   

# Feasibility Study on Demand Based Rates for Residential and Small Commercial Customers

Prepared for: EPCOR Distribution & Transmission Inc.

June 25, 2025

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| | |
|---|---|
| 12CP | Coincident Metered Demand |
| AER | Australian Energy Regulator |
| AESO | Alberta Electric System Operator |
| AFREA | Alberta Federation of Rural Electrification Associations |
| AIES | Alberta Interconnected Electric System |
| AUC | Alberta Utilities Commission |
| AMI | Advanced Metering Infrastructure |
| ANSI | American National Standards Institute |
| ADMS | Advanced Distribution Management System |
| BU | Business Unit |
| CCA | Consumers' Coalition of Alberta |
| CP | Coincident Peak |
| COSS | Cost-of-Service Study |
| DAS | Distribution Access Service |
| DBR | Demand Based Rates |
| DERs | Distributed Energy Resources |
| DFOs | Regulated Distribution Facility Owners |
| DC | Direct Current |
| DTS | Demand Transmission Service |
| DSI | Distribution System Inquiry |
| EDTI | EPCOR Distribution & Transmission Inc. |
| EV | Electric Vehicle |
| FTE | Full-time Equivalent Employee |
| HES | Head-End System |
| IDC | Interest During Construction |
| IoT | Internet of Things |
| ISO | Independent System Operator |
| IT | Information Technology |
| LSAs | Load Settlement Agents |
| LTE | Long-Term Evolution |
| MDMs | Meter Data Managers |
| MDMS | Meter Data Management System |
| MDR | Meter Data Repository |
| MSA | Market Surveillance Administrator |
| NCP | Non-Coincident Peak |
| NSLS | Net System Load Shape |
| NVE-RME | Norwegian Energy Regulation Authority |
| OEB | Ontario Energy Board |
| OTA | Over-the-Air |
| PV | Photovoltaic |
| QA | Quality Assurance |
| REAs | Rural Electrification Associations |
| REM | Restructured Electricity Market |
| RoLR | Rate of Last Resort |
| RRO | Regulated Rate Option |
| SRP | Salt River Project |
| STARS | Settlement Tariff and Revenue System |
| TFOs | Transmission Facility Owners |
| TOU | Time of Use |
| UCA | Utilities Consumer Advocate |

## EXECUTIVE SUMMARY

On July 11, 2022, the Alberta Utilities Commission (AUC) directed EPCOR Distribution & Transmission Inc. (EDTI) to conduct a feasibility study on implementing demand-based billing for residential and small commercial customers, following its Phase 2 Distribution Tariff Application. While EDTI had proposed an 80/20 fixed-to-variable split to stabilize revenues and address cross-subsidization, the Commission instead approved a 71/29 ratio, pending future deployment of demand-based billing enabled by advanced metering infrastructure. Recognizing both the cost and complexity of such an approach, the Commission required EDTI to assess existing capabilities, implementation costs, rate design alternatives, and potential customer impacts. This report summarizes the findings of that study, conducted by Power Advisory LLC with Ignite Energy Solutions.

Electricity distribution utilities typically rely on a mix of fixed fees, energy-based rates, and demand-based charges to recover costs and manage customer behaviour. Fixed fees provide stable revenue but may reduce customer incentives for energy efficiency or peak-shifting, while energy-based charges encourage efficiency but do not reflect the timing or intensity of usage. Demand-based rates—which charge customers based on their highest usage over a given interval—may be more cost-reflective, especially in relation to infrastructure needs of a utility building out its system to meet peak demands. Although commonly applied to commercial and industrial customers, it is typical for Canadian distributors to apply fixed-fee and energy-based rates for residential customers. Ontario has fully transitioned to fixed base distribution rates for residential customers, while Manitoba Hydro's residential electricity rates include a basic monthly charge that varies by service size (not exceeding 200 Amps vs. exceeding 200 Amps) and an energy charge. Internationally, various jurisdictions—such as France, Norway, Sweden, Australia, and parts of the U.S.—have implemented or piloted residential demand-based rates to better align charges with cost drivers, address cross-subsidization, and encourage load-shifting.

However, global experience with residential demand-based rates has yielded mixed outcomes. Studies have found limited customer responsiveness, confusion around rate structures, and muted peak demand reductions, often due to weak price signals or poor alignment with actual system peaks. Some regulators have rejected default demand-based rates in favour of more familiar time-of-use (TOU) structures due to fairness and comprehension concerns. In Alberta, the feasibility of residential and small commercial demand-based billing must be evaluated considering the province's deregulated electricity market, distinct cost structures, and unbundled retail environment.

Generally, demand-based rates moderately advance many core electricity rate design objectives but come with trade-offs. They can enhance revenue sufficiency and cost-reflectivity by targeting demand-related infrastructure costs, especially when rates are aligned with system peaks. These rates may reduce cross-subsidization and support system reliability, electrification, and demand flexibility, but their effectiveness depends heavily on design details—particularly whether they reflect coincident or non-coincident peak demand. However, demand-based rates are often complex, less intuitive for residential customers, and may negatively impact affordability, especially for low-income users, without careful mitigation.

To assess the feasibility of implementing demand-based rates for residential and small commercial customers, Power Advisory examined the capabilities of EDTI's metering infrastructure and related systems. EDTI's AMI network supports more than 412,000 residential and 37,500 commercial and industrial meters with capabilities such as load profiling, remote disconnect, and power quality monitoring. EDTI's existing advanced metering infrastructure (AMI), supported by Landis+Gyr's Gridstream RF platform, is technically capable of recording and transmitting interval data as granular as five minutes. However, this capability is currently not enabled and would require modifications to the existing meters. Further, modifying the functionality of the meters would need to be supplemented with further upgrades to existing data management and billing systems in order to result in the implementation and billing of new rate designs.

Implementing demand-based rates would require targeted system upgrades including remote or manual reprogramming of meters, enhancements to IT systems to process interval data, and the development of robust billing-grade data validation procedures. Five rate design options were evaluated—from simple peak demand charges to more complex 5-minute interval demand and TOU structures—with estimated timelines ranging from 9 to 48 months depending on implementation complexity. Cost estimates for each option vary widely depending on whether over-the-air (OTA) meter updates can be used or whether full meter replacements are needed. Estimated costs range from under $0.5 million for simpler models using existing peak demand data, up to $74 million for complex options involving new hardware and meter replacements.

While OTA programming could significantly reduce costs, its feasibility remains uncertain due lack of prior testing by EDTI and remains uncertain because OTA programming is not approved for use by Measurement Canada. Risks associated with OTA implementation include potential delays, accuracy challenges, and the possibility that more meters may require replacement than forecasted. Additionally, costs could increase due to changes in resource availability, development timelines, or required system specifications.

Power Advisory assessed five rate design alternatives for feasibility in applying demand-based billing to residential and small commercial customers. While Coincident Peak (CP) demand rates offer the most cost-reflective price signal, they were excluded from further analysis due to customer complexity, unpredictability, and limited applicability to small users. Instead, four viable options were evaluated: (1) Non-Coincident Peak (NCP) Demand rates, which are simple to administer but may not align well with system peaks; (2) TOU Demand rates, which apply demand charges during fixed peak periods to balance cost-reflectiveness and predictability; (3) Subscription-Based Demand rates, where customers pay based on selected demand tiers, providing high bill stability and predictability; and (4) TOU Energy rates, which use time-varying energy charges to influence behaviour without relying on demand measurements. These four alternatives were selected based on their practicality, alignment with EDTI's system and customer characteristics, and potential to send effective price signals while remaining manageable for residential and small commercial users.

Power Advisory conducted a customer bill impact analysis of the four alternatives using residential and small commercial consumption data from 2022 to 2024 to compare potential outcomes under different rate design options. The analysis evaluated each option under both the current fixed-to-variable rate proportions and alternative proportions aligned with EDTI's 2022 Cost of Service Study (COSS), holding consumption and total revenue constant. TOU energy rates resulted in the smallest changes relative to current rates. Among demand-based options, TOU demand and NCP demand produced modest bill impacts for most customers, generally within a ±10% range. The subscription rate had the highest bill impact, particularly for small commercial customers.

Overall, bill impacts from demand-based rates were more pronounced when a larger share of revenue was collected through variable charges. Customers with low load factors were most affected, with a small subset experiencing bill increases exceeding 15%. While NCP and TOU demand rates offered moderate volatility reduction for most customers, they introduced higher variability for others. Subscription-based rates provided greater bill stability across the board, assuming customers could accurately estimate their peak demand; however, real-world misalignment between actual and subscribed demand levels could result in unexpected penalties. Design choices—such as tier thresholds and pricing structures—would significantly influence outcomes under a subscription model.

Alberta's unbundled market structure further complicates implementation of alternative rates, as distribution rate changes alone may not provide strong enough signals to shift customer behaviour. Implementing effective alternatives rates would require extensive customer education, retailer coordination, and regulatory support. Implementation would also involve IT upgrades, interval data validation processes, and potentially meter reprogramming and Measurement Canada approval.

In conclusion, while technically feasible, demand-based billing for residential and small commercial classes in Alberta would require a cautious, well-coordinated approach along with considerable investment.

Table 1: Compliance with Direction 7

| Questions as part of direction no. 7 from decision 27018-D01-2018 | Report Section Reference |
|---|---|
| Identify the objectives of moving to demand based billing. | Section 4. |
| Assess the capabilities of EPCOR Distribution & Transmission Inc.'s (EDTI) existing meters and related systems. | Section 5.1 |
| Identify all possible alternatives to provide demand-based billing with detailed preliminary cost estimates and timelines for implementation, including investigating and reporting on all of the options as to how EDTI should recover the variable demand-related costs, the pros and cons with each option, including but not limited to conducting practical testing within the feasibility study, using a small number of demand metered customers of various classes. This should include the costs of any modifications that would be required to EDTI's current communication systems. | Section 6, with exception of detailed preliminary costs and timelines for implementation.<br><br>Section 5.3 addresses detailed preliminary costs and timelines for implementation |
| The current capital and operating costs incurred by EDTI to support Time-of-Use (TOU) rates for interval rate classes, and the incremental costs that would be incurred to the other non-TOU rate classes if TOU rates were to be implemented for them. This should include a discussion of whether there are any thresholds that result in a step function of cost increases for the non-TOU classes to measure interval data. | Section 5.2 |
| Whether hourly or subhour interval data (i.e., 15 minutes) will be required, including a discussion of the pros and cons of hourly versus subhourly data, and whether these requirements differ by rate class or type of customer (for example, whether industrial customers may need 15-minute interval data but hourly or less frequent measurements would be sufficient for residential and small commercial customers. | Section 7.1 |
| Whether operating costs for residential customers could be reduced by only collecting interval data for energy and demand during residential peak periods and, if so, the pros and cons of doing so, including the expected loss in billing accuracy. | Section 5.4 |
| If the Alberta Electric System Operator (AESO) had TOU rates, would it enable the potential flow-through of AESO's tariffs to distribution facility owner customers and enable them to be able to see and respond to AESO price signals? | Section 7.2 |
| Whether demand billing and/or TOU rates would assist in price signaling for electric vehicle owners and incent them to charge vehicles outside of peak hours. | Section 7.3 |

# 1: BACKGROUND AND PURPOSE

On July 11, 2022, the Alberta Utilities Commission (AUC) issued Decision 27018-D01-2022 regarding EPCOR Distribution & Transmission Inc.'s (EDTI) Phase 2 Distribution Tariff Application, which focused on rate design and established the rate class cost allocation used to determine how much of the revenue requirement should be recovered from each customer class, as well as the billing determinants that will apply to each class.

In its Phase 2 Distribution Tariff Application, EDTI proposed maintaining an 80/20 fixed-to-variable billing ratio for residential customers, diverging from its cost-of-service study (COSS) results of a 41.6% fixed component. EDTI argued that the higher fixed charge is necessary due to metering limitations that prevent demand-based billing, and the approach helps avoid cross-subsidization from customers without distributed generation (e.g., rooftop solar) to those with it. EDTI also cited expert recommendations and the need to stabilize revenues amid declining consumption. While the Utilities Consumer Advocate (UCA) supported this approach, the Consumers' Coalition of Alberta (CCA) opposed it, urging alignment with the COSS. Concerned about equity among customers with varying usage levels, the Commission directed EDTI to adopt a 71% fixed and 29% variable split, based on a balanced allocation of demand-related costs, pending the future implementation of demand-based metering.

The Commission further acknowledged the complexities faced by utilities, like EDTI, in determining an appropriate fixed-to-variable billing ratio, especially for demand-related costs that cannot currently be billed by demand volumes due to metering limitations. Although expert input during the Distribution System Inquiry[1] (DSI) highlighted that distribution costs are mostly fixed in the short term but variable in the long term, there was consensus that rates should retain a variable component to provide meaningful price signals. All parties in EDTI's Phase 2 proceeding agreed that implementing demand-based billing, supported by demand-capable metering, is the ideal solution. The Commission noted that EDTI's existing advanced metering infrastructure (AMI) meters can already record demand, and the main costs would relate to system upgrades needed to collect, store, and bill based on demand data. While EDTI previously estimated a $10 million cost to enable such billing, both the CCA and UCA advocated for a more detailed feasibility study. In response, the Commission directed EDTI to conduct a comprehensive feasibility study to be submitted as part of EDTI's next Phase 2 application, addressing the capabilities of existing infrastructure, costed alternatives, pilot testing, time of use (TOU) rate implications, data granularity needs, and potential customer benefits such as improved price signals for electric vehicle charging.

EDTI retained Power Advisory LLC (Power Advisory), with subcontractor Ignite Energy Solutions (Ignite), to conduct this study. Appendix A provides background information on the firms and applicable expertise.

This report summarizes the findings and results of the feasibility study for demand-based billing for residential and small commercial customers.

[1] AUC Decision 24116-D01-2021

 

## 2: INTRODUCTION TO DEMAND-BASED RATES

Electricity distribution utilities commonly use three rate structures: fixed fees, energy charges, and demand-based rates.

- Fixed Fees are flat monthly charges that do not vary with usage. They typically recover fixed utility costs such as metering, billing, and customer service, and may include a portion of distribution system costs that are classified as customer related. While predictable and simple to administer, high fixed fees can reduce the incentive for energy efficiency and limit customers' ability to manage bills through changes in energy usage.
- Energy-based rates (also known as energy charges) are based on the total electricity consumed during a billing period (measured in kilowatt-hours, kWh). This structure directly links costs to energy use, encouraging efficiency. However, flat energy rates do not reflect the timing or intensity of consumption, limiting their effectiveness in managing system peaks. TOU rates address this by applying higher prices during peak periods, encouraging customers to shift usage to off-peak times.
- Demand-based rates (also known as demand charges) are based on a customer's maximum demand—typically measured in kilowatts (kW) or kilovolt-amperes (kVA)—during an interval within the billing cycle. This rate design reflects the utility's need to maintain infrastructure capable of serving the highest levels of demand, regardless of total energy consumed. While demand-based rates can encourage load management and system efficiency, they can also introduce billing complexity, especially for smaller customers.

Electricity delivery costs are primarily driven by peak demand on the electricity system, which dictates the scale of investment required in infrastructure. When these costs are recovered solely through energy-based rates, the resulting price signals may fail to reflect the true demand-driven nature of system costs. This misalignment can lead to unintended cross-subsidization, where customers with lower peak demand end up subsidizing those who place greater strain on the electricity system during peak periods. Additionally, those who can afford to invest in energy efficient technologies or self-generation can reduce their bills more significantly than others. By reducing their net energy consumption, self-generators may avoid paying their share of demand-related costs. As self-generation increases, the lower revenues recovered from self-generating customers tends to be greater than the demand-related costs that are avoided by utilities, and utilities must raise rates to offset those lost revenues. Demand-based rates can, in principle, mitigate cross-subsidization, align prices more closely with costs, encourage smarter load management, and can promote fairness, particularly for low-income users and distributed generation owners.

Demand-based rates are commonly used for commercial and industrial customers, including EDTI's large commercial and industrial customers. In Canada, it is common for distribution utilities to use a combination of energy-based and fixed-fee distribution rates for residential customers. Ontario has adopted a fully fixed structure for base electricity distribution rates for residential and small commercial customers.[2] Manitoba Hydro's residential electricity rates include a basic monthly charge that varies by service size (not exceeding 200 Amps vs. exceeding 200 Amps) and an energy charge.[3]

That said, electric utilities in some jurisdictions, especially in Europe, have had residential demand-based rates for many years. For example, since as early as 1981, France's largest electric utility (EDF) has billed residential customers receiving the default tariff on a subscribed-demand model. In recent years, more jurisdictions and/or utilities are piloting demand-based rates for low volume customers or seeking to transition low volume customers towards demand-based rates. The reasons for examining the implementation of demand-based rates vary and can include:

- Rebalancing fixed vs. variable charges to reflect fixed vs. variable costs;
- Influencing changes to customers consumption behaviour leading to reduced peak demand and thereby reducing grid costs; and
- Trying to ensure customers with solar PV are not being subsidized by customers without generation.

Demand-based rates have taken various forms across jurisdictions—sometimes with the specific design left to the discretion of distribution utilities—including:

- Measured non-coincident peak (NCP) demand
- Measured demand within a predefined peak period window
- Subscription-based demand charges

For example, in 2020, the Norwegian Energy Regulation Authority (NVE-RME), following an extensive consultation period, proposed a mandatory transition of low-voltage distribution rates from energy-based to capacity-based pricing, to be implemented between 2022 and 2027.[4] A key reason cited for the change was to make distribution rates more reflective of the underlying cost structure—predominantly fixed rather than variable costs. Anticipated impacts from electrification were also noted as a motivating factor. The specific design of the demand-based charge was left to the discretion of individual utilities.

However, recent analysis of the Norwegian early experience to date found that "…there is no clear evidence in the analyzed data that the introduction of the new grid tariff has contributed to household demand response such as reduced peak loads. There are multiple possible reasons for this, such as lack of customer awareness and ability for efficient demand response, that the price incentive related to the capacity

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[2] Ontario Energy Board, *Rate Design for Electricity Distributors (formerly Revenue Decoupling for Distributors)*, Case No. EB-2012-0410, launched November 26, 2012. https://www.oeb.ca/industry/policy-initiatives-and-consultations/rate-design-electricity-distributors-formerly-revenue

[3] Manitoba Hydro's Residential Electricity rates: https://www.hydro.mb.ca/account/billing/rates/residential/

[4] See NVE-RME (2020), Proposed changes to the design of network tariffs for low voltage grid users in Norway: English Summary: https://publikasjoner.nve.no/rme_rapport/2020/rme_rapport2020_02.pdf

component is too weak, or that the grid tariff is considered negligible by household customers compared to much stronger price signals from the market price of electricity."[5]

Similar to Norway, Sweden is mandating some form of demand-based rates for low-volume customers between 2022 and 2027—a shift from the previous approach, where offering such rates was at the discretion of utilities.[6] A study of demand charges in Sweden examined data from a utility with a demand-based rate that was based on the measured average of customers' three highest hourly demands in a month between the hours of 7:00 a.m. to 7:00 p.m. The study concluded that, to be effective, demand-based rates should target system peaks—which occur infrequently during a limited number of hours each year—rather than a customer's monthly peak demand, which may not coincide with the system peak, or broad peak-demand windows.[7]

However, in many instances, demand-based rates are based on maximum NCP demand rather than maximum coincident peak demand. Overall, the result of NCP demand-based rates is that "users face incentives to reduce demand during hours that have little impact on the system instead of when a system peak is at its highest. It may be that if users respond with a general, indiscriminate *reduction* in electricity consumption then they may have some indirect, unintended impact on the system's coincident peak. Load-shifting however, the action more emphasized by utilities and policymakers promoting demand-based rates, may at best, have little to no impact on system peaks, and at worst, exacerbate them."[8] (emphasis in original)

Demand-based rates have, in some cases, been met with opposition from customers, and even the utility's regulator. For example, in Australia, an electricity distribution utility (Energex) proposed in its 2025-30 rate application to make demand-based rates (along with TOU pricing) the default option for residential and small business customers with smart meters. The rate was based on the highest demand over a 30-minute interval between 4:00 p.m. to 9:00 p.m. weekdays and weekends. This proposal was rejected by the Australian Energy Regulatory (AER) in its draft decision which stated:

> "The fundamental change we require of Energex is to shift default assignment for residential and small business customers with smart meters from time-of-use demand tariffs to time-of-use tariffs. While demand tariffs remain a viable cost reflective tariff preferred by some customers and retailers, *we consider the potential impact on small customers of default*

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[5] Erlend Kiel & Sæle, Hanne & Bjarghov, Sigurd, (2024). Experiences from the introduction of a hybrid energy and capacity-based distribution grid tariff in Norway. IET Conference Proceedings, 927-930: https://www.researchgate.net/publication/387853285_Experiences_from_the_introduction_of_a_hybrid_energy_and_capacity-based_distribution_grid_tariff_in_Norway/

[6] Swedish Energy Markets Inspectorate (2022), Sweden's electricity and natural gas market: 2022, p. 37: https://ei.se/download/18.2b54186118afe6e6d30ede/1696496742338/Sweden's-electricity-and-natural-gas-market-2022-Ei-R2023-13.pdf

[7] Fouad El Gohary, Britt Stikvoort, Cajsa Bartusch (2023) Evaluating demand charges as instruments for managing peak-demand, Renewable and Sustainable Energy Reviews, Volume 188: https://www.sciencedirect.com/science/article/pii/S1364032123007347

[8] Ibid.

*demand tariffs could be unacceptably high for the 2025–30 period, as it would be the first exposure of many to cost reflective tariffs and customers typically find demand tariffs more difficult to understand and therefore to respond to, relative to time-of-use tariffs*."[9] (emphasis added)

In response to the draft finding, Energex revised its proposal to default smart meter customers to TOU energy pricing, but would offer demand-based rates as an option.[10] This revised proposal was accepted by the AER in its April 2025 final decision.[11] Note, however, that many Australian distribution utilities do offer demand-based billing to residential and small business customers on an opt-in basis and have done so for a number of years under an Australia-wide rate reform initiative that required distributors to move from flat to TOU and/or demand-based distribution charges. Nonetheless, at least one distributor has recently reported a low uptake of demand tariffs at the residential level, with only 0.1% of customers moving from the default TOU distribution charge to a demand-based rate since 2019 (though small business customer uptake was higher, at 13%).[12]

Finally, in the United States, the Salt River Project (SRP), which serves customers in Arizona, launched a residential demand price plan pilot in 2015.[13] The pilot features a demand-based rate combined with three-part TOU energy pricing. The demand-based rate is calculated currently based on the highest-demand hour of the month, between the hours 4:00 p.m. and 7:00 p.m. An examination of data from early years of the pilot (2015-2017) found that participants' energy consumption did not change; however, customers recruited for the pilot reduced demand by 0.3 kW while those that self-selected into the pilot had reduced demand by 0.9 kW on average.[14]

While residential and small commercial demand-based rates have been adopted or piloted in several jurisdictions, their implementation has produced mixed results. In some cases, expected demand

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[9] AER (2024), Draft Decision Energex Electricity Distribution Determination 2025 to 2030, pp. 21-22: https://www.aer.gov.au/system/files/2024-09/AER%20-%20Draft%20Decision%20-%20Overview%20-%20Energex%20-%202025-30%20Distribution%20revenue%20proposal%20-%20September%202024.pdf

[10] Energex (2024), Revised Regulatory Proposal 2025-30, Table 39, p. 95: https://www.aer.gov.au/system/files/2024-12/Energex%20-%202025-30%20Revised%20Regulatory%20Proposal%20-%202%20December%202024%20-%20public.pdf

[11] AER (2025), Final Decision Energex Electricity Distribution Determination 2025 to 2030: https://www.aer.gov.au/system/files/2025-04/AER%20-%20Final%20Decision%20Overview%20-%20Energex%20-%202025-30%20Distribution%20determination%20revenue%20proposal%20-%20April%202025.pdf

[12] Essential Energy (2023), 2024–29 Revised Tariff Structure Explanatory Statement, p. 8: https://www.essentialenergy.com.au/-/media/Project/EssentialEnergy/Website/Files/About-Us/2024-29-Revised-Tariff-Structure-Explanatory-Statement.pdf

[13] See Salt River Project, SRP Residential Demand Price Plan Pilot: https://www.srpnet.com/price-plans/residential-electric/demand. Note that beginning in late 2025 this pilot rate will transition to a permanent rate, with somewhat different characteristics.

[14] Mark Carroll (2018), Demand rate impacts on residential rooftop solar customers, The Electricity Journal, Volume 31, Issue 8, pp. 44-51: https://www.sciencedirect.com/science/article/pii/S1040619018302197

reductions or customer responsiveness have not materialized, due to factors such as limited customer awareness, weak price signals, or misalignment between the rate structure and system peaks. In others, customer resistance and regulatory concerns have highlighted challenges related to complexity, bill volatility, and fairness. These experiences underscore that the design and context in which demand-based rates are introduced are critical to their success. When considering the feasibility of implementing such rates for residential and small commercial customers in Alberta, it is essential to evaluate local factors—including Alberta's unique market structure, load patterns, and policy objectives. Alberta operates a fully deregulated electricity market where competitive retail and wholesale energy markets are separated from regulated distribution utilities. This separation introduces different cost drivers, incentive structures, and communication channels, all of which must be carefully considered to ensure demand-based rates are aligned with broader system goals and customer interests.

## 3: ALBERTA MARKET AND REGULATORY CONTEXT

### 3.1 Stakeholder Roles

Alberta is the only province in Canada with a fully deregulated electricity market, meaning it consists of competitive generation and retail markets with regulated transmission and distribution providers. Several key stakeholders play crucial roles in this market, as described in Table 2 below:

Table 2: Applicable Alberta Stakeholders[15]

| Entity | Role |
|---|---|
| Alberta Electric System Operator (AESO) | As the Independent System Operator (ISO), the AESO is responsible for the safe and reliable operations of the Alberta Interconnected Electric System (AIES), operating the wholesale electricity market, and planning transmission infrastructure. |
| Alberta Utilities Commission (AUC) | As the Alberta Electricity Regulator, the AUC regulates investor-owned utilities, generation development, and the electricity and natural gas markets. |
| Regulated Distribution Facility Owners (DFOs), such as EDTI | DFOs own and operate the low-voltage distribution lines that deliver electricity from substations to most end-use consumers. Their tariffs are regulated by the AUC. They are often referred to as "wire service providers." |
| Regulated Transmission Facility Owners (TFOs), such as EDTI | TFOs own, operate, build, and maintain the high-voltage power lines and associated equipment that transport electricity from generating plants to local distribution systems and large industrial customers, all under the regulation of the AUC. |
| Competitive retailers, such as Encor by EPCOR | Retailers purchase electricity in the wholesale market and sell it to residential, commercial, and industrial customers, managing billing and offering various rate plans to customers. |
| Rate of Last Resort (RoLR) Provider | In addition to the of DFO, EDTI is also mandated to serve as the "Rate of Last Resort" (RoLR) provider for eligible customers—residential, farm/irrigation, and small businesses consuming less than 250,000 kWh per year—within its service area. If a customer does not select a competitive electricity retailer, they automatically receive retail energy services from EDTI at the RoLR rate. |

Given the various roles of EDTI, it is important to assert that this study focuses solely on EDTI's role as a DFO and does not assess its RoLR function. To clarify the distinction between the two: RoLR rates recover energy commodity costs, while EDTI's distribution rates recover the costs of providing distribution services.

In Alberta, electric utility bills include separate charges for transmission deliver charges (SAS), distribution delivery charges (DAS) and energy charges from either a competitive retailer or a provider of the Rate of Last Resort (RoLR). DAS rates recover the cost to deliver or distribute electricity from where the transmission system connects to the distribution systems (substations) to the end-use customer and SAS rates recover the transmission cost to deliver electricity from the generators to substations. From a customer billing perspective, these are seen as a 'Distribution Charge' and a 'Transmission Charge,'

[15] Other Alberta stakeholders include generators that sell electricity into the wholesale market under AESO and AUC oversight; the Market Surveillance Administrator (MSA), which monitors market fairness and competitiveness; and the Balancing Pool, which manages legacy contracts and is expected to dissolve by 2030.

respectively. See sample bill in Figure 1 for a visual example of residential customer charges on an Alberta electricity bill.

This structure of customer bills in Alberta is an important distinction when comparing Alberta to jurisdictions with bundled electricity rates, where a single rate includes energy commodity charges as well as distribution and transmission tariffs. When considering various rate structures in Alberta, it is important to consider which lines items the rate is associate with, how it will impact customers' bills, and how it might impact their usage patterns.

Figure 1: Illustrative Residential Customer Electricity Bill

## Details of your new charges

**ELECTRICITY**

Encor by EPCOR

[redacted]- GUARANTEED RATE POWER (5YR)
Billing period: Apr 23 to May 21, 2025
Meter Readings by EPCOR Dist. & Trans.

Meter: 115220

| | | | |
|---|---|---|---|
| Reading on May 21 | (Actual) | 58050.00 | |
| Reading on Apr 30 | (Actual) | 57696.00 | |
| Reading on Apr 22 | (Actual) | 57549.00 | |
| Amount used | | 501.00 | kWh |

**Electric Energy Charges**
Provided by Encor by EPCOR 310-4300
New charges based on 501.00 kWh

| | |
|---|---|
| Apr 23-May 21 501.00 kWh at 9.89¢ / kWh | $49.55 |
| Administration Charge | $7.83 |
| **Subtotal** | **$57.38** |

**Delivery Charges**
Provided by EPCOR Dist. & Trans. 1-780-412-4500
Consumption: 501.00 kWh
New Charges:

| | |
|---|---|
| Distribution Charge | $28.87 |
| Transmission Charge | $19.16 |
| Transmission Deferral Rider K Apr2025 | $0.66 |
| Transmission True-Up Rider | $0.47 |
| Balancing Pool Allocation Rider | $0.68 |
| Local Access Fee Edmonton | $6.63 |
| **Subtotal** | **$56.47** |

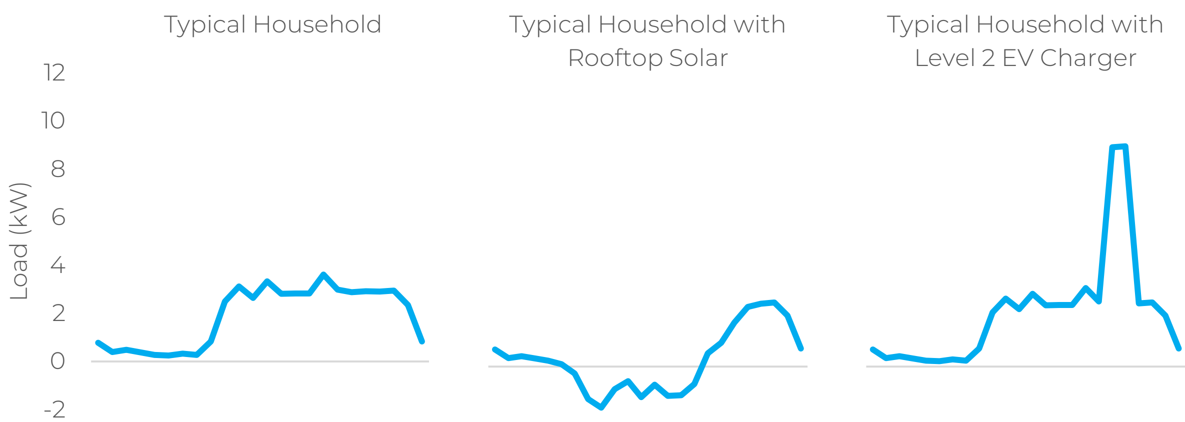
| | |
|---|---|
| GST (reg.845992171RT) at 5% on $113.85 | $5.69 |
| **Total** | **$119.54** |

Advanced rate structures are often used to influence customer behaviours. In the Alberta context, achieving this goal through rates is much more complex than in jurisdictions with vertically integrated utilities and bundled electricity rates. With no correlation between distribution or transmission tariffs structures and retail energy rates, shifting distribution rate structures alone in Alberta will have limited impact on customer bills (see detailed analysis in Appendix C), creating less incentive to influence customer behaviours.

## 3.2 Evolving Load Profiles

Beyond the complexity of tariff structures and energy rates in Alberta, rate design and implementation are becoming increasingly complex due to growing proliferation of distributed energy resources (DERs). For example, electric vehicles (EVs) and solar photovoltaic (PV) installation result in new load profiles for both residential and commercial customers. See Figure 2 below. With more customers connecting EV and PV to the grid, rate design is often paired with other load management tools to shift customer load patterns. See additional context for EV charging and rate design in Section 7.2.

Figure 2: Illustrative Residential Daily Load Profiles




Some DFOs have started piloting advanced rate design or customer programs to shift customer usage patterns. ATCO Electric tested the implementation of TOU rates through a small-scale residential pilot study in Grande Prairie, Alberta from November 1, 2021, to October 31, 2022. Like other TOU pilots, the core aim of ATCO's study was to determine if customers, when faced with different electricity prices based on the time of day, would shift their electricity consumption from "on-peak" hours to "off-peak" hours. "On-peak" was set at 4:00 p.m. to 9:00 p.m., daily.

ATCO's pilot applied TOU rates to the variable component of its distribution charges on customers' bills. This is a significant distinction when comparing to TOU rates in other jurisdictions in Canada. For example, Ontario's TOU rates apply only to the energy commodity charges and not the distribution charges, and distribution charges for residential and low volume customers are fixed. No official results of ATCO's TOU rate pilot have been publicly released as of the date of this report.

## 3.3 Factors Impacting Rate Design

Other regulatory and market design choices in Alberta will also influence electricity rate design choices. Specifically, the AESO is currently leading a multi-year effort to modernize Alberta's electricity market (Restructured Electricity Market, REM). One of the components of the proposed changes includes moving to shorter settlement intervals by 2040. When implemented, these shorter intervals of load settlement (which may be as granular as 5 minutes) will become a further enabler of complex and dynamic rate designs in response to near-real-time operations of the AIES.

The AESO is also actively engaged in consultation to adjust the transmission tariff rate structure (Rate DTS or Demand Transmission Service). The transmission revenue requirement collected via Rate DTS is allocated between a monthly system coincident peak charge (12CP), a non-coincident demand charge, and an energy charge. In its last attempt to redesign Rate DTS, the AESO attempted to significantly shrink the 12CP charge. While the Commission rejected that application, it is largely expected that a reduction in the 12CP continues to be warranted. If the AESO moves a majority of those charges to the demand charge, the price signal from the transmission tariff and ability of ISO market participants to avoid transmission tariff costs will be limited.

Given these considerations, it is important to clearly define the objectives and rationale behind exploring demand-based tariffs in Alberta. Despite structural challenges, such rates may support long-term system efficiency, cost-reflectivity, and fairness as customer load profiles evolve. The following section explores the strategic motivations behind demand-based rate design, including system cost drivers, equity considerations, and the need to incent more efficient electricity use in a transforming energy landscape.

# 4: OBJECTIVES OF DEMAND-BASED RATES

In response to Direction 7, this section outlines the key objectives of transitioning to demand-based billing. Power Advisory considered established rate design principles, the rationale for implementing demand-based rates, and the associated trade-offs and challenges in addressing this element of the feasibility study.

Electricity rate design is central to how utilities recover costs, how customers interact with the grid, and how broader policy goals are achieved. As the electricity system evolves—with electrification, uptake of DERs, and smart technologies—advanced rate structures must continue to balance a diverse set of objectives, and requires navigating trade-offs between cost recovery, fairness, simplicity, and system efficiency.

This section of the report draws on Power Advisory's expertise in electricity rate design and the Alberta electricity sector, and leading research on rate design best practices—including recent work such as Berkeley Lab and the Brattle Group's report *"Deliberate Design: Creating Electricity Rates with Purpose.*[16]

## 4.1 Rate Design Principles

Rate design principles have long been guided by the foundational Bonbright framework,[17] emphasizing revenue adequacy, cost reflectivity fairness, and simplicity. Over time, these principles have evolved to reflect the realities of a modern grid—shaped by electrification, DERs, and changing customer behaviours. Today, rate design must balance traditional goals with new priorities like demand flexibility and equity to support a reliable, efficient, and inclusive energy transition.

One of the primary principles of rate design is ensuring *revenue sufficiency*—that is, rates must enable utilities to recover their full cost of service. However, *revenue certainty* is equally important, referring to the stability and predictability of that cost recovery under varying usage conditions. For example, a rate structure may be sufficient in theory to recover costs under average conditions but may expose the utility to revenue volatility if it relies heavily on volumetric charges that fluctuate with customer consumption. As customer usage patterns become less predictable—due to factors such as solar PV adoption, EV charging, or energy efficiency—non-cost-reflective or highly variable rates increase the risk of both under- and over-recovery. At the same time, rates should be *cost-reflective*, aligning customer charges with the actual cost of serving them—particularly during peak demand periods when the system faces the highest strain.

That said, simplicity of electricity rates is essential. While advanced rate structures may be more responsive to a complex electricity system, electricity rates must remain understandable and actionable for customers. While economically efficient, highly cost-reflective rates can be complex and harder for customers to understand. If customers do not understand their rates, they are less likely to support the

[16] *Ryan Hledik, Sanem Sergici, Sai Shetty, and Peter Cappers (2025), Deliberate Design: Creating Electricity Rates with Purpose, 2025*

[17] *The Principles of Public Utility Rates*, James C. Bonbright, Albert L. Danielsen, David R. Kamerschen (Second Edition, 1988), Public Utilities Reports, pages 383-4

rate structure if they change or become more volatile. Striking the right balance between economic precision and customer usability is key to successful implementation of any rate design.

Bill stability is also important for customers, helping them manage their household budgets and enabling predictable utility revenues. However, greater stability may reduce customers' exposure to time-varying price signals that promote energy efficiency or load shifting. Rate design must also consider equity and affordability. Equitable rates ensure customers pay in proportion to the costs they impose on the system, while affordability ensures vulnerable households can maintain access to essential energy services.

Increasingly, rates are also expected to support policy goals such as electrification, energy efficiency, and demand flexibility. For example, time-varying or demand-based rates may better reflect system costs and encourage customers to shift usage away from peak periods. However, these designs may require significant utility investment in customer education, automation, or enabling technologies to be effective.

## 4.2 Rationale for Demand-Based Rates

Given the rate design principles discussed above, the following are rationales for considering demand-based rates for residential and small commercial customers:

- Cost Reflectivity: Improving cost-reflectivity is typically a primary objective of demand-based rates, particularly for the infrastructure required to meet the peak demand of the distribution system. When implemented using coincident peak demand (i.e., the customer's usage during the system-wide peak) or a peak-window approach, demand-based rates send accurate price signals that reflect the utility's costs of maintaining grid capacity. In contrast, NCP demand-based rates may be easier to administer but provide weaker alignment with system-level cost drivers.

- Revenue Sufficiency: As customers adopt more energy-efficient technologies, electrify end-uses, or generate their own electricity, utilities may experience reduced volumetric consumption, making it harder to recover demand-related costs through energy-only rates. By linking part of the bill to peak demand, utilities may be able to ensure more stable revenue streams that better match their cost structures—even as overall consumption patterns evolve.

- Equity: Demand-based rates can reduce customer cross-subsidization by ensuring that customers who place greater demand on the system pay proportionally more of the system's costs. However, some lower-income households may face higher peaks due to factors beyond their control—such as older appliances or poor building insulation—potentially leading to regressive outcomes. These impacts can be mitigated through targeted customer support programs or by layering demand-based rates within broader rate structures.

- System Reliability and Demand Flexibility: Coincident peak demand-based rates or on-peak demand-based rates encourage customers to reduce usage during high-stress periods on the grid, helping to manage capacity constraints and potentially delay costly infrastructure upgrades. Customers are incentivized to shift or flatten their load profiles using technologies such as smart thermostats, load controllers, or battery storage.

- Affordability: When designed appropriately, demand-based rates can align costs with usage patterns, promote efficiency, and may help control long-term system costs and mitigate future rate increases. However, achieving these outcomes requires a strong emphasis on customer education, transparent communication, and access to tools and technologies that help customers manage their demand effectively.

Demand-based rates have the potential to better align with a utility's cost drivers, improve revenue stability, and promote more efficient use of the distribution system. For residential and small commercial customers—who have historically been served under simple energy-based rate structures—these rates can offer more accurate price signals that reflect their actual impact on the grid. However, unlike larger commercial or industrial customers, smaller customers typically lack sophisticated energy management systems or the expertise to effectively monitor and respond to complex rate designs. As a result, translating the theoretical benefits of demand-based rates into practical and equitable outcomes remains challenging. The next section explores the specific challenges and potential unintended consequences of implementing demand-based rates for residential and small commercial customers.

## 4.3 Trade-offs and Challenges of Demand-Based Rates

While demand-based charges may help achieve a range of objectives and pursue multiple goals, there are trade-offs that must be carefully balanced. While common for larger commercial and industrial customers, the complexities and trade-offs related to demand-based rates for residential and small commercial customers include:

- Customer Understanding: Demand-based rates are often perceived as complex and difficult for low-volume customers to understand. Customers may struggle to grasp how their maximum demand impacts their bills, leading to confusion and dissatisfaction. Where there is customer confusion, there can also be political sensitivities. In Alberta, customers often do not have visibility of distribution costs given retailer billing.

- Limited Control: Customers may have limited ability to manage their demand effectively due to lack of resources, knowledge, or flexibility in their energy usage patterns.

- Potential Inequity: Demand-based rates may disproportionately impact customers with high peak demand but low overall usage, such as small businesses or low-income households. This could lead to affordability concerns if not carefully designed.

- Complex Design Requirements: Designing cost-reflective demand-based charges requires careful consideration of utility costs and load profiles. Misaligned charges could penalize customers for usage patterns that do not actually drive utility costs. For example, customers on NCP rates with higher demands in off-peak periods which do not drive utility costs.

- Customer Education Needs: Utilities must invest in educating customers about demand-based rates, including how to manage their demand effectively and reduce their bills. Without proper education, customers may fail to respond to price signals or adopt beneficial behaviours.

- Reduced Incentives for Energy Efficiency and Load Flexibility: By shifting a larger portion of the bill to demand-based rates, these rate structures reduce the share of costs tied directly to energy consumption. This can weaken customer incentives to invest in energy efficiency measures or DERs. Additionally, when paired with time-varying rates, demand-based rates may diminish price responsiveness by lowering the avoidable portion of the bill, reducing the effectiveness of peak and off-peak price signals.

While demand-based rates offer the potential to improve cost reflectivity and revenue stability, their feasibility for residential and small commercial customers is constrained by significant trade-offs—particularly in Alberta's market context, where customers are billed through retailers and may have limited visibility of distribution charges. These complexities heighten the risk of customer confusion, political sensitivity, and inequitable outcomes, underscoring the importance of broader stakeholder engagement—including retailers, regulators, and customer advocates—to ensure demand-based rates are both practical and publicly acceptable.

As an alternative approach to managing challenges associated with energy-based rates, the Ontario Energy Board (OEB) adopted fully fixed base electricity distribution rates for residential customers. This decision was the result of a multi-year consultation process initiated under case EB-2012-0410, which built on earlier work regarding revenue decoupling for distributors.[18] Recognizing that distribution costs are largely fixed and not significantly influenced by customer usage, the OEB concluded that a fixed rate structure would promote fair cost recovery, ensuring that all customers contributed equitably to maintaining the distribution system. The OEB found that fixed rates also offered revenue stability for distributors, supported conservation and innovation by removing disincentives to distributors of promoting energy efficiency, and provided a more transparent and understandable pricing model for customers.

## 4.4 Summary and Discussion

Overall, demand-based rates offer a moderate alignment with many core rate design objectives, particularly with respect to cost reflectivity. While demand-based rates can better reflect demand-related infrastructure costs and help reduce cross-subsidization, their effectiveness depends heavily on how they are designed—particularly whether they target on-peak demand or NCP demand.

Importantly, EDTI's current rate structure for residential and small commercial customers does not appear to present a revenue sufficiency concern, reducing the urgency of a shift to demand-based billing from a utility perspective. For context, EDTI's 2022 COSS attributed approximately 35% of peak demand costs to Residential and approximately 11% to Small Commercial.[19]

Furthermore, demand-based rates introduce complexity and present customer comprehension challenges, especially in Alberta's retail market, where customer communication is largely mediated by retailers. Any future implementation would need to include strong customer education efforts and clear communication. Additionally, consideration should be given to how demand-based rates may interact

[18] Ontario Energy Board, *Rate Design for Electricity Distributors (formerly Revenue Decoupling for Distributors)*, Case No. EB-2012-0410, launched November 26, 2012. https://www.oeb.ca/industry/policy-initiatives-and-consultations/rate-design-electricity-distributors-formerly-revenue

[19] INCP-50 Weightings from AUC Proceeding 27018, Exhibit 27018-X0003, Appendix C

with any future changes to electricity pricing or rate structures in Alberta to achieve broader policy or regulatory goals.

The summary table below is consistent with the Berkeley Labs and Brattle Group (2025) summary report on rate design objectives referenced above.

Table 3: Summary of Demand-Based Rate Objectives

| Objective | Rate Design Considerations & Trade-offs | Demand-Based Rates Achievement of Objectives |
|---|---|---|
| 1. Revenue Sufficiency | Load forecasts are uncertain due to customer behaviour, weather, and technology adoption. Non-cost-reflective rates increase risk of over- or under-recovery by the utility. | Medium – Provides stable revenue from demand-driven infrastructure costs and may improve revenue certainty for the utility. |
| 2. Cost-Reflectivity | High cost-reflectivity may introduce complexity that customers find difficult to understand and act upon. Balance needed between economic accuracy and customer comprehension. | Medium – May improve cost alignment by targeting demand-related costs. While coincident peak (CP) and on-peak designs may be cost reflective, NCP designs are not necessarily cost reflective as customer's peak usage may not be coincident with the system peak. |
| 3. Bill Stability | Trade-off with reflecting time-varying or seasonal cost variations. May reduce customers' exposure to cost-based price signals that influence behaviour. | Medium – May increase bill variability. Demand ratchets[20] may improve stability but reduce flexibility. |
| 4. Equity | Hard to achieve in a diverse customer base with limited rate classes. May conflict with simplicity. Sometimes overlaps with affordability for vulnerable populations. | Medium – Aligns bills more closely with customer impact on grid, reducing cross-subsidies. Less avoidable by micro-generation customers currently on energy-based rates. |
| 5. Energy Affordability | Potential cost shift to other customers. Policy decisions often needed on whether to address affordability through rate design or through separate support mechanisms like discounts or credits. | Low – Can disproportionately impact low-income customers if not well-designed. Hard to understand and requires education and thoughtful design to avoid harm. |
| 6. Simplicity | Simplification may reduce granularity and accuracy of cost | Low – Often seen as complex and difficult for residential customers to understand. |

[20] Demand ratchets set a minimum billing demand based on a customer's historical peak usage, helping recover fixed costs but potentially penalizing short-term spikes.

| | | |
|---|---|---|
| | signals, potentially leading to less economically efficient outcomes. | Requires significant investment in customer education. |
| 7. Promote Electrification | Lower energy prices to support electrification can reduce incentives for DERs and energy efficiency. Must ensure rates reflect cost of serving new electric loads without overburdening other customers. | Medium – Reduces energy charges, improving electrification economics (for high-load factor electricity usage like heat pumps). May hinder EV charging adoption unless charging is managed. |
| 8. Promote Energy Efficiency & DERs | May conflict with goals to support electrification. Policy decisions needed on whether to apply technology-neutral vs. technology-specific rates. | Medium – Lower energy-based rates reduce DER/efficiency payback. Mixed signal depending on DER type and usage profile. |
| 9. Encourage Demand Flexibility | May require enabling technologies or incentive programs. Customers may need automation or education to respond effectively. Can be implemented via rates or external programs. | Medium – CP or on-peak charges can encourage load shifting, but they may be less effective than time-varying rates due to diluted price signal. |
| 10. Improve System Reliability | Focus is on managing peak load, not outage recovery. Trade-off between customer responsiveness and rate design complexity. | Medium – CP demand-based rates align with peak reduction, helping reliability; NCP charges less effective. |

# 5: OVERVIEW OF EDTI CAPABILITIES AND COSTS

To assess the capabilities of EDTI's existing meters and related systems, Power Advisory issued an information request to gather relevant data. This approach was chosen to obtain accurate, comprehensive, and up-to-date information directly from EDTI, enabling Power Advisory's evaluation of the metering infrastructure, associated systems, and their ability to enable alternative rate designs.

## 5.1 EDTI Capabilities

Per Directive 7, this section provides an assessment of the capabilities of EDTI's existing meters and related systems.

The current system configuration enables EDTI to collect and reconcile billing data, recorded through kilowatt-hour registers, every 24 hours and bill residential and small commercial customers based on energy consumption. Residential and small commercial meters are currently programmed to record data (i.e., kWh consumed) in 60-minute intervals. However, this interval data is not used for billing, therefore it is not subjected to the validation processes required to meet the accuracy standards necessary for generating customer tariff bill files. While not currently enabled, all of EDTI's AMI meters are technically capable of capturing interval data at various frequencies. Further details on how to enable this capability are outlined in Section 5.3.

EDTI's AMI network is enabled by Landis+Gyr's Gridstream Radio Frequency (RF) Advanced Metering Solution, a platform designed to support advanced multi-utility metering, customer energy management, and distribution automation applications. The Gridstream solution supports electric, gas, and water meters, offering two-way communication and interval data collection as granular as five minutes. EDTI has configured the system with a Head-End System (HES) and a Communication Network to manage a large population of electric and water meters. These systems are used to collect, reconcile, and analyze meter data for billing and load settlement, while also enabling command and control of networked devices and metering endpoints.

The Command Center HES is hosted by Landis+Gyr's Command Center application in a secure, server-based environment. This application facilitates the management of metering endpoints across the Gridstream RF network and integrates with EDTI's Meter Data Repository (MDR), Settlement Tariff and Revenue System (STARS), SAP-based Meter Management System, and Advanced Distribution Management System (ADMS). Key functionalities of the Command Center include remote meter programming, TOU configuration, basic data validation and exception management, billing extract generation, remote disconnect operations, critical peak usage analysis, demand response device management, voltage monitoring, and real-time system mapping and diagnostics. The platform also supports various analytics, administrative dashboards, and system monitoring tools for improved operational oversight.

The field area network consists of 32 collectors and 9 network gateways—each equipped with Internet of Things (IoT) modems enabled with 4G Long-Term Evolution (LTE) cellular connectivity—for backhaul communication. Additionally, 383 routers are deployed throughout the network to act as communication repeaters and support consistent data transmission.

EDTI's electric meter population includes approximately 430,000 residential smart meters (Landis+Gyr FOCUS AXe and AXi, in forms 1S, 2S, and 12S) and approximately 30,000 commercial and industrial smart meters (Landis+Gyr E650 S4x, in forms 16S, 45S, 36S, and 9S). Residential meters offer active energy measurement, optional reactive energy measurement, remote disconnect capability (200A and 320A), power quality monitoring (sag, swell, total harmonic distortion), tamper detection, magnetic field detection, and over-the-air (OTA) firmware updates. Commercial and industrial meters support four-quadrant energy measurement, milli-unit and micro-unit resolution, three-phase power supply, magnetic tamper detection, and tilt/vibration sensors.

EDTI's STARS system is the primary platform used to manage billing and settlement processes for both cumulative (residential mass market) and interval (commercial and industrial TOU) metering sites. To facilitate integration across platforms, EDTI employs internally developed middleware that enables communication between enterprise applications. The custom-built MDR functions as EDTI's Meter Data Management System (MDMS), delivering just-in-time meter reads to STARS to support billing and settlement.

Table 4: Current Infrastructure

| Meter Type | Quantity | Model(s) | Form Factors | Features & Functionality |
|---|---|---|---|---|
| Residential | ~430,000 | Landis+Gyr FOCUS AXe & AXi | 1S, 2S, 12S | • Active Energy ("kWh"); optional Reactive Energy ("kVAh" or "kVARh")<br>• Two simultaneous demands: kW, kVA, kVAR<br>• 100A, 200A and 320A remote disconnect<br>• Exceeds American National Standards Institute (ANSI) accuracy requirements (0.2% active); surge protection up to 10kV<br>• Power Quality Metrics: Sag, Swell, Total Harmonic Distortion<br>• Up to 8 channels of Load Profile (standard)<br>• Optional independent second 8-channel Load Profile Recorder (E331/E351)<br>• Tamper detection (removal/insertion)<br>• Magnetic and Direct Current (DC) presence detection<br>• Over-the-air firmware and program updates<br>• Dedicated Voltage Log<br>• Configurable optical port lockout |
| Commercial & Industrial | ~30,000 | Landis+Gyr E650 S4x | 16S, 45S, 36S, 9S | • Four-quadrant measurement<br>• Delivered and received kW, kVA, kVAR demands<br>• Two alternate methods of VAR and VA calculation |

| | | | | |
|---|---|---|---|---|
| | | | | • Milli-unit energy and demand resolution<br>• Micro-unit instrumentation resolution<br>• 16-channel, 256K standard memory; 1 MB optional<br>• Optional second recorder<br>• Three-phase power supply<br>• Magnetic tamper detection<br>• Cover removal switch<br>• Tilt and vibration sensor |

## 5.2 Current Costs

In response to the Direction 7 to provide "The current capital and operating costs incurred by EDTI to support Time-of-Use (TOU) rates for interval rate classes," it is important to note that EDTI does not currently offer TOU rates, therefore does not incur capital or operating costs associated with TOU.

EDTI offered TOU energy rates prior to 2023 that recovered a relatively small percentage of class revenues through an on-peak energy charge. The TOU energy rates were mandatory and applicable to the Commercial/Industrial 150 kVA to <5,000 kVA secondary (Distribution Access Service - Time-of-Use, DAS-TOU) and primary (Distribution Access Service - Time-of-Use – Primary, DAS-TOUP) rate classes. The rates were initially implemented as an energy efficiency measure when EDTI owned generation facilities. As the COSS does not classify EDTI's current costs as energy-related, it discontinued energy-based rates for classes with demand metering in EDTI's 2022 Phase II tariff application.[21]

EDTI's STARS is a single settlement, tariff and billing system which accommodates both cumulative and interval meter readings. In response to Direction 3 of AUC Decision 2011-375, EDTI described the effort required for interval-metered billing and cumulative energy-metered billing. Though the processes differ based on how volumes are metered, EDTI assessed that they require a similar level of complexity. An excerpt from the 2022 Phase II tariff application is provided below.[22]

> The settlement and billing requirements for interval and cumulative metered sites differs in approach and process, not in complexity. For example, interval and cumulative meters differ in the approach to load settlement but are equally complex as hourly settlement values are required for both interval and cumulative metered sites. Interval sites rely on measured interval data whereas cumulative metered sites rely on interval data derived using the Net System Load Shape ("NSLS"). The volume of sites in each type of metering class and the corresponding volume of billing cycles also varies. For example, EDTI currently has approximately 420,000 sites that are billed using cumulative data, and 1,800 sites that are billed using interval data. Cumulative meter reads are billed as per their corresponding billing cycle each business day of the month, and interval

[21] AUC Proceeding 27018, 27018-X0005 Appendix E, page 9

[22] AUC Proceeding 27018, 27018-X0001, pages 4-5

metered sites are billed in a single billing cycle each month. The load settlement process aggregates interval-metered consumption meter read data to obtain hourly consumption values for use in the load settlement process. For cumulative sites, consumption is allocated according to profiles based on the Net System Load Shape ("NSLS"). These examples illustrate there was not a higher level of complexity designed into the STARS system to accommodate the needs of both interval and cumulative metered customers. Therefore, smaller customers did not incur increased costs to accommodate a higher level of complexity.

The capital costs associated with the STARS system did not materially differ between TOU and non-TOU rate classes. TOU rates required marginally higher operational support costs to respond to technical issues associated with the larger set of interval data. These higher costs were not significant given the relatively low number of sites with TOU rates but could be material if all Residential customers were moved to TOU rates or the other rates discussed in this report.

## 5.3 Costs to Enable Demand-Based Rates

Through an information request to EDTI, Power Advisory received a description of the modification to existing infrastructure and estimated costs required to implement demand-based rates for customers.

To support demand-based rates—and potentially TOU pricing—using the existing infrastructure, several key modifications would be required to EDTI's current system:

1. Meter Programming Adjustments

Depending on the chosen rate model, meters would need to be reprogrammed to deliver interval data to the HES at the appropriate frequency (e.g., 5, 15, or 60 minutes).

To change the data collection frequency, the meter programming must be updated and applied to each meter. This can be done in one of three ways:

a) During the manufacturing process,

b) At EDTI's Meter Lab during a re-service activity, or

c) Remotely via the AMI network using OTA communication.

While OTA updates are technically feasible, they are subject to regulatory requirements—such as Measurement Canada standards—and must undergo testing to ensure the reliability and accuracy of the changes. EDTI would need to seek explicit approval from Measurement Canada in order to remotely reprogram residential and small commercial meters.

2. Information Technology (IT) Infrastructure Enhancements

Increased data collection would necessitate upgrades to IT infrastructure to handle the additional processing and storage demands. In parallel, middleware and workflow integrations between the AMI system, the MDMS, and billing systems would need to be updated. These enhancements could be applied to current systems or incorporated into the new system planned for release around 2030.

3. Billing-Quality Data Validation

Finally, it would be essential to ensure that the interval data collected from meters meets billing-grade standards. This involves transforming raw meter data into billing-quality data through a defined process that includes selecting specific reads, importing them into the billing system, and applying a robust validation procedure. This process ensures consistency and accuracy by comparing data against established parameters and historical trends.

When considering costs of implementing demand-based rates, EDTI considered the following rate design options:

Table 5: Rate Design Options

| Option | Rate Type & Structure | Data Required | Billing Determinant & Notes |
|---|---|---|---|
| 1 | Demand – $/kW/day | Peak metered demand from the billing period (cycle or month); W or kW | Highest metered demand during the billing period. Similar to the Distribution Access Service (DAS)[23] demand-based rate currently used for the Medium Commercial Class. |
| 2 | Demand – $/kW/day | One-hour interval demand (same as hourly energy); W or kW | Highest one-hour demand during the billing period. |
| 3 | Demand – $/kW/day | 15-minute interval; W or kW | Highest metered 15-minute demand during the billing period. Similar to the demand-based rate used for EDTI's previous TOU and TOU Primary (TOUP) classes. |
| 4 | Demand – $/kW/day | 5-minute interval; W or kW | Highest metered 5-minute demand during the billing period. |
| 5 | Time-of-Use – $/kWh (on-peak/off-peak) | Total on-peak and off-peak energy for the billing period; kWh | Total energy measured in specified on-peak and off-peak hours. Similar to the rate structure previously used for TOU and TOUP classes. |

EDTI summarized costs for implementing demand-based rates into the following categories. These costs reflect both internal and external resources, infrastructure upgrades, and necessary overheads:

1. Internal – IT: Costs related to system development and implementation activities performed by internal IT staff. This includes updates to billing systems, data platforms, and other internal digital infrastructure.

2. Internal – Business Unit (BU): Costs associated with internal resources dedicated to business process updates, including quality assurance (QA) testing to validate new billing determinants and workflows.

[23] See Appendix B for details.

3. Capital Overhead: General overhead applied to capital projects, including project management, administrative support, and shared services.

4. Contractor & Consultant: External services hired to support implementation, such as specialized IT development, engineering, rate design expertise, or regulatory support.

5. Meter Lab: Costs incurred by the meter laboratory for reprogramming, calibration, or testing of meters to support the new rate structure.

6. Meter Field Operations: Labour costs associated with field crews for meter replacement, reprogramming, or onsite validation.

7. AMI HES: Upgrades or changes required to the AMI HES to enable more granular demand data collection and processing.

8. Hardware: Physical equipment required for implementation, such as upgraded meters, communication modules, or IT servers.

9. Miscellaneous: Other costs that includes:

   a. IT Systems: Minor system upgrades or licensing.

   b. Data Storage: Additional storage capacity to accommodate higher-resolution interval data;

   c. Other Incrementals: Any other incidental costs related to implementation.

10. Contingency (15%): A risk-based allowance to account for unforeseen expenses or scope changes during implementation, set at 15% of total estimated costs.

11. Interest During Construction (IDC): Financing costs calculated as part of the capital formula to account for interest accrued during the implementation period.

With respect to implementation requirements, EDTI identified the following timelines and resource requirements for each option.

Table 6: Implementation Timelines

| Option | Rate Type | Implementation Requirements |
|---|---|---|
| 1 | Demand (Peak Billing Demand) | ~9 months total for IT development, QA, and implementation. Requires internal IT developers or contractors, systems QA, and a project manager. (No meter changes are required) |
| 2 | Demand (Hourly Peak) | ~9 months for IT work, plus up to 48 months for account/site conversion. Requires same resources as Option 1. |
| 3 | Demand (15-Minute Interval) | ~9 months for IT development, 7 months for meter seed lot prep, and up to 48 months for account/site conversion, meter changes, and programming. Requires IT developers, QA, meter lab, field operations (internal/contractors), and project management. |
| 4 | Demand (5-Minute Interval) | Same as Option 3. |
| 5 | Time-of-Use (On/Off-Peak Energy) | ~9 months for IT development, up to 48 months for account/site conversion. If interval changes are needed, add time/resources for meter programming and replacement. Core resources are IT developers, QA, and a project manager; meter work may require meter lab and field operations. |

EDTI evaluated opportunities to reduce implementation costs by assessing whether meter programming changes could be completed through OTA updates rather than requiring physical meter replacements. Utilizing OTA programming significantly lowers costs by eliminating the need for field installation labor and the procurement of a meter seed lot. Meter programming or replacement is necessary for Options 3, 4, and 5. For these options, EDTI developed two cost scenarios: Options 3A, 4A, and 5A assume OTA programming can be used, while Options 3B, 4B, and 5B assume a full physical meter swap is required.

Therefore, based on information received from EDTI, the cost estimates are as follows.

Table 7: Cost Estimates

| Cost Component | Option 1 - Peak Meter | Option 2 - Demand 1 hr | Option 3A - Demand 15 min | Option 3B - Demand 15 min | Option 4A - Demand 5 min | Option 4B - Demand 5 min | Option 5A - TOU | Option 5B - TOU |
|---|---|---|---|---|---|---|---|---|
| Internal: IT | $21,480 | $21,480 | $21,480 | $21,480 | $21,480 | $21,480 | $21,480 | $21,480 |
| Internal: BU | $22,766 | $22,766 | $22,766 | $22,766 | $22,766 | $22,766 | $22,766 | $22,766 |
| Capital Overhead | $11,158 | $11,158 | $11,158 | $11,158 | $11,158 | $11,158 | $11,158 | $11,158 |
| Contractor & Consultant | $227,900 | $227,900 | $227,900 | $227,900 | $227,900 | $227,900 | $227,900 | $227,900 |
| Meter Lab | 0 | 0 | $55,000 | $24,660,000 | $55,000 | $24,660,000 | 0 | 0 |
| Meter Field Operations | 0 | 0 | $40,000 | $18,280,000 | $40,000 | $18,280,000 | 0 | 0 |
| AMI HES | 0 | 0 | $77,500 | 0 | $77,500 | 0 | 0 | 0 |
| Hardware | 0 | 0 | $2,760,000 | $2,760,000 | $2,760,000 | $2,760,000 | 0 | $51,550,000 |
| Miscellaneous | 0 | $3,550,000 | $14,300,000 | $14,300,000 | $14,300,000 | $16,700,000 | $5,720,000 | $5,720,000 |
| Contingency | $42,496 | $574,996 | $9,042,496 | $9,042,496 | $9,042,496 | $9,402,496 | $900,496 | $8,632,996 |
| IDC | $9,997 | $157,230 | $1,919,157 | $1,919,157 | $1,919,157 | $2,127,171 | $241,619 | $4,709,629 |
| Totals | **$335,797** | **$4,565,530** | **$28,477,457** | **$71,244,957** | **$28,477,457** | **$74,212,971** | **7,145,419** | **70,895,929** |

These cost estimates are based on current information and expected requirements for development time, resource availability, and hardware needs. Adjustments to any of these variables could result in increased implementation costs.

Additionally, there remains technical uncertainty regarding the use of OTA updates for meter programming, as this process has not yet been tested or implemented by EDTI. As a result, the time required to complete OTA updates may exceed expectations or lead to a greater number of meter replacements than initially forecasted.

Finally, since OTA updates require prior approval from Measurement Canada, there is risk associated with the current assumptions regarding the OTA solution, including the process, timelines, and potential cost impacts.

## 5.4 Potential for Reduced Operating Costs

Enabling billing data from more granular intervals to enable demand-based rates is not likely to result in operational expense savings for EDTI. To the contrary, EDTI would expect a potential increase in operational costs.

EDTI expects an increase in operational support costs given the increased reliance on interval data, which would require more work to ensure billing is accurate and technical issues are addressed, and to address an anticipated higher number of inquiries. The incremental work required includes:

1. AMI HES Operations

As reliance on interval data for accurate billing and settlement grows, adjustments in manpower will be necessary to ensure timely investigation of technical issues affecting AMI network communications needed for metering data collection. It is anticipated that an increase in manpower would be required primarily for proactive maintenance and assurance routines, along with support requests from the Meter

Data Billing Teams. This requirement would impact AMI HES Operators, who are responsible for conducting remote diagnostics and fault remediation.

2. Meter Field Operations

Additional Meter Field Operations staff would be required to handle site investigations and the replacement of faulty network equipment and metering endpoints.

3. Load Settlement Operations

No additional resources would be required from Load and Settlement perspective if only the peak demand is used (Option 1). Substantial changes would be required if cumulative load is changed to interval load, resulting in a different treatment in MDR prior to billing in STARS. Currently, all interval load and estimation for interval sites are reviewed and processed daily by the Senior Analyst, Load and Settlement Group. There are currently approximately 3,000 active interval sites. With the inclusion of all cumulative monthly sites converted to interval sites a significant manual review and validation may be needed for approximately 300,000 sites in MDR before data can be loaded to STARS.

Demand intervals of 5 minutes or 15 minutes would require more extensive data to account for as a part of daily operations. As a result, the team will be looking at 96 intervals per site every single day that may not have complete set of data.

4. Market Support Operations

With the transition to shorter settlement periods, market participants are likely to have an increased number of inquiries, including:

- Missing Settlement and Billing Transactions: As with the current system, participants will continue to reach out with issues or questions regarding how their transactions are settled or billed. However, the shift to shorter settlement periods would result in a higher volume of market transactions, leading to more questions about the accuracy and completeness of transaction records.

- System and Communication Issues: There may be challenges related to how internal systems communicate and process data. Participants will need to ensure their systems are compatible and capable of handling the increased speed of transactions.

- Billing, Settlement, and Demand-Related Questions and Disputes: The increased complexity of shorter settlement periods would likely lead to more customer inquiries and disputes related to billing, settlement amounts, and demand charges. This includes questions about discrepancies in bills, unexpected charges, or issues with how demand is calculated and billed. Retailers would continue to contact Market Support to address these concerns.

Table 8 summarizes EDTI's estimated incremental number of full-time equivalent employees (FTEs) for each of the rate types.

Table 8: Ongoing Incremental FTEs

| Option | Rate Type | AMI Headend System | Meter Field | Load Settlement | Market Support | Total |
|---|---|---|---|---|---|---|
| 1 | Demand (Peak Billing Demand) | 0.28 | 0.24 | 0.00 | 0.13 | **0.65** |
| 2 | Demand (Hourly Peak) | 0.84 | 0.56 | 3.00 | 0.65 | **5.05** |
| 3 | Demand (15-Minute Interval) | 0.84 | 0.56 | 5.00 | 1.30 | **7.70** |
| 4 | Demand (5-Minute Interval) | 0.84 | 0.56 | 5.00 | 2.00 | **8.40** |
| 5 | Time-of-Use (On/Off-Peak Energy) | 1.12 | 1.69 | 5.00 | 2.60 | **10.41** |

## 6: EVALUATION OF DEMAND-BASED RATE ALTERNATIVES

Per Direction 7, this section identifies alternatives for implementing demand-based billing. While it is not feasible to identify and evaluate all possible options, this section of the report reviews a spectrum of viable and practically implementable demand-based rate designs, based on Power Advisory's expertise and knowledge of rate designs implemented in other jurisdictions.

While preliminary cost estimates and implementation timelines were provided in Section 5.3, this section focuses on the different options available to EDTI for recovering variable, demand-related costs. Section 6.3 presents a review of the pros and cons of each option. In addition, a desktop analysis is included to assess the feasibility of demand-based rates by evaluating the bill impacts associated with each identified rate design, using a sample of customer consumption data from the residential and small commercial rate classes.

### 6.1 Overview of Demand-Based Rate Design Alternatives

Power Advisory considered the following rate design alternatives in this feasibility study.

1. NCP Demand: NCP demand-based rates are based on a customer's own maximum demand within a billing period, regardless of when it occurs. This approach is commonly used for commercial and industrial customers, including by EDTI, but is less frequently applied to residential and small commercial customers.

The key advantages of this design include administrative simplicity and ease of customer understanding relative to CP demand. It encourages customers to manage their individual peak usage but does not align as closely with system costs. It may also penalize customers whose peaks occur during off-peak periods and therefore do not contribute to system-wide peaks.

2. CP Demand: This rate design charges customers based on their demand during the system's peak hour(s), typically aligned with monthly or seasonal system peaks. It is generally more suitable for larger customers with sophisticated energy management systems and the ability to monitor system conditions.

While CP demand rates provide a strong, cost-reflective price signal aligned with system investment drivers, Power Advisory does not consider this option viable for residential and small commercial customers and has therefore excluded it from further analysis. Although CP designs are used for large industrial customers—such as Alberta's transmission tariff, which is based on a 12-CP structure—they are not appropriate for smaller customer classes. Key challenges include the risk of significant bill volatility due to unpredictable peaks and the difficulty for residential and small commercial customers to understand or anticipate system-level peaks. Moreover, system peaks may not align with local distribution system peaks, further complicating rate design and customer communication. Power Advisory is not aware of any jurisdiction that currently applies CP demand rates to these customer segments

3. TOU Demand: Under this design, demand-based rates are applied to a customer's peak usage during pre-defined on-peak periods (e.g., weekdays from 4:00 p.m. to 9:00 p.m.). This option has been implemented in several jurisdictions that apply demand billing to residential and small commercial customers.

TOU demand provides a middle ground by offering more accurate cost-reflective signals than NCP demand and more predictability than CP demand. It aligns reasonably well with typical system load shapes and can encourage load shifting and peak reduction. However, it may still be challenging for some customers to understand and does not fully capture seasonal or atypical peak variations.

4. Subscription-Based Demand (Fixed kW Tiers): In this rate design, customers subscribe to a fixed demand level (e.g., 5 kW, 10 kW, 15 kW) and pay a corresponding flat fee. If their usage exceeds the subscribed level, they may incur penalties or be charged higher rates. This model is more common in European markets (e.g., France) but is not commonly used in North America.[24], [25]

Subscription-based demand offers high bill predictability and allows customers to manage usage within clear limits, which can also aid distribution system planning. However, this approach is less directly tied to actual system cost drivers (often relying on simplified assumptions like NCP demand) and requires careful consideration when setting appropriate tier levels.

While subscription-based demand charges share many characteristics with fixed-fee distribution rates—such as offering predictable billing and simplifying cost recovery—they differ in one important respect: the charge is based on a customer's selected or historical peak demand, rather than being uniform across all customers. As a result, not all customers pay the same amount; instead, charges are scaled to reflect the customers' individual capacity needs.

5. TOU Energy: TOU energy rates are also included in this feasibility study as a comparative alternative. In this model, customers are charged based on the amount of energy consumed during defined on-peak and off-peak periods. While this structure does not include a demand-based charge, it still sends a price signal that can influence customer behaviour.

TOU energy rates are widely used across North America, though typically applied to the commodity portion of the bill (as in Ontario) or embedded within energy rates for vertically integrated utilities. In Australia, TOU rates for delivery charges are common.[26] This design encourages customers to shift consumption to lower-cost, off-peak periods and reduce usage during high-cost peak periods, thereby contributing to system optimization without the complexity of demand-based billing.

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[24] A subscription rate plan is currently being piloted by ConEdison in New York (https://www.coned.com/en/accounts-billing/smart-energy-plan) and is being contemplated in California as part of The California Public Utilities Commission's CalFUSE Framework (California Flexible Unified Signal for Energy).

[25] Note that Manitoba Hydro's electricity rate, which includes tiers based on service size (amperage), is similar to a subscription-based charge. A fixed-fee structure based on service size has not been fully explored in this feasibility study, which focuses more specifically on demand-based rates.

[26] Under what are referred to in Australia as "cost-reflective tariffs", distributors must structure rates to reflect their "efficient costs of providing services to each consumer". In practice this means TOU and/or demand billing for the delivery portion of the bills is offered as the default option for customers, including residential and small business customers. See *Distribution Network Pricing Arrangements* folio at the Australian Energy Market Commission for more information (https://www.aemc.gov.au/rule-changes/distribution-network-pricing-arrangements)

In addition to the primary demand rate design options discussed above, several complementary rate design features can be considered to refine implementation and improve customer outcomes. These features can be layered onto core rate structures to better align with system needs, customer preferences, and policy objectives.

- Demand ratchets, which set a minimum demand-based rate based on past peak usage, help ensure fixed cost recovery and discourage load volatility, though they may penalize customers for short-term spikes and are challenging to explain to smaller customers. This approach is already in use by EDTI for larger customers.
- Seasonal demand-based rates apply different rates during peak versus off-peak seasons, encouraging demand reduction when the system is most constrained, but they add complexity and may confuse customers without strong communication.
- Opt-in versus mandatory implementation approaches offer trade-offs: opt-in models allow customers to self-select based on interest and ability to respond but may lead to cross-subsidization and slower adoption, while mandatory participation ensures broader alignment with system costs but may result in bill impacts and pushback.
- Performance-based demand-based rates adjust rates based on participation in grid-supporting programs, incentivizing demand response and DER integration, though few examples currently exist, and implementation would require additional infrastructure and program design.
- Tiered demand-based rates apply different $/kW rates across usage bands, promoting affordability for smaller users and encouraging moderation in peak demand, but may not fully reflect cost causation and require careful communication to avoid confusion at tier thresholds.

Power Advisory did not incorporate these features in its comparative analysis to maintain simplicity and clarity; however, if demand-based rates were to be implemented, it would be important to consider these design features as part of the overall rate strategy.

Based on Power Advisory's assessment of viable rate design alternatives for residential and small commercial customers, four options were considered in this feasibility study: NCP Demand, TOU Demand, Subscription-Based Demand, and TOU Energy rates. These options were selected for their relative feasibility, potential to provide meaningful price signals, and applicability to smaller customer classes. These alternatives were also selected due to their practical implementation potential and relevance to EDTI's objectives and system characteristics.

In the following sub sections, each option is evaluated for its potential to promote load management, improve revenue stability for the utility, align with system cost drivers, and support customer engagement and equity.

## 6.2 Pros and Cons of Each Alternative

The table below outlines the main advantages and drawbacks of each rate design. NCP and TOU demand-based rates both link customer bills more directly to system usage patterns, while demand subscription charges offer predictability and customer choice. TOU energy pricing, which is more familiar to many customers based on implementation in other jurisdictions, encourages load shifting based on time but may require stronger price signals to be effective. Each design presents trade-offs in terms of complexity, equity, and alignment with utility planning goals, and would require varying levels of customer education and system enablement to implement successfully.

Table 9: Rate Design Pros and Cons

| Rate Design | Pros | Cons |
|---|---|---|
| NCP Demand-based rate | • More closely ties customer bill to their use of system demand relative to fixed fee or flat energy rates<br>• Encourages customers to manage their own peak demand (i.e., promote customer investment/engagement in load control)<br>• Encourages reduction in demand "spikes" (i.e., high demand for short periods)<br>• Could increase revenue stability for utility (i.e., less sensitive to energy volume fluctuations due to energy efficiency initiatives or installation of self-generation) | • Charges based on individual peaks (i.e., not coincident with system peaks), which do not encourage shift away from critical system peaks. Therefore, overall system cost and infrastructure needs would not be reduced if the charge does not target the maximum system peak.<br>• Residential and small commercial customers may lack awareness of peak demand (or tools to manage peak demand), therefore requires investment in customer education to avoid confusion or perceived unfairness<br>• Some customers may experience higher bill volatility if there is high demand in a short interval<br>• Potential to discourage EV adoption, electrification of home heating, etc.<br>• While EDTI does not have a specific mandate for energy efficiency, this rate design does not inherently promote energy efficiency (i.e., focus on demand rather than total energy consumed).<br>• May cause equity concerns (i.e., if low-income customers have inflexible load, or limited access to load management / information, etc.) |
| TOU Demand-based rate | • More closely ties customer bill system costs incurred during peak periods than NCP demand-based rate<br>• Encourages customers to reduce or shift usage during utility defined peak periods<br>• Relatively "actionable" for customers (i.e., customers can modify behaviour given known peak window) and provides incentive to invest in technology enablement (i.e., home energy management, load-shifting appliances, etc.)<br>• Could improve the utility load factor, by discouraging short-term peak usage, consistent with other non-wires solutions. Overall, there is an opportunity to reduce system and asset peaks and could increase utilization of existing assets (i.e., overall potential to | • Charges are still based on an approximation of coincident demand on the distribution system. There is no single coincident peak to plan and design the rates around (i.e., AESO-wide demand, EDTI's system, high-voltage transformers/circuits, and lower voltage transformers can all peak at different times).<br>• Relatively complex for residential and small commercial customers, requiring investment and effort by the utility in customer awareness and/or technology; lack of understanding in the rate design risks limiting shifts in customer behaviour.<br>• Need to consider how TOU periods for utility (i.e., distribution rate) would correspond to a TOU energy rate (i.e. commodity charge), if offered by a |

 

| | | |
|---|---|---|
| | defer growth investments if system peaks are reduced).<br>• Could increase revenue stability for utility because a customers' peak demand is typically more consistent than total energy (i.e., less sensitive to energy volume fluctuations due to energy conservation initiatives or installation of self-generation) | retailer – potential for additional complexity<br>• Some customers are likely to experience higher bill volatility if there is high demand in a short interval<br>• Does not inherently promote energy efficiency (i.e., focus on demand rather than total energy consumed).<br>• May have equity concerns (i.e., if low-income customers have inflexible load, or limited access to load management / information, etc.)<br>• Potential for new demand spikes to occur outside utility defined "peak windows" (e.g., programmed EV charging ramps in hours following the peak window) |
| Demand Subscription Charge | • Incentive for customer to manage their load within their subscription level<br>• Reduces bill volatility and is highly predictable<br>• Aligns with capacity planning (i.e., clear signal to utility about expected peak demand)<br>• Provides customer choice and empowerment as customers can subscribe to the usage level for their actual needs (i.e., addition of EV, pool pump, DER, etc.)<br>• May be more equitable as lower demand customers (i.e., smaller dwellings) have lower charges relative to higher demand customers (i.e., larger dwellings). Also provides lower-income households predictability on their monthly utility bill.<br>• Likely to increase revenue stability for utility because a customer's lock in their subscription level for a period of time. | • Requires significant amount of customer education / customer care (i.e., risk of over- or under subscribing)<br>• Can result in negative customer experience if customer exceeds subscription level and is penalized (e.g., financial penalty, curtailment, etc.)<br>• Need to establish monitoring and enforcement processes, which add additional costs for the utility<br>• Charges based on individual peaks (i.e., not coincident with distribution system peaks), which do not encourage shift away from critical system peaks (unless time-aligned) |
| TOU Energy | • TOU energy pricing is widely used in other jurisdictions, and relatively easy for customers to understand<br>• Encourages customers to shift energy usage to off-peak periods, particularly discretionary loads (i.e., appliances, EVs, etc.)<br>• Compatible with enabling DERs and EV adoption | • Still requires customer education and outreach to shift peak usage<br>• Need to consider how TOU periods for utility (i.e., distribution rate) would correspond to a TOU energy rate (i.e. commodity charge), if offered by a retailer – potential for additional complexity<br>• Potential for new demand spikes to occur outside utility defined "peak windows" (i.e., programmed charging ramps in hours following the peak window)<br>• May have equity concerns (i.e., if low-income customers have inflexible load, or limited access to load management / information, etc.) or for seniors who may be home more frequently during peak periods |

| | | |
|---|---|---|
| | | • May require very high on-to-off-peak ratio to motivate change in customer behaviour, otherwise change in customer behaviour may be relatively modest |

## 6.3 Bill Impacts and Bill Volatility

Potential customer bill impacts were evaluated for each rate design option relative to the current rate design using a sample of residential and small commercial customer data spanning 2022 to 2024. The evaluation was performed using the fixed-to-variable proportions embedded in current rates and an alternative fixed-to-variable proportion consistent with the classifications of customer- and demand-related costs in EDTI's 2022 COSS. The evaluation assumed that consumption profiles would remain static across all rate design options and held total revenue constant.

TOU energy rates led to the smallest change in customer bills compared to current fixed energy rates. Among the demand rates, NCP demand and TOU demand had a similar effect, with bill increases and decreases generally less than 10%. The subscription rate had the highest bill impact. All three demand-based rates were associated with limited change in annual total bills for most customers a small number of customers experiencing more significant bill increases. Table 10 presents the share of each customer class with potential bill increases exceeding 5%, 10% and 15% thresholds assuming the current fixed-to-variable proportions embedded in rates and the fixed-to-variable proportions from EDTI's 2022 COSS.

Table 10: Customer Total Bill Impact (Increases)

| Fixed/Variable Proportions | Rate Design | Customer Class | Greater than 5% Increase | Greater than 10% Increase | Greater than 15% Increase |
|---|---|---|---|---|---|
| 71/29 (Current) | NCP | Residential | 6% | 0% | 0% |
| 71/29 (Current) | TOU Demand | Residential | 5% | 0% | 0% |
| 71/29 (Current) | Subscription | Residential | 12% | 2% | 0% |
| 71/29 (Current) | TOU Energy | Residential | 0% | 0% | 0% |
| 19/81 (Current) | NCP | Small Comm. | 36% | 19% | 10% |
| 19/81 (Current) | TOU Demand | Small Comm. | 30% | 15% | 7% |
| 19/81 (Current) | Subscription | Small Comm. | 46% | 31% | 21% |
| 19/81 (Current) | TOU Energy | Small Comm. | 0% | 0% | 0% |
| 43/57 (COSS) | NCP | Residential | 21% | 5% | 2% |
| 43/57 (COSS) | TOU Demand | Residential | 20% | 5% | 1% |
| 43/57 (COSS) | Subscription | Residential | 28% | 12% | 5% |
| 43/57 (COSS) | TOU Energy | Residential | 0% | 0% | 0% |
| 42/58 (COSS) | NCP | Small Comm. | 30% | 13% | 6% |
| 42/58 (COSS) | TOU Demand | Small Comm. | 24% | 10% | 4% |
| 42/58 (COSS) | Subscription | Small Comm. | 41% | 25% | 15% |
| 42/58 (COSS) | TOU Energy | Small Comm. | 0% | 0% | 0% |

*Values are rounded to the nearest percent (%)

Overall, bill impacts from demand-based rates are greater when the variable proportion of distribution revenue in the rate design is higher. Bill increases were particularly high for customers with low load factors. NCP demand and TOU demand rates reduced bill volatility for most customers but can substantially increase bill volatility for a small subset of customers.

 

The subscription rate reduces bill volatility for nearly all customers. When interpreting bill impact results for the subscription rate, it is important to note the assumption that all customers accurately predict their demand. Real-world implementation of a subscription rate could lead to unexpected penalty charges for customers which exceed their subscription demand. Bill impact for the subscription rate could also vary if different design parameters, such as number of subscription tiers, thresholds between tiers, and price ratios, were used.

More details on the methodology and results of the bill impact analysis are provided in Appendix C.

### 6.4 Comparison of Rate Design Alternatives

Demand-based distribution rates can improve cost reflectivity for the residential and small commercial rate designs, but they are unlikely to significantly influence customer behaviour in practice. For most residential and small commercial customers, distribution charges account for only a small share of the total electricity bill. As a result, the incentives introduced by demand-based rates may not be strong enough to encourage meaningful changes in usage patterns. There is also limited evidence that residential and small commercial customers respond predictably to demand-based rates. Research on TOU energy rates indicates that customer response tends to increase the larger the difference between peak and off-peak prices. When TOU rates are only applied to a portion of the customers' electricity bill, it is challenging to provide the magnitude of incentive required to motivate changes in customer behaviour.[27]

The introduction of demand-based rates for Residential and Small Commercial customers would have modest effects on most customer bills. However, some customers, particularly those with low load factors or inconsistent monthly peaks, could see higher bills or increased bill volatility compared to current rate designs. One benefit of all demand-based rates considered is revenue stability; customers self-generation may have less ability to avoid distribution charges.

Among the options considered, TOU demand rates offer the best alignment with the cost drivers of shared distribution infrastructure which is planned to meet coincident peak demand. However, if customers adjust their usage in response to these signals, there is a possibility that demand could shift to the beginning of the off-peak period, creating a localized "shadow peak" (see Section 7.2).

All rate options considered have the potential to increase complexity and lead to customer confusion. For the TOU options, customers may receive conflicting or difficult-to-interpret price signals if peak periods are not aligned between the distribution rate and other TOU bill components. This risk of confusion could reduce the effectiveness of any demand-based design and increase the need for customer education. For example, the subscription-based demand charge would likely require more extensive customer support and communication than traditional demand charges (i.e., supporting customers selecting the

[27] For example, see Jenya Kahn-Lang, Yuqi Zhu, Karen Palmer, and Peter Cappers. "Different Prices for Different Slices: A Meta-Analysis of Time-Based Electricity Rates." (2025), Resources for the Future, Working Paper 25-04: "We find that rate design and the relative rate levels have implications for a time-based rate's efficacy in promoting peak demand and on-peak usage reductions. Specifically, we show that the on-peak usage response increases with the on-to-off-peak TOU price premium." https://media.rff.org/documents/WP_25-04_vSszGzz.pdf

appropriate tier, communications on potential fees for over-usage). A TOU energy charge is relatively easier for customers to understand relative to the demand-based rate options considered.

Further, many of the goals associated with demand-based rates, such as improving cost reflectivity and managing system peaks, can also be achieved by demand response programs. In the case of EVs, managed charging offers greater potential benefits than demand-based rates alone.

# 7: FEASIBILITY CONSIDERATION

This section addresses the remaining elements of the feasibility study as outlined in Direction 7. Specifically, it examines the data requirements for implementing demand-based billing, including the potential need for subhourly (e.g., 15-minute) interval data versus hourly data, and how those needs may vary by customer class. Additionally, this section evaluates the role of demand-based and TOU energy rates in providing effective price signals for electric vehicle owners and encouraging off-peak charging. Finally, it considers whether TOU rates at the AESO level could support the flow-through of AESO tariffs to end customers and enhance their ability to respond to system-level price signals.

## 7.1 Hourly Versus Subhourly Interval Data

Implementing demand-based billing for residential and small commercial customers requires careful consideration of the appropriate data granularity needed to fairly and accurately reflect customers' contribution to peak demand. Interval data—whether hourly or subhourly (e.g., 15-minute)—forms the foundation for demand-based billing structures, enabling utilities and system operators to measure and bill customers based on their highest demand during a billing period. The choice between hourly and subhourly intervals carries implications for billing accuracy, system costs, and customer responsiveness, and may differ depending on the characteristics of different customer classes.

The AESO explored this issue in its *Shorter Settlement Cycle Options Paper*, released on July 18, 2024, as part of the REM consultation kick-off. While the paper focuses primarily on wholesale market settlement, it provides valuable insights for retail-level demand-based billing—particularly in highlighting the trade-offs between enhanced price signaling and the added complexity of data and system requirements.

Prior to the Options Paper, the AESO surveyed market participants to understand private costs associated with a transition to shorter settlement intervals. It received responses from Rural Electrification Associations (REAs), Load Settlement Agents (LSAs), Meter Data Managers (MDMs), billing agents, retailers, municipalities and generators. These responses were kept confidential but were discussed on an aggregate level in the Options Paper.

The AESO noted that most stakeholders had already implemented interval meters or are currently developing or implementing a plan to transition to interval meters that can read data at 15-minute intervals. Timelines vary by participant but are all expected to be complete by the end of 2029. This was not a unanimous position, as some stakeholders indicated no plans to replace cumulative meters with interval meters.

Stakeholders indicated that a further transition from 15-minute meters to 5-minute meters would be time consuming as only firms that are Measurement Canada certified are allowed to re-seal meters to change or set the measurement interval to five-minutes. Stakeholders indicated a transition from hourly settlement to 15-minute settlement would take 2 to 5 years and a transition to 5-minute settlement would take 5 to 10 years.

Costs associated with shorter settlement intervals include a requirement to upgrade:

- IT system

- Storage
- Load settlement systems
- Meter data management
- Retailer systems
- Forecasting and billing capabilities
- Customer reporting

The AESO provided the following aggregate cost estimate range based on all stakeholder responses:

| Shorter settlement | Load | Generators |
|---|---|---|
| 5-minute settlement | $281.6M - $331.6M | $4.9M - $67.7M |
| 15-minute settlement | $187.5M - $197.5M | $3.2M - $15.5M |

The AESO quantified the benefits of moving to shorter settlement by calculating the mean absolute error per-unitized to the average energy. Based on data from April 2023 to April 2024, the net-demand error would have been 0.61% lower with 15-minute settlement and a further 0.21% lower with 5-minute settlement. The AESO also calculated the error associated with a specific solar generator and found a decrease of 10.12% with 15-minute settlement and a further 3.60% with 5-minute settlement, illustrating larger reductions in errors can occur for specific assets.

On December 13, 2024, the AESO released its REM High-Level Design which included a recommendation for shorter settlement intervals as follows:

> REM will introduce a 5-minute settlement interval in the real-time market for transmission-connected generators and loads, as well as the interties by 2032. All market participants will need to be able to settle to a 5-minute settlement interval by 2040.

Stakeholders provided feedback on the AESO's REM High-Level Design in January 2025, with various DFOs, TFOs, and retailers weighing in on the proposal to adopt shorter settlement intervals. The Alberta Federation of Rural Electrification Associations (AFREA) expressed concern that the AESO had not fully considered all associated costs and benefits. AFREA also raised specific technical concerns about the use of Power Line Carrier technology, noting that its limited capacity could result in increased data transmission costs if more granular interval data were required.

Direct Energy supported 15-minute settlement as offering sufficient price fidelity for generators and large load customers, suggesting that 5-minute settlement is both unnecessary and costly. The company also emphasized that retailers are currently unable to develop innovative, mass-market load-shifting products without a centralized data hub similar to SmartMeter Texas or Ontario's Smart Meter Entity. As such, it recommended focusing first on properly utilizing AMI before introducing subhourly settlement for distribution-connected loads.

ENMAX highlighted the importance of including a robust transition plan should the AESO proceed with a 5-minute settlement interval. This plan should account for estimated consumer costs and benefits, system procurement processes, and the necessary testing and implementation timelines for retailers, DFOs, and TFOs. EDTI similarly argued that the AESO had not demonstrated that the benefits of 5-minute settlement for distribution-connected loads outweigh the associated costs when compared to a 15-minute option. They called for further analysis of the trade-offs and recommended aligning any transition with DFO meter capital replacement schedules to minimize costs. EPCOR also stressed that all costs related to the transition should be recoverable through the DFO rate base, rather than borne directly by the DFOs.

FortisAlberta offered a more optimistic view, suggesting that shorter settlement intervals could yield consumer benefits by enhancing affordability and supporting customer responsiveness to tariff price signals, ultimately aiding grid optimization. However, they also noted that further work is needed to quantify these potential benefits and costs.

Overall, Power Advisory views that the AESO analysis shows some reduction in net demand error from subhourly settlement; however, the benefits quickly diminish as the settlement interval shortens. Given the significant costs of moving from 15-minute settlement to 5-minute settlement, it is likely that the incremental benefits of that settlement interval reduction do not provide value to load customers. The AESO does show more significant benefits of shorter settlement intervals for generation, but this does not justify implementation of 5-minute settlement on load customers, especially distribution-connected load customers where the costs are significant.

Increased data granularity—such as collecting 15-minute interval data—could enable DFOs to more accurately flow through existing transmission tariff rates, including the Coincident Metered Demand (12CP) charge, which is settled based on demand during a 15-minute interval. However, the value of this added precision is limited if customers lack the visibility or tools to respond to these signals, particularly in Alberta's retail market structure where retailers—not DFOs—issue bills and typically do not itemize distribution or transmission charges. Without meaningful customer-facing price signals, the benefits of granular settlement may not translate into behavioral change or improved system efficiency.

While subhourly data will allow changes to transmission and distribution rates, DFO collection of subhourly settlement data is unlikely to, on its own, provide benefits to distribution-connected load customers on the energy portion of the bill. Many distribution load customers, especially those on residential or small commercial rate classes, pay for energy through a retailer where many opt into offered products such as a fixed rate. Those customers will not benefit from any efficiencies gained from energy price fidelity due to shorter settlement intervals, nor do they benefit from the shift from cumulative to interval metering for the energy portion of their bill.

Retailers require access to the AMI data to offer innovative and complex energy price products that allow retail customers to benefit from load-shifting behaviours. This will require DFO investments beyond meter upgrades, data collection, and data storage to allow use of the detailed subhourly data by third parties including retailers.

Overall, pros and cons of subhourly data granularity are summarized in the following table.

Table 11. Pros and cons of subhourly data granularity

| Category | Pros | Cons |
|---|---|---|
| Billing Accuracy & Price Fidelity | • Improved granularity (especially 15-minute) reduces billing error and more accurately reflects peak demand contributions.<br>• Enables more precise transmission cost pass-through (e.g., 12CP). | • Diminishing returns: minimal accuracy gains beyond 15-minute intervals (e.g., only 0.21% improvement from 15-min to 5-min). |
| Rate Design & Cost Reflectiveness | • Supports better-aligned distribution and transmission rate designs.<br>• Enables time-based pricing signals that could promote load shifting. | • Limited value for most residential/small commercial customers who use fixed-rate retail contracts and cannot respond to price signals. |
| System Operations | • Facilitates better demand forecasting, grid optimization, and settlement accuracy. | • Requires major IT, meter data management, and forecasting system upgrades. |
| Stakeholder Readiness | • Most stakeholders are transitioning to 15-minute capable meters by 2029. | • 5-minute settlement may take 5–10 years and require Measurement Canada-certified technicians to reset meters. |
| Regulatory & Technical Feasibility | • Aligns with existing structures like 12CP (15-min demand windows). | • Higher data volumes strain communications infrastructure (e.g., Power Line Carrier tech) and increase costs. |
| Retail Market Impacts | • Enables foundational data for future innovations in retail pricing. | • Collection of subhourly data alone does not benefit fixed-rate customers or enable cost savings without broader system integration. |

## 7.2 Implications for EV Charging

Considerable research shows that, in general, TOU rates incentivize changes in electricity consumption behaviour, including with respect to EV charging. Birk Jones et al. note definitively that "TOU rate schedules are simple and effective in shifting controllable loads away from peak periods"[28] and cite Bivji et al., who in 2014, using data from Pacific Gas & Electric (California) and Portland General Electric (Oregon), found that "residential EV charging load profiles show different characteristics than does a normal residential load profile", and that "with TOU rates, EV charging mostly takes place late at night during off-peak hours."[29] In 2013, a review prepared for the Ontario Energy Board approximately 3 years after the

[28] Huggins, J., Brooker, A., & Jenn, A. (2022). How Vehicle Usage and Powertrain Impact the Life Cycle Greenhouse Gas Emissions of Passenger Vehicles. https://docs.nrel.gov/docs/fy22osti/83514.pdf

[29] Biviji, M., Uçkun, C., Bassett, G., Wang, J., & Ton, D. (2014). Patterns of electric vehicle charging with time of use rates: Case studies in California and Portland. https://ieeexplore.ieee.org/document/6816454

introduction of TOU rates for the commodity component of the customer's bill found that "TOU rates have led to an approximately 3.3% reduction in residential summer On-Peak consumption."[30]

Since 2022, several pilots have been led by Alberta DFOs to better test incentives to influence customer electricity usage. These pilots have studied customer load (demand) shifting from residential EV charging (ENMAX Power and FortisAlberta) and voluntary time of use rates (ATCO Electric).

ENMAX Power's "Charge Up" EV Charging Study, which concluded in April 2023, found financial incentives to be highly effective.[31] The most significant finding was that EV owners are highly responsive to financial incentives. A monetary reward of 3.5 cents per kilowatt-hour for charging during off-peak hours (10 p.m. to 6 a.m.) successfully shifted approximately 70% of charging to overnight periods, when grid demand is lowest. It is important to note that this reward was not implemented through rates or billing changes, showcasing that specific rate design may not be necessary to influence residential EV charging times.

FortisAlberta's "Electric Vehicle Smart Charging Pilot" ran from January 2023 to June 30, 2024.[32] The study aimed to understand EV charging patterns, their impact on the distribution system, and the effectiveness of managed charging (including incentives) to mitigate potential issues.

While FortisAlberta is still examining the data to be fully published, a working paper from the University of Calgary and the National Bureau of Economic Research[33] (which partnered with FortisAlberta and Optiwatt for the study) has already shed significant light on the findings, including:

- While TOU pricing is effective at shifting EV charging from peak to off-peak hours (beneficial for system-wide demand peaks), it can unintentionally introduce new and larger "shadow peaks" of simultaneous charging in localized areas.
- This means that if everyone is incentivized to charge during the same off-peak window (e.g., overnight), it can lead to a coordinated surge in demand on specific distribution transformers, potentially exceeding local capacity limits.
- These "shadow peaks" can accelerate the need for costly distribution network upgrades (e.g., to transformers).
- In contrast, centrally managed charging (where the utility, via an app like Optiwatt, optimizes individual charging schedules to prevent multiple vehicles from overloading a transformer)

[30] Navigant Consulting Inc. (2013). Time-of-Use Rates in Ontario – Part 1: Impact Analysis. https://www.oeb.ca/oeb/_Documents/EB-2004-0205/Navigant_report_TOU_Rates_in_Ontario_Part_1_201312.pdf

[31] ENMAX Power concludes Alberta's first EV smart charging pilot: https://www.enmax.com/news/enmax-power-concludes-albertas-first-ev-smart-charging-pilot

[32] FortisAlberta's Electric Vehicle Smart Charging Pilot: https://fortisalberta.com/electric-vehicles-and-electric-vehicle-chargers/2023-electric-vehicle-smart-charging-pilot

[33] Bailey, M. R., Brown, D. P., Myers, E., Shaffer, B. C., & Wolak, F. A. (2024). Electric Vehicles and the Energy Transition: Unintended Consequences of a Common Retail Rate Design. https://www.nber.org/system/files/working_papers/w32886/w32886.pdf

successfully reduces the magnitude of capacity violations. This approach can defer or minimize infrastructure costs associated with EV growth.

- The study found that managed charging was generally well-tolerated by consumers with participants rarely opting out of managed charging sessions (e.g., less than 1% of charge sessions).

That being said, the design of TOU rates significantly impacts the rate's ability to change customer behaviour: as far back as 2013, Faruqi and Sergici[34] observed wide variation in customer responsiveness to TOU rates, and concluded that this was largely a function of the peak to off-peak price ratio; having analyzed 163 rates/rate designs, they found that "as the peak-to-off-peak price ratio increases, the peak reduction also increases. In addition... the use of enabling technology further boosts demand response".

Customer responsiveness to TOU rates, including on the part of EV owners, may be further limited by rate unbundling (as is the case in Ontario, Alberta, and Australia) For example, a report reviewing rates in Ontario observed that:

> *Unlike many jurisdictions in which TOU rates are offered, TOU prices in Ontario are not "bundled". Only the commodity is charged according to the TOU periods. The commodity cost makes up only a portion of the bill, and, in more efficient households may account for as little as half of the total bill. This can mean that even substantial changes in behaviour in response to commodity price signals can result in only quite small changes to the total bill itself.*[35]

With specific respect to EV owners, two additional findings brought out in the literature are salient. Firstly, a study in Australia[36] (where TOU distribution rates are prevalent) found that lower-income households were less responsive to TOU billing; insofar as EV owners can be presumed to be higher-income, they may be more responsive than the average customer. Secondly, the review of a series of rate design pilots run in Ontario from approximately 2017-2020 found that:

> *Of all the price plans evaluated as part of this set of pilots, none have exhibited as much of a behavioural impact as the Overnight price plan*[37]*. The estimated increase in demand between*

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[34] Faruqui, A., & Sergici, S. (2013). Arcturus: International Evidence on Dynamic Pricing. https://www.sciencedirect.com/science/article/abs/pii/S1040619013001656

[35] Ontario Energy Board. (2021). RPP Pricing Pilot Meta-Analysis Report. https://www.oeb.ca/sites/default/files/report-RPP-Pilot-Meta-Analysis-20211110.pdf

[36] Lewis, P. (2006). Electricity Tariff Structures for Low-Income Households: Possibilities for Australia. https://vuir.vu.edu.au/40599/1/200612%20TOU%20tariff%20paper.pdf

[37] This was an opt-in pilot run by Alectra Utilities (a distribution utility serving many of the suburban areas surrounding Toronto) in which participants accepted a higher On-Peak (~18 cents/kWh) price in exchange for a price (2 cents/kWh) in the period from midnight to 6am that was less than one third the status quo TOU Off-Peak rate. Otherwise, the price structure matched that of the status quo TOU. This pilot initially targeted recruiting EV owners (43% of participants own or lease EVs), and customers that might benefit from the price plan "due to shift work, lifestyle, etc.").

> *midnight and 6 a.m. of between 45% and nearly 75% (summer, winter) is, in absolute terms, many times greater than the impact estimated for any other static price period plans.*

The report hypothesizes that this increase in demand was driven by EV-owning customers (one of the target groups of the pilot) switching from public charging to at-home charging.[38] This finding also lends credence to the notion that greater peak to off-peak ratios enhances customer responsiveness. The findings this pilot project led directly to the 2023 province-wide implementation of a similar rate (referred to as the “ultra-low overnight rate”),[39] largely targeted at, though not exclusive to, residential EV owners.

Research on the impact of demand billing on residential customer consumption patterns – including on EV charging behaviour – is considerably more limited than is available concerning TOU billing. This is likely due to a combination of residential demand billing being less common (especially in North America) and a lack of disaggregation between TOU and demand billing. Indeed, Australia’s 2025 *Consumer Energy Report Card* does not distinguish between TOU and demand rates in its survey of customers’ knowledge of, and responsiveness to, these rates.[40] Of the limited research directly comparing Australian residential TOU to residential demand-based rates, Kelly et al. found that “the demand tariffs thus far proposed by [distributors] may not be more cost-reflective than current pricing structures such as time-of-use tariffs”[41]. This suggests that the effect on the grid, and therefore changes to customers’ consumption patterns, are not markedly different between the two structures.[42] More research is likely needed to fully understand the relative merits, as concerns impact on EV charging behaviour specifically, of TOU versus demand-based distribution charges.

Although this section of the report is focused on the question of whether TOU and/or demand rates influence EV customer behaviour charging, it is worth noting briefly that when such shifting does happen, there may be unintended consequences for the distributor, specifically insofar as TOU rates can both concentrate demand in a shorter window of time (i.e., off-peak periods) and cause sudden spikiness in load patterns immediately following the end of peak periods. Using simulations from over 200 EV customers in Alberta, Bailey et al. found that TOU rates

[38] Ipsos (2021). Regulated Price Plan Pilot Meta-Analysis, pg 23: https://www.oeb.ca/sites/default/files/report-RPP-Pilot-Meta-Analysis-20211110.pdf

[39] Government of Ontario (2023). Ontario Launches New Ultra-Low Overnight Electricity Price Plan. https://news.ontario.ca/en/release/1002916/ontario-launches-new-ultra-low-overnight-electricity-price-plan

[40] Energy Consumers Australia (2025). Consumer Knowledge of Electricity Pricing and Responsiveness to Price Signals. https://energyconsumersaustralia.com.au/sites/default/files/wp-documents/survey-consumer-energy-report-card-dec-24-report-consumer-knowledge-electricity-pricing-2.pdf

[41] Kelley, D. (2015). Customer-led adoption of demand-side energy technology: A case study of solar PV and battery storage in Australia. https://apvi.org.au/solar-research-conference/wp-content/uploads/2015/12/D-Kelly_Peer-Reviewed_FINAL.pdf

[42] Though it should be acknowledged that this study was conducted shortly after Australian distributors’ launch of residential demand rates, some of which will have evolved since then.

*Can result in coordination of charging into the narrow set of lowest-priced hours and, consequently, large "shadow demand peaks" of simultaneous charging on distribution transformers in areas with high levels of EV penetration. As a result, TOU pricing risks accelerating the need for distribution transformer upgrades relative to a flat retail price where the price is constant across all hours*[43]

Instead, managed charging, where the distributor controls the charging of EVs on the network or transformer, "effectively resolve[s] the coordination problem and appears well-tolerated"[44], with few customers in the trial taking advantage of their ability to override managed charging and charge their vehicle at a time of their own choosing. This finding also aligns in some respects with that of Faruqi and Sergici (see above) who noted that enabling technologies (such as, in their case, in-home informational displays, smart or utility-controllable thermostats, etc.) greatly enhance the effectiveness of TOU rates.

## 7.3 *Overview of the AESO Tariff Structure*

Per Direction 7, the AUC askes "If the Alberta Electric System Operator (AESO) had TOU rates, would it enable the potential flow-through of AESO's tariffs to distribution facility owner customers and enable them to be able to see and respond to AESO price signals?"

One component of the ISO tariff is the 12CP charge, a significant fee applied to usage during the 15-minute system coincident peak. This charge is likely to be significantly reduced or possibly eliminated entirely in the next ISO tariff application, currently planned for filing with the Commission in January 2027. If the charge continues after that decision, further consideration can be given to whether it can or should be flowed through to residential and small commercial distribution-connected customers.

The 12CP charge is extremely difficult to respond to, as it cannot be known when it will apply until the month is over. Further compounding the difficulty is the fact that responding to what would have otherwise been the 12CP settlement period can cause the 12CP to shift to a different time in the month. Price-responsive industrial loads typically need to engage in demand response for over 20 hours per month to avoid the 15-minute settlement window.

Residential customers are already unlikely to respond meaningfully to a real-time energy charge, even when prices are known in advance. Expecting them to respond to a retrospective and unpredictable charge like the 12CP is likely unrealistic. This result has been observed in practice. For example, in 2015, Spain made real-time pricing (RTP) the default option for households with prices varying hourly and based

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[43] Bailey, M.R., Brown, D.P., Myers, E., Shaffer, B.C., & Wolak, F.A. (2024). *Electric Vehicles and the Energy Transition: Unintended Consequences of a Common Retail Rate Design*. https://www.nber.org/system/files/working_papers/w32886/w32886.pdf

[44] Ibid.

on day-ahead wholesale prices.[45] Price schedules were published and made available to customers. Analysis has concluded that customers on RTP did not exhibit evidence of price responsiveness, finding that (1) "RTP is unlikely to make a difference in the absence of enabling technologies;" and, (2) that the lack of response is likely due to a series of factors, such as "lack of consumer awareness, costly information acquisition, and small gains of demand response due to low price variation."[46]

It is also worth noting that New Zealand introduced a RTP option for residential customers in 2013, but has seen less than 1.25% of customers switch to this retail option after seven years of availability.[47] Analysis of customers suggested that "price uncertainty is a serious threat to widespread adoption of real-time pricing because when prices spike unexpectedly and remain high for several weeks, prospective adopters forego adoption and recent adopters switch to another tariff and do not return."[48] Further, one of the energy retailers was offering a RTP retail option has ceased offering it to new customers because of "continued wholesale market volatility."[49]

A best approximation of the 12CP charge for residential and small commercial customers is likely a TOU rate. The 12CP charge typically occurs on non-holiday weekdays during the evenings. It is possible to create a 3-to-4-hour window of time on these days with a higher energy charge relative to the remaining hours. The 12CP costs would be allocated to collection during this TOU period to incent customers to shift load out of the hours that could result in 12CP charges. However, this suggestion is subject to all the other concerns raised by TOU rates as discussed in Section 6.2 of this report.

Further, DFOs do not currently use TOU rates for residential and small commercial rate classes. Accordingly, this suggestion would have high implementation costs, as described in Section 5.3.

[45] Natalia Fabra, David Rapson, Mar Reguant, and Jingyuan Wang. 2021. "Estimating the Elasticity to Real-Time Pricing: Evidence from the Spanish Electricity Market." *AEA Papers and Proceedings*, 111: 425–29: https://www.aeaweb.org/articles?id=10.1257/pandp.20211007

[46] Fabra et al. (2021).

[47] Charles Pébereau, Kevin Remmy, "Barriers to real-time electricity pricing: Evidence from New Zealand," *International Journal of Industrial Organization*, Volume 89, 2023: https://www.sciencedirect.com/science/article/abs/pii/S0167718723000607

[48] Pébereau and Remmy (2023).

[49] Flick Electric Co.: The company's "Wholesale: Pay the real-time, wholesale price of power" retail option states " Due to continued wholesale market volatility we're not offering this plan to new customers at the moment." https://www.flickelectric.co.nz/pricing-and-plans/ (Accessed June 13, 2025).

# 8: CONCLUSION

While demand-based rates are widely used for large commercial and industrial customers—including within EDTI's existing rate structures— most jurisdictions in Canada rely on a combination of energy-based and fixed-fee distribution rates for low volume customers. In Ontario, for example, distributors employ fully fixed base distribution rates for residential and small commercial customers to address concerns around fairness, cost recovery, and system planning. Meanwhile, in Manitoba, residential electricity rates include a basic monthly charge that varies by service size, an energy charge per kilowatt-hour.

Jurisdictions that have explored or piloted demand-based rates for residential customers have reported mixed results. In several cases, anticipated demand reductions did not materialize, often due to limited customer awareness, weak price signals, or misalignment between rate design and system peaks. Where implementation has moved forward, concerns have emerged regarding complexity and perceived fairness—issues that have led to customer pushback and regulatory caution.

In Alberta, implementing advanced demand-based rates is technically feasible but presents unique challenges. In vertically integrated jurisdictions, retail electricity prices, transmission charges, and distribution rates are often bundled, enabling a more unified approach to sending price signals. In contrast, Alberta's fully unbundled and competitive retail market makes it difficult to align distribution rate structures with broader customer incentives. As a result, adjusting only the distribution component of the bill may have limited effectiveness in influencing customer behaviour, particularly in the absence of corresponding changes to energy or transmission pricing.

Given the complexities and nuances of Alberta's market structure, an alternative that may warrant further consideration is a subscription-based charge. This approach shares many of the benefits of a fixed rate—such as bill predictability and simplified cost recovery—but introduces differentiation by tying customer charges to their selected or historical peak demand levels. In doing so, subscription-based charges better accounts for variation in usage across the residential and small commercial customer classes while aligning with broader goals of customer choice and empowerment. By allowing customers to select a service level that reflects their actual needs, subscription-based models may offer a more balanced approach to fairness and flexibility. That said, successful implementation would require significant customer engagement and the development of robust education and care tools to help customers choose appropriate subscription tiers. Broad consultation would also be necessary to ensure customer understanding and acceptance of the rate structure, as well as coordination with retailers and other market participants to align communications, billing, and ongoing support.

Importantly, the costs of implementing demand-based rates—subscription-based or otherwise—are not insignificant. Meter programming would need to be updated to collect and transmit interval data (e.g., every 5, 15, or 60 minutes), subject to regulatory approvals and technical constraints. While OTA reprogramming may be technically possible, it is currently not approved by Measurement Canada for EDTI's residential and small commercial meters. Additionally, significant enhancements to EDTI's IT infrastructure would be required to manage increased data volumes and ensure integration between the AMI system, MDMS, and billing systems. These upgrades could either be implemented in the near term or integrated into EDTI's planned system replacement around 2030. Finally, a robust billing-grade data validation process would need to be developed to ensure interval data meets accuracy and consistency standards suitable for customer billing.

In conclusion, while demand-based billing is technically feasible for residential and small commercial customers, its implementation in Alberta must be approached with caution. Subscription-based models may offer a middle ground, but any approach will require thoughtful evaluation in the context of the current regulatory and policy landscape, sustained customer engagement, collaboration with retailers, and regulatory alignment.

# APPENDIX A: POWER ADVISORY AND IGNITE ENERGY SOLUTIONS

## About Power Advisory

Power Advisory LLC is a North American energy sector management consulting firm specializing in electricity markets, rate regulation, wholesale market design, and market products. Founded in 2007, the firm provides customized consulting services to a diverse range of clients, including distributors, transmitters, generators, regulators, system operators, and investors. Power Advisory's team comprises seasoned professionals with expertise in economics, engineering, and policy, offering strategic insights that mitigate project risks and deliver value to customers.

The firm has extensive experience in Alberta, working with agencies like the Alberta Utilities Commission (AUC), Alberta Electric System Operator (AESO), and the Ministry of Affordability and Utilities. Its Alberta office staff have significant experience in regulatory filings, investment analysis, wholesale market design, and electricity market operations. Power Advisory has supported numerous regulatory proceedings, including distribution Phase II applications, transmission cost-of-service tariff applications, and performance-based regulation initiatives.

Power Advisory's consultants have a proven track record in rate design, regulatory strategy, and grid modernization. They have worked on projects involving distributed energy resources (DERs), non-wires solutions, and electrification strategies. For example, Power Advisory led the Ontario Energy Board's EV rate design project, developing alternative rate structures to support EV fast charging and successfully implementing a new electricity delivery rate design. Its expertise spans jurisdictions across Canada and the U.S., enabling tailored solutions that align with local market dynamics and regulatory frameworks.

## About Ignite Energy Solutions

Ignite's Founder, TL Duque, plays various roles on electricity transformation project teams, typically as project leader, facilitator, strategic advisor and stakeholder and relationship management. With 17 years of utility experience, we have expertise in power systems planning and operations, electricity system capital infrastructure project and portfolio management, pilot project and innovation portfolio development and delivery, policy and regulatory strategy, corporate investment planning and executive/board-level strategy and decision making.

Since 2018, our founder has focused on integrating new resources into the distribution and transmission grid to enable more customer choice and competitiveness while ensuring resiliency, reliability, and affordability of electricity service. We offer in-depth experience within Alberta, with recent projects on Distribution Policy, Advanced Metering Infrastructure, Advanced Rate Design, Customer Program Design, and Customer Experience Research. She also has experience working with clients in New Brunswick, Ontario and the US Pacific Northwest, combined with a solid understanding of jurisdictional trends, specific examples, and utility relationships across Canada and the United States.

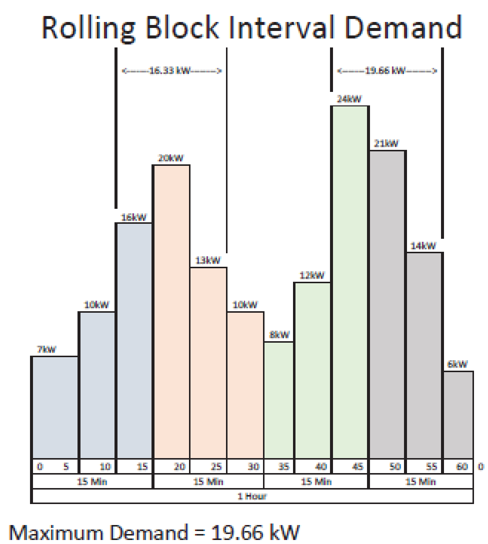
## APPENDIX B: EDTI'S DAS RATE FOR MEDIUM COMMERCIAL CLASS

EDTI's Distribution Access Service (DAS) rate for the Medium Commercial Class currently includes a demand-based charge component. Under this rate design, billing demand may be either estimated or measured, and is determined as the greatest of the following values:

- (a) the highest metered demand during the billing period;
- (b) 85% of the highest metered demand over the 12-month period ending with the current billing period;
- (c) the estimated demand;
- (d) the contract demand;
- (e) a minimum of 5 kVA.

Demand is calculated using a 15/5 sliding or rolling block method: the meter records demand every 5 minutes and then determines the maximum demand for each 15-minute interval. This method is illustrated in the figure below.

Figure 3: Rolling Block Interval Demand



## APPENDIX C: ALTERNATIVE RATE DESIGN BILL IMPACT ANALYSIS

### C1. Methodology

EDTI provided Power Advisory with a dataset of hourly non-billing-quality electricity consumption data spanning 2022 through 2024 to support the bill impact assessment. Customer data was filtered to remove a small number of customers with negative consumption records. The dataset was also limited to customers with nonzero consumption in each of the 36 months in the study period. Power Advisory randomly sampled 1,000 residential and 1,000 small commercial customers from the filtered dataset for the bill impact analysis.

Total monthly customer bills were calculated using the current rate design and assumptions for non-distribution charges outlined in Table 12.[50] Two fixed-to-variable proportion options were considered in the analysis. One option maintained the existing fixed-to-variable proportions currently embedded in distribution rates: 71/29 for the residential class and 19/81 for the small commercial class. The second applied fixed-to-variable proportions consistent with the customer-related and demand-related cost classifications in EDTI's 2022 COSS: 43/57 for the residential class and 42/58 for the small commercial class.[51] Total revenues are held constant for each rate class between the current and COSS fixed-to-variable proportions.

Table 12: Assumptions for Baseline Rates

| Charge Type | Units | Residential (Current 71/29) | Small Commercial (Current 19/81) | Residential (COSS 43/57) | Small Commercial (COSS 42/58) |
|---|---|---|---|---|---|
| Generation | $/kWh | 0.137 | 0.137 | 0.137 | 0.137 |
| Transmission Energy (SAS-R1 Variable) | $/kWh | 0.038 | 0.040 | 0.038 | 0.040 |
| Distribution Fixed (DAS-R1) | $/day | 0.700 | 0.613 | 0.427 | 1.149 |
| Distribution Energy (DAS-R2) | $/kWh | 0.017 | 0.032 | 0.032 | 0.024 |
| Retail Billing Charge | $/month | 6.913 | 7.936 | 6.913 | 7.936 |
| Riders and Franchise | $/kWh | 0.012 | 0.010 | 0.012 | 0.010 |

Alternative rate designs were then applied to the same customer load data. The alternative rate designs replace the Distribution Energy charge of the baseline rates in Table 12; other charges such as the Distribution Fixed charge are left unchanged. Two core assumptions were used to isolate the impact of rate design. First, total distribution revenue recovered from each rate class over the 36-month analysis

[50] Based on AUC Proceeding 29293, Exhibit 29293-X0006.02, Appendix G

[51] AUC Proceeding 27578, Exhibit 27578-X0003.01. Power Advisory understands EDTI's latest proposed COSS will have a lower proportion of costs classified as demand related. If approved, the proposed COSS proportions with lower shares of variable revenue would result in a lower magnitude of bill changes than the impacts using the 2022 COSS proportions as provided in this report.

period was held constant across all rate designs. Second, hourly customer electricity consumption was assumed to remain static under all alternative rates.

The bill impact of each alternative was assessed by comparing each customer's total charges under each design to charges under current rates. The change in volatility of monthly bills was also assessed.

## C2. Illustrative Rate Designs

For the NCP demand rate design, customers are billed based on their highest hourly demand in each month, regardless of when it occurs. For the TOU demand rate, billing demand is defined as the highest hourly demand during the on-peak period, which is 4:00 p.m. to 9:00 p.m. prevailing time, seven days a week. The TOU energy rate applies different energy charges for on-peak and off-peak consumption, using the same 4:00 p.m. to 9:00 p.m. window to define the on-peak period. A 2.5:1 peak-to-off-peak price ratio was applied to set the TOU energy rates. The choice of peak period and peak-to-off-peak ratio is consistent with ATCO's D13 Distribution Rate.[52]

Table 13 presents the alternative rate designs for NCP, TOU demand, and TOU energy. These replace the Distribution Energy charge in the Baseline Rates from Table 12.

Table 13: Alternative Rate Designs: NCP, TOU Demand, TOU Energy

| Rate Design | Charge Type | Units | Residential (71/29) | Small Comm. (19/81) | Residential (43/57) | Small Comm. (42/58) |
|---|---|---|---|---|---|---|
| NCP | Distribution NCP Demand | $/kW-month | 2.267 | 9.004 | 4.217 | 6.703 |
| TOU Demand | Distribution On-Peak Demand | $/kW-month (Peak) | 2.517 | 10.972 | 4.692 | 8.168 |
| TOU Energy | Distribution On-Peak Energy | $/kWh (Peak) | 0.029 | 0.058 | 0.054 | 0.044 |
| TOU Energy | Distribution Off-Peak Energy | $/kWh (Off-Peak) | 0.012 | 0.023 | 0.022 | 0.017 |

The demand subscription rate design requires customers to select a predefined subscription tier representing a monthly peak demand allowance. Customers are charged a fixed monthly amount based on their selected tier, with overage charges applied for having demand exceeding the subscription level. The selection of subscription tier thresholds, subscription fees, and overage charges requires balancing customer flexibility and cost-causation principles against complexity. Table 14 and Table 15 show the subscription rate design used in this analysis, which replaces the Distribution Energy charge in the

[52] AUC Proceeding 24747, Exhibit 24747-X0001, Section 5, Attachment 5-2

baseline rate design from Table 12.[53] The price ratio describes how the subscription fee increases compared to the lowest subscription tier available.

Table 14: Alternative Rate Designs: Residential Subscription

| Subscription Tier | Price Ratio | Subscription Fee ($/Month, 71/29) | Subscription Fee ($/Month, 43/57) |
|---|---|---|---|
| 3kW | 1 | 3.67 | 6.83 |
| 6kW | 2 | 7.34 | 13.65 |
| 9kW | 3 | 11.01 | 20.48 |
| 12kW | 4 | 14.68 | 27.31 |
| Over 12 kW | 5 | 18.35 | 34.14 |

Table 15: Alternative Rate Designs: Small Commercial Subscription

| Subscription Tier | Price Ratio | Subscription Fee ($/Month, 19/81) | Subscription Fee ($/Month, 42/58) |
|---|---|---|---|
| 3 kW | 1 | 14.19 | 10.56 |
| 6 kW | 2 | 28.37 | 21.12 |
| 9 kW | 3 | 42.56 | 31.68 |
| 12 kW | 4 | 56.75 | 42.25 |
| 18 kW | 6 | 85.12 | 63.37 |
| 30 kW | 10 | 141.87 | 105.61 |
| 50 kW | 17 | 236.45 | 176.02 |

As illustrated in Table 15 and Figure 5 below, the distribution of NCP is right skewed, with a small number of customers in each class having very high demand relative to the median customer in each class. To accommodate high-demand customers in this analysis, the residential class includes an "Over 12 kW" tier. Alternative options could also be considered for high-demand residential customers, such as defining additional high-demand subscription tiers with a very small number of customers or reclassifying residential customers above a demand threshold.

Customers were assigned to subscription tiers based on their maximum observed demand over the full 36-month analysis period. This approach involves two simplifying assumptions: first, that customers do not change their subscription level over time; and second, that each customer is able to accurately anticipate and manage their peak demand and avoid overage charges.

[53] Illustrative subscription tiers were developed using the distribution of peak demand in the hourly customer load dataset and with reference to Électricité de France's (EDF's) Tarif Bleu. EDF bundles fixed and variable costs into a single monthly rate for each tier. In this analysis, fixed and variable costs are tracked separately, and the subscription fee is used only for variable costs. https://particulier.edf.fr/content/dam/2-Actifs/Documents/Offres/Grille_prix_Tarif_Bleu.pdf.

### C3. Customer Load Characteristics

Summary statistics for the 36 months of hourly load data are provided in Table 16 below.

Table 16: Load Data Summary Statistics

| Variable | Residential | Small Commercial |
|---|---|---|
| Count | 1,000 | 1,000 |
| Monthly Consumption (kWh) | | |
| Mean | 541 | 2,024 |
| Median | 463 | 1,094 |
| Minimum | 0 | 0 |
| Maximum | 12,613 | 30,090 |
| Monthly NCP (kW) | | |
| Mean | 4.1 | 7.2 |
| Median | 4.0 | 5.1 |
| Minimum | 0.0 | 0.0 |
| Maximum | 37.9 | 48.4 |
| Monthly Load Factor | | |
| Mean | 0.18 | 0.38 |
| Median | 0.17 | 0.34 |
| Minimum | 0.00 | 0.00 |
| Maximum | 0.99 | 1.00 |

Load factor is the average hourly demand divided by peak demand for a customer. It measures how consistent a customer's energy demand is over time. A load factor of 1.0 indicates steady consumption at the customer's peak demand, while a load factor closer to 0 suggests typically low demand with infrequent high peaks. Recovering more costs using demand-based rates rather than energy charges would tend to increase bills for customers with lower load factors.

Figure 4 and Figure 5 below show the distribution of monthly consumption and monthly NCP in the dataset for the residential and small commercial customer classes.

Figure 4: Distribution of Monthly Energy Consumption

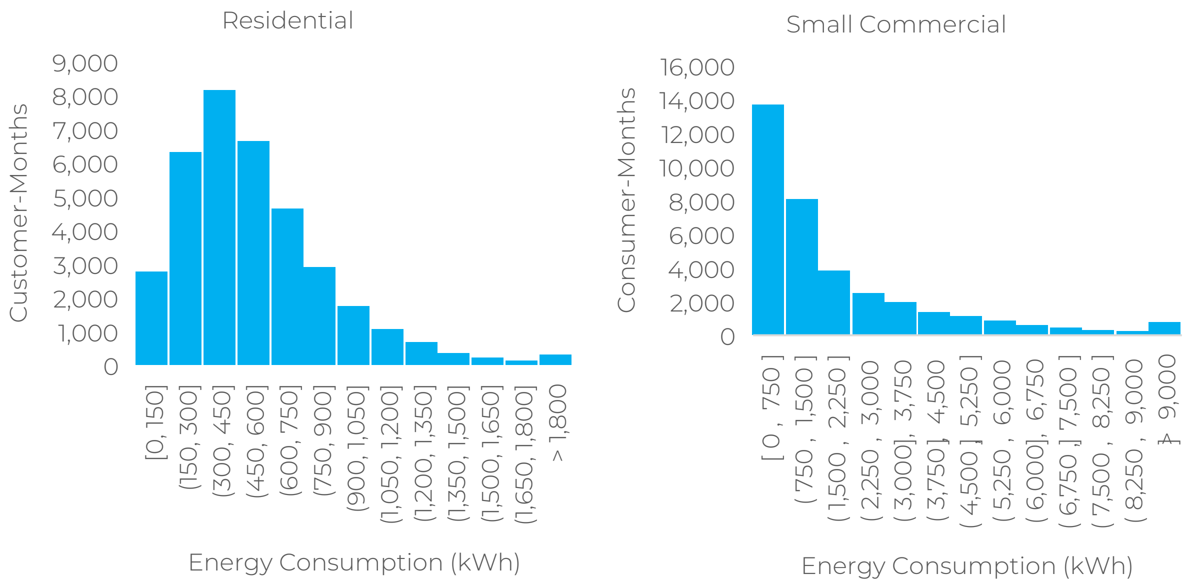
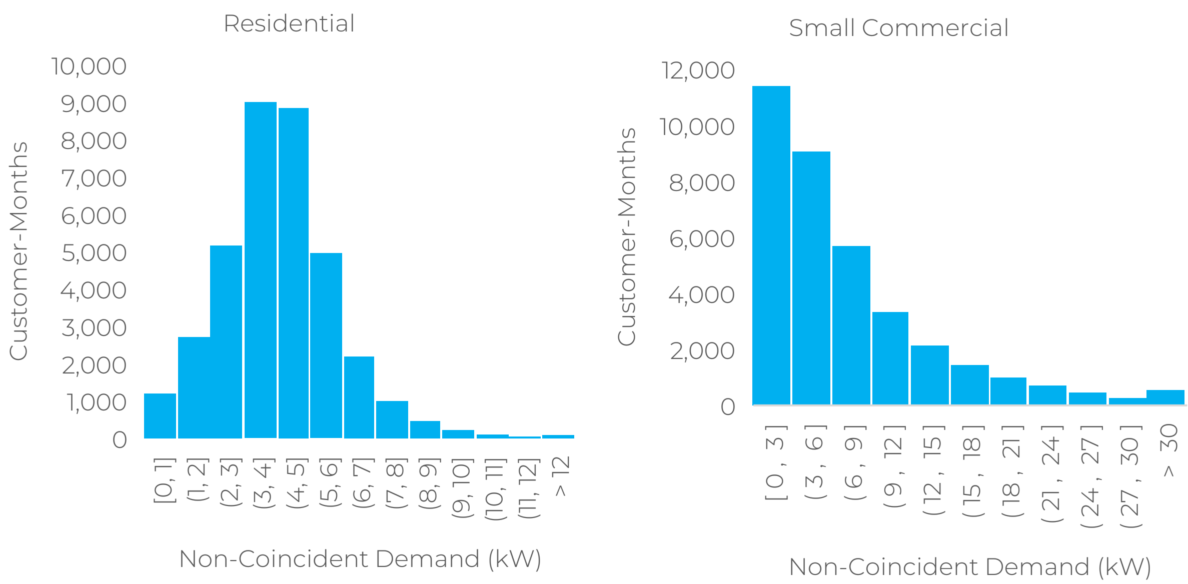


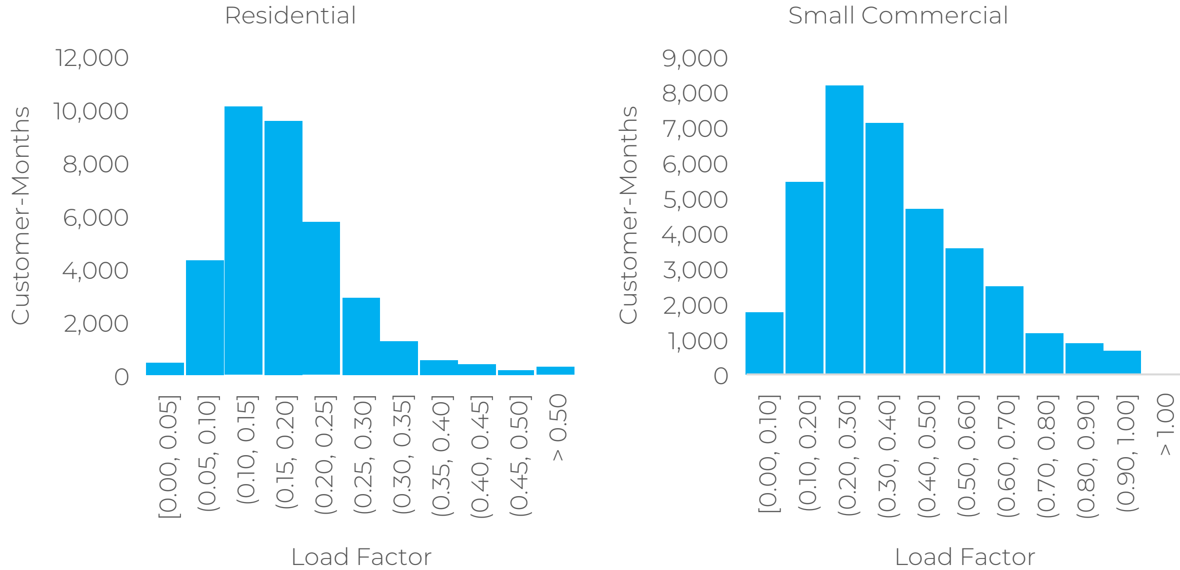

Figure 5: Distribution of Monthly Non-Coincident Demand




Residential peak demand is clustered around 4 kW with an approximately symmetric distribution. For small commercial customers, peak demand is strongly right skewed.

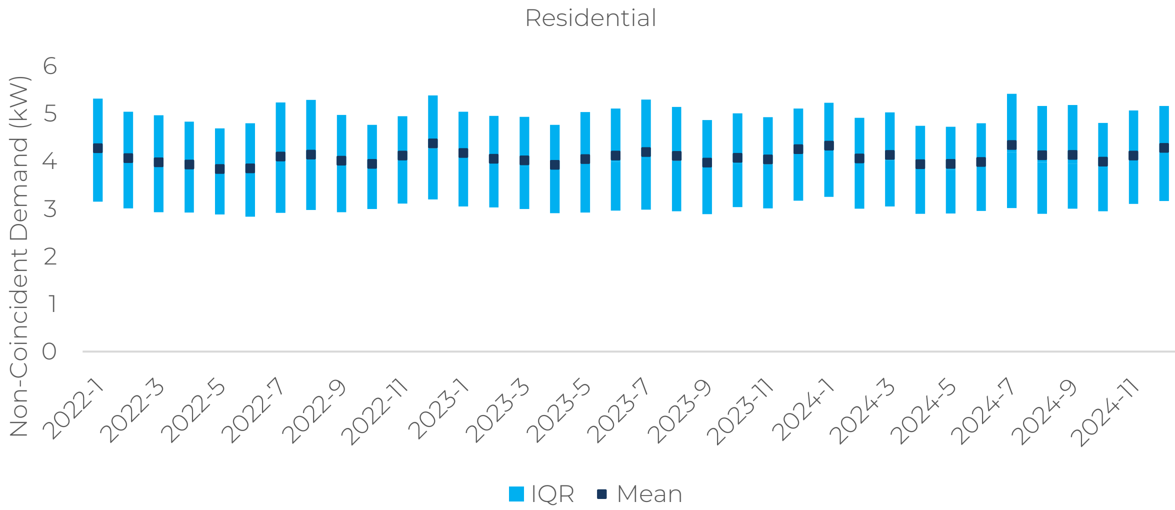
Figure 6 below shows the distribution of load factor in the dataset for the residential and small commercial customer classes. Residential customers typically have load factors in the 10 to 20% range. Small commercial customers have a wider distribution of load factors.

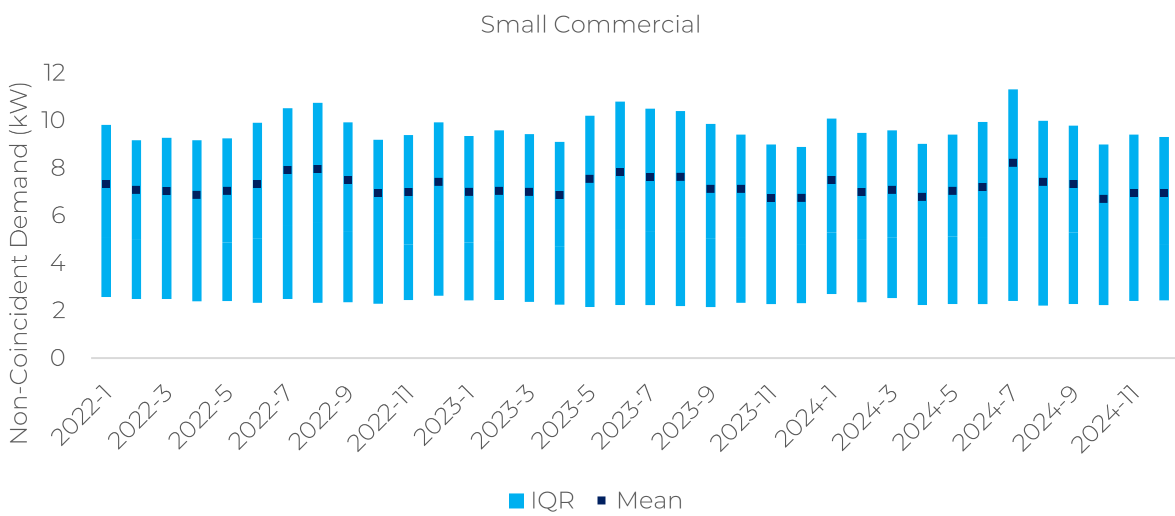
Figure 6: Distribution of Monthly Load Factor




The boxplots in Figure 7 below show how the mean and interquartile range (IQR, the range between the 25th and 75th percentiles) of monthly customer-level NCP varies over time. Residential non-coincident peak demand, in aggregate, has limited seasonal variation. Small commercial non-coincident peak demand has more notable variation, particularly in the summer.

Figure 7: Time Series of Monthly Non-Coincident Demand




## C4. Bill Impacts

The annual customer total bills under each alternative rate design were compared to the baseline bills calculated using the current rate design.

Table 17Table 17 presents the distribution of bill impacts across three categories: increases greater than 2%, decreases greater than 2%, and changes within 2%. The 2% threshold was selected to identify customers who experience negligible or minimal impact under each rate.

Table 17: Customer Total Bill Impact

| Fixed/Variable Proportions | Rate Design | Customer Class | Increases more than 2% | Decreases more than 2% | Less than 2% Change |
|---|---|---|---|---|---|
| 71/29 | NCP | Residential | 28% | 11% | 61% |
| 71/29 | TOU Demand | Residential | 27% | 11% | 63% |
| 71/29 | Subscription | Residential | 34% | 13% | 53% |
| 71/29 | TOU Energy | Residential | 0% | 0% | 100% |
| 19/81 | NCP | Small Commercial | 50% | 27% | 23% |
| 19/81 | TOU Demand | Small Commercial | 44% | 25% | 31% |
| 19/81 | Subscription | Small Commercial | 57% | 26% | 17% |
| 19/81 | TOU Energy | Small Commercial | 1% | 2% | 97% |
| 43/57 | NCP | Residential | 41% | 22% | 36% |
| 43/57 | TOU Demand | Residential | 40% | 24% | 36% |
| 43/57 | Subscription | Residential | 44% | 25% | 31% |
| 43/57 | TOU Energy | Residential | 0% | 0% | 100% |
| 42/58 | NCP | Small Commercial | 48% | 23% | 29% |
| 42/58 | TOU Demand | Small Commercial | 41% | 21% | 38% |
| 42/58 | Subscription | Small Commercial | 54% | 23% | 22% |
| 42/58 | TOU Energy | Small Commercial | 0% | 1% | 99% |

*Values are rounded to the nearest percentage point (%)

All three demand-based rate designs also lead to a greater share of bills increasing than decreasing. Naturally, the magnitude of bill impacts, both positive and negative, is greater when the ratio of variable costs to fixed costs is greater. The magnitude of impact is otherwise similar between residential and small commercial customers.

Table 18Table 18 provides more detail on the magnitude of bill increases, reporting the percentage of customer-years in each class where bills would rise by more than 5%, 10%, and 15%. The bill increases for these customers are offset by bill decreases for other customers for each class to maintain revenue neutrality. These thresholds highlight the most-affected customers under each design.

Table 18: Customer Total Bill Impact: Increases

| Fixed/Variable Proportions | Rate Design | Customer Class | Greater than 5% Increase | Greater than 10% Increase | Greater than 15% Increase |
|---|---|---|---|---|---|
| 71/29 | NCP | Residential | 6% | 0% | 0% |
| 71/29 | TOU Demand | Residential | 5% | 0% | 0% |
| 71/29 | Subscription | Residential | 12% | 2% | 0% |
| 71/29 | TOU Energy | Residential | 0% | 0% | 0% |
| 19/81 | NCP | Small Commercial | 36% | 19% | 10% |
| 19/81 | TOU Demand | Small Commercial | 30% | 15% | 7% |
| 19/81 | Subscription | Small Commercial | 46% | 31% | 21% |
| 19/81 | TOU Energy | Small Commercial | 0% | 0% | 0% |
| 43/57 | NCP | Residential | 21% | 5% | 2% |
| 43/57 | TOU Demand | Residential | 20% | 5% | 1% |
| 43/57 | Subscription | Residential | 28% | 12% | 5% |
| 43/57 | TOU Energy | Residential | 0% | 0% | 0% |
| 42/58 | NCP | Small Commercial | 30% | 13% | 6% |
| 42/58 | TOU Demand | Small Commercial | 24% | 10% | 4% |
| 42/58 | Subscription | Small Commercial | 41% | 25% | 15% |
| 42/58 | TOU Energy | Small Commercial | 0% | 0% | 0% |

*Values are rounded to the nearest percent (%)

The magnitude of bill increases appears to be higher for the subscription rate compared to NCP or TOU demand. Notably, the subscription rate plan causes approximately 1% of annual small commercial bills to increase over 50%. In this analysis, the subscription tier is assigned based on a customer's highest NCP across the three-year study period. This approach can lead to a substantial bill increase for customers which significantly changed their peak demand during the study period. For example, one small commercial customer had a typical monthly peak which ranged from 20 to 25 kW in 2022 and averaged below 1 kW in 2023 and 2024.

Figure 8, Figure 9, and

Figure 10 present histograms illustrating the distribution of customer-level bill impacts for each demand-based rate design, separated by customer class.

Figure 8: NCP Demand Distribution of Customer Total Bill Impact

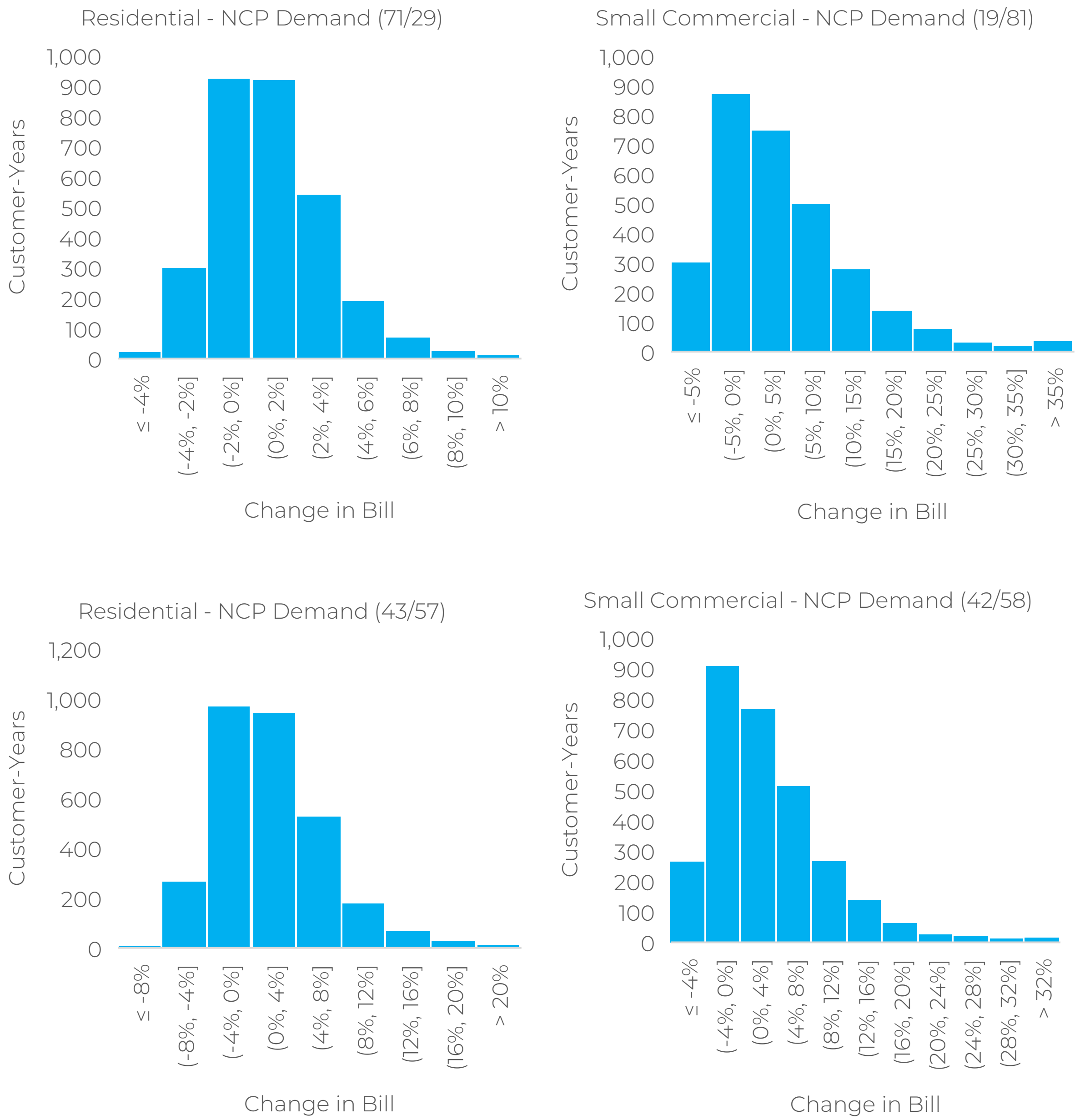


Figure 9: TOU Demand Distribution of Customer Total Bill Impact

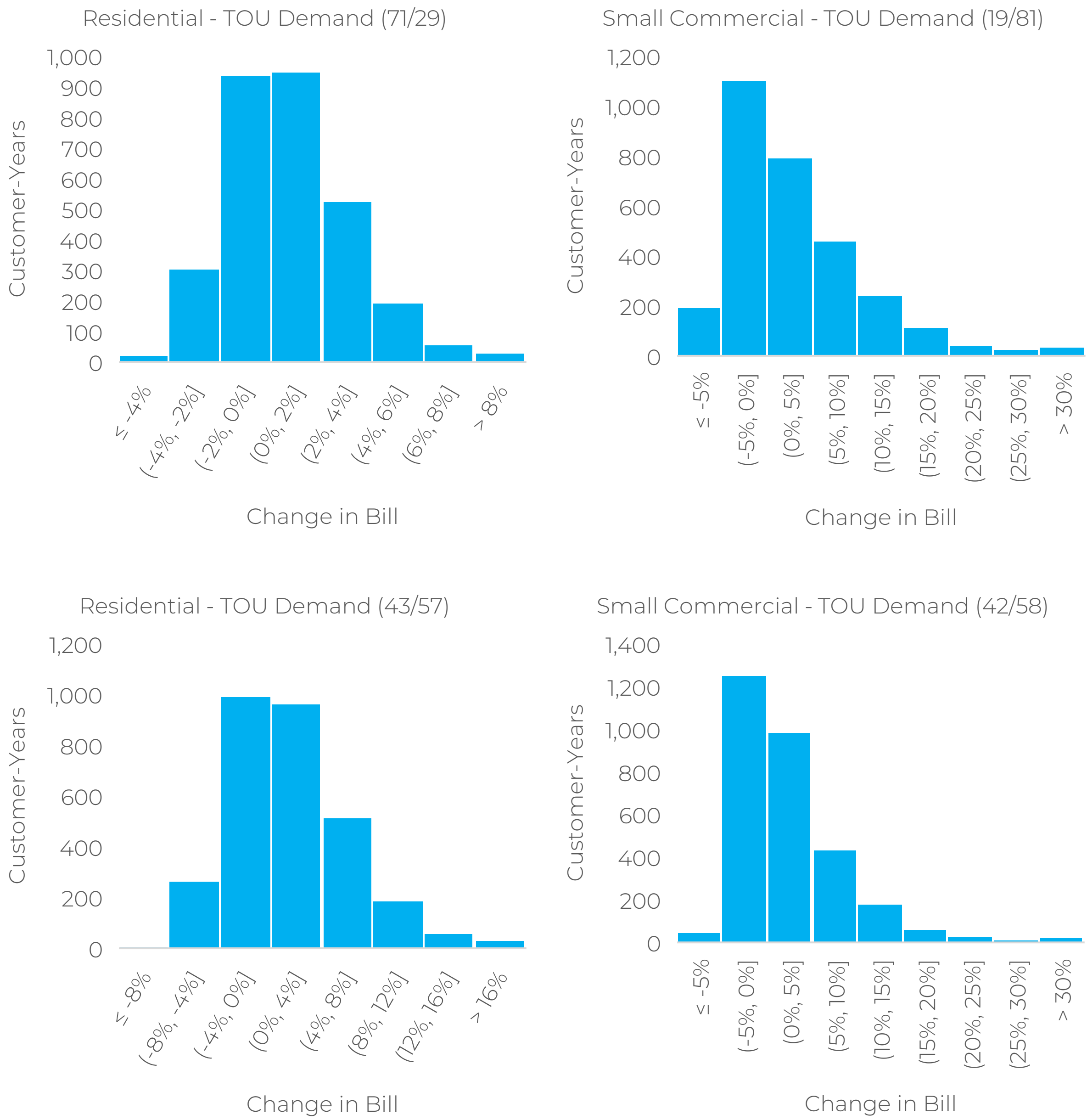


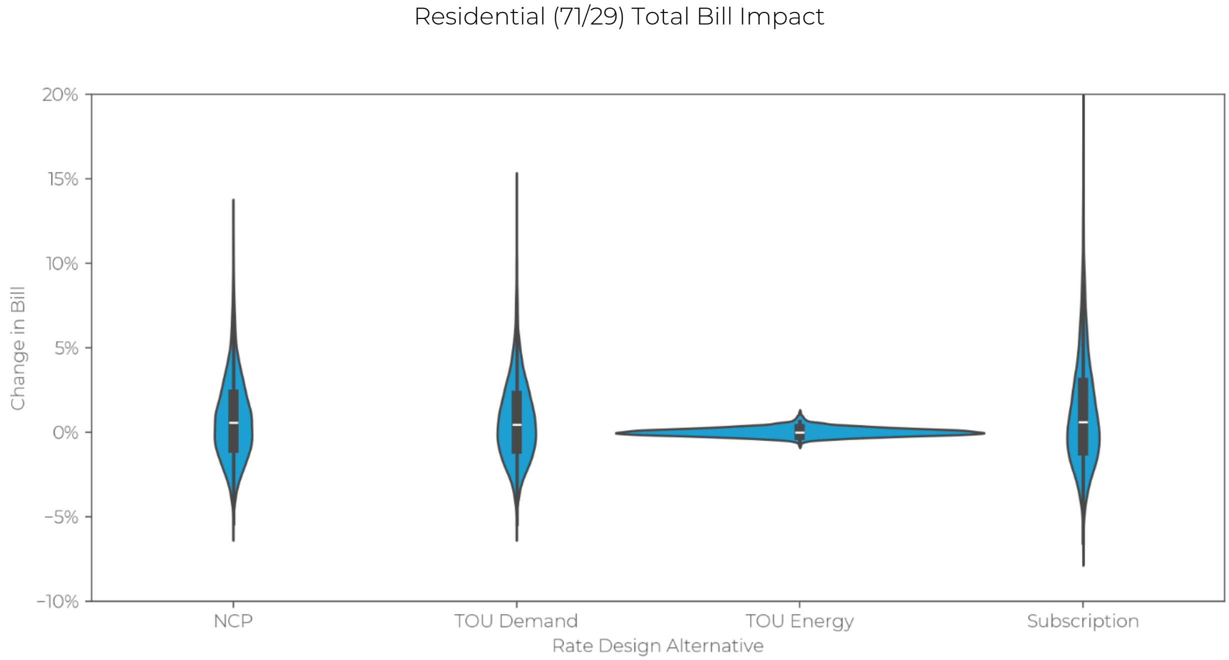
Figure 10: Subscription Demand Distribution of Customer Total Bill Impact


While changes in bills are relatively symmetrical among residential customers, the bill impact on commercial customers is more right skewed, with a small number of customers paying much more than they currently do while more customers benefit from the cost savings of the revenue balancing factor. The distribution of bill impact in each rate class mirrors the distribution of load factor; this connection is further discussed below.

While all the demand-based rates create notable bill impact, the effect is largely confined within a 10% change for NCP and TOU demand rates. The subscription rate design creates the highest bill impact, particularly in terms of bill increases.

To provide additional insights into the change in annual total bills, violin plots are provided below for each rate class and fixed-to-variable proportion option. A violin plot is a data visualization that combines a box plot and a kernel density plot to show the distribution, probability density, and summary statistics (like median and interquartile range) of a dataset. The width of each plot indicates the share of customers with a bill increase or decrease at that level (i.e., wider indicates more customers affected). The white dash in the middle of the plot is the median and the bar around it is the interquartile range (i.e., 25$^{th}$ to 75$^{th}$ percentile).

Figure 11: Violin Plots for Residential Total Bill Impact



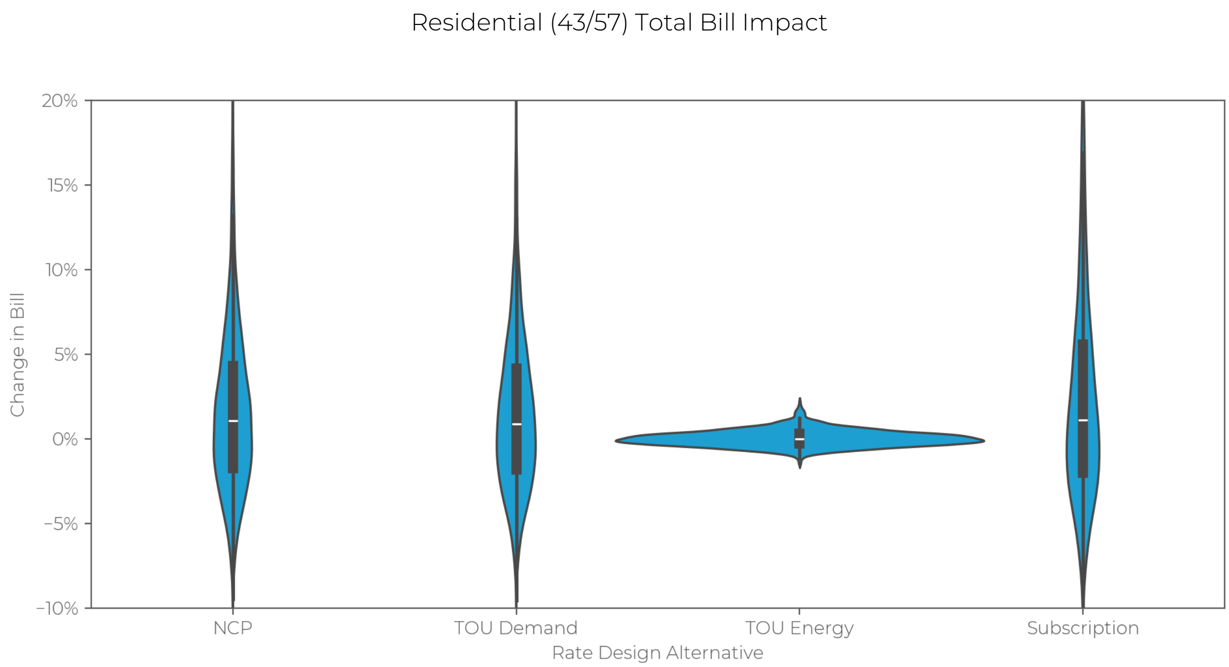
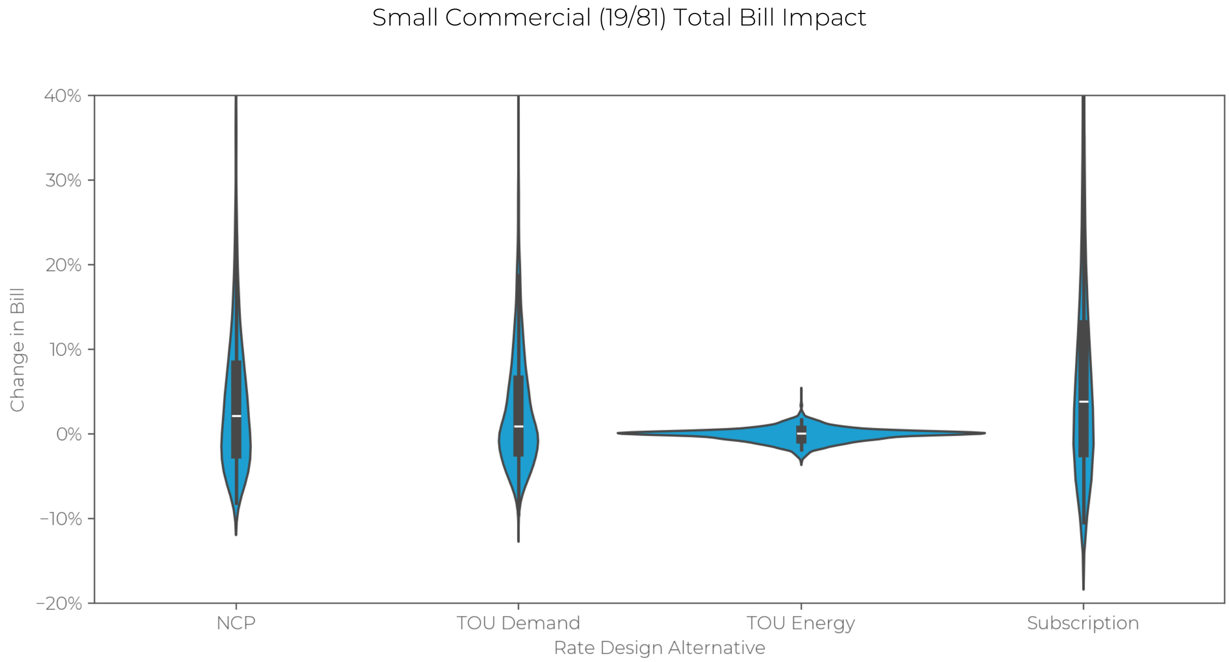
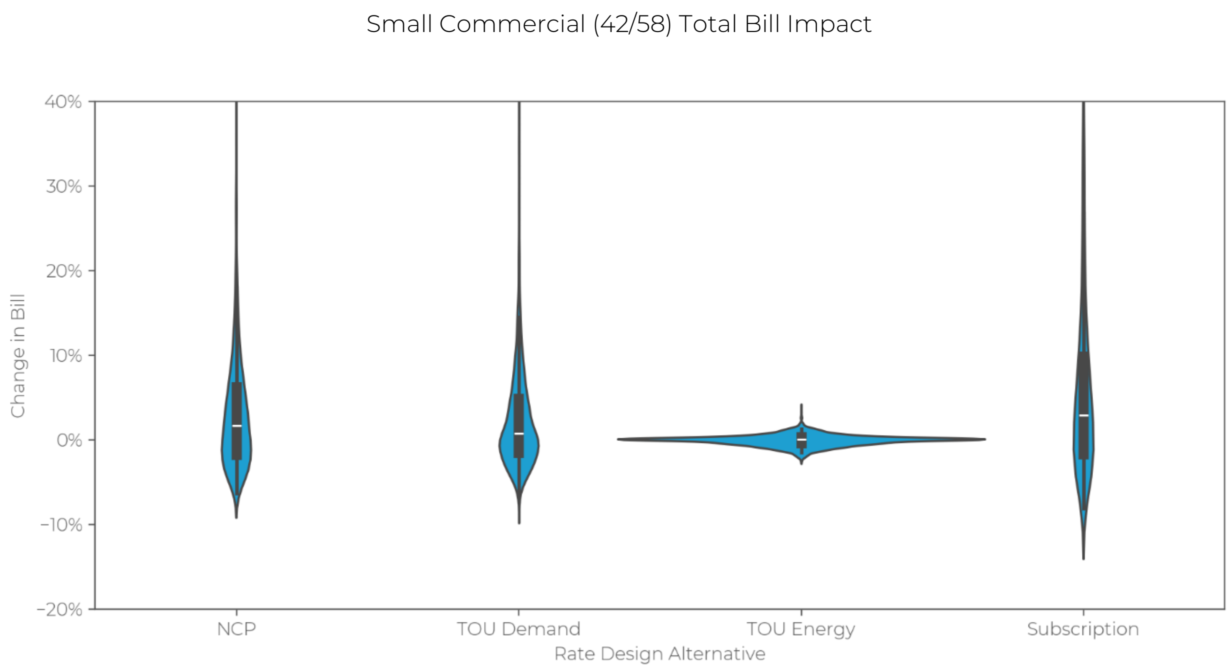



Figure 12: Violin Plots for Small Commercial Total Bill Impact




The violin plots better illustrate the long tails of the bill impact distribution, most notably in the small commercial customer class and with the subscription rate design. The TOU energy design, in contrast, leads to minimal change in customer bills and few outliers in either customer class.

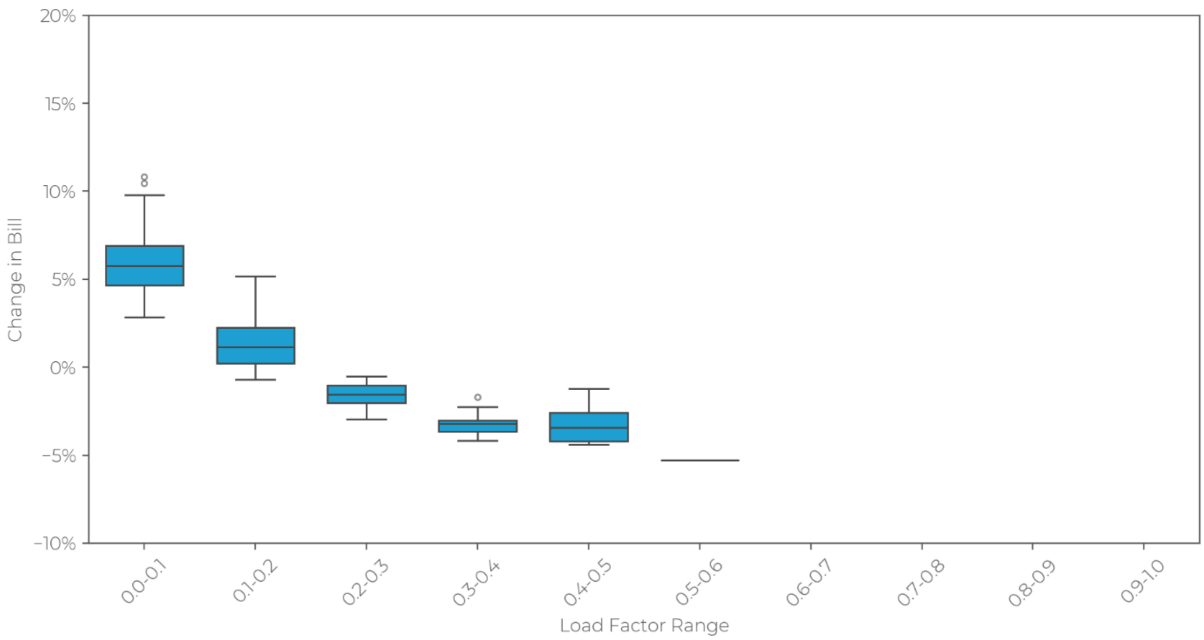
A natural driver of bill changes in any demand-based rate is customer load factor. Figure 13, Figure 14,

Figure 15, and

Figure 16 below are boxplots showing the customer bill increase or decrease, binned by load factor in 0.1 increments. The box plots show overall change in bill over the 36-month period. Load factor is also calculated based on the highest NCP in the 36-month period. The blue box represents the interquartile range (25th to 75th percentile), the middle line represents the median value, the whiskers represent the most extreme data points that are within 1.5 times interquartile range. Outliers that extend beyond that range are shown as dots.

Figure 13: Residential NCP Bill Change by Load Factor Box Plots

Residential (71/29) Load Factor and Total NCP Bill Change




Residential (43/57) Load Factor and Total NCP Bill Change

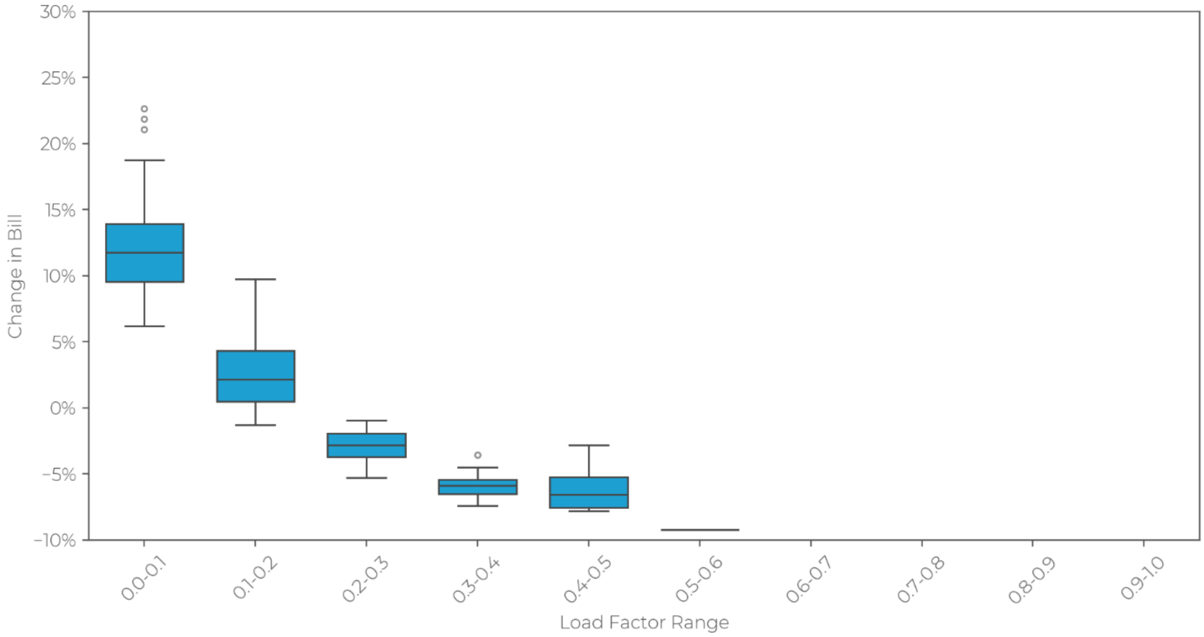
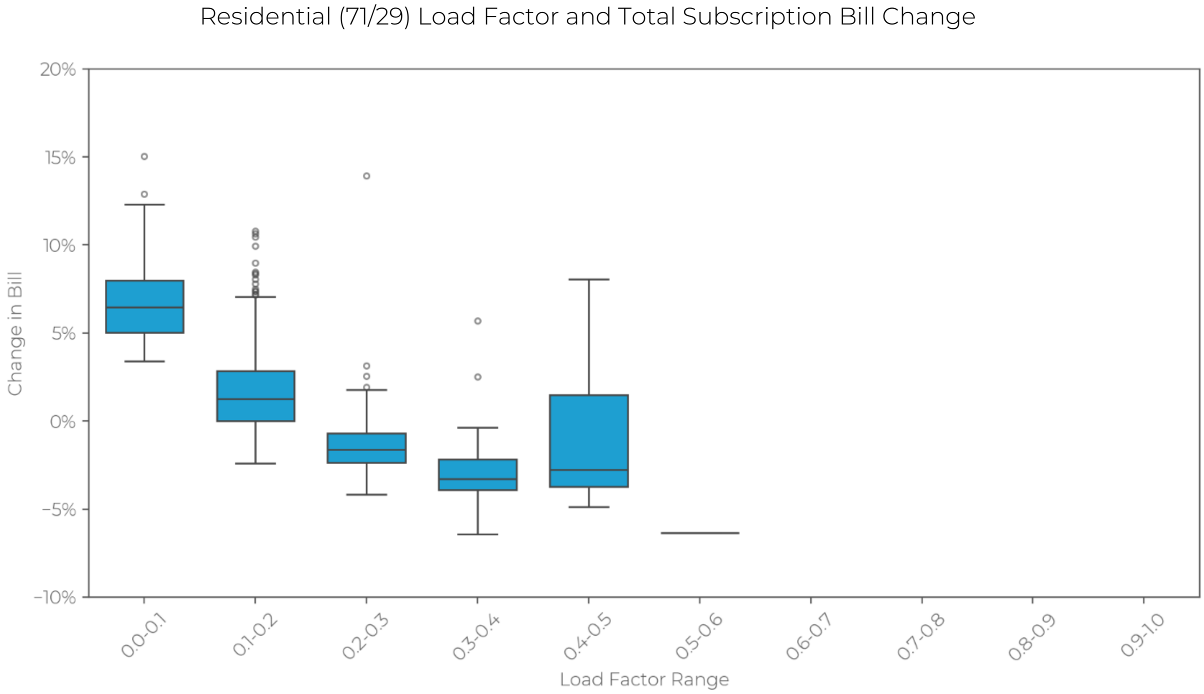

30%
25%
20%
15%
10%
5%
0%
−5%
−10%
Change in Bill
0.0-0.1
0.1-0.2
0.2-0.3
0.3-0.4
0.4-0.5
0.5-0.6
0.6-0.7
0.7-0.8
0.8-0.9
0.9-1.0
Load Factor Range

Figure 14: Residential Subscription Bill Change by Load Factor Box Plots



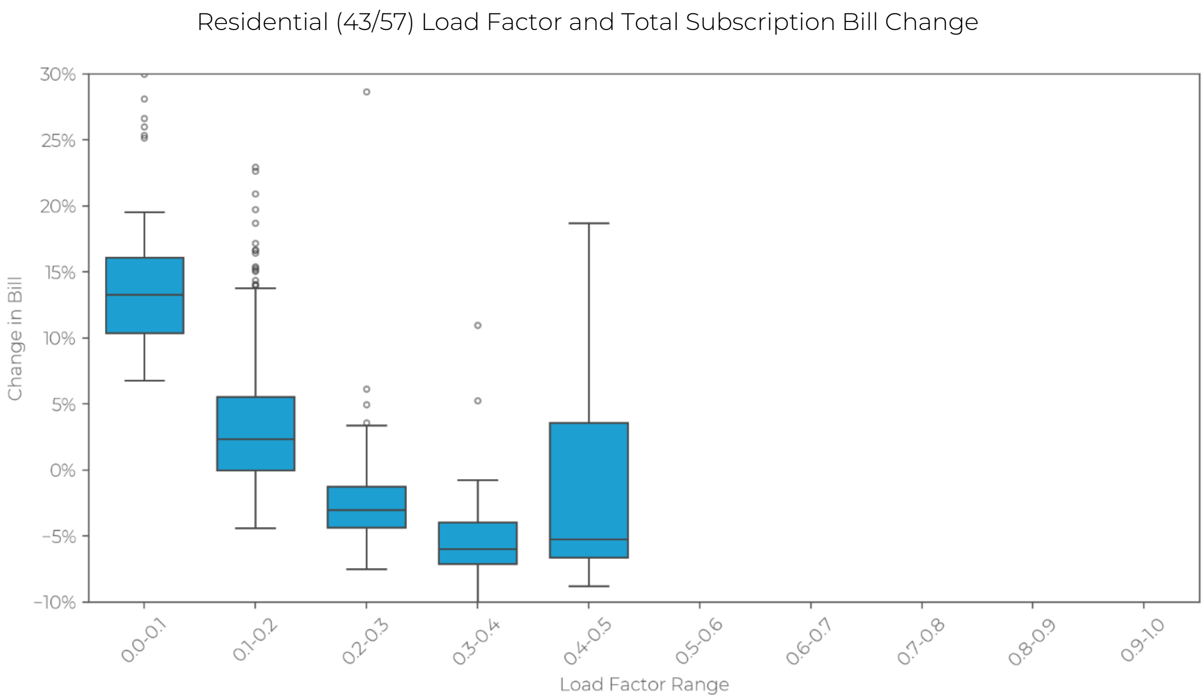
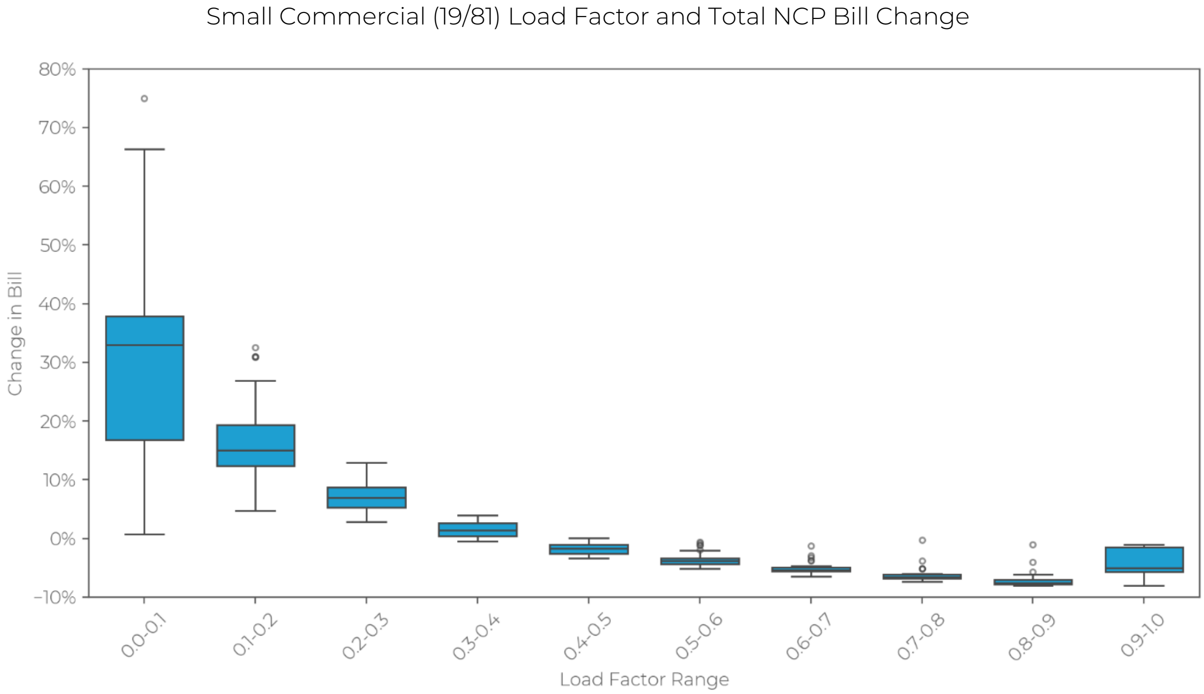



Figure 15: Small Commercial NCP Bill Change by Load Factor Box Plots



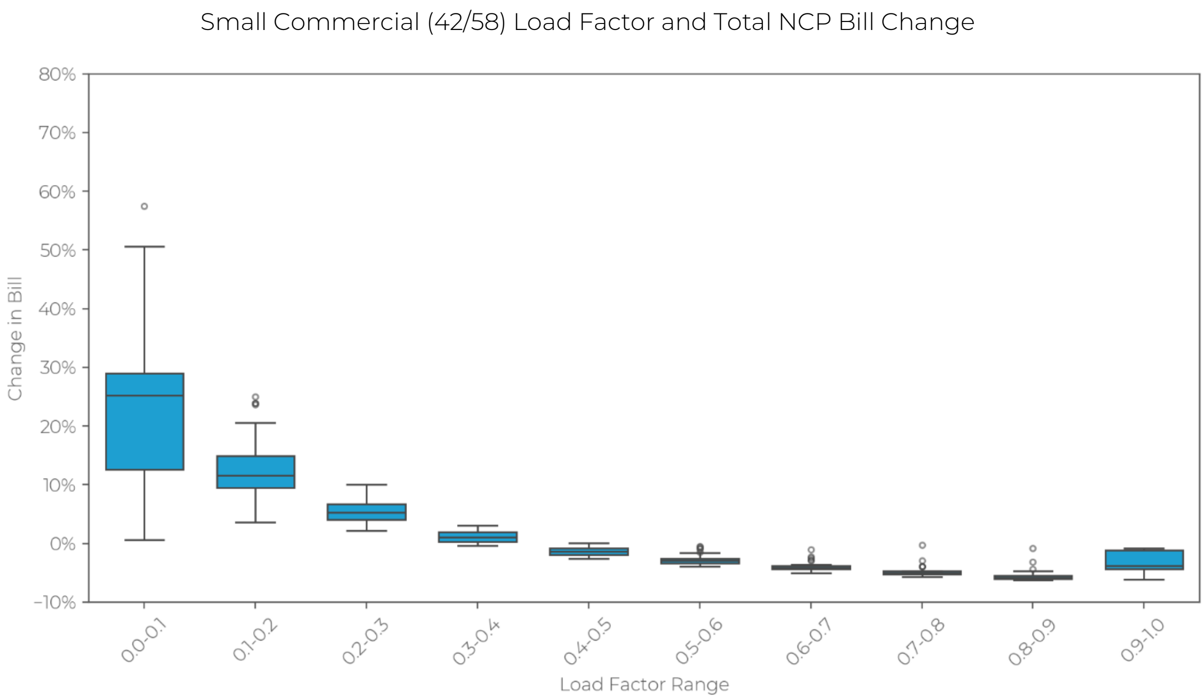
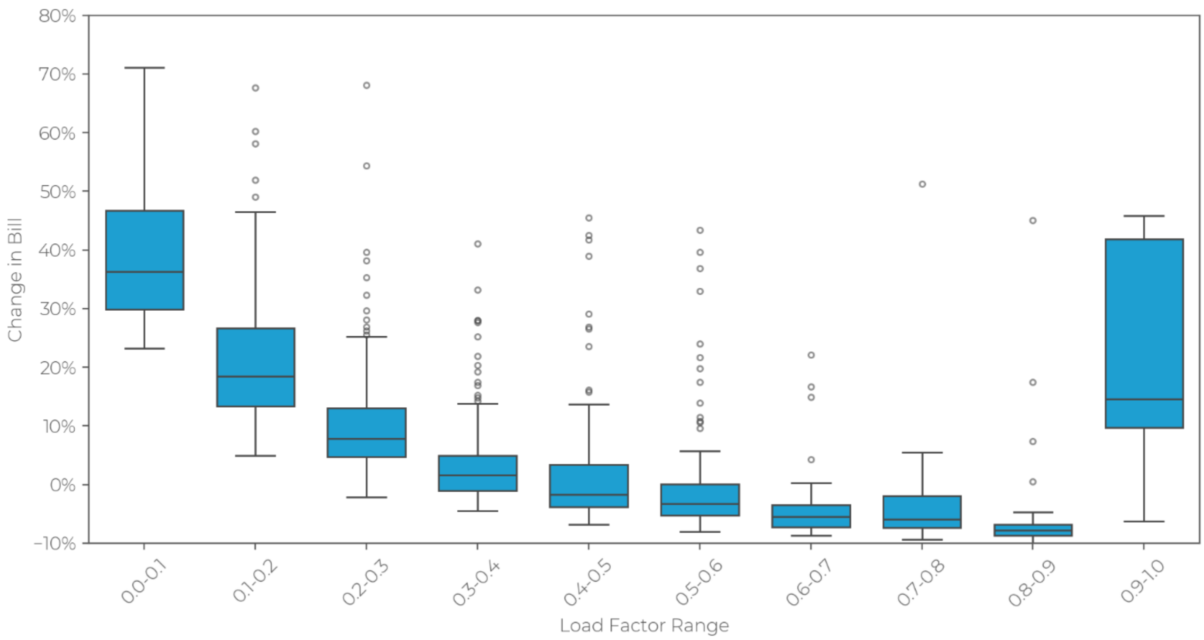
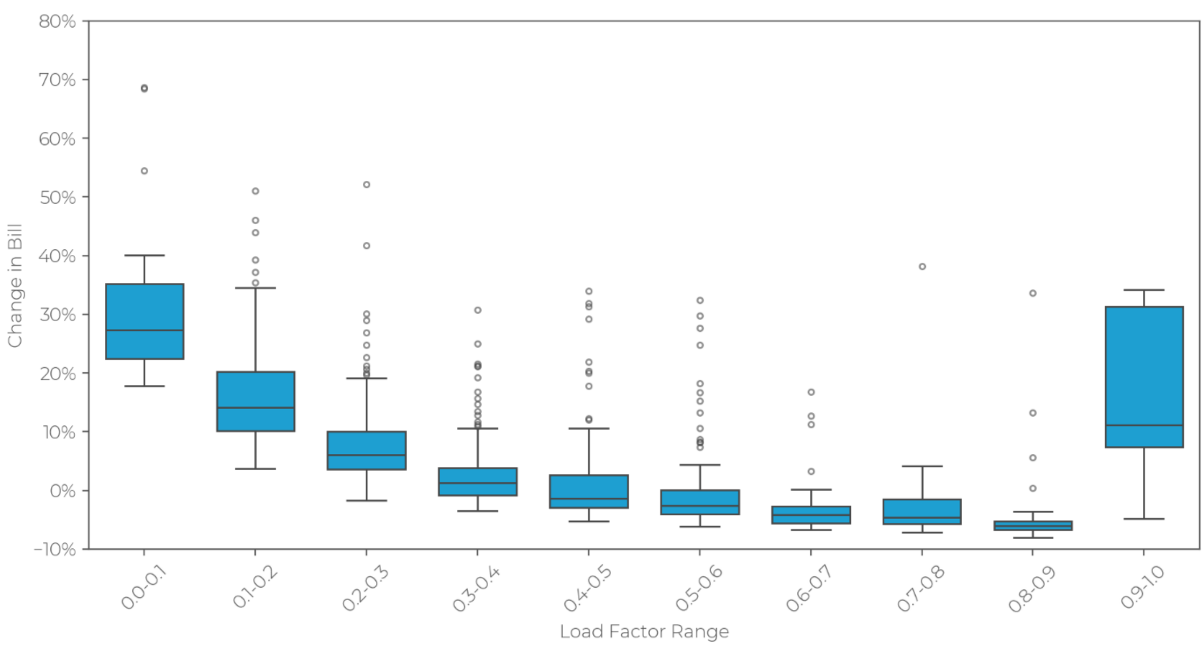



Figure 16: Small Commercial Subscription Bill Change by Load Factor Box Plots

Small Commercial (19/81) Load Factor and Total Subscription Bill Change




Small Commercial (42/58) Load Factor and Total Subscription Bill Change




A consistent trend for the demand-based rate designs is the inverse effect that load factor has on bill impact, with low load factor resulting in bill increases and high load factor resulting in bill decreases. The NCP demand rate design demonstrates this inverse effect with fewer outliers than the subscription demand rate. The subscription rate design was modelled using the highest demand in a three-year period and, rounding measured demand up to the next subscription tier threshold. This approach necessarily measures demand less precisely than billing on monthly metered NCP demand and leads to a higher magnitude of bill increases and decreases compared to current rates, particularly for customers with highly variable monthly NCP.

## C5. Bill Volatility

In addition to changes in total bill amounts, the analysis also considered monthly bill volatility, measured as the standard deviation of each customer's 36 monthly bills. This metric provides insight into the predictability and stability of billing under each rate design.

Table 19 summarizes how bill volatility changes under each alternative rate design, relative to the current rate design. The table reports the proportion of customers whose monthly bill volatility increases or decreases by more than 2%, as well as those with minimal change. An increase in bill volatility means that customer bills vary more from month to month while a decrease in bill volatility means bills are more stable.

Table 19: Impact on Bill Volatility

| Fixed/Variable Proportions | Rate Design | Customer Class | Increases more than 2% | Decreases more than 2% | Less than 2% Change |
|---|---|---|---|---|---|
| 71/29 | NCP | Residential | 6% | 83% | 12% |
| 71/29 | TOU Demand | Residential | 8% | 73% | 19% |
| 71/29 | Subscription | Residential | 0% | 100% | 0% |
| 71/29 | TOU Energy | Residential | 1% | 0% | 99% |
| 19/81 | NCP | Small Commercial | 25% | 61% | 14% |
| 19/81 | TOU Demand | Small Commercial | 36% | 45% | 19% |
| 19/81 | Subscription | Small Commercial | 0% | 100% | 0% |
| 19/81 | TOU Energy | Small Commercial | 11% | 4% | 85% |
| 43/57 | NCP | Residential | 8% | 84% | 7% |
| 43/57 | TOU Demand | Residential | 13% | 76% | 11% |
| 43/57 | Subscription | Residential | 0% | 100% | 0% |
| 43/57 | TOU Energy | Residential | 6% | 1% | 94% |
| 42/58 | NCP | Small Commercial | 22% | 60% | 19% |
| 42/58 | TOU Demand | Small Commercial | 33% | 44% | 23% |
| 42/58 | Subscription | Small Commercial | 0% | 100% | 0% |
| 42/58 | TOU Energy | Small Commercial | 8% | 2% | 90% |

*Values are rounded to the nearest percent (%)

For most residential and small commercial customers in the dataset, demand-based rates lead to lower bill volatility than the current rate design. By design, subscription rate leads to a substantial decrease in bill volatility for nearly all customers. Figure 17 shows histograms of the change in customer-level bill volatility.

Figure 17: Change in Bill Volatility for NCP and TOU Demand Rates