Demand-Based Rate Research
Executive Summary

Prepared for:
EPCOR Distribution & Transmission Inc.

Prepared by:
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NOTE TO THE READER

This document summarizes three research initiatives conducted by Power Advisory and Stone-Olafson. The work includes two complementary types of research:

- **Jurisdictional market scans:** systematic review and analysis of how other regions and countries have approached similar opportunities
- **Marketing research:** qualitative and quantitative methods to gather and analyze public attitudes, perceptions, and behaviours.

The purpose of this document is to provide an overview of the external landscape and public perspectives, grounded in an understanding of how systems operate today.

The findings presented here are **intended to inform discussion and support evidence-based decision-making.** They should not be interpreted as directives, recommendations, or requirements, but rather as research inputs to be considered alongside other policy, technical, and operational factors.

This executive summary is a synthesis of seven reports:

Stone — Olafson

Executive Summary
(Stone-Olafson)
Summarize Power Advisory Reports (2) + Customer Engagement (3) + Summary of Customer Engagement

- **Power Advisory**
  Assessment of System Readiness
  Executive Summaries Embedded in each report
  - **Module A Report**
    Demand-Based Rates Feasibility Study
  - **Module B Report**
    Jurisdictional Scan (Rate Types in Market)
- **Stone-Olafson**
  Assessment of Market & Consumer Readiness
  Summary of Customer Engagement
  - **Global Jurisdictional Discovery**
    Report on implementation strategies and outcomes
  - **Local Voice**
    Qualitative Report
  - **Market Validation**
    Quantitative Report

Focus: Operational Readiness

Focus: Market Readiness

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What this is about? The Regulatory Direction

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On July 11, 2022, the Alberta Utilities Commission (AUC) issued Decision 27018-D01-2022 in EPCOR Distribution & Transmission Inc.'s Phase 2 Distribution Tariff Application. In that decision, the Commission directed EDTI to commence a feasibility study to determine the scope and cost to build and implement a metering system that is able to measure demand for residential and small commercial customers, and to identify alternatives to provide demand-based billing.

EDTI chose to add to the feasibility study by including customer engagement research. This additional research explored customer interest, willingness and readiness for demand-based rates or other advanced rates.

Why now? The Opportunity

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Natural Resources Canada awarded EPCOR a grant through its *Energy Innovation Program's Smart Grids Regulatory Innovation Capacity Building* Call for Proposals. This funding was specifically earmarked to "**study the feasibility of different advanced-rate structures and how they can help guide lower electricity costs.**"

The NRCAN grant was part of a broader $3 million investment supporting four **Alberta projects aimed at enhancing grid reliability and resiliency – particularly critical during peak demand periods like winter months when the grid faces its heaviest loads.**

As EPCOR's Senior Vice President of Electricity Service, Kirstine Hull, explained: ***"Through the feasibility study, we are working to better understand if advanced, customer-focused rate options have the potential to reduce peak demand and make better use of the grid we already have."***

The Convergence

EPCOR saw the opportunity to expand the feasibility assessment beyond the meters to a broader assessment involving customer interest, willingness and readiness.

EPCOR's Challenge: From Regulatory Direction to Customer Readiness

The AUC's direction to explore system feasibility for demand-based rates was clear, but it raised a second, critical question for EPCOR to consider:

Is the Edmonton market ready? ***And if not, what is required?***

Demand based rates is both a system readiness question (operational feasibility, cost) and a market readiness one (communication, adoption, behaviour). Therefore, the need to explore market readiness in parallel became apparent as successful market implementation assumes foundational assumptions:

- Customers understand their electricity bills and rate structures
- Customers will recognize and respond to new signals regarding electricity consumption
- The resulting behaviour will positively impact peak-demand.

But are these assumptions true?

For EPCOR to conduct a true feasibility study, they need to validate whether Edmonton's residential and small commercial customers are prepared for - and receptive to - advanced rate options. A more fulsome analysis includes both system readiness and market readiness.

To that end, EPCOR initiated two main streams of work: an **assessment of system readiness** and an **assessment of market and customer readiness**. This report is a summary of this fulsome body of work.

Phases of Work

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Assessment of System Readiness

EPCOR undertook a multi-phase research program to assess EPCOR's system readiness demand-based rate structures.

Phase 01 — **Demand-Based Rates Feasibility Study**
March – June 2025

EPCOR commissioned a feasibility study to explore options, costs, and trade-offs of Demand Based Rates.

Phase 02 — **Study Submitted to AUC**
June 2025

The outcomes of the feasibility study on demand-based rates (DBR) were submitted along with EPCOR's Phase 2 Rate Application.

Phase 03 — **Jurisdictional Scan**
July 2025

Jurisdictions where DBR was either piloted or implemented were identified for comparison with the Edmonton market.

Assessment of Market & Consumer Readiness

At the same time, EPCOR undertook a three-phase research program to assess Edmonton customers' readiness for advanced electricity rate structures, with the phases for this research described below.

Phase 01 — **Global Jurisdictional Discovery**
August 2025

Reviewed advanced rate implementations across North America and select international markets (17 jurisdictions in total) to identify success factors, risks, and failure modes.

Phase 02 — **Local Voice**
September 2025

Conducted four in-person focus groups with Edmonton residents to explore values, concerns, behavioral constraints, and perceived fairness issues.

In addition, we conducted in-depth interviews with with two internal subject matter experts (SMEs), and a a virtual focus group with indigenous entrepreneurs.

Phase 03 — **Market Validation**
November 2025

Surveyed 641 Edmontonians to quantify awareness, understanding, priorities, and willingness to adopt advanced rate options.

OVERALL FINDINGS FROM ALL PHASES

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1. Policy Clarity is an Enabler

Clear policy direction related to decarbonization, electrification, and grid modernization has been identified as a key enabler of successful adoption of advanced rate structures in other jurisdictions.

2. Customer Understanding and Simplified Bills Facilitate Acceptance

Customer understanding and bill transparency emerged as important factors across multiple sources. In jurisdictions where advanced rates have been introduced, simplified bill formats and clear communication of rate impacts have been associated with higher customer acceptance. In Alberta's market structure, where distribution charges represent approximately one-quarter of total bills, distribution rate design alone may generate limited price signals for behavior change. Further, one quarter of Edmontonians find their bill difficult to understand.

3. Alignment of Customer Value and System Outcomes

Most Edmontonians say they need roughly a 30 percent discount, or about 52 dollars per month in savings, to meaningfully change behaviour.

Advanced rate structures should be designed with clear objectives—whether reducing peak demand, integrating distributed energy resources, or improving cost recovery—and evaluated based on their ability to deliver measurable benefits to both the grid and individual customers.

4. Customer Engagement and Equity Considerations

Jurisdictional research and local customer engagement consistently highlighted that meaningful input from a range of customers helps ensure that advanced rate designs are practical, effective, and broadly supported. Equity concerns—particularly for shift workers, low-income customers, and those with limited flexibility—were identified by Edmontonians as important considerations in rate design.

Jurisdiction-wide messaging and protections (opt-outs, bill guarantees, explicit equity safeguards) are highly desired by customers to demonstrate that they are the primary beneficiaries. This supported greater acceptance.

5. Coordinated Implementation Approach

International and North American experience suggests that successful implementation of advanced rates has included phased rollouts, customer education tools, and enabling technologies (such as monitoring apps and smart home devices) to support customer adoption.

Learning from the Jurisdictional Scan

What We Learned From the World

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Across all jurisdictions there were more cautionary tales (consumer push back, problematic implementation) than success stories.

Much of the opposition stemmed from weak consultation, communication issues, implementation complexity, privacy concerns, and organized consumer/association opposition rather than fundamental problems with the rate structures themselves.

Pilot programs that were properly implemented and communicated generally showed positive customer satisfaction among participants, strong uptake/support, and positive reputational (as well as operational) impact.

We found three exemplars in terms of consultation and communication design: Ontario, SCE Arizona Pilot, and Puget Sound WA Pilot.

Success stories primarily involved government and/or regulator, and DFO coordination.

Key Insight:

Opposition typically stems from communication failures, not rate structure problems.

Silver Lining:

Well-designed pilots show strong satisfaction and positive operational impact (next slide).

Implementation in North America (AN OVERVIEW)

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Jurisdiction	New Rate Implementation	Reputation Impact	Operating Impact
Ontario	Successful	Positive	Modest, but positive (3% NET in summer 2017, 2021 change to peak hours)
British Columbia	Successful	No Change 'optional' nature well received (reddit)	Estimate 8% of non-EV owners, and 25% of EV owners will opt in by 2030. No hard load-impact numbers.
Arizona Public	Successful (operationally)	Negative	Limited. Budget impact negative due to recovery from poor implementation.
Arizona Salt River	Successful (pilot) Pending (scale roll out)	Positive	TBC
California Multiple DFOs	Successful (Dynamic rates, Real-time yet to be completed)	Mixed to Negative	Dynamic rates is net positive, but real time pricing pilot has not realized significant new gains.
Washington Puget Sound	Successful (pilot) Pending (scale roll out)	Positive	Net positive (94% behaviour impact for participants)

Key Insight: Well-designed pilots show strong satisfaction and positive operational impact. However, consumers show reluctance to choose demand-based rates (modest uptake – 8% to 25%) out of concern it will will increase their bill.

Implication? Guarantee or line of sight to lower bills is required along with broad implementation.

Summary of Critical Success Factors

Learning From Alternative Rate Pilots & Implementation in Other Jurisdictions

Success Factors:
Joint gov/regulator-DFO leadership
Intensive, tailored customer education
Structured (funded) pilots and iterative feedback to provide validation, optimisation
Simple, transparent rate design
Customer protections (bill guarantees)
Ongoing support and responsiveness
Proactive equity measures
Broad uptake of enabling technologies (e.g. smart technology, connected apps)
Use of Price Signals and Incentive Programs: Integrating ARS with DSM programs, rebates, and automation to reduce customer burden

Causes of Issues or Mixed Results:
Unilateral or siloed oversight
Limited, one-way, or technical communication
Rushed, untested, or poorly monitored rollout
Overly complex, confusing structures
Absence of opt-outs or risk mitigation
Lack of post-rollout education/support
Ignoring vulnerable group impacts

Assessment of System Readiness

What we learned from the system readiness assessment

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Financial & Regulatory vs. Feasibility Barriers

- While demand-based billing, using maximum monthly metered demand, is currently the lowest cost option using EDTI's current Advanced Metering Infrastructure (AMI), it is not the best option with respect to lowering system peaks.
- **Full-scale implementation presents substantial financial and regulatory challenges**, with estimated costs ranging from under $5 million for simplified models to approximately $74 million for more complex designs requiring meter hardware replacement.
- Any new demand side structure would require significant time to be ready (most options reviewed are 3+ years of preparation).
- Due to the challenges, Power Advisory noted: "Any move to advanced or demand-based rate structures should be guided by clearly defined outcomes and rate design objectives that reflect specific system challenges, customer segments, and policy goals, rather than implementing them for their own sake."

Market Structure Constraints & Customer Impacts

- In Alberta's unbundled retail market, changing only distribution rates will have limited impact on total bills and weak incentives for customers to change behaviour.
- Delivery appears as a single, opaque line that is only about a quarter of the bill, so customers have low visibility into distribution rate design and struggle to understand advanced or demand-based charges.
- Multiple, uncoordinated price signals (retail, transmission, distribution) increase complexity for customers and can dilute or conflict with any advanced rate signal.
- Based on preliminary bill modelling, Edmonton customers with low load factors (such as those in apartments or those with solar panels) tended to see negative bill impacts (higher bills), while customers with high load factors (such as EV charging needs) tended to see positive bill impacts (lower bills) under all demand-based designs.

Core Objectives of Demand-Based Rates

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Cost Reflectivity: Align customer charges with the infrastructure costs required to meet peak demand.

Revenue Sufficiency: Ensure stable utility revenue as customers adopt energy-efficient technologies and self-generation (e.g., rooftop solar).

Equity: Mitigate cross-subsidization where low-peak customers subsidize those placing higher strain on the grid.

System Reliability: Encourage load-shifting to reduce peak demand, potentially deferring costly grid upgrades.

Edmonton's Advanced Metering Infrastructure Network

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For residential and small commercial customers, 15-minute and hourly intervals are the dominant practice where measured demand is used. Jurisdictions that apply demand-based charges to these classes (e.g., Norway, parts of Australia, and pilots in North America) either use:

- Contracted/subscription kW with underlying metering often at 15-minute resolution, or
- Measured non-coincident or TOU demand based on 15-minute intervals, with hourly also used where systems are less granular.

Current System Capabilities

EDTI's current advanced metering infrastructure (AMI) network consists of over 412,000 residential and 37,500 commercial/industrial meters; residential meters record 60-minute interval data, but customers are billed on cumulative consumption based on the difference between meter readings at the start and end of each billing cycle, not on summed daily interval reads.

Interval Data *(if enabled)*

While data is currently recorded in 60-minute intervals, the infrastructure is *technically capable* of recording and transmitting data in smaller intervals.

Requirements for Implementation

Transitioning to demand-based rates would necessitate (at the very least) remote or manual reprogramming of meters, IT system enhancements to process interval data, and robust billing-grade data validation. However, interval shorter than 60 minutes will require meters to be removed and replaced with either new meters or modified existing meters.

Time and Costs Depend on Complexity

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While demand-based billing is technically feasible using EDTI's existing AMI, full implementation faces significant financial and regulatory hurdles. Costs range from under $5 million for simple models to $74 million for complex designs requiring hardware replacements.

Rate Design Option	Data Collection Interval	Estimated Cost	Estimated Timeline
Simple Models (using existing meters peak data)	60 minutes	Under $5 million	9 months
Moderate Complexity (requiring minor modifications to meters and OTA updates)*	5-15 minutes	~$28 million	18-30 months
Complex Models (requiring hardware/meter replacement)	5 minutes	Up to $74 million	48 months

**The feasibility of Over-the-Air (OTA) programming is uncertain as it is not currently approved by Measurement Canada. Being unable to utilize OTA would necessitate manual updates or full meter replacements, significantly increasing costs.*

Customer Bill Impact

The transition to demand-based rates introduces a series of structural trade-offs. Customers with consistent, flat-load profiles may experience lower charges, while customers with more variable or “spiky” usage patterns, or distributed generation are likely to face higher bills due to greater contribution to peak demand.

General Impact

Most customers would see bill changes within a ±10% range under time-of-use or non-coincident demand models.

Small Commercial Class

This class saw the highest impacts under subscription-based rates.

Low Load Factor Customers

This group, characterized by high peak usage relative to total energy consumption, would experience the most significant bill increases, with some exceeding 15%. A common example of these customers are solar panel users.

Volatility

While DBR can reduce volatility for some, it introduces higher variability for others, particularly those unable to manage their peak usage.

Full Summary of Options Explored & Recommendations

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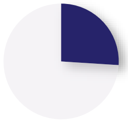
DSM approach	Primary goal contribution	Indicative utility cost range (incremental)	Typical timeline to scale	System & market readiness (EPCOR/AB)	Key constraints/risks
1. **TOU energy for distribution** *(simple on/off-peak kWh)*	• Moderate peak reduction • Limited but broad customer reach	• From ~7M (IT + process, OTA meter reprogramming) to ~71M (if meter replacements required)	• ~9 months for core IT + • 3–4 years for full meter/program rollout across classes	• High technical feasibility • AMI 1.0 already installed • Billing and MDM upgrades required but well understood	• Distribution only ~20–25% of bill, so weak net price signal • Risk of "shadow peaks" if EVs cluster on same hours • Needs AUC and retailer alignment
2. **TOU demand** *(max kW within fixed peak window)*	• Better alignment with system peak window • Potentially stronger peak-saving signal if designed well.	• Low-teens of millions if OTA reprogramming works • Up to ~70M+ if full meter change and substantial IT uplift	• 9 months IT + • 3–4 years for meter and rate class conversion.	• AMI can support, but billing, validation, and customer tools are not yet in place at required scale.	• Complex to explain • Material bill volatility for some low load-factor customers • Risk of customer/political pushback, (i.e., Australia and Nordics)
3. **NCP demand charges** *(monthly max kW, all hours)*	• Some load-flattening at customer level • *Modest* system-peak impact • Improves cost allocation	• ~0.3–4.6M if based on existing hourly or peak reads • Higher if shorter intervals adopted for other reasons.	• 9 months IT if using existing data • Up to 4 years if interval configuration and conversions needed	• Technically straightforward (meters already demand-capable) • Systems need billing determinant changes	• Weak alignment with system peaks • Mixed international evidence on impact • Equity and comprehension issues • Limited bill-savings incentive on a small share of the bill
4. **Subscription demand** *(customer picks kW tier)*	• Indirect peak management via self-selected caps • Good for bill stability and cost allocation	• Similar to TOU demand • Design and customer-support costs higher due to tier selection and overage management	• Multi-year (design + pilots + phased rollout), similar to TOU demand timelines	• Technically feasible • Requires advanced analytics and customer-facing tools	• Highest modeled bill impacts, especially for small commercial • Mis-sizing risk • Heavy customer education and care requirements
5. **EV-specific TOU/managed charging programs** *(with or without separate EV rate)*	• High leverage on local peaks and transformer loading • Strong potential to reduce system strain if automated	• Incremental, program-scale costs (rebates, control platforms) estimated in low-millions range for initial pilots (cheaper than universal rate transformation)	• 1–3 years to pilot and scale within EV-owning segment.	• Technically feasible now • Existing AMI, DERMS, and pilot experience in Alberta and elsewhere • Can be targeted to high-risk feeders	• Limited to EV adopters • Must avoid creating rebound peaks • Needs tight coordination with retailers and device vendors • Regulatory clarity on DSM funding
6. **Non-rate DSM** *(energy efficiency & traditional demand response)*	• Reduces underlying load and peaks • Durable capacity benefit • Supports affordability	• Essential and often more cost-effective than complex ARS, especially where AMI/billing upgrades would otherwise be sunk solely for rate design	• Program-by-program: 1–3 years to design and scale • Can ramp in parallel with rate changes	• Conceptually mature but historically under-funded in Alberta • Current regulatory framework has rejected most DSM proposals except EV pilots	• Requires new regulatory mandate and cost-recovery framework • Administrative overhead and evaluation requirements
7. **Highly dynamic / locational ARS** *(RTP, CPP, DLMP, bi-directional export tariffs)*	• Strong theoretical peak and DER management • Best long-run efficiency	• Very high: requires AMI 2.0, real-time data platforms, ADMS/ DERMS maturity, and deep retailer integration • Beyond quantified costs in feasibility study	• 5–10+ years • Realistically contingent on REM evolution and AMI/billing upgrades post-2030	• Not ready in Alberta for mass-market load • Foundation elements (AMI 1.0, ADMS, DERMS) exist but not configured for this use	• High complexity: strong risk of customer confusion and backlash • Needs clear policy direction, cross-entity governance, and robust customer tools.

Assessment of Market Readiness

What we learned from the market readiness assessment

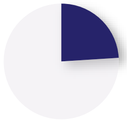
Customers require education and support

Edmonton customers are not currently ready for advanced rate structures. Low system understanding, bill complexity, and trust concerns represent material barriers to adoption.



Only 26% say they understand smart meters

50% are aware that alternative rate options exist



24% find their electricity bill difficult to understand

Savings need to be <u>substantial</u> for behaviour change

85% of customers say they would **change behavior to save money**, showing strong intent

However, customers indicate 'meaningful savings' means approximately **30% or ~$52/month** savings on an average bill (as such, lower distribution charges alone are likely not significant enough).

Convenience is the Primary Barrier to Action

Not all members of the market feel they would be able to change behaviours. In particular, there is concern that time-of-use structures disproportionately disadvantage shift workers, larger households, and caregivers with limited flexibility

Tools and structures that make it easy as convenience is a key barrier to action – 48% would like to see an app to monitor usage.

Trust and Fairness Are Divisive

There is a trust gap between some customers and utilities. Transparency, customer control, and protections for vulnerable customers are viewed as essential – not optional.

42% cite concerns about price gouging

Discount and rewards are preferred nearly **3 to 1 vs.** structures that have penalties.

Knowledge and perceptions of electrical grid peak demand risk in Edmonton is mixed

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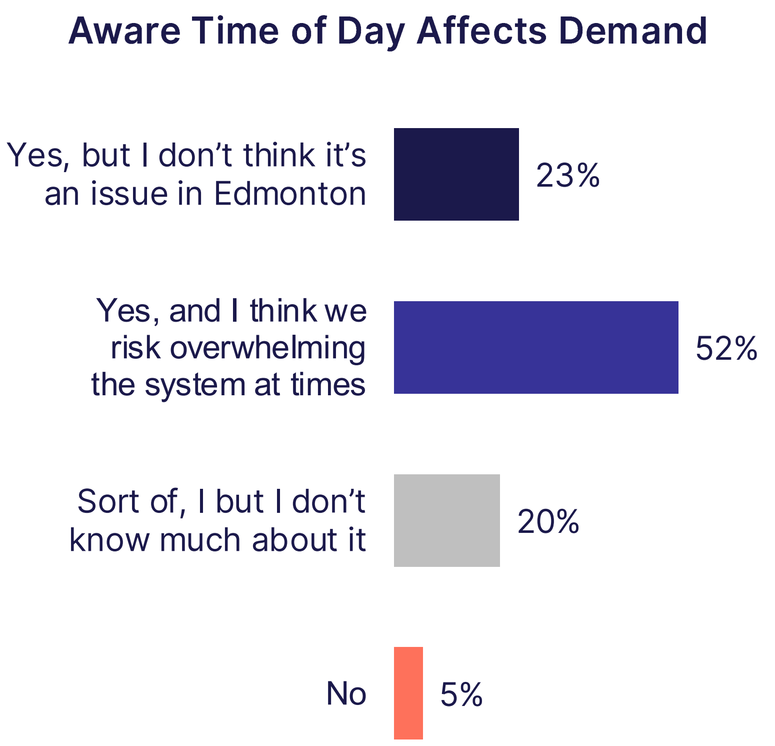


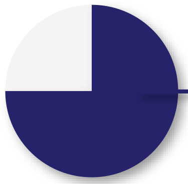
Nearly half (48%) of Edmontonians are unaware that the grid is at risk of being overwhelmed.

Younger demographics (18-34) are much less aware.

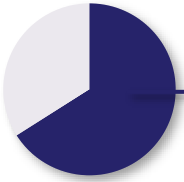
Key insight: Messaging about grid needs won't resonate uniformly.

Base: All respondents (n=641)
Q13. Are you aware that electricity use at different times of day affects overall demand and electricity grid management?

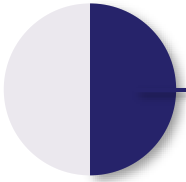
Edmontonians are more aware of grid management than alternative rates



75% of Edmontonians are aware that the time of day can affect grid management.



66% of Edmontonians are aware that advanced (or smart) meters exist.



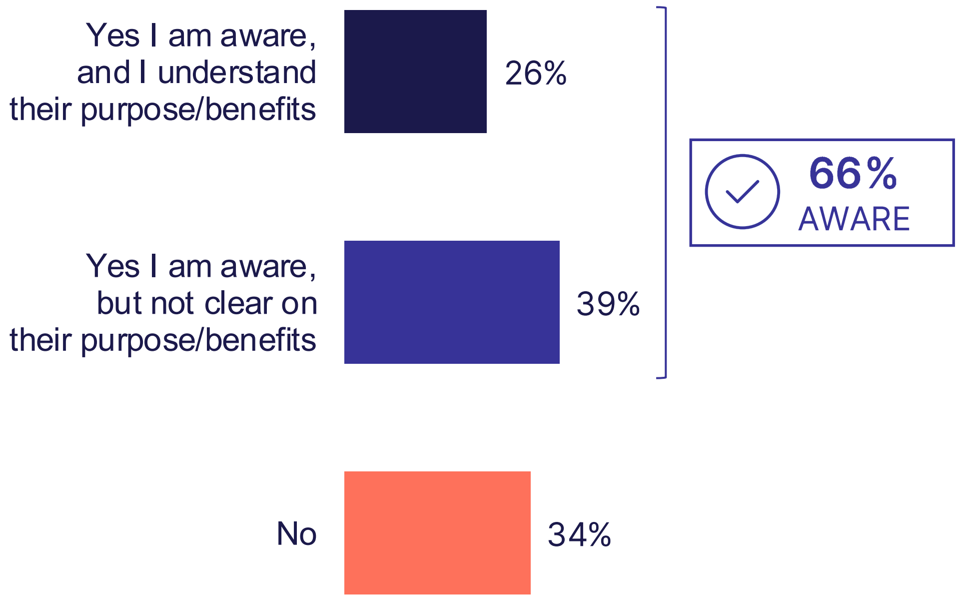
50% of Edmontonians have heard of alternative rate structures, where cost can vary by time of use.

Base: All respondents (n=641)
Q13. Are you aware that electricity use at different times of day affects overall demand and electricity grid management?
Q14. Are you aware that advanced electrical meters (or smart meters) exist, and understand their purpose/benefits?
Q15. Have you heard of alternative rate structures where electricity cost varies by time of day, season, or use?

Awareness does NOT mean understanding

The majority of Edmontonians have some awareness of advanced electrical meters, although fewer understand their benefit or purpose. However, those aged between 35-54 tend to understand these benefits more often. Further, those who have a higher degree of bill understanding are also much more likely (33%) to understand the benefits of smart meters.

Aware of Smart Meters and Their Purpose



Base: All respondents (n=641)
Q14. Are you aware that advanced electrical meters (or smart meters) exist, and understand their purpose/benefits?

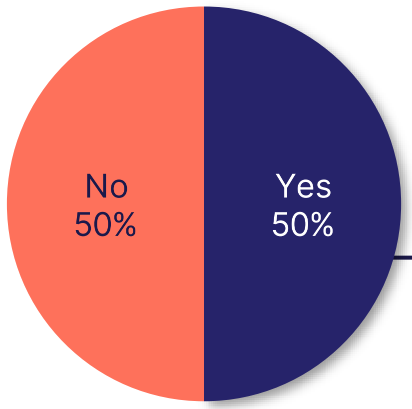
Those who find their bill easy to understand are more likely to have positive perceptions of alternative rate structures

Alternative rate structures have the lowest degree of awareness compared to grid management and smart meters. Those who live in more central locations tend to be less aware than other quadrants of the city, potentially due to the higher volume of renters and attached housing units.

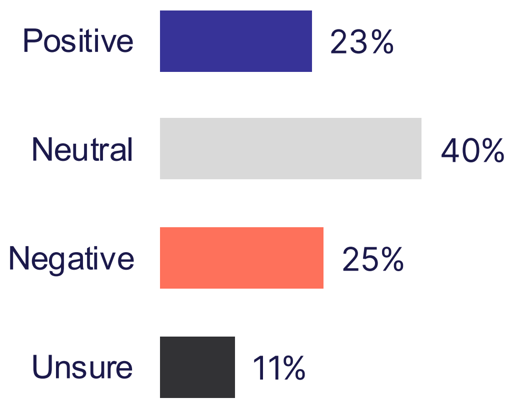
Those who have a greater understanding of their bills are slightly more likely to be aware of alternative rates (56%) compared to those who find it more difficult (40%).

More importantly, of those who are aware of alternative rate structures, those who find their bill 'easy to understand' are far more likely to indicate positive perceptions. Similar to awareness, those who have a greater understanding of their bills are also more likely to have positive perceptions of advanced rate structures (27%) vs. those who find it difficult (16%)

Aware of Alternate Rate Structures
COST VARIES WITH TIME OF DAY, SEASON, USE



Perceptions of Alternative Rate Structures
OF THOSE AWARE



Q15. Have you heard of alternative rate structures where electricity cost varies by time of day, season, or use? Base: All respondents (n=641)
Q15A. What is your overall perception of alternative rate structures that varies by time of day, season, or use? Base: Aware of alternate rate structures (n=323)

Bill Understanding: The Readiness Foundation

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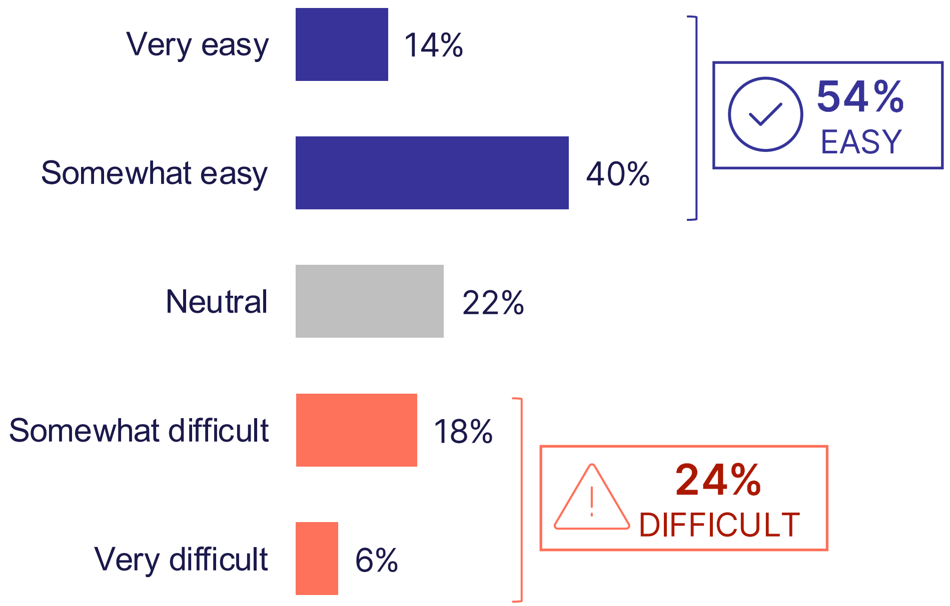
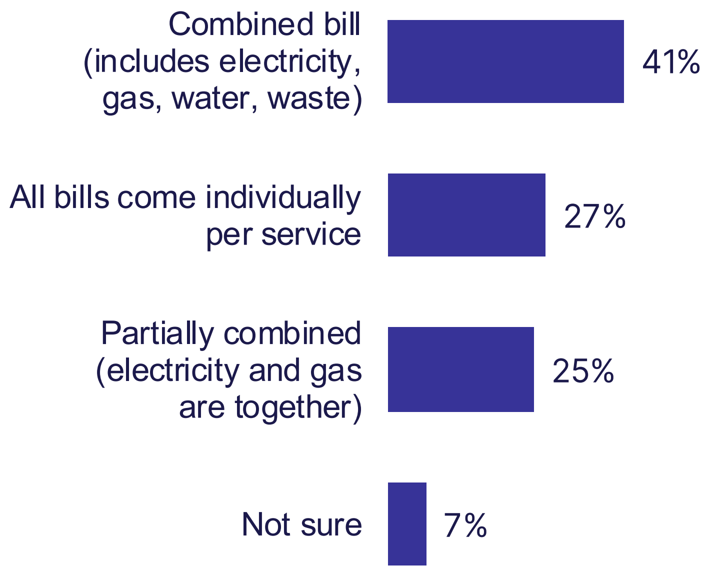
Roughly half of Edmontonians feel their bill is easy to understand, though only 14% indicate 'easy.' Further, one quarter of Edmontonians find their bill 'difficult to understand.' Those who understand their bill are more likely to have positive views about alternative rates.

Bill Understanding is Mixed



Most bills are combined



Base: All respondents (n=641)
Q9. How easy or difficult is it to understand your bill and use it to impact usage or cost?
Q5. What type of electricity bill plan do you have?

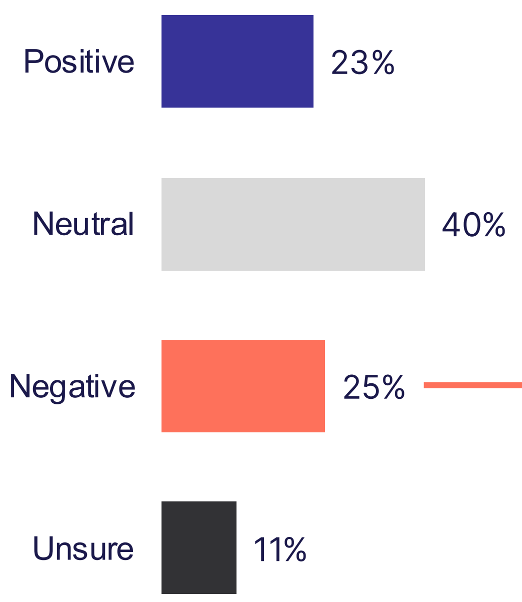
Negative perceptions of alternative rate structures are driven by trust issues

Stone Olafson

Concerns of alternative rate structures primarily revolve around price gouging and corporate distrust. Edmonton residents question the motives of utility companies thinking they are the ones who will ultimately benefit.

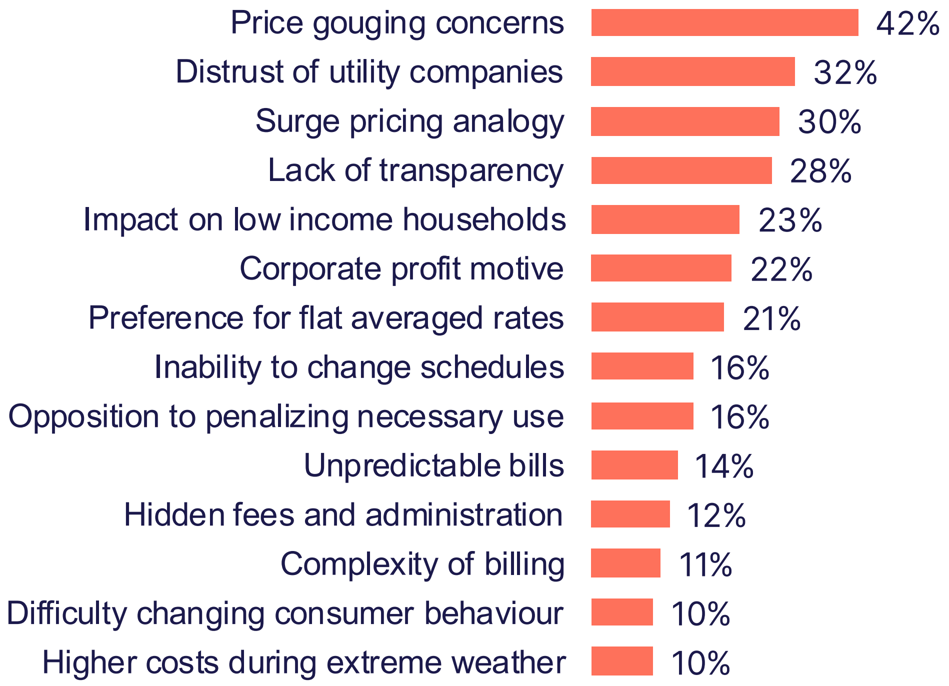
Perceptions of Alternative Rate Structures

OF THOSE AWARE



Reasons for Negative Perceptions

MENTIONS OF 10% OR MORE



Q15A. What is your overall perception of alternative rate structures that varies by time of day, season, or use? Base: Aware of alternate rate structures (n=323)
Q15B. Why is your perception of alternative rate structures that varies by time of day, season, or use negative? (n=81)

The Market Context: Four critical realities

Stone – Olafson

Billing complexity with cost frustration

The electrical distribution system is not well understood. Aside from a select, highly engaged group, research participants are not well informed on the various line items on their bill (e.g., distribution charges, their use, or how they are calculated). The various line items in the bill are felt to be confusing, with some questioning if it is done intentionally to obfuscate the issues.

Apathy and lack of grid relevance

Grid performance is not perceived to be an important or urgent issue for customers. There are very few examples of electricity grid reaching (or being at risk of reaching) maximum capacity and causing an interruption of services.

Skepticism and lack of trust

There is significant skepticism about utility company motives and the move to advanced rate structures. Current distribution charges and administrative line items are perceived to be “profit lines” and new rate structures are expected to benefit the utility’s bottom line.

Peak demand and consumption rates are conflated and confused

Even after a thorough explanation of the two terms the difference between overall demand and peak demand, are conflated and confused. A conversation will begin discussing peak demand and how to reduce strain on the electrical grid, but the conversation transitions into discussions about how to reduce overall consumption. It was difficult for research participants to understand or focus on how changing when electricity is consumed will benefit the system.

Market Readiness: The market is not ready

Stone Olafson

Lack of understanding of their role

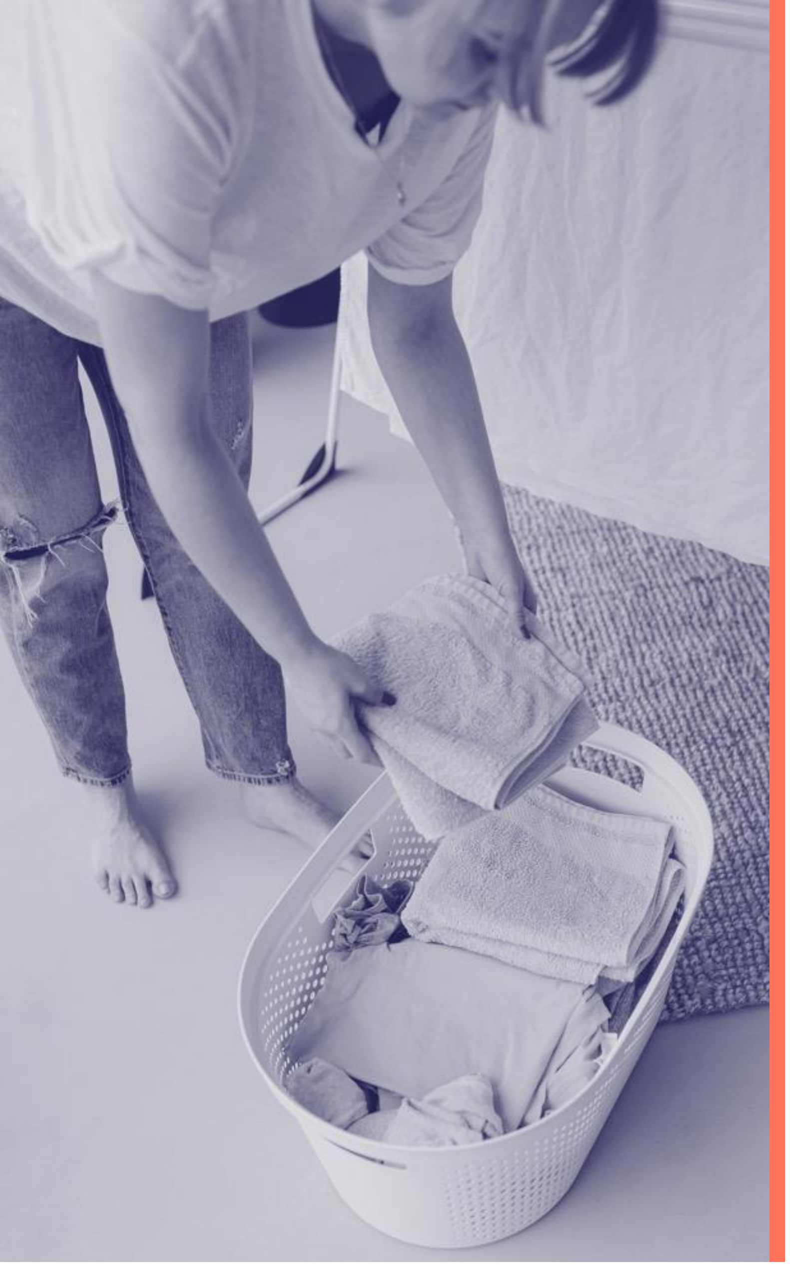
- People don't want to be wasteful; they believe they are already being responsible consumers.
- Participants perceive they have little ability to influence their bill overall. Past actions have not resulted in significant differences in cost.
- Lack of awareness of which appliances and activities consume the most electricity.
- Many don't understand how changing when they use electricity will benefit the system and consequently don't see the role they have to play.

Need better and more timely information

- Electricity customers, with the exception of those using solar, do not have access to information that will inform behaviour change.
- Participants indicate they would need more information to better understand the usage patterns in the home and where there are opportunities for meaningful change.

Meaningful motivation & incentives are essential

- Participants indicate that any incentives or cost savings will need to offset the challenges (hassle, stress, or lifestyle impact) of introducing the new rate structure.
- Savings need to be substantial (between \$20 to \$40 per billing period) to encourage behaviour change.
- Changes to the distribution charge only is not expected to be significant enough to be noticed.
- The opportunity for "savings" are more influential than the risk of "penalties."
- The people who indicate an interest in changing usage behaviour to reduce pressure on the grid have already taken action by investing in solar panels and are monitoring their peak consumption times.



Three theoretical types of demand-based rates were explored with Edmontonians

Stone — Olafson

DEMAND SUBSCRIPTION
Customers choose a subscription that dictates the maximum demand for electricity they agree to stay below throughout the billing cycle.

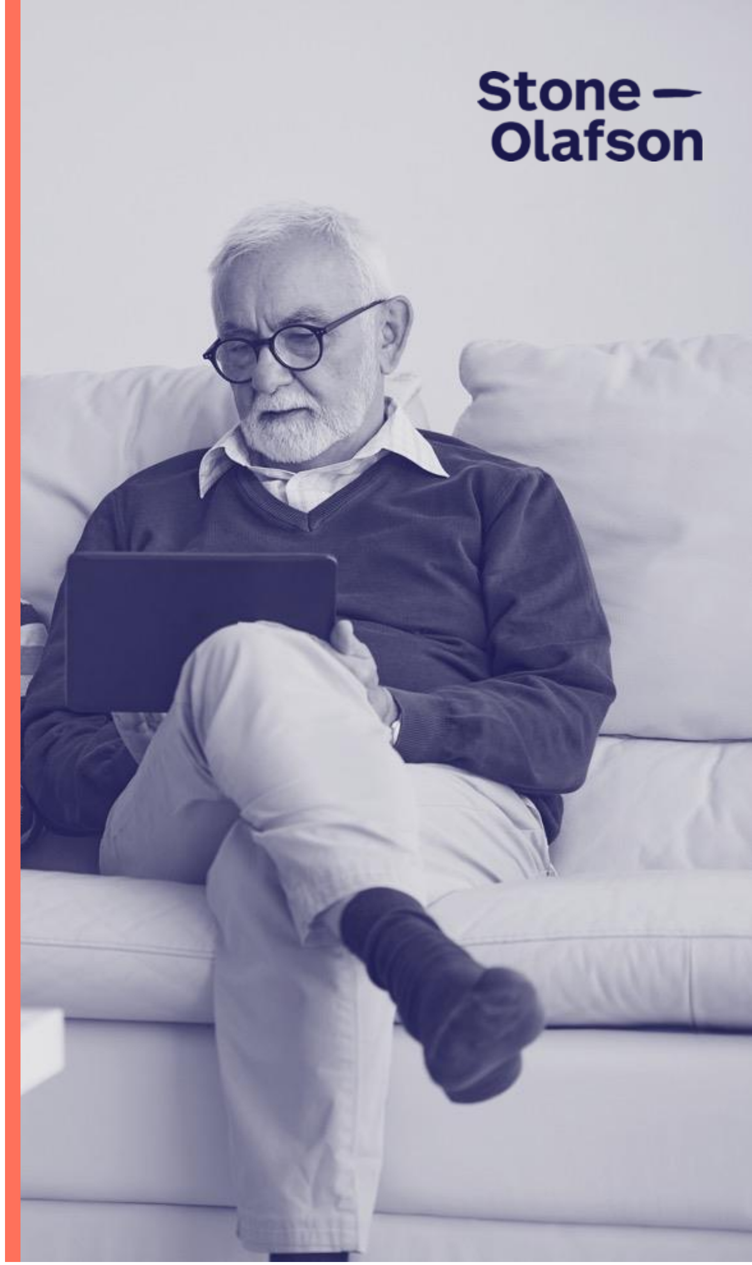
TIME-OF-USE
On-peak and off-peak periods are established with different $/kWh prices. On-peak rates are higher. Peak rate structures may change based on season/ time of year.

PEAK DEMAND CHARGES
Fees are imposed by the utility provider based on the highest rate of energy consumption during the billing period. In other words, the cost of delivering electricity for the billing period is set based on the moment of the highest metered demand from the billing period. The cost will change monthly based on the peak demand from the period.

SUMMARY

Reaction to Theoretical Models

Structure	Reception	Key Insight
Demand Subscription	Moderate	Offers predictability but anxiety about penalties
Time-of-Use	Mixed	Familiar to some; unfair to shift workers and families
Peak Demand Charges	Least Popular	Seen as punitive; removes sense of control



Distilling It All Down

Three Key Tensions We Discovered

1

Knowledge vs. Action

Customers are somewhat aware of the need but are not confident they can make a difference.

2

Good Intentions vs. Skepticism

Moral desire to "do the right thing" conflicts with suspicion (Will it end up costing more? Is this fair for everyone?).

3

Savings vs. Convenience

People need substantial savings to justify lifestyle changes (and there is baggage – attempts they have made in the past have not resulted in strong savings).

Why This Matters: The Readiness Gap

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Global Evidence Says:
Successful implementations require community buy-in, clear communication, transparency, and careful design.

Edmonton's status: Low baseline understanding, skepticism, and modest sense of urgency.

The implication: Jumping into alternative rate implementation without groundwork will likely not be successful (as most other jurisdictions have found).

What We Know:
Advanced rates CAN work – but not by accident.

What Edmonton Needs: Intentional groundwork, authentic stakeholder and customer engagement, and phased implementation.

What Success Looks Like: Customers feel informed, respected, and able to influence their costs, grid efficiency improves, and fairness is preserved.

Current Readiness Implications

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Structure	Current State	Observed in Successful Implementations
Technical Infrastructure	AMI 1.0 installed, 60-min intervals captured	15-min intervals, billing-grade validation, customer tools
Regulatory Framework	Interval data not yet approved for billing by Measurement Canada	Clear tariff rules, measurement systems in place
Bill Presentation	24% find bills difficult to understand	Simplified formats, clear demand charge communication
Customer Awareness	50% aware alternative rates exist	Sustained education campaigns, phased implementation
Market Structure	Distribution ~ 25% of bill, unbundled retail	Coordinated price signals or full-bill context

Appendix

Indigenous & Entrepreneur Considerations

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Primary Concerns

Bill Complexity & Trust Deficit

- Confusing utility bills and lack of transparency create frustration
- Emotional burden of navigating systems as Indigenous persons feels particularly off-putting

Equity in Voluntary Systems

- Voluntary advanced rate structures are expected to disadvantage those unable to adjust consumption (shift workers, vulnerable populations). This would crate an equity gap effectively creating a two-tier system

Primary Recommendations

Holistic Approach

- Need for systems thinking that respects Indigenous rights and addresses root causes of energy consumption, not just utility-centric solutions (i.e., strong, thoughtful approach with smart, fully integrated solutions)

Early Engagement Critical

- Importance of diverse perspectives from start to avoid past failures
- Tailored strategies to addressing varying user needs

Key Insight: Fairness is of even greater concern to Indigenous Entrepreneurs, and any solutions should have input. Expectations of entrepreneurs and businesses are that solutions are intuitive, easy to understand, and elegantly designed to work well with systems.

Indigenous & Entrepreneur Considerations

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Critical Cautions

Affordability Concerns

- Fixed-income customers are already struggling; many don't reach out until 2-3 months in arrears
- The 'no surprises' must be certain

Fixed Charge Burden

- High fixed charges mean usage reduction doesn't significantly impact bills
- Advanced rates on distribution only may not provide meaningful savings.

Zero Flexibility Populations

- Multiple jobs, shift workers, medical equipment users, large families have no capacity to adjust usage

EPCOR Must Provide

Substantial Education

- Clear communication with realistic savings scenarios and bill simulators

Early Intervention

- Proactive outreach before customers fall behind
- Enhanced payment plans

Sufficient Timeline

- Minimum 1-3 years for system changes and customer preparation

Key Insight: The internal teams who face the public and those most at risk are aligned to the general community concerns, as well as the risk areas identified in the early jurisdictional scan. Clarity, real impact, ease, and flexibility for those at risk delivered well and supported with education and planning is key.

Key findings from Jurisdictional Scan

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Jurisdiction	Utility/Retailer	Rate Structure	Context and Lessons Learned
Australia	Ausgrid	Demand Tariff ($0.37/kW/day) charged on day when highest 30-minute period of consumption occurs within the peak demand window (3pm-9pm) from June-August and November-March.	Intended to incentivize customers to reduce consumption during peak hours. Requires smart meters to be installed.
Australia	Energex	Residential Demand Tariff ($5.127/kW/month) charged to either the highest demand that occurred in a 30-minute interval or the highest demand during the peak demand charging window (4-9pm every day).	The choice of how to apply the demand tariff is left to retailers. Requires smart meters to be installed.
Australia	Ergon Energy	Residential Demand Tariff (14A: $5.98/kW, 14B: $10.49/kW) charged on peak consumption within the on-peak window (4-9pm every day).	Customers can opt-in to the demand tariff. Requires smart meters to be installed.
Australia	Endeavor Energy	Residential Demand Tariff has a high-season ($4.61/kW/month) and a low-season ($1.28/kW/month) demand charge based on the highest demand that occurs in any 30-minute interval. High season is November-March and low season is April-October. Peak hours are business days from 4-8pm.	As of 2024, residential customers with smart meters are enrolled in or shifted to (new/existing customers, respectively) seasonal TOU rates by default. Customers may instead opt-in to seasonal TOU demand rate. Flat distribution rate being phased out except for customers without smart meters. Customers moving from flat rate to TOU benefit from a transitional rate for the first 12 months.
Arizona, USA	Arizona Public Service (APS)	Weekday Demand Charge charges a monthly demand charge for the highest hour of usage during on-peak hours (4-7pm on weekdays).	Customers can opt in to the demand charge plan.

Key findings from Jurisdictional Scan
CONTINUED

Jurisdiction	Utility/Retailer	Rate Structure	Context and Lessons Learned
Arizona, USA	Salt River Project (SRP)	Monthly demand charge is calculated per kW, based on the 30-minute interval in which a customer uses the most electricity during on-peak hours (May-October: weekdays 2-8pm, November-April: weekdays 5-9am and 5-9pm).	Plan is intended to incentivize customers to lower their demand during on-peak hours. Pilot program – customers can opt in. May require a meter upgrade. Pricing plan will be eliminated no later than November 2029 and new TOU hours and programs will be introduced. Analysis of the rate plan found that participants did not consume more or less energy after moving to the demand rate pilot.
Alabama, USA	Alabama Power	Time Advantage – Demand Rate Plan adds a demand charge ($1.50/kW) to customer's highest demand across a 15-minute period during peak hours (June-September: weekdays 1-7pm, November-March: weekdays 5-9am).	Customers can opt in to the plan.
North Carolina, USA	Duke	Residential TOU Demand Charge ($1.95/On-Peak kW, $4.18/Max kW) is applied to the maximum demand during any 15-minute interval during on-peak hours (May-September,	Customers can opt in to the plan.
Sweden	Ellevio	Demand-based pricing adds a demand charge based on the average of the 3 hours with the highest average power over 3 different days. Between 10pm-6am, only half of the peak power is counted. Charge is 81.25 SEK/kW.	Adopted to result in a more efficient use of the grid and cost minimization.
Sweden	Municipal Distributor	Hourly and seasonally differentiated demand charge applies between 7am-7pm and applies 12.91 € /kW from November-March and 5.35 € /kW from April-October.	Demand charges based on maximum billing demand did not reflect costs that a user imposes on the grid, nor provide users with accurate price signals, since maximum coincident demand is absent from the price signal in a demand charge.

Learning From Others

What has driven success and/or failure in other jurisdictions that we can learn from?

In-depth look at Ontario, BC, Arizona, and California (complete to implementation)

Review of feasibility studies and/or lessons learned documents from other North American jurisdictions include:

- Michigan
- Illinois
- Georgia
- Maryland
- Massachusetts
- Colorado
- Nova Scotia

In-depth look at Australia, Norway, Sweden, France, Spain (complete to implementation)

- Some tangential information on other countries may also be noted if referenced in review of the above.

Traditional and Advanced Rate Structure Designs

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Rate Structure	Description	Pricing Basis	Typical Use Case / Benefit
Fixed Monthly Charge	Flat fee covering basic service and infrastructure access.	$/month	Recovers fixed utility costs regardless of usage. Traditionally used for delivery charges (i.e., wires charges)
Flat Energy Rate	Fixed price per kWh, regardless of time or usage level.	$/kWh	Simple structure for residential customers. Traditionally used for both delivery charges and/or electricity commodity charges)
Tiered Rate	Rates increase with higher consumption blocks (e.g., after 1,000 kWh/month).	$/kWh (by usage blocks)	Encourages energy conservation. Typically used for electricity commodity charges.
TOU Energy	Prices vary by time of day (e.g., on-, mid-, and off-peak periods) and/or by season.	$/kWh (time-based)	Reflects daily and/or seasonal system cost variation; encourages shifting. Applicable to both delivery charges and/or electricity commodity charges.
CPP	Very high prices during rare, pre-notified system-critical periods.	$/kWh (event-based)	Reduces strain during peak demand events. Applicable to delivery charges and/or electricity commodity charges.
Peak Time Rebate (PTR)	Customers receive bill credits for reducing load during peak events.	$/kWh rebate (no penalty)	Non-punitive demand response option. Applicable to both delivery charges and/or electricity commodity charges.
Real-Time Pricing (RTP)	Prices reflect hourly wholesale market rates.	$/kWh (dynamic, hourly)	Enables price-responsive demand; requires automation for optimal customer experience. Applicable to electricity commodity charges.
Non-Coincident Peak Demand Charge	Charges based on highest kW demand during the billing period.	$/kW (monthly peak demand)	Common in commercial/industrial; reflects infrastructure cost. Applicable to delivery charges.
Demand Subscription	Customers select a maximum kW level; usage above it incurs penalties.	$/kW (subscribed) + overage penalties	Encourages demand predictability; supports planning. Applicable to delivery charges.
TOU Demand Charge	Charges based on a highest kW demand during a defined "peak window" during the billing periods.	$/kW (monthly peak demand)	Emerging approach for residential and small commercial customers; reflects infrastructure cost. Applicable to delivery charges
Coincident Peak Demand Charge	Charges based on usage during top system peak hours (e.g., top 5 per year).	$/kW (monthly coincident peak)	Aligns customer use with system-level cost drivers. Applicable to delivery charges and/or electricity commodity charges.
EV-Specific / Managed Charging Rates	Incentive rates for EV charging, sometimes with utility control.	$/kWh or program-based incentive (may be time-based)	Supports off-peak EV charging. Applicable to both delivery charges and/or electricity commodity charges.
Grid-Access / Export Tariff (DERs)	Credits or charges based on DER injections and imports from the grid.	$/kWh (import/export, may be time-based or locational)	Supports DER integration and locational value signals. Applicable to both delivery charges and/or electricity commodity charges.
Distribution Locational Marginal Pricing (DLMP)	Prices reflect local grid constraints at the distribution level.	$/kWh (location-based, dynamic)	Advanced concept for DER integration and grid optimization. Applicable to both delivery charges and/or electricity commodity charges.

Overview of Pros and Cons of Rate Structures

Stone — Olafson

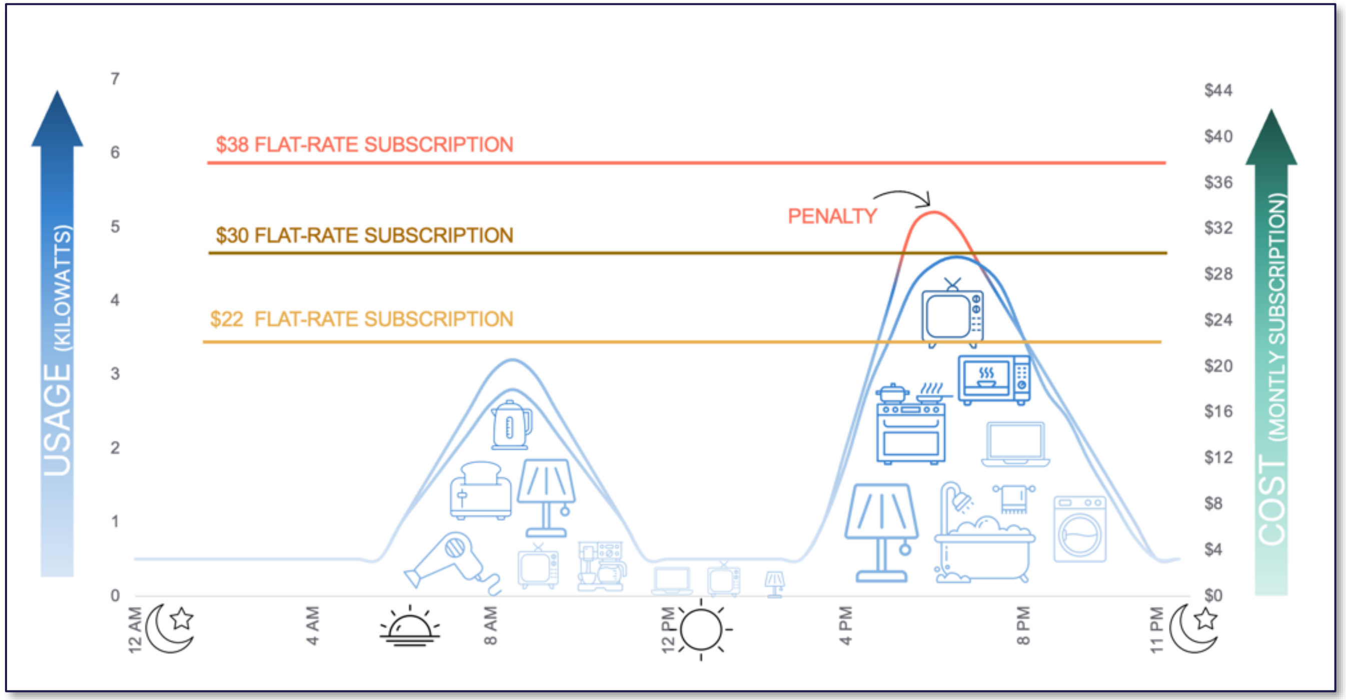
Rate Structure	Pros	Cons
Fixed Monthly Charge	Stable revenue; simple to understand	Does not reflect actual usage or encourage conservation
Flat Energy Rate	Simple and easy to understand	Ignores time and demand variation; poor cost signals
Tiered Rate	Encourages conservation by penalizing high usage	Can be confusing; may unfairly impact some customers
TOU Energy	Encourages shifting usage to off-peak; cost reflective	May confuse some customers; may not be truly cost-reflective
CPP	Strong incentives to reduce load during peaks	Can cause bill volatility; requires event notifications
Peak Time Rebate (PTR)	Non-punitive; rewards load reduction	Less effective if customers don't respond
Real-Time Pricing (RTP)	Reflects actual market costs; promotes efficient use	Complex for customers; requires automation for optimal customer experience
Non-Coincident Peak Demand Charge	Recovers infrastructure costs; encourages demand control	Difficult for residential customers to manage; not truly cost reflective of on-peak usage
Demand Subscription	Promotes predictable demand; supports planning	Penalties may deter customers; complexity in setting limits
TOU Demand Charge	Charges are more aligned with system peaks; fair costs allocation	Some complexity for customers, can cause bill volatility
Coincident Peak Demand Charge	Aligns charges with system peaks; fair cost allocation	Complexity; may require customer education
EV-Specific / Managed Charging Rates	Supports grid-friendly EV charging; incentivizes off-peak use	Limited to EV owners; may require control technology
Grid-Access / Export Tariff (DERs)	Supports DER integration; compensates exports fairly	Complex calculations; potential cross-subsidies
Distribution Locational Marginal Pricing (DLMP)	Provides precise cost signals by location and time	High complexity; requires advanced grid monitoring

Demand Subscription

Stone Olafson

Rate Description: Customers choose a subscription that dictates the maximum demand for electricity they agree to stay below throughout the billing cycle.

If the customer exceeds that maximum demand level, they will move to the next highest subscription level (or the subscription level that includes the demand level reached in the billing cycle). Each progressive subscription level will have a higher $/kW price.



MODERATE SUPPORT

Pros:

Predictable bills, easier for budgeting.

Feeling of control and ability to choose tiers.

Some see fairness in "pay for what you select."

Cons:

Anxiety over being penalized for going over by a small amount; concern about lack of credit for unused "allowance."

No way to monitor usage to see if they are on track to "go over."

Reactionary – even small overage will have significant bill implication.

Complexity if tiers are not transparent or adjustable; monthly resets without annual or seasonal smoothing are viewed as unfair.

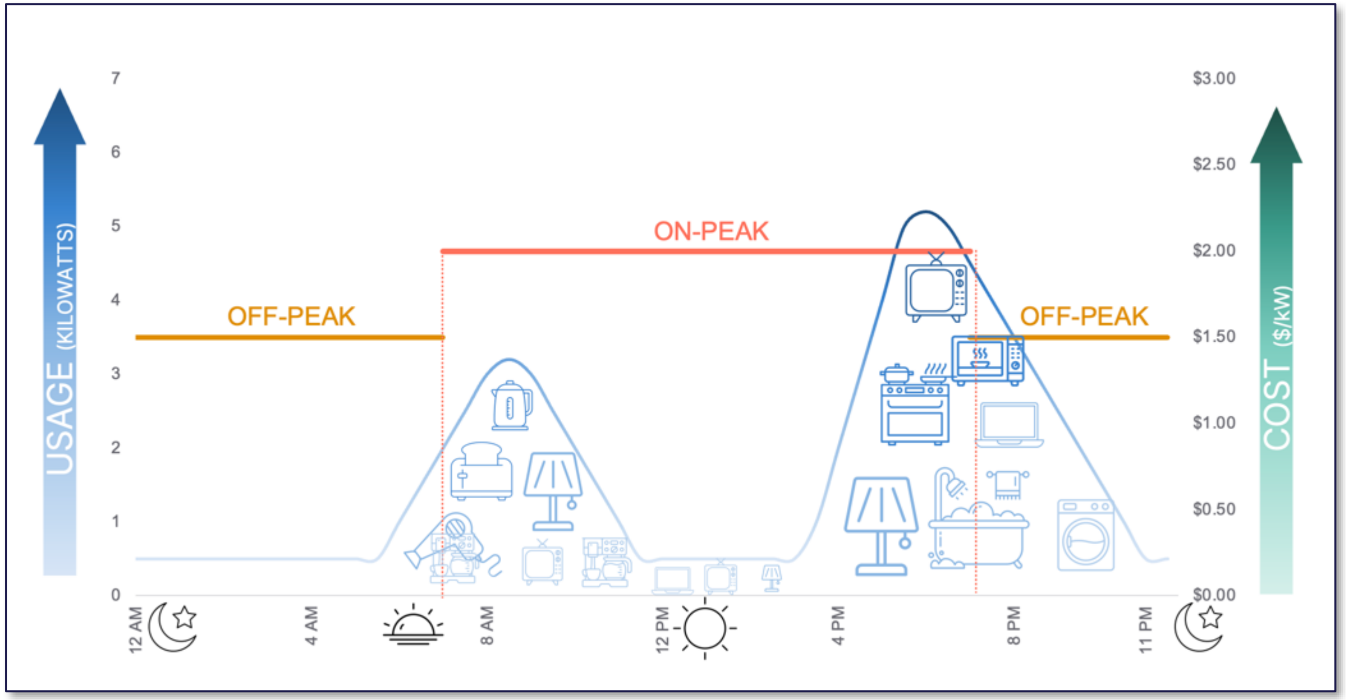
"Sunk cost" fallacy: risk people overuse electricity to 'get their subscription's worth'

Time-of-use Rates

Stone — Olafson

Rate Description: On-peak and off-peak periods are established with different $/kWh prices. On-peak rates are higher. Peak rates may change based on season/ time of year.

Monthly bills are based on the amount of energy consumed in each of the on-peak and off-peak periods during the billing cycle.



MIXED SUPPORT

Pros:

Familiar to those with Ontario experience.

Rewards those who can easily shift loads (retirees, flexible workers).

Perceived as slightly more fair, as it provides visible choices/ clear path to managing cost.

Weekend is off-peak.

Cons:

Penalizes shift workers, large families, and those unable to shift loads (families, people with disabilities/ care workers)

Only works if the difference between on- and off-peak is significant enough; but then can feel punitive

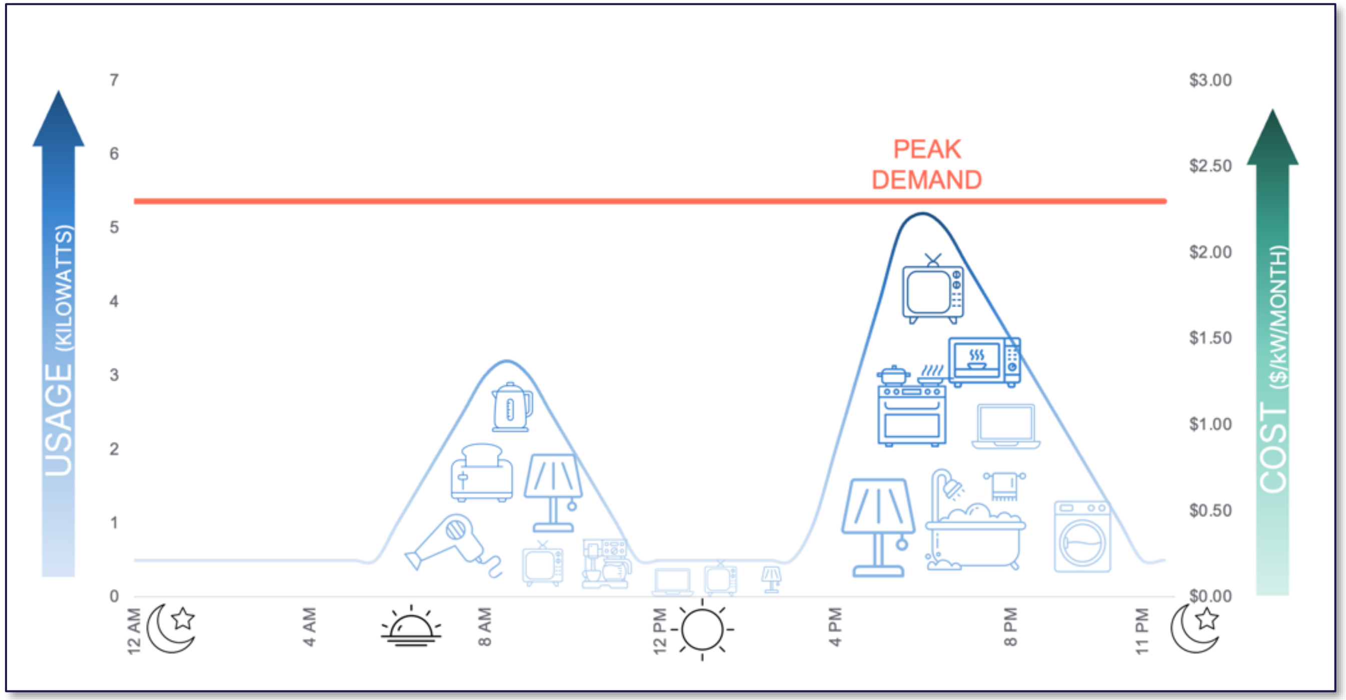
Perceived risk of “herding” of everyone to new peaks.

Peak Demand Charges

Stone Olafson

Rate Description: Fees are imposed by the utility provider based on the highest rate of energy consumption during the billing period. In other words, the cost of delivering electricity for the billing period is set based on the moment of the highest metered demand from the billing period. The cost will change monthly based on the peak demand from the period.

The cost of delivering electricity reflects the capacity needed by the distribution system (or electrical grid) to meet the customer's peak demand.



LEAST POPULAR

Pros:

Incentivizes spreading usage and can help grid stability conceptually.

Cons:

Deeply unpopular; seen as punitive—one spike (e.g., extra AC during a heatwave) can ruin a month's bill.

Perception that they cannot plan/ budget – expect significant fluctuation.

Removes sense of control; penalizes for unavoidable needs.

Not aligned with consumer understanding of fairness. Creates stress and unpredictable bills

Understanding People

It’s what we do.

Stone Olafson