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Article

An Equilibrium Analysis of Time-Varying and Flat Electricity Rates

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Abstract

Many electricity providers are offering their customers an array of tariff options intended to discourage electricity consumption at specific times of the day. The problem facing a customer is whether to switch from their existing tariff to a new tariff. This paper develops two methods to assist a residential customer when presented with the opportunity to switch from a traditional flat rate tariff (commonly referred to as domestic service tariff) to either of two time-varying electricity pricing structures, Time-of-Use or TOU, with known times and rates, and event-based, that can occur at any time throughout the heating season. The methods identify the specific consumption distributions at which TOU or event-based are in energy- and cost-equilibrium with the domestic service tariff for residential customers. For the TOU structure, the analysis shows that customers must maintain a non-winter to winter-peak consumption ratio exceeding 3.0756 for cost neutrality, a condition rarely met by households with winter-dominant loads. In contrast, event-based structures require only minimal behavioral adjustments to achieve savings, with as little as 1.75% of annual consumption needing to be avoided during event periods to match domestic-service costs. Additional savings are observed with partial or full load shifting away from peak events. The findings highlight that while TOU may benefit households with high summer usage, event-based tariffs present a more practical and economically favorable option for residential customers living in the Canadian province of Nova Scotia. The paper concludes with implications for tariff selection and consumer behavior. This research will be of value to anyone considering designing a time-varying rate or having to choose between an existing flat rate tariff and a time-varying tariff.

Keywords: Time-varying pricing; Electricity tariffs; Demand reduction; Load shifting; Electricity pricing ; Electric vehicles

1. Introduction

Electricity tariffs serve as the cornerstone of a functional and sustainable electricity system. They are essential not only for enabling utilities to recover the capital and operating costs associated with power generation, transmission, and distribution, but also for ensuring affordability for end-users and offering a fair rate of return to investors. Tariff structures play a critical role in shaping consumer behavior, influencing load profiles, and guiding investment in infrastructure and demand-side technologies (Rostom & Hamdy, 2022) (Rostom & Hamdy, 2022).

Traditional electricity pricing has relied heavily on flat-rate tariffs, which charge customers a single rate per kilowatt-hour regardless of the time of use. While simple to understand and administer, flat rates do not reflect the real-time cost variations associated with electricity generation and grid operations (Faruqui & Sergici, 2010)(Faruqui & Sergici, 2010). To address this, many jurisdictions have introduced time-differentiated tariffs that encourage customers to shift their electricity usage away from high-demand periods.

Time-varying pricing mechanisms, such as Time-of-Use (TOU), Real-Time Pricing (RTP), and event-based tariffs, have gained interest in response to the growing complexity of electricity systems and the integration of variable renewable energy sources (Schittekatte, Mallapragada, Joskow, & Schmalensee, 2022) (Schittekatte, Mallapragada, Joskow, & Schmalensee, 2022). These pricing models provide financial incentives for consumers to modify their electricity consumption in alignment with grid needs. One type of event-based tariff, Critical Peak Pricing (CPP), represents an advanced form of dynamic pricing where extremely high rates are applied during a limited number of critical peak periods during each year's heating season. CPP aims to reduce demand during moments of extreme grid stress, typically driven by weather-related spikes in residential or commercial usage.

In addition to encouraging load shifting, time-sensitive pricing structures have proven effective in deferring investments in costly infrastructure upgrades by flattening demand curves (Gutiérrez-Alcaraz, 2011) (Gutiérrez-Alcaraz, 2011). For example, reducing peak demand during high-stress periods through dynamic pricing can avoid or delay the need for new generation or transmission capacity. This not only improves operational efficiency but also supports long-term decarbonization goals.

However, the transition to dynamic pricing poses several challenges, particularly related to consumer awareness, behavioral inertia, and the upfront costs of enabling technologies (Matisoff, Beppler, Chan, & Carley, 2020) (Matisoff, Beppler, Chan, & Carley, 2020). These barriers may limit the effectiveness of such tariffs among vulnerable populations, raising concerns around affordability and fairness. Designing dynamic pricing programs that are inclusive and supported by targeted education and financial incentives will be critical to ensuring a just energy transition.

As electrification expands into sectors such as transportation and heating, electricity providers are under increased pressure to deploy more sophisticated tariff models that balance grid reliability, affordability, and equity. This paper contributes to the demand-side management by analyzing how time-of-use and event-based tariffs can impact the choice of electricity tariff for residential customers in the Canadian province of Nova Scotia when compared with the existing domestic service tariff (NSP, 2025b) (NSP, 2025b). Specifically, it investigates the equilibrium point at which the annual cost under the time-of-use and event-based tariffs structures equals the domestic service tariff for customers with identical total electricity consumption. Using algebraic equilibrium analyses and examples of consumption loads, the paper identifies the point where the energy consumption and cost of the two time-varying tariffs equals the flat rate. By quantifying this threshold, the study aims to inform both policymakers and electricity providers on how to structure tariffs that balance affordability, efficiency, and fairness.

2. Background

Understanding the efficacy of time-varying tariff models necessitates a comparative evaluation of tariff structures implemented across diverse regulatory contexts. Around the world, electricity providers have implemented a spectrum of tariff designs aimed at balancing operational reliability, economic efficiency, and equity in power distribution. These tariff structures are not only financial instruments for revenue recovery and cost allocation but also behavioral tools to influence when and how electricity is consumed. As the energy transition accelerates and grids accommodate increasing shares of variable renewables such as wind and solar, pricing mechanisms become essential for achieving grid flexibility and cost-effectiveness.

The most prominent and widely adopted tariff models include flat-rate pricing, TOU pricing, and event-based. Flat-rate tariffs are characterized by simplicity and uniformity, making them highly accessible for mass-market customers, while TOU rates reward users who shift consumption to off-peak periods. Meanwhile, event-based tariffs offer a dynamic and responsive structure that targets specific moments of grid stress by levying very high prices during pre-designated critical hours. Each tariff type reflects distinct regulatory control and system conditions, from customer protection to real-time market integration.

2.1. Flat-Rate Tariffs

Flat-rate tariffs apply a consistent per-kilowatt-hour charge irrespective of time-of-day or seasonal grid conditions. They are the most straightforward pricing model and remain prevalent in markets where smart meter penetration is limited or where administrative ease is prioritized over cost-reflective efficiency. Flat-rate pricing is often used as a default or legacy option for customers who opt out of more complex plans. However, they fail to signal the cost of peak demand or renewable intermittency, potentially increasing the need for costly infrastructure investments. Examples of flat-rate tariffs include:

- Singapore (Standard Tariff): As of 2024, SP Group charges a uniform rate of approximately SGD 0.299/kWh for residential users (SP Group, 2025) (SP Group, 2025). This tariff is applied consistently across all hours, days, and seasons, without distinction between peak and off-peak periods.
- Ireland (Standard Rate): Before widespread deployment of smart meters, most households paid a static rate of roughly €0.32/kWh (Electric Ireland, 2025) (Electric Ireland, 2025). The simplicity of this rate remains attractive to certain demographics, though it provides no incentive for behavioral change in electricity usage.

2.2. Time-of-Use (TOU) Tariffs

TOU pricing introduces temporal granularity to electricity rates by segmenting the day into multiple pricing bands typically off-peak and on-peak based on historical consumption patterns and grid load. This model helps shift load away from congested periods, thereby flattening demand curves and reducing reliance on expensive peaking generation. TOU tariffs are enabled by smart meters and require well-informed consumers to adjust their routines accordingly, examples include:

- In Ontario, Canada, the Ontario Energy Board's TOU scheme for residential customers are charged \$0.076/kWh during Off-Peak hours (7:00 p.m. to 7:00 a.m.), \$0.122/kWh for Mid-Peak (7:00 a.m. to 11:00 a.m. and 5:00 p.m. to 9:00 p.m.), and \$0.158/kWh for On-Peak (11:00 a.m. to 5:00 p.m.), with seasonal adjustments introduced to reflect variations in demand (Ontario Energy Board, 2025) (Ontario Energy Board, 2025).
- In California, Pacific Gas and Electric (PG&E) offers two TOU rate plans E-TOU-C and E-TOU-D that vary electricity prices based on the time of day and season:
 - Under the E-TOU-C plan, peak pricing applies every day from 4:00 p.m. to 9:00 p.m. During the summer season (June to September), the off-peak rate (from 12:00 a.m. to 4:00 p.m. and 9:00 p.m. to 12:00 a.m.) is \$0.50/kWh above baseline and \$0.40/kWh below baseline, while the peak rate is \$0.63/kWh above baseline and \$0.52/kWh below baseline. In the winter season (October to May), off-peak rates are \$0.47/kWh above baseline and \$0.37/kWh below baseline, with peak hours (4:00 p.m. to 9:00 p.m.) priced at \$0.59/kWh above baseline and \$0.40/kWh below baseline (PGE, 2025) (PGE, 2025).
 - The E-TOU-D plan applies peak pricing on weekdays only, from 5:00 p.m. to 8:00 p.m. In the summer, the rate during off-peak hours (all times except 5:00 p.m. to 8:00 p.m. on weekdays) is \$0.44/kWh, while the peak rate rises to \$0.57/kWh. In the winter, the off-peak rate remains the same at \$0.44/kWh, but the peak rate is slightly lower at \$0.48/kWh (PGE, 2025) (PGE, 2025).
- In Tasmania, Australia, residential customers under the TOU tariff are charged a daily supply charge of \$1.511814/day. The electricity rate is \$0.354782/kWh during peak hours and \$0.166862/kWh during off-peak hours. Peak hours are from 7:00 a.m. to 10:00 a.m. and 4:00 p.m. to 9:00 p.m., Monday to Friday. Off-peak hours are from 10:00 a.m. to 4:00 p.m. and 9:00 p.m. to 7:00 a.m. on weekdays, and all day on weekends (Aurora Energy, 2025) (Aurora Energy, 2025).

2.3. Event-Based Tariffs

Event-based tariffs represent a more targeted approach to load management. Rather than fixed price bands, event-based tariffs impose steep price hikes during a limited number of designated “critical events” typically periods of high demand or system stress. These tariffs are often paired with advanced notification systems (e.g., day-ahead alerts) and are especially designed to effectively curtail the demand during the most expensive hours of the year (MIT CEEPR, 2022) (MIT CEEPR, 2022), examples include:

- In France, the EDF Tempo tariff rates for July 2025, valid until July 31, vary by day type and season. Blue days (300 days, year-round, including Sundays) cost 0.1552 €/kWh during peak hours (06:00 a.m. to 10:00 p.m.) and 0.1288 €/kWh during off-peak hours (10:00 p.m. to 06:00 a.m.). White days (43 days, mostly fall/spring) are 0.1792 €/kWh (peak) and 0.1447 €/kWh (off-peak). Red days (22 days, November 1 to March 31, winter only) are 0.6586 €/kWh (peak) and 0.1518 €/kWh (off-peak) (EDF, 2025) (EDF, 2025).
- In Nova Scotia, the Critical Peak Pricing (CPP) pilot program was effective by Nova Scotia Power on 1 November 2024 and is scheduled to run until 31 October 2025. The pilot aims to test how dynamic pricing can reduce peak demand during winter months (NSP, 2025a) (NSP, 2025a). Participants are notified by 4:00 p.m. the day before via email or SMS, allowing them time to shift or reduce usage. The CPP structure, with its sharp price differential and targeted event scheduling, is designed to curtail electricity use during the most expensive and high-stress hours on the grid.

2.4. Comparison and Key Differences

Flat-Rate tariffs emphasize administrative ease and customer simplicity but fall short in managing peak demand or supporting renewable integration. TOU tariffs use temporal signals to shift demand across predictable intervals, providing economic and operational benefits with moderate complexity (Zaki & Hamdy, 2022) (Zaki & Hamdy, 2022). Event-based tariffs offer sharp and responsive price signals during extreme conditions, making them suitable for reducing demand during the most critical periods (Rabobank, 2023) (Rabobank, 2023).

The choice of tariff model involves complex trade-offs between transparency, cost reflectiveness, consumer comprehension, and system flexibility. As smart grid technologies mature, the success of dynamic pricing increasingly hinges on consumer awareness, real-time communication systems, and supportive policy frameworks, including targeted subsidies and automation incentives.

3. Methodology and Analysis

Nova Scotia Power is a vertically integrated electricity utility serving approximately 520,000 customers, or about 95 % of residents and businesses in Nova Scotia (NSP, 2025c) (NSP, 2025c). As a privately owned subsidiary of Emera Inc., Nova Scotia Power is regulated by the Nova Scotia Utility and Review Board (NSUAR) and is responsible for the province’s generation, transmission, and distribution of electricity. By law, Nova Scotia Power must develop and implement tariffs, including open-access transmission tariffs, distribution tariffs, and spill or interconnection tariffs as mandated under the Electricity Act (2004), while ensuring that costs are borne by retail suppliers and their customers rather than Nova Scotia Power’s general customer base (Canlii, 2025) (Canlii, 2025).

This study adopts a two-stage approach to compare the financial implications of Nova Scotia Power’s dynamic electricity pricing models, time-of-use (TOU) and critical-peak pricing (CPP), with Nova Scotia Power’s domestic service tariff Standard Residential Service (SRS) tariff. The primary objective is to determine the equilibrium point at which a residential customer’s annual electricity cost under a dynamic tariff becomes equal to that under the flat-rate SRS tariff. By identifying these thresholds, the analysis aims to guide residential customers in selecting the most cost-effective tariff option based on actual consumption patterns.

In section 0, the SRS tariff is compared with the TOU tariff. The TOU tariff is divided into three pricing periods: non-winter, winter off-peak, and winter peak hours. A series of equations are

derived to determine how a customer's annual electricity consumption must be distributed across these time blocks to match the cost of the SRS tariff. The analysis reveals a critical consumption ratio between non-winter and winter peak periods that must be met for the TOU and SRS tariffs to be cost-equivalent. This mathematical relationship enables the identification of the specific conditions under which TOU becomes a more economical option than SRS.

Section 0 applies a similar approach to the SRS-TOU comparison to evaluate the CPP tariff against the SRS tariff. The CPP model introduces increased electricity rates during a limited number of “critical peak” events, typically triggered by projected periods of system stress or high demand. This part of the analysis focuses on determining the number of critical peak events and the percentage of electricity consumption during those periods that would result in total annual costs equaling those under the flat SRS rate. By modeling different usage scenarios and varying the share of consumption during peak events, the analysis identifies a threshold at which CPP becomes cost-effective or, conversely, burdensome, to the customer.

Both parts of the methodology involve modeling Nova Scotia Power’s tariff structures and applying them to a range of different consumption profiles. These sections include detailed calculations, illustrative tables, and a discussion of the practical implications of each tariff option.

3.1. Comparing SRS with TOU

In this section, we are interested in determining the point at which a customer’s SRS cost is equal to the TOU cost. The equilibrium point is defined as the point at which the number of kilowatt-hours and the total cost of the two tariffs are equal.

The TOU service has three rates: one for April to October (non-winter) and two for November to March (winter); the winter off-peak rate of \$0.18561 is equal to the SRS rate. The SRS rate and TOU rates are shown in **Table 1**.

Table 1. TOU tariff in Nova Scotia (NSP, 2025) (NSP, 2025).

Service	Dates	Hours	Rate (per kWh)
SRS	All year	All hours	\$0.18561
TOU Winter	November to March	Peak Hours	\$0.35492
		7:00 am to 11:00 am 5:00 pm to 9:00 pm	
		Off-Peak Hours	\$0.18561
9:00 pm to 7:00 am 11:00 am to 5:00 pm			
TOU Off-peak winter	April to October	All hours	\$0.13056

This puts several restrictions on finding the equilibrium point:

- Since the winter off-peak rate equals the SRS rate, the equilibrium point can be met if all TOU kilowatt-hours are consumed during the winter off-peak hours. This is not possible if the TOU consumer uses electricity during the non-winter and winter peak hours.
- The non-winter rate and the winter peak rate are unable to meet the equilibrium requirements without being combined with another rate, as the following charts show.

In **Figure 1**, we see the volume of kilowatt-hours consumed by a consumer paying \$2,000 for each of the TOU’s three rates. The Standard Residential Service and the Winter Off-Peak totals are the same at 10,775 kWh; the winter peak rate has the highest cost per kilowatt-hour rate and limits the volume purchased to 5,635 kWh, while the lowest-cost-per-kilowatt-hour is the non-winter rate lets the customer purchase 15,319 kWh.

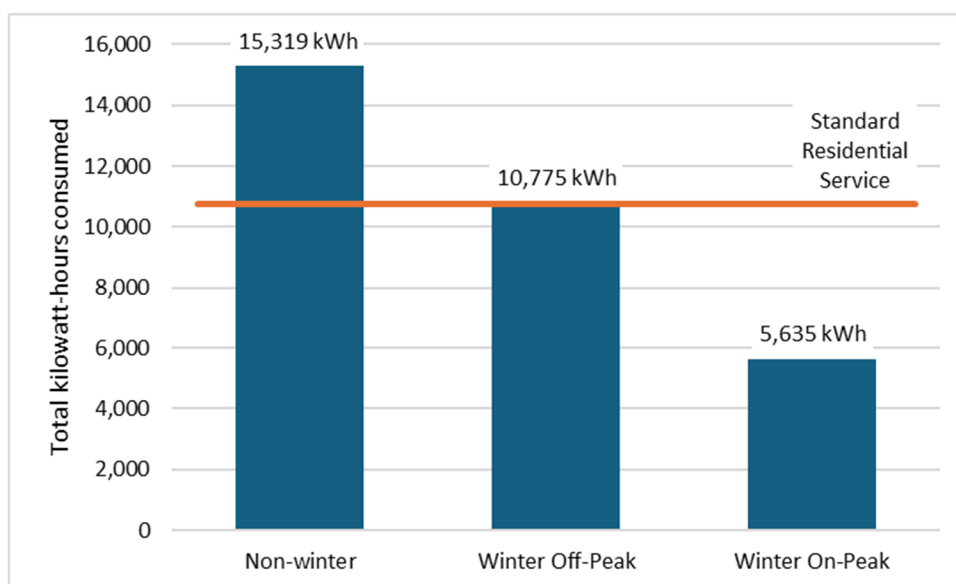


Figure 1. Total kilowatt-hours consumed for \$2,000.

The cost of purchasing 8,760 kWh during one of the three pricing periods is shown in Figure 2. The lowest total cost is \$1,144 with the non-winter rate and the highest is \$3,109 for the winter peak rate. As before, since the per-kilowatt-hour rates are equal for the Standard Residential Service and winter off-peak, the costs are the same at \$1,626.

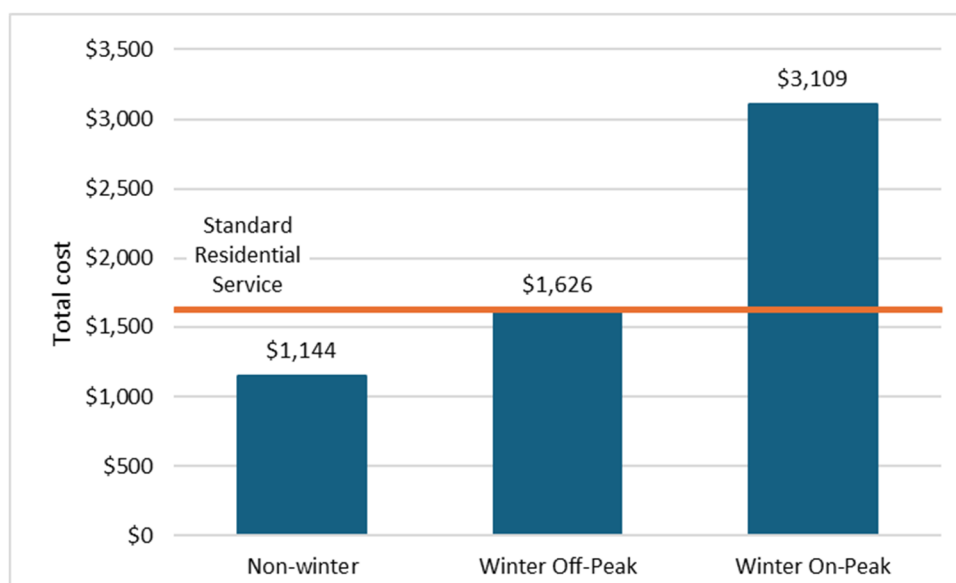


Figure 2. Total cost for consuming 8,760 kilowatt-hours of electricity.

Unless a customer only uses electricity during the winter off-peak hours, all three TOU rates must be considered when determining the SRS-TOU.

3.1.1. Method

The equilibrium SRS-TOU point occurs when the SRS energy cost equals the TOU energy cost and the total energy consumed in kilowatt-hours is equal. The SRS cost is the produce of the volume of electricity used (SRS.kWh) and the rate (SRS.Rate), while the TOU cost consists of three electricity volumes (NW.kWh, WOP.kWh, and WP.kWh) and the corresponding rates (NW.Rate, WOP.Rate, and WP.Rate). The equilibrium point can be expressed in terms of energy and cost:

- The cost equilibrium point is:

$$\text{SRS.kWh} \times \text{SRS.Rate} = \text{NW.kWh} \times \text{NW.Rate} + \text{WOP.kWh} \times \text{WOP.Rate} + \text{WP.kWh} \times \text{WP.Rate} \quad (1)$$

- The energy equilibrium point is:

$$\text{SRS.kWh} = \text{NW.kWh} + \text{WOP.kWh} + \text{WP.kWh} \quad (2)$$

or

$$\text{SRS.kWh} - \text{WOP.kWh} = \text{NW.kWh} + \text{WP.kWh} \quad (3)$$

The total kilowatt-hours available for the non-winter and winter peak consumption is (this is equivalent to $\text{SRS.kWh} - \text{WOP.kWh}$):

$$\text{Total.kWh} = \text{NW.kWh} + \text{WP.kWh} \quad (4)$$

The cost of the reduction of the winter off-peak kilowatt-hours (WOP.kWh) must equal the cost of the non-winter (NW.kWh) and winter peak (WP.kWh) consumption:

$$\text{Total.kWh} \times \text{SRS.Rate} = \text{NW.kWh} \times \text{NW.Rate} + \text{WP.kWh} \times \text{WP.Rate} \quad (5)$$

Replacing WP.kWh with $\text{Total.kWh} - \text{NW.kWh}$ (from Eqn. 4) gives:

$$\text{Cost} = \text{NW.kWh} \times \text{NW.Rate} + (\text{Total.kWh} - \text{NW.kWh}) \times \text{WP.Rate} \quad (6)$$

or

$$\text{Cost} = \text{Total.kWh} \times \text{WP.Rate} + \text{NW.kWh} \times \text{NW.Rate} - \text{NW.kWh} \times \text{WP.Rate} \quad (7)$$

Rearranging Eqn. (7) gives:

$$\text{NW.kWh} = (\text{Cost} - \text{Total.kWh} \times \text{WP.Rate}) / (\text{NW.Rate} - \text{WP.Rate}) \quad (8)$$

By replacing Cost with $\text{Total.kWh} \times \text{SRS.Rate}$, (from Eqn. (5)), we find:

$$\text{NW.kWh} = (\text{Total.kWh} \times \text{SRS.Rate} - \text{Total.kWh} \times \text{WP.Rate}) / (\text{NW.Rate} - \text{WP.Rate}) \quad (9)$$

Or simply:

$$\text{NW.kWh} = \text{Total.kWh} \times (\text{SRS.Rate} - \text{WP.Rate}) / (\text{NW.Rate} - \text{WP.Rate}) \quad (10)$$

Applying the respective rates to Eqn. (10) gives:

$$\text{NW.kWh} = \text{Total.kWh} \times (\$0.18561 - \$0.35492) / (\$0.13056 - \$0.35492) \quad (11)$$

The ratio of the difference between the winter non-peak and peak rates and the difference between the non-winter and winter-peak rates is a constant, 0.754635407, and can be applied to any total consumption to find the SRS-TOU equilibrium point.

$$\text{NW.kWh} = \text{Total.kWh} \times 0.754635407 \quad (12)$$

The winter-peak consumption, WP.kWh , is therefore $1 - 0.754635407$ or 0.245364593. This means there must be 3.0756 non-winter kilowatt-hours consumed for every one kilowatt-hour of winter-peak consumption (the ratio of the non-winter consumption and the winter-peak consumption) to achieve the equilibrium point. When the non-winter-to-winter-peak ratio exceeds 3.0756, an SRS customer would pay less for their electricity charges if they subscribed to the TOU tariff and should consider switching from the SRS tariff to the TOU tariff.

3.1.2. Application

By applying Eqn. (12), we can determine the cost and volume of energy used for the non-winter and winter-peak TOU periods are to be in equilibrium with the same cost and volume of an SRS customer; examples of this are shown Table 2.

The total number of kilowatt-hours to be divided between the non-winter and winter peak periods range from 1 kWh to 21,900 kWh. For example, if 4,380 kWh were available, the customer would need to use 3,305.3 and 1,074.7 during the non-winter and winter-peak periods, respectively. The cost of the non-winter and winter-peaks is \$812.97, which is equal to the SRS cost for an equivalent amount of electricity.

In all examples considered, there is a constant non-winter-to-winter-peak ratio of 3.076 for the equilibrium to be reached. That is, for every kilowatt-hour of winter-peak use, 3.076 kilowatt-hours of non-winter electricity must be consumed.

Table 2. Examples of the TOU ratio and the SRS-TOU equilibrium point.

Total kWh	1	4,380	8,760	13,140	17,520	21,900
Non-winter kWh	0.755	3,305.303	6,610.606	9,915.909	13,221.212	16,526.515
Winter peak kWh	0.245	1,074.697	2,149.394	3,224.091	4,298.788	5,373.485
Non-winter to Winter peak ratio	3.0756	3.0756	3.0756	3.0756	3.0756	3.0756
Non-winter + Winter peak cost	\$0.186	\$812.972	\$1,625.944	\$2,438.915	\$3,251.887	\$4,064.859
SRS Cost	\$0.186	\$812.972	\$1,625.944	\$2,438.915	\$3,251.887	\$4,064.859

The above examples only consider the total volume of electricity a customer consumes during the non-winter and winter-peak hours. It is not necessary to account for the winter non-peak hours because the cost of electricity during the winter non-peak equals the SRS cost.

3.2. Comparing SRS with CPP

The equilibrium point for the CPP rate and the SRS rate is the point at which the number of kilowatt-hours and the total cost of the service are equal for both rates.

The CPP has two rates, one for all non-event hours during the year and a second for up to 18 four-hour events that can occur between 1 November and 31 March of the following year. The SRS and CPP rates are summarised in Table 3.

Table 3. CPP tariff in Nova Scotia (NSP, 2025a) (NSP, 2025a).

Service	Dates	Rate (per kWh)
SRS	All hours	\$0.18561
CPP non-event	All hours between 1 April and 31 October, except for critical peak event hours	\$0.15852
CPP event	Up to 18 four-hour events between 1 November and 31 March	\$1.70940

3.2.1. Method

The SRS-CPP equilibrium point occurs when the cost of using the SRS rate equals the cost of the CPP rates, both with and without events throughout the year (1 April to 31 March). Up to 18 four-hours critical peak events can occur between 1 November and 31 March. The equilibrium point is expressed algebraically as follows (.NEv refers to all non-events and .Ev to all events between 1 November and 31 March):

$$\text{SRS.kWh} \times \text{SRS.Rate} = \text{CPP.NEv.kWh} \times \text{CPP.NEv.Rate} + \text{CPP.Ev.kWh} \times \text{CPP.Ev.Rate} \quad (13)$$

The total CPP kilowatt-hours consumed (both during non-events and events) are constrained by:

$$\text{CPP.Ev.kWh} = \text{SRS.kWh} - \text{CPP.NEv.kWh} \quad (14)$$

Replacing CPP.Ev.kWh on the righthand side of Eqn. (13) with Eqn. (14), SRS.kWh - CPP.NEv.kWh, gives:

$$\text{CPP.NEv.kWh} \times \text{CPP.NEv.Rate} + (\text{SRS.kWh} - \text{CPP.NEv.kWh}) \times \text{CPP.Ev.Rate} \quad (15)$$

Eqn. (15) can be rewritten as:

$$\text{CPP.NEv.kWh} \times \text{CPP.NEv.Rate} + (\text{SRS.kWh} \times \text{CPP.Ev.Rate} - \text{CPP.NEv.kWh} \times \text{CPP.Ev.Rate}) \quad (16)$$

or:

$$\text{CPP.NEv.kWh} \times \text{CPP.NEv.Rate} - \text{CPP.NEv.kWh} \times \text{CPP.Ev.Rate} + \text{SRS.kWh} \times \text{CPP.Ev.Rate} \quad (17)$$

And finally:

$$\text{CPP.NEv.kWh} \times (\text{CPP.NEv.Rate} - \text{CPP.Ev.Rate}) + \text{SRS.kWh} \times \text{CPP.Ev.Rate} \quad (18)$$

Incorporating Eqn. (18) into Eqn. (13) we find:

$$\text{SRS.kWh} \times \text{SRS.Rate} = \text{CPP.NEv.kWh} \times (\text{CPP.NEv.Rate} - \text{CPP.Ev.Rate}) + \text{SRS.kWh} \times \text{CPP.Ev.Rate} \quad (19)$$

Rearranging Eqn. (19) allows us to determine the number of non-event kilowatt-hours possible:

$$\text{CPP.NEv.kWh} = (\text{SRS.kWh} \times \text{SRS.Rate} - \text{SRS.kWh} \times \text{CPP.Ev.Rate}) / (\text{CPP.NEv.Rate} - \text{CPP.Ev.Rate}) \quad (20)$$

Eqn. (20) can be simplified to:

$$\text{CPP.NEv.kWh} = \text{SRS.kWh} \times (\text{SRS.Rate} - \text{CPP.Ev.Rate}) / (\text{CPP.NEv.Rate} - \text{CPP.Ev.Rate}) \quad (21)$$

Applying the rates in Table 3 to Eqn. (21) gives the number of CPP non-event kilowatt-hours:

$$\text{CPP.NEv.kWh} = \text{SRS.kWh} \times (\$0.18561 - \$1.70940) / (\$0.15852 - \$1.70940) \quad (22)$$

The ratio of the differences of the SRS and CPP event rates and the differences of the CPP non-event and event-rates is 0.98253, reducing Eqn. (22) to simply:

$$\text{CPP.NEv.kWh} = \text{SRS.kWh} \times 0.98253 \quad (23)$$

The SRS-CPP equilibrium point is reached when the CPP non-event load is 98.253% of the SRS load. This limits the customer's load to 1.747% of the SRS load during all events, regardless of the number of events. If the customer can use less than 1.747% of the SRS load, the CPP tariff will cost less than the SRS tariff; however, exceeding the 1.747% limit will mean the SRS tariff is less expensive.

3.2.2. Application

The SRS-CPP equilibrium point can be obtained from the number of CPP non-event kilowatt-hours (from Eqn. (23)) and the number of SRS kilowatt-hours, allowing us to determine the number of CPP event kilowatt-hours using Eqn. (14). Examples of this are shown in Table 4.

Table 4. Cost and Consumption Comparison Between SRS and CPP Tariffs at Varying Annual Consumption Levels.

Row	Activity	876 kWh	4,380 kWh	8,760 kWh	13,140 kWh	17,520 kWh	21,900 kWh
1	SRS.kWh	876	4,380	8,760	13,140	17,520	21,900
2	CPP.NEv.kWh	860.70	4,303.49	8,606.98	12,910.48	17,213.97	21,517.46

3	CPP.Ev.kWh	15.30	76.51	153.02	229.52	306.03	382.54
4	CPP.kWh	876	4,380	8,760	13,140	17,520	21,900
5	SRS cost	\$162.594	\$812.972	\$1,625.944	\$2,438.915	\$3,251.887	\$4,064.859
6	CPP.NEv cost	\$136.438	\$682.190	\$1,364.379	\$2,046.569	\$2,728.758	\$3,410.948
7	CPP.Ev cost	\$26.156	\$130.782	\$261.564	\$392.347	\$523.129	\$653.911
8	CPP cost	\$162.594	\$812.972	\$1,625.944	\$2,438.915	\$3,251.887	\$4,064.859

For example, if a consumer used 13,140 kilowatt-hours in a year (Row 1), the number of non-event and event kilowatt-hours are limited to 12,910.48 (Row 2) and 229.52 (Row 3), respectively at the equilibrium point. The total number of CPP kilowatt-hours is 13,140 (Row 4, the sum of Rows 2 and 3).

The cost breakdown is shown in rows 5 through 8 of Table 4, with an SRS cost of \$2,438.915 for the 13,140 kilowatt-hours customer (Row 5). The final three rows are the CPP non-event cost (\$2,046.569; Row 6), the CPP event cost (\$392.347; Row 7), and the total CPP cost (\$2,438.915; Row 8). The total CPP and SRS kilowatt-hours are equal, as are the total costs, indicating that the equilibrium point has been reached.

The available number of CPP-event kilowatt hours is independent of the number of events; as the number of events increases, the cost per event decreases. However, the total cost remains the same.

For example, to meet the SRS-CPP equilibrium point, a household consuming 13,140 kilowatt-hours would need to use 229.52 kilowatt-hours, this is regardless of the number of events; this effect is illustrated in Figure 2 for several SRS consumption values (from Table 4). If there was one event, the equilibrium would be met if the customer used 229.52 kilowatt-hours during the event for a cost of \$392.347, and during that event, the customer would need to consume more than 22.952 kilowatt-hours during the event for a cost of \$392.347.

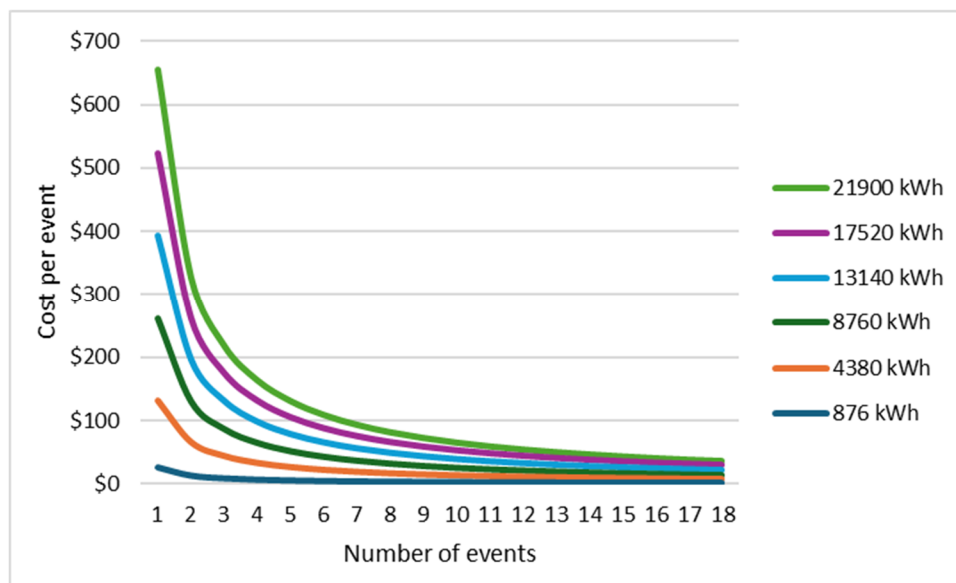


Figure 2. SRS costs-per-kilowatt-hour for different consumption and events at equilibrium points.

The equilibrium cost per event for any annual consumption can be expressed as follows:

$$\text{CPP.NEv.Cost}^{\text{-Number of Events}} \quad (24)$$

For example, if five CPP events occur for a customer consuming 13,140 kilowatt hours, the cost for all events is $\$392.347^5$ or \$78.47 per event.

4. Discussion

4.1. Time-of-Use (TOU) Tariff

The equilibrium point for the Time-of-Use rate and SRS rate shows that to switch from SRS to TOU, the SRS customer's non-winter load must be at least 3.07 times greater than their winter-peak load. However, for most SRS customers, the opposite is usually true, with the winter-peak load being greater than the non-winter load because of less daylight hours and colder days requiring the use of electric heating.

The TOU rate structure favours those customers with a summer peak load, such as a customer driving an electric vehicle or with a heavy air conditioner load, or both. If the customer was to charge their vehicle during the non-peak hours during the winter months (November to March), the TOU rate would equal the SRS rate. In this scenario, the TOU customer would always pay less than the SRS customer.

4.1.1. Application of TOU

An SRS customer contemplating a switch to TOU must determine their total annual non-winter consumption (SRS.NW.kWh) and their winter peak consumption (SRS.WP.kWh). These values can be obtained directly from hourly or interval data, such as those provided by a smart meter from their provider. The non-winter to winter-peak ratio is calculated as:

$$\text{Ratio} = \text{SRS.NW.kWh} / \text{SRS.WP.kWh} \quad (25)$$

If this ratio exceeds the threshold value of 3.0756, the TOU tariff becomes the more economical option. This threshold is derived from the linear cost-equivalence model presented in Section 3.1.1 and represents the point at which the annual cost of electricity under TOU equals that under the SRS rate for identical total consumption.

The ratio method avoids the need for intermediate calculations when both non-winter and winter-peak consumption figures are available. However, the result remains sensitive to marginal changes in consumption distribution across TOU periods. Customers with dynamic or seasonal load profiles, particularly those with elevated summer usage from EV charging, may find that even small shifts in usage can influence whether TOU is advantageous.

4.1.2. Improving the Non-winter to Winter-peak ratio

Changing from the SRS rate to the TOU rate requires the non-winter-to-winter-peak ratio to exceed 3.075, which can be achieved by increasing the non-winter consumption and decreasing the winter-peak consumption. This can be achieved in any of three ways, assuming the SRS load remains constant: First, shifting all or part of the winter peak load to the winter off-peak; second, shifting all or part of the winter off-peak load to the non-winter; and finally, shifting all or part of the winter peak to the non-winter.

Some of these changes are easier said than done. For example, shifting from the winter peak to the non-winter might not be possible if there are season-specific loads, such as heating and lighting during the winter months. Similarly, the TOU rate might not be appropriate for customers with a high winter-peak load and a low non-winter load since it might not be possible to achieve the non-winter-to-winter-peak ratio.

If an SRS customer reduces their winter peak load, for example replacing a baseboard heating system with a heat pump, this might improve the non-winter-to-winter-peak ratio. This could also be achieved by increasing the non-winter load, for example, by purchasing an electric vehicle.

4.2. Critical Peak Pricing (CPP) Tariff

The CPP structure introduces a degree of uncertainty into household electricity consumption planning. Electrically intensive activities, such as preparing large meals or operating baseboard

(resistance) heating during cold evenings may coincide with critical peak events. This unpredictability can be inconvenient for consumers, particularly given that event notifications are issued at 4:00 p.m. on the day prior, and up to two events may be scheduled within a single day. Such limited advance notice can restrict the ability of households to adjust their usage patterns effectively, especially in situations where flexibility is constrained by comfort or routine.

4.2.1. Choosing the CPP

At the start of the heating season (November to the following March), CPP customers have no indication of the number of events that can happen or when they will occur. However, Eqn. allows us to determine the number of event kilowatt-hours permitted for an annual number of SRS kilowatt-hours. This requires the customer to have a record of past annual kilowatt-hours consumed.

Table 5 can be used as a guide for a customer to decide whether to use the CPP. For example, if the customer's non-event consumption is below the non-event limit, but the customer's consumption during events is above the event limit, it is necessary to check Eqn. to decide which rate to use. If the customer exceeds both the non-event and event limits, the SRS will be less expensive.

Table 5. When to use (or not use) CPP.

		CPP Non-event consumption	
		Equal or Below Non-event Limit	Above Non-event limit
CPP Event consumption	Equal or Below Event Limit	Use CPP	Use CPP unless CPP exceeds SRS
	Above Event Limit	Use CPP unless CPP exceeds SRS	Use SRS

Notwithstanding the above, customers are not given the option to unilaterally select SRS or CPP once the heating season has started, they must decide long before the start of the heating season.

4.2.2. Load shifting

One of the arguments for time-varying pricing is that it can encourage consumers to change their consumption habits, either reducing it or shifting it to a non-peak time. Both actions will reduce the customer's overall costs.

Figure 3 shows the effect of shifting consumption from CPP events to non-events, assuming the same total consumption of 13,140 kilowatt-hours. If 50% of the event load is shifted, the CPP cost is \$2260 and a savings of \$178 is realized. If 90% of the load is shifted, the total savings are \$320. Savings such as these could be achieved if, for example, the consumer did not have a baseboard heater but used a storage heat (charged overnight) or a secondary heating source such as wood or propane; a heat pump could reduce costs further, even if operated during the events.

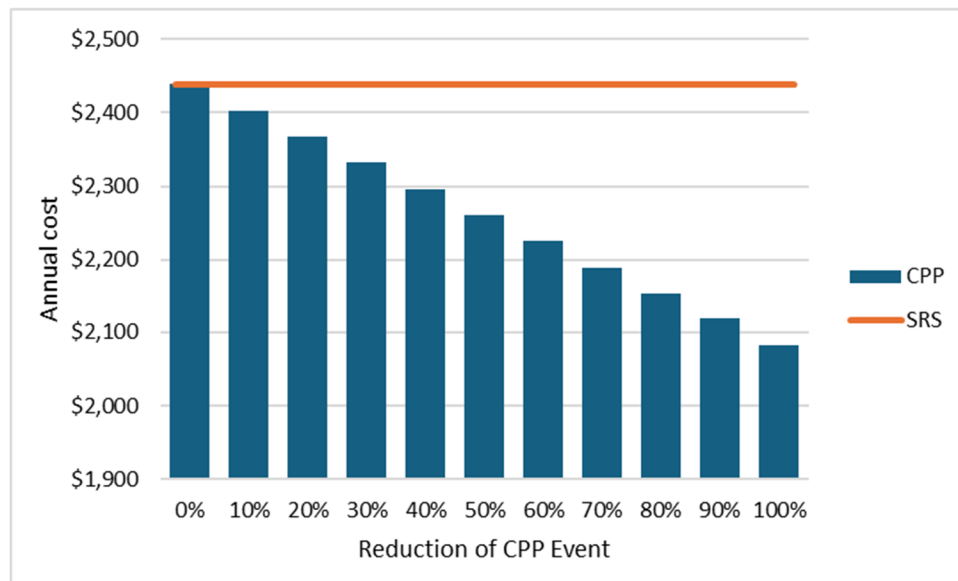


Figure 3. Effect of shifting CPP event load to non-event time for customer using 13,140 kilowatt-hours.

The electricity supplier faces a potential problem if loads are shifted immediately after the event ends. In these situations, a secondary or delayed peak could occur, with the supplier being forced to meet the shifted loads. This could occur if, for example, large numbers of electric vehicles began charging at the end of an event.

4.3. The customer's dilemma

The dilemma facing an electricity customer considering changing from the SRS tariff to a time-varying tariff is not only whether to change tariffs, but which new tariff to select, TOU or CPP. This decision is complicated by the fact the customer must know their hourly consumption for the upcoming year. One approach is to use the previous year's hourly consumption data (from 1 April to 31 March) and determine its effect depending on the tariff.

With TOU, the customer needs to determine their electricity use during the non-winter hours and winter peak hours from their hourly consumption data. If the ratio shown in Eqn. (25) is applied and exceeds 3.0756, they can switch to the TOU tariff.

The CPP tariff is more complicated since there is no indication at the start of the year of the number of events or when the events will occur. For example, between 1 November 2024 and 31 March 2025, three events occurred on 22 December 2024 (5:00p.m. to 9:00p.m.) and 23 December 2024 (7:00a.m. to 11:00a.m. and 5:00p.m. to 9:00p.m.) (NSP, 2025) (NSP, 2025); the timing of these events could have been disruptive for a residential customer with plans for seasonal festivities such as Christmas. However, by using their previous year's hourly consumption and calculating the energy consumed during the events that occurred, if this is less than 1.747% of the year's total energy, they can change their tariff to CPP.

Nova Scotia Power's customers have access to their hourly consumption data; a customer could take this data and apply the methods described in this paper to determine whether they should switch from SRS to either the TOU or CPP tariff. Alternatively, prior to the sign-up date for the tariffs, Nova Scotia Power could notify its residential customers of the potential benefits, if any, of changing tariffs using the previous year's data.

5. Conclusion

This paper examined the financial implications to residential customers of two time-varying pricing (TVP) structures introduced by Nova Scotia Power, Time-of-Use (TOU) and Critical Peak Pricing (CPP), in comparison to the existing SRS tariff. The study identified the specific consumption

patterns under which each TVP rate would become more cost-effective than the flat-rate SRS structure.

In the case of TOU, the analysis revealed that for a customer to benefit over the SRS rate, their non-winter electricity consumption must be at least 3.0756 times greater than their winter-peak usage. This consumption profile is atypical for most Nova Scotian households, which tend to have high electricity usage during winter peaks due to electric heating and days with less daylight. As a result, the TOU structure would not offer cost savings for most SRS customers unless they have unusually low winter peaks or non-winter loads, such as electric vehicle charging or extensive air conditioning use.

In contrast, the CPP model allows for significant savings even with minimal behavioral adjustments. The equilibrium analysis showed that a customer using 13,140 kWh annually could shift just 1.75% of their consumption (approximately 229.5 kWh) away from critical peak periods to match the cost of the SRS rate. If that same customer entirely avoided usage during CPP events, they would reduce their annual electricity bill by \$813. Even partial reductions in event consumption, such as shifting 50% or 90% of event load, would still result in savings of \$178 and \$320, respectively.

The findings indicate that the TOU model requires a disproportionately high ratio of non-winter to winter-peak consumption to yield savings over the SRS rate, a condition unlikely to be met by most households, particularly those with winter-dominant loads. Whereas, the CPP model offers more favorable cost outcomes under typical residential consumption patterns, provided customers can manage their electricity use during the limited number of critical peak events. The relative simplicity of achieving cost parity with the SRS tariff under the CPP framework requiring only modest reductions in event-period usage suggests that it presents a more practical and financially beneficial option for most residential customers. Therefore, the CPP tariff structure holds greater potential for promoting both affordability and demand-side responsiveness within Nova Scotia's residential electricity sector.

When introducing new tariffs, both policymakers and electricity providers on how to structure tariffs that balance affordability, efficiency, and fairness. The methods described in this paper show how new tariffs can be compared with existing ones, allowing customers to understand the potential costs and benefits of changing tariffs.

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Abbreviations

The following abbreviations are used in this manuscript:

CPP	Critical Peak Pricing
CPP.NEv.kWh	Annual energy consumption during Critical Peak Pricing non-event periods (kWh)
CPP.Ev.Cost	Annual energy cost during Critical Peak Pricing non-event periods (\$)
CPP.Ev.kWh	Annual energy consumption during Critical Peak Pricing event periods (kWh)
CPP.Ev.Cost	Annual energy cost during Critical Peak Pricing event periods (\$)
NSUARB	Nova Scotia Utility and Review Board
RTP	Real Time Pricing
SRS	Standard Residential Service

SRS.kWh	Annual energy consumption for Standard Residential Service tariff (kWh)
SRS.kWh	Annual energy consumption for Standard Residential Service tariff (kWh)
TOU	Time of Use
TOU.NW.kWh	Annual non-winter energy consumption for TOU tariff (kWh)
TOU.WOP.kWh	Annual winter off-peak energy consumption for TOU tariff (kWh)
TOU.WP.kWh	Annual winter peak energy consumption for TOU tariff (kWh)
TOU.NW.Cost	Annual non-winter energy consumption for TOU tariff (\$)
TOU.WOP.Cost	Annual winter off-peak energy consumption for TOU tariff (\$)
TOU.WP.Cost	Annual winter peak energy consumption for TOU tariff (\$)
NSP	Nova Scotia Power

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