	156,046,475	617,296,471	681,201,074	397,436,840	1,851,980,860
F2038	165,357,992	663,733,855	726,735,321	423,615,250	1,979,442,417

Fiscal Year	Customer-Related Cost ($)	Energy-Related Cost ($)	Generation and Transmission Demand-Related Cost ($)	Distribution Demand-Related Cost ($)	Total Embedded Cost ($)
F2039	175,430,435	713,575,652	775,791,926	451,832,800	2,116,630,813

5 Calculate Revenue to Cost Ratio

As mentioned in section 2 above, BC Hydro assesses cost recovery by calculating the revenue to cost ratio for a group of customers (i.e., by dividing the revenue collected from a group of customers by the cost to serve those customers). A revenue to cost ratio of one means the revenue recovered from a customer class or customer group equals the cost of providing service to this customer class or group.

As also mentioned in section 2 above, based on BC Hydro's Fiscal 2020 FACOS Study, the revenue to cost ratio of the Residential rate class was 93%. A comparable revenue to cost ratio for the Optional Residential TOU Rate would provide reasonable certainty that the rate will have the same level of cost recovery as the Residential rate class, and therefore, will not result in cost shifting between participants and non-participants.

Table G-19, Table G-20, and Table G-21 below provide the revenue to cost ratio calculation for the Reference Case, and the low-end and high-end sensitivities.

Our cost of service assessment concludes that the proposed Optional Residential TOU Rate will result in lower revenue to cost ratios than the Residential class revenue to cost ratios in the near and mid-term; however, over the long term (i.e., by fiscal 2035 (Year 11)), the forecast revenue to cost ratio of the Optional Residential TOU Rate participants is expected to be similar to all Residential rate class customers at 93.1%. After fiscal 2035 the forecast revenue to cost ratio of the Optional Residential TOU Rate is expected to exceed that of the Residential rate class, reaching 94.5% by fiscal 2039 (Year 15).

Table G-19 Reference Case Revenue to Cost Ratio Calculation

Year	Fiscal Year	Revenue ($)	Embedded Cost and Implementation Cost ($)	Revenue to Cost Ratio
Year 0	F2024	-	-	-
Year 1	F2025	30,216,460	36,414,431	83.0%
Year 2	F2026	97,231,530	112,054,075	86.8%
Year 3	F2027	198,546,092	224,853,302	88.3%
Year 4	F2028	311,060,795	349,403,414	89.0%
Year 5	F2029	353,939,046	394,918,958	89.6%
Year 6	F2030	398,552,695	441,006,502	90.4%
Year 7	F2031	443,695,632	486,783,269	91.1%
Year 8	F2032	494,309,217	539,164,501	91.7%
Year 9	F2033	550,796,293	597,657,981	92.2%
Year 10	F2034	613,852,276	662,665,131	92.6%
Year 11	F2035	683,715,949	734,560,714	93.1%
Year 12	F2036	760,647,017	813,578,990	93.5%
Year 13	F2037	845,982,755	901,255,381	93.9%
Year 14	F2038	939,082,675	996,914,601	94.2%
Year 15	F2039	1,038,145,886	1,098,669,121	94.5%

Table G-20 Low-End Sensitivity Revenue to Cost Ratio Calculation

Year	Fiscal Year	Revenue ($)	Embedded Cost and Implementation Cost ($)	Revenue to Cost Ratio
Year 0	F2024	-	-	-
Year 1	F2025	18,479,417	23,460,405	78.8%
Year 2	F2026	59,738,714	70,882,575	84.3%
Year 3	F2027	122,646,059	141,886,822	86.4%
Year 4	F2028	193,469,861	221,679,397	87.3%
Year 5	F2029	222,681,501	253,850,714	87.7%
Year 6	F2030	253,454,303	286,648,726	88.4%

Year	Fiscal Year	Revenue ($)	Embedded Cost and Implementation Cost ($)	Revenue to Cost Ratio
Year 7	F2031	285,286,930	320,308,490	89.1%
Year 8	F2032	321,045,223	359,247,398	89.4%
Year 9	F2033	361,026,222	402,895,312	89.6%
Year 10	F2034	405,704,543	451,449,592	89.9%
Year 11	F2035	455,272,383	505,267,864	90.1%
Year 12	F2036	509,938,523	564,565,042	90.3%
Year 13	F2037	570,444,816	630,188,132	90.5%
Year 14	F2038	636,338,032	701,637,112	90.7%
Year 15	F2039	706,361,569	777,534,648	90.8%

Table G-21 High-End Sensitivity Revenue to Cost Ratio Calculation

Year	Fiscal Year	Revenue ($)	Embedded Cost and Implementation Cost ($)	Revenue to Cost Ratio
Year 0	F2024	-	-	-
Year 1	F2025	100,304,774	113,624,215	88.3%
Year 2	F2026	317,528,582	353,951,281	89.7%
Year 3	F2027	636,051,353	704,098,902	90.3%
Year 4	F2028	971,646,774	1,070,387,090	90.8%
Year 5	F2029	1,057,930,068	1,158,526,551	91.3%
Year 6	F2030	1,140,697,026	1,240,798,073	91.9%
Year 7	F2031	1,210,824,063	1,306,292,595	92.7%
Year 8	F2032	1,288,040,098	1,379,072,229	93.4%
Year 9	F2033	1,372,615,839	1,458,391,084	94.1%
Year 10	F2034	1,465,814,971	1,545,163,799	94.9%
Year 11	F2035	1,567,559,774	1,639,320,714	95.6%
Year 12	F2036	1,677,758,008	1,740,607,082	96.4%
Year 13	F2037	1,802,166,109	1,855,509,970	97.1%
Year 14	F2038	1,939,830,360	1,983,103,662	97.8%
Year 15	F2039	2,087,732,615	2,120,425,569	98.5%

BC Hydro Optional Residential Time-of-Use Rate Application

Appendix H

Economic Assessment

Table of Contents

List of Figures

List of Tables

1 Introduction

In this Appendix, BC Hydro provides the calculation and results of our analysis of the economic impacts on ratepayers from the proposed Optional Residential TOU Rate.

The Optional Residential TOU Rate is an "add-on" rate that applies year-round and every day of the year (i.e., weekdays and weekends and holidays). Participating customers will still be billed for their total electricity usage during a billing period at their existing Residential rate.[1] They will then receive a 5-cent credit for each kWh of electricity consumed during the Overnight period (11 p.m. to 7 a.m.) and a 5-cent additional charge for each kWh of electricity consumed during the On-Peak period (4 p.m. to 9 p.m.). No credit or additional charge will be applied to consumption during the Off-Peak period (9 p.m. to 11 p.m. and 7 a.m. to 4 p.m.).

BC Hydro set the Optional Residential TOU Rate to collect, on average, the same amount of revenue, assuming customers who enrol in the Optional Residential TOU Rate do not shift their consumption from the On-Peak period. This was done by applying a credit for every kWh consumed during the Overnight period and an additional charge, of the same amount, for every kWh consumed during the On-Peak period. This approach works because, on average, Rate Schedule 1101 (**RS 1101 or RIB Rate**) customers consume the same amount of electricity, approximately 26% each, during these two periods each year.

Over the longer-term, the rate is expected to deliver benefits to all ratepayers. Our economic assessment shows that the proposed Optional Residential TOU Rate can achieve a benefit to cost ratio of greater than one by fiscal 2033 (a 9-year period). Over the longer-term, the rate is expected to deliver benefits to all ratepayers.

[1] Most of BC Hydro's Residential customers living in the integrated service area take service under Rate Schedule 1101, the Residential Inclining Block Rate and a small number of farm customers take service under RS 1151 Exempt Residential Service rate.

This Appendix is structured as follows:

- Section 2 summarizes BC Hydro's ratepayer economic analysis framework;
- Section 3 explains how we forecast the benefit of the Optional Residential TOU Rate;
- Section 4 explains how we estimated the costs of the Optional Residential TOU Rate; and,
- Section 5 presents the economic assessment results for the Reference Case, and the low-end and high-end sensitivities.

2 BC Hydro's Ratepayer Economic Analysis Framework

This section summarizes our ratepayer economic analysis framework. The framework calculates a benefit to cost ratio using the following formula:

$$\frac{Forecast\ Value\ of\ Capacity\ Savings}{(Estimated\ Implementation\ Cost + Forecast\ Revenue\ Loss)}$$

A benefit to cost ratio greater than one indicates that the estimated value of capacity savings from the Optional Residential TOU Rate exceeds the forecast revenue loss from the bill savings that participants are expected to achieve as well as the estimated implementation costs, resulting in benefits to all BC Hydro customers over time. A benefit to cost ratio of one indicates no impact on ratepayers – the value of the capacity savings equals the forecast revenue loss from participant bill savings and the implementation costs. A benefit to cost ratio less than one indicates a negative impact on non-participating ratepayers because the revenue loss and implementation costs exceed the estimated value of the capacity savings.

Table H-1 below summarizes the benefits and costs considered for the Optional Residential TOU Rate.

Table H-1 Economic Assessment of BC Hydro Benefits and Costs

Benefit	Cost
Forecast value of capacity savings: • Non-bulk transmission and distribution capacity savings; and, • Generation capacity savings.	• Estimated implementation costs (refer to section 4.8.4 of Chapter 4); and, • Forecast revenue loss.

3 Forecast Benefit of the Optional Residential TOU Rate

The Optional Residential TOU Rate is expected to deliver capacity savings to meet customers' future electricity needs, which will benefit all ratepayers.

As discussed in section 4.3 of Chapter 4, BC Hydro developed Reference Case and low-end and high-end sensitivity assumptions for the Optional Residential TOU Rate. These assumptions were used to estimate the capacity savings benefits from the Optional Residential TOU Rate through the following three step process:

- **Step 1 – Forecast Participants:** forecast the number of participants with electric vehicles and without electric vehicles on the Optional Residential TOU Rate;
- **Step 2 – Forecast Consumption:** forecast the shift (i.e., to other periods) and reduction (i.e., conservation) in household usage and electric vehicle charging consumption during the On-Peak period by participants in the Optional Residential TOU Rate to determine the resulting capacity savings; and,
- **Step 3 – Estimate Value of Capacity Savings**: estimate the value of the forecast capacity savings by applying the reference prices set out in Appendix L of BC Hydro's 2021 Integrated Resource Plan Application.

3.1 Step 1 - Forecast Participants

Table H-2 below provides the estimated number of participants by fiscal year under the assumptions set out in the Reference Case, and the low-end and high-end sensitivities.[2]

Table H-2 Optional Residential TOU Rate - Participation Forecast

Fiscal Year	Total Number of Residential Customers	Reference Case Participation Forecast		Low-End Sensitivity Participation Forecast		High-End Sensitivity Participation Forecast	
		No EV	With EV	No EV	With EV	No EV	With EV
F2024	1,937,455	0	0	0	0	0	0
F2025	1,963,798	14,077	6,306	7,941	4,250	61,736	11,437
F2026	1,988,250	41,596	20,519	23,467	13,829	182,430	37,216
F2027	2,010,571	81,251	44,616	45,837	30,070	356,342	80,923
F2028	2,032,932	118,472	74,486	66,836	50,202	519,586	135,099
F2029	2,055,293	120,960	95,163	68,239	64,138	530,496	172,604
F2030	2,077,609	122,464	119,051	69,088	80,237	537,093	215,931
F2031	2,099,100	116,848	142,750	65,919	96,209	512,461	258,914
F2032	2,122,192	110,629	168,847	62,411	113,799	485,189	306,251
F2033	2,145,284	103,729	197,463	58,519	133,087	454,926	358,154
F2034	2,168,376	96,195	228,755	54,268	154,177	421,883	414,909
F2035	2,191,468	87,935	262,745	49,608	177,085	385,657	476,559
F2036	2,214,560	78,856	299,464	44,487	201,833	345,842	543,158
F2037	2,237,652	69,854	338,683	39,408	228,265	306,362	614,293
F2038	2,260,744	60,984	379,876	34,404	256,028	267,458	689,005
F2039	2,283,836	52,295	422,036	29,502	284,444	229,351	765,476

3.2 Step 2 - Forecast Consumption

As set out in section 3.1 above, participants on the Optional Residential TOU Rate are categorized as:

[2] As discussed further in Section 4.3 of Chapter 4, BC Hydro assumes a six-year S-shaped participation ramp up.

- Participants without an electric vehicle; and,
- Participants with an electric vehicle.

The average annual consumption of the customers without an electric vehicle who can achieve bill savings on the Optional Residential TOU Rate is 11,348 kWh.

The average annual consumption of customers with an electric vehicle that can achieve bill savings on the Optional Residential TOU Rate, excluding customers in apartments, is 14,684 kWh.[3]

Table H-3, Table H-4, and Table H-5 below provide the breakdown of this annual average consumption by period (i.e., On-Peak, Off-Peak, and Overnight) using the assumptions set out in the Reference Case, and the low-end and high-end sensitivities.[4]

Table H-3 Reference Case Average Consumption of Participants

	Participant with no Electric Vehicle		Participant with Electric Vehicle	
	Pre-shift Consumption (kWh)	Post-shift Consumption (kWh)	Pre-shift Consumption (kWh)	Post-shift Consumption (kWh)
Total Consumption	11,348	11,348	14,684	14,684
On-Peak	2,932	2,785	4,001	3,067
Off-Peak	5,444	5,517	7,033	7,264
Overnight	2,972	3,046	3,649	4,352

[3] The average consumption of participants with electric vehicles is higher due to the exclusion of apartments and the inclusion of electric vehicle charging load. Section 4.3.5.1 of Chapter 4 provides further details on the assumptions used for average electric vehicle charging load.

[4] The average annual consumption is different in each case due to the different participation and consumption shifting assumptions in the Reference Case and in the low-end and high-end sensitivities.

Table H-4 Low Sensitivity Case Average Consumption of Participants

	Participant with no Electric Vehicle		Participant with Electric Vehicle	
	Pre-shift Consumption (kWh)	Post-shift Consumption (kWh)	Pre-shift Consumption (kWh)	Post-shift Consumption (kWh)
Total Consumption	11,475	11,357	15,022	14,894
On-Peak	2,964	2,757	4,093	3,339
Off-Peak	5,505	5,549	7,195	7,348
Overnight	3,006	3,050	3,733	4,208

Table H-5 High Sensitivity Case Average Consumption of Participants

	Participant with no Electric Vehicle		Participant with Electric Vehicle	
	Pre-shift Consumption (kWh)	Post-shift Consumption (kWh)	Pre-shift Consumption (kWh)	Post-shift Consumption (kWh)
Total Consumption	11,016	11,016	14,747	14,747
On-Peak	2,846	2,561	4,019	2,774
Off-Peak	5,284	5,427	7,063	7,401
Overnight	2,885	3,028	3,665	4,572

The average consumption amounts above are used to estimate customers' load shifting and bill savings. To identify customers' peak demand reduction to estimate capacity savings, BC Hydro calculated the average participant load shape using the consumption above to identify the average coincident peak demand[5] of customers who are expected to have bill savings under the Optional Residential TOU Rate[6] as shown in Table H-6 below.

5 Coincident Peak (also referred to as four coincident peak or 4CP) is the average monthly peak demand of a customer class at the time of the system's peak demand for four winter months.

6 The average hourly consumption of customers who are expected to save under the Optional Residential TOU Rate that coincides with the peak demand hour of BC Hydro's system in November, December, January, and February in fiscal 2022.

Table H-6 Household Consumption of Peak Demand Reduction

Input	Reference Case	Low-End Sensitivity	High-End Sensitivity
Customers with No Electric Vehicle			
Average Coincident Peak Demand (kW)	2.54	2.56	2.46
Load Shifting (%)	5	3	10
Load Reduction (%)	0	4[7]	0
Estimated Average Coincident Peak Demand Reduction (kW)	0.127	0.176	0.246
Customers with Electric Vehicle			
Average Coincident Peak Demand (kW)	2.64	2.70	2.67
Load Shifting (%)	5	3	10
Load Reduction (%)	0	4[8]	0
Estimated Average Coincident Peak Demand Reduction (kW)	0.132	0.186	0.267

As explained in section 4.3.5.2 of Chapter 4, BC Hydro estimated the capacity savings associated with electric vehicle charging load based on the assumptions set out in the Reference Case and the low-end and high-end sensitivities. These estimates are shown in Table H-7 below.

Table H-7 Peak Demand Reduction per Electric Vehicle

Input	Reference Case	Low-End Sensitivity	High-End Sensitivity
Average Peak Demand (kW)	1.17	1.17	1.17
Load Shifting %	75%	50%	90%
Estimated Average Coincident Peak Demand Reduction (kW)	0.88	0.59	1.05

7 BC Hydro assumes 4% load reduction (i.e., energy conservation) in the low-end sensitivity. When combined with the load shifting assumption, this causes a greater average peak demand reduction than the Reference Case even though the load shifting assumption is higher in the Reference Case.

8 Ibid.

Table H-8 below combines the participation estimates set out in section 4.1 above with the estimated shift (i.e., to other periods) and reduction (i.e., conservation) in household usage and electric vehicle charging consumption during the On-Peak period by participants in the Optional Residential TOU Rate to determine the resulting capacity savings.

Table H-8 Estimated Capacity Savings

Fiscal Year	Reference Case Estimated Capacity Savings (MW)	Low-End Sensitivity Estimated Capacity Savings (MW)	High-End Sensitivity Estimated Capacity Savings (MW)
F2024	0	0	0
F2025	8	3	30
F2026	26	11	94
F2027	55	23	195
F2028	90	38	306
F2029	111	48	358
F2030	136	58	417
F2031	159	69	468
F2032	185	80	524
F2033	213	93	585
F2034	243	106	652
F2035	276	121	724
F2036	312	137	802
F2037	351	154	886
F2038	391	172	976
F2039	433	191	1067

3.3 Estimated Value of Capacity Savings

To estimate the value of the forecast capacity savings set out in Table H-8 above, BC Hydro applied the reference prices set out in Appendix L of BC Hydro's 2021 Integrated Resource Plan Application.[9]

Figure H-1 below provides the generation and non-bulk transmission and distribution capacity references prices set out in the 2021 Integrated Resource Plan Application in fiscal 2022 dollars.

Figure H-1 Reference Prices (Fiscal 2022$) for the Duration of the 2021 Integrated Resource Plan

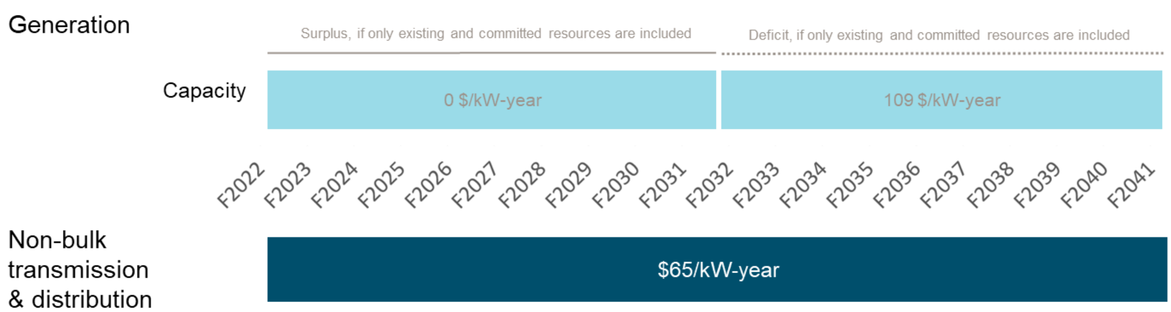


Table H-9 below applies these reference prices to the forecast capacity savings set out in Table H-8 above to estimate the value of the forecast capacity savings from the Optional Residential TOU Rate under the Reference Case and the low-end and high-end sensitivities.[10]

---

[9] https://docs.bcuc.com/Documents/Proceedings/2021/DOC_65194_B-1-BCH-IntegratedResourcePlan-Public.pdf.

[10] In Table H-9, the amounts provided in Figure H-1 are escalated by an assumed inflation rate of 2% for each year. In addition, the generation capacity long-run marginal cost of $109/kW-year is adjusted by an effective load carrying capability factor of 66% (explained Appendix H-2 of BC Hydro's 2021 Integrated Resource Plan Application) and a 7% line loss benefit is added to the estimated capacity benefit.

Table H-9 Estimated Value of Capacity Savings

Fiscal Year	Non-bulk Transmission and Distribution Marginal Cost ($/kW-Year)	Generation Capacity Long-Run Marginal Cost ($/kW-Year)	Reference Case Value of Estimated Capacity Savings ($)	Low-End Sensitivity Value of Estimated Capacity Savings ($)	High-End Sensitivity Value of Estimated Capacity Savings ($)
F2024	65.00	0	0	0	0
F2025	66.43	0	602,916	251,663	2,240,108
F2026	67.76	0	1,960,787	822,040	7,092,485
F2027	69.11	0	4,258,981	1,793,735	14,966,786
F2028	70.50	0	7,081,507	2,998,401	24,031,976
F2029	71.91	0	8,919,471	3,806,017	28,691,359
F2030	73.34	0	11,082,629	4,758,444	34,068,489
F2031	74.81	0	13,237,605	5,715,737	38,971,433
F2032	76.31	84.45	33,020,494	14,322,625	93,730,210
F2033	77.83	86.14	38,794,986	16,890,178	106,754,968
F2034	79.39	87.87	45,275,315	19,772,163	121,328,596
F2035	80.98	89.62	52,499,185	22,985,770	137,521,229
F2036	82.60	91.42	60,507,522	26,549,647	155,407,741
F2037	84.25	93.24	69,315,832	30,468,047	175,154,331
F2038	85.93	95.11	78,857,302	34,711,456	196,609,027
F2039	87.65	97.01	88,958,153	39,202,943	219,369,643

4 Forecast Costs of the Optional Residential TOU Rate

There are two costs considered in this economic assessment:

1. **Implementation Costs:** These costs are assumed to be the same in the Reference Case and in the low-end and high-end sensitivities; and,
2. **Estimated Revenue Loss:** This is the forecast revenue reduction from participants' bill savings under the Optional Residential TOU Rate. This revenue loss was estimated using the Reference Case and low-end and high-end sensitivity assumptions.

4.1 Implementation Costs

As outlined in section 4.8.4 of Chapter 4, BC Hydro will incur incremental technology, operations and customer education and communication costs to implement the Optional Residential TOU Rate. The implementation costs are not expected to vary much based on participation or customer response. Therefore, these costs are assumed to be the same in the Reference Case and in the low-end and high-end sensitivities. Table H-10 below provides the estimated implementation costs for the Optional Residential TOU Rate.

Table H-10 Estimated Implementation Costs

Fiscal Year	Estimated Technology Costs ($)	Estimated Operations Costs ($)	Estimated Customer Education and Communications Costs ($)	Estimated Total Implementation Costs ($)
F2024	0	104,604	0	104,604
F2025	1,082,093	1,472,638	63,493	2,618,224
F2026	2,164,186	1,308,731	159,861	3,632,778
F2027	2,164,186	1,568,700	265,274	3,998,160
F2028	2,164,186	2,031,637	367,407	4,563,229
F2029	2,164,186	2,035,214	429,699	4,629,099
F2030	1,082,093	2,092,353	485,699	3,660,145
F2031	0	2,166,390	540,699	2,707,089
F2032	0	2,206,441	595,699	2,802,140
F2033	0	2,410,268	650,699	3,060,967
F2034	0	2,471,496	695,699	3,167,196
F2035	0	2,540,112	740,699	3,280,811
F2036	0	2,616,009	785,699	3,401,708
F2037	0	2,698,411	830,699	3,529,110
F2038	0	2,785,546	875,699	3,661,245
F2039	0	2,874,056	920,699	3,794,755

4.2 Estimated Revenue Loss

Participants in the Optional Residential TOU Rate can achieve bill savings if their consumption pattern results in them receiving more credits than additional charges under the Optional Residential TOU Rate. These bill savings will result in a reduction in revenue, which is treated as a cost in this economic assessment.

Table H-11 below provides the forecast revenue loss from the Optional Residential TOU Rate. The revenue loss is calculated by comparing the revenue BC Hydro would have collected from customers under the RIB Rate to the revenue that BC Hydro would expect to collect from participating customers on the Optional Residential TOU Rate, using the assumptions set out in the Reference Case, and the low-end and high-end sensitivities.

Table H-11 Forecast Revenue Loss

Fiscal Year	Reference Case Forecast Revenue Loss ($)	Low-End Sensitivity Forecast Revenue Loss ($)	High-End Sensitivity Forecast Revenue Loss ($)
F2024	0	0	0
F2025	588,795	301,190	2,468,154
F2026	1,861,021	945,226	7,600,767
F2027	3,926,671	1,979,217	15,586,253
F2028	6,331,629	3,162,200	24,263,867
F2029	7,692,931	3,788,495	27,889,442
F2030	9,247,778	4,500,667	31,937,718
F2031	10,697,645	5,148,403	35,226,565
F2032	12,293,779	5,861,483	38,845,183
F2033	14,042,914	6,642,723	42,804,444
F2034	15,955,762	7,497,038	47,134,938
F2035	18,032,548	8,424,369	51,831,195
F2036	20,274,052	9,424,902	56,888,553
F2037	22,677,220	10,499,258	62,361,423
F2038	25,208,966	11,632,552	68,169,240
F2039	27,805,230	12,795,733	74,153,775

5 Calculate Benefit to Cost Ratio

As mentioned in section 2 above, the economic impacts of the Optional Residential TOU Rate are assessed by calculating the benefit to cost ratio of the rate (i.e., by dividing the benefit of the rate by the costs of offering the rate). The benefit to cost ratio in each year is a cumulative calculation of the benefits and costs from the inception of the rate in fiscal 2025.

The benefit to cost ratio is calculated using the following formula:

$$\frac{Forecast\ Capacity\ Savings}{(Estimated\ Implementation\ Cost + Forecast\ Revenue\ Loss)}$$

A benefit to cost ratio greater than one indicates that the estimated value of capacity savings from the Optional Residential TOU Rate exceeds the forecast revenue loss from the bill savings that participants are expected to achieve as well as the estimated implementation costs, resulting in benefits to all BC Hydro customers over time. A benefit to cost ratio of one indicates no impact on ratepayers – the value of the capacity savings equals the forecast revenue loss from participant bill savings and the implementation costs. A benefit to cost ratio less than one indicates a negative impact on non-participating ratepayers because the revenue loss and implementation costs exceed the estimated value of the capacity savings.

Table H-12, Table H-13, and Table H-14 below provide the benefit to cost ratio calculation for the Reference Case, and the low-end and high-end sensitivities. A 5% discount rate[11] is used to calculate the net present value of all benefits and costs to derive the benefit to cost ratios.

[11] Based on BC Hydro's Weighted Average Cost of Capital (**WACC**) for fiscal 2023 and previous years.

Table H-12 Reference Case Benefit to Cost Ratio Calculation

Year	Fiscal Year	Capacity Saving Benefit ($)	Implementation Cost & Revenue Loss ($)	Benefit to Cost Ratio
Year 0	F2024			-
Year 1	F2025	574,206	3,054,304	0.19
Year 2	F2026	2,352,698	8,037,342	0.29
Year 3	F2027	6,031,766	14,883,109	0.41
Year 4	F2028	11,857,739	23,846,336	0.50
Year 5	F2029	18,846,378	33,500,969	0.56
Year 6	F2030	27,116,406	43,133,060	0.63
Year 7	F2031	36,524,125	52,659,554	0.69
Year 8	F2032	58,873,695	62,877,066	0.94
Year 9	F2033	83,881,289	73,902,380	1.14
Year 10	F2034	111,676,404	85,642,218	1.30
Year 11	F2035	142,371,591	98,103,698	1.45
Year 12	F2036	176,064,443	111,287,247	1.58
Year 13	F2037	212,824,109	125,185,024	1.70
Year 14	F2038	252,652,405	139,766,442	1.81
Year 15	F2039	295,442,797	154,966,575	1.91

Table H-13 Low-End Sensitivity Benefit to Cost Ratio Calculation

Year	Fiscal Year	Capacity Saving Benefit ($)	Implementation Cost & Revenue Loss ($)	Benefit to Cost Ratio
Year 0	F2024			-
Year 1	F2025	239,679	2,780,394	0.09
Year 2	F2026	985,294	6,932,779	0.14
Year 3	F2027	2,534,789	12,096,261	0.21
Year 4	F2028	5,001,581	18,451,991	0.27
Year 5	F2029	7,983,695	25,047,397	0.32
Year 6	F2030	11,534,519	31,137,120	0.37

Year	Fiscal Year	Capacity Saving Benefit ($)	Implementation Cost & Revenue Loss ($)	Benefit to Cost Ratio
Year 7	F2031	15,596,586	36,719,872	0.42
Year 8	F2032	25,290,702	42,583,753	0.59
Year 9	F2033	36,178,262	48,838,838	0.74
Year 10	F2034	48,316,654	55,385,753	0.87
Year 11	F2035	61,755,958	62,229,530	0.99
Year 12	F2036	76,539,795	69,371,866	1.10
Year 13	F2037	92,697,651	76,811,409	1.21
Year 14	F2038	110,229,295	84,535,816	1.30
Year 15	F2039	129,086,581	92,516,124	1.40

Table H-14 High-End Sensitivity Benefit to Cost Ratio Calculation

Year	Fiscal Year	Capacity Saving Benefit ($)	Implementation Cost & Revenue Loss ($)	Benefit to Cost Ratio
Year 0	F2024			-
Year 1	F2025	2,133,436	4,844,170	0.44
Year 2	F2026	8,566,530	15,033,326	0.57
Year 3	F2027	21,495,402	31,951,078	0.67
Year 4	F2028	41,266,568	55,667,201	0.74
Year 5	F2029	63,746,999	81,146,330	0.79
Year 6	F2030	89,169,430	107,710,003	0.83
Year 7	F2031	116,865,700	134,668,743	0.87
Year 8	F2032	180,305,996	162,857,290	1.11
Year 9	F2033	249,121,200	192,422,543	1.29
Year 10	F2034	323,606,433	223,303,690	1.45
Year 11	F2035	404,012,247	255,526,538	1.58
Year 12	F2036	490,549,093	289,098,412	1.70
Year 13	F2037	583,437,174	324,041,568	1.80
Year 14	F2038	682,738,093	360,320,845	1.89
Year 15	F2039	788,258,642	397,815,420	1.98

BC Hydro Optional Residential Time-of-Use Rate Application

Appendix I

Relief from Reporting Requirements under BCUC Order No. G-92-19

Table of Contents

List of Tables

1 Introduction

As discussed in section 4.8.5 of Chapter 4, BC Hydro proposes to submit an evaluation report of the Optional Residential TOU Rate in fiscal 2029.

This evaluation report will include information on the number of customers installing a second BC Hydro meter to facilitate their electric vehicle charging and BC Hydro's incremental costs to administer these additional electric vehicle charging meters. This information duplicates certain information contemplated in Directive No. 2 of Order No. G-92-19. Therefore, as discussed in section 1.3 of Chapter 1, our orders sought in this Application include an order to:

- Rescind Directive 2 of Order No. G-92-19 so that reporting requirements which correspond to Appendix C of our Annual Report to the Commission regarding Residential Service Customers Charging Zero Emission Vehicles at their Dwelling are no longer required; and,
- Incorporate any of the reporting requirements set out in Directive No. 2 of Order No. G-92-19 that the Commission still considers helpful into the scope of the proposed evaluation report on the Optional Residential TOU Rate to be filed in fiscal 2029.

BC Hydro submits that this is a more efficient and effective approach that will consolidate reporting requirements and provide information in a more coordinated and informative manner.

This Appendix is structured as follows:

- Section 2 provides the background of BC Hydro's January 15, 2019 Electric Tariff Terms and Conditions Amendments Application (**Amendments Application**) and Order No. G-92-19; and,

- Section 3 provides a summary of the reporting information that has been provided to the Commission in accordance with Directive No. 2 of Order No. G-92-19 to date.

2 Background

On January 15, 2019, BC Hydro filed its Amendments Application to facilitate charging of zero-emission vehicles by Residential customers at their dwelling. BC Hydro proposed these amendments in consideration of the growing number of Residential customers residing in multi-unit Residential buildings and the increasing number of zero-emission vehicles being brought to the market.

The amendments were to:

1. Clarify that a dwelling may include spaces such as parking stalls, storage areas, garage areas and similar spaces or areas used for the benefit of the customer;
2. Allow more than one meter to be installed at a dwelling; and,
3. Implement aggregate billing for consumption from multiple meters under one account so that customers would pay one Basic Charge and so that the Step 1 Energy Charge threshold of 675 kWh per month would apply to all consumption in aggregate.

On April 29, 2019, the Commission approved the Amendments Application by Order No. G-92-19[1] and directed BC Hydro to file information regarding its experience resulting from the amended terms and conditions starting with its Fiscal 2020 Annual Report to the BCUC.

[1] BC Hydro Electric Tariff Terms and Conditions Amendments Application, Order No. G-92-19 (https://www.ordersdecisions.bcuc.com/bcuc/orders/en/400728/1/document.do), Directive No. 2.

In Directive No. 2 of the Order the BCUC directed that the reporting should include, but not be limited to, the following:

(a) Number of accounts that have installed additional meters and whether BC Hydro is meeting the needs of customers;

(b) Analysis of having one Basic Charge per account with additional meters and any plans to review the Basic Charge in a future process; and,

(c) Analysis as to whether additional amendments to the Electric Tariff are appropriate for other rate classes that may have similar multi-unit characteristics such as commercial strata developments.

3 Order No. G-92-19 Compliance Information

The sub-sections below summarize the reporting information that has been provided to the Commission in accordance with Directive No. 2 of Order No. G-92-19.

3.1 Part A – Number of Accounts that have Installed Additional Meters and Whether BC Hydro is Meeting the Needs of Customers

BC Hydro determines the annual number of accounts with an additional meter by the change in the number of active Residential accounts being billed in aggregate. This approach allows for the exclusion of accounts that have closed during the year. Additionally, in October 2019, BC Hydro implemented a tracking mechanism to identify secondary meter installations for the purpose of electric vehicle charging.

Table I-1 below provides the number of accounts where customers have installed an additional meter where the additional meter is for electric vehicle charging. BC Hydro notes the number of customers who have an additional meter for electric vehicle charging has been updated from what we previously provided in our Fiscal 2020, Fiscal 2021, and Fiscal 2022 Annual Report to the Commission. These updates have been done to remove the non-Residential service accounts that were included in the previous reporting as well as any changes up to December 31, 2022.

Table I-1 Number of Residential Service Accounts with an Additional Meter

Fiscal Year	Cumulative Total of Active Aggregate Billing Accounts	Change in Number of Active Aggregate Billing Accounts	Cumulative Total of Active Aggregate Billing Accounts for Electric Vehicle Charging	Change in Number of Active Aggregate Billing Accounts for Electric Vehicle Charging
2020*	496	496	16	16
2021	1,095	599	51	35
2022	1,903	808	69	18
2023**	2,352	449	84	15

* As of April 29, 2019, i.e., the effective date of BCUC Order No. G-92-19.

** As of December 31, 2022, i.e., quarter three of fiscal year 2023.

To assess whether customer needs are being met, we surveyed customers who have an account with an additional meter. We did not issue surveys to all of these customers as some do not have an available email address or have requested that BC Hydro not contact them. Table I-2 below summarizes the response rate for these surveys.

Table I-2 Survey of Residential Customers with an Additional Meter

Fiscal Year	Number of Surveys Issued	Total Number of Responses Received	Response Rate (%)	Number of Responses Received for Electric Vehicle Charging	Response Rate (%)
2020	210	28	13	3	1
2021	492	72	15	7	1

Given the low number of responses from customers with an additional meter for electric vehicle charging, BC Hydro is unable to accurately determine the level of satisfaction with the program, but notes that:

- In fiscal 2020, the three electric vehicle charging respondents felt the installation of the second meter met their needs and two indicated they were extremely satisfied with the service;
- In fiscal 2021, the seven electric vehicle charging respondents felt the installation of the second meter met their needs, five indicated they strongly agreed and two indicated they somewhat agreed; and,
- General comments included concerns about the costs to install an additional meter and some dissatisfaction with aggregate billing.

Given that the two previous surveys had a low response rate and provided little insight into the customer experience, a survey was not conducted in fiscal 2022. Instead, an analysis of customer complaints to BC Hydro was undertaken to determine if additional meters installed for electric vehicle charging were the subject of any comments received. A review of customer complaints between April 29, 2019 and March 31, 2022 determined that no complaints or escalations were related to the additional meters installed for electric vehicle charging.

3.2 Part B - Analysis of Having One Basic Charge per Account with Additional Meters and Any Plans to Review the Basic Charge in a Future Process

In our Fiscal 2020, Fiscal 2021, and Fiscal 2022 Annual Reports to the Commission, BC Hydro noted that the number of additional meters used for electric vehicle charging purposes was small and therefore, BC Hydro was unable to perform meaningful analysis with respect to having one basic charge per account with additional meters. To date, there continues to be insufficient data available to conduct useful analysis.

The Optional Residential TOU Rate does not include an additional basic charge for customers with a separate meter for electric vehicle charging load. However, the basic charge will continue to be billed on the concurrent service the customer receives. At this time, BC Hydro does not see a need to apply an additional basic charge to separately metered electric vehicle charging load. This would add additional administration cost as well as complexity. It would harm customer understanding by creating different pricing for the Optional Residential TOU Rate depending on whether a customer applied the rate to their separately metered load. BC Hydro will continue to monitor the number of accounts with additional meters for electric vehicle charging to determine whether an increase in the number of these accounts warrants further consideration of an additional basic charge for separately metered electric vehicle charging load in the future.

3.3 Part C - Analysis as to Whether Additional Amendments to the Electric Tariff are Appropriate for Other Rate Classes that may have Similar Multi-Unit Characteristics such as Commercial Strata Developments

BC Hydro's Street Lighting Rate Application, approved by Order No. G-312-21, amended the Electric Tariff for mixed use loads. BC Hydro expects these amendments to have a favourable economic impact on all ratepayers because they remove barriers to electrification and load growth.[2] Specifically, for electric vehicle growth, the amendments facilitate metering and billing for multiple end-uses, including electric vehicle charging which allows for options other than potentially costly, single use installations. BC Hydro believes such a change will support future load configurations and respond to the growing need for curbside electricity use.

[2] Refer to pages 63 to 66 of BC Hydro's Street Lighting Application at https://docs.bcuc.com/Documents/Proceedings/2020/DOC_59807_B-1-BCH-2020-Street-Light-Rates-Application.pdf. Also refer to BCUC Order No. G-312-21 at: www.ordersdecisions.bcuc.com/bcuc/decisions/en/515300/1/document.do.

BC Hydro will continue to consider and propose further amendments where appropriate.