


Pathway for Advanced Rated Structures for Residential and Small Commercial Customers

Prepared for: EPCOR Distribution & Transmission Inc.

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List of Acronyms

ACER	Agency for the Cooperation of Energy Regulators (European Union)
AER	Australian Energy Regulator
AESO	Alberta Electric System Operator
ARS	Advanced Rate Structures
AUC	Alberta Utilities Commission
AMI	Advanced Metering Infrastructure
ADMS	Advanced Distribution Management System
CPP	Critical Peak Pricing
DER	Distributed Energy Resource
DERMS	DER Management Systems
DSM	Demand Side Management
DFO	Distribution Facility Owner
EDTI	EPCOR Distribution & Transmission Inc.
EV	Electric Vehicle
GMP	Green Mountain Power
PV	Photovoltaic
ROLR	Rate of Last Resort
RTP	Real-Time Pricing
TOU	Time-of-Use

EXECUTIVE SUMMARY

As Alberta's electricity system undergoes significant transformation, there is growing interest in modern, cost-reflective pricing approaches that better support grid efficiency, decarbonization, and the integration of emerging technologies. Advanced Rate Structures (ARS)—including demand-based rates and time-of-use (TOU) rates—have been adopted in various jurisdictions to more accurately align customer bills with system costs and incentivize efficient consumption patterns. This report supports EPCOR Distribution & Transmission Inc. (EDTI) in evaluating the potential for implementing ARS for residential and small commercial customers, providing strategic insights to inform a strategic approach tailored to Alberta's unique deregulated electricity market. It also positions ARS within a broader suite of Demand Side Management (DSM) tools that collectively enhance grid optimization and policy outcomes.

Unlike traditional, uniform electricity pricing—such as fixed monthly fees and flat energy or demand charges—ARS can reflect the true cost drivers of electricity delivery by incorporating time- or demand-based elements. Examples include TOU rates, critical peak pricing (CPP), real-time pricing (RTP), and electric vehicle (EV)-specific managed charging. These designs deliver clearer price signals that encourage customers to shift or reduce consumption during peak periods, improving system efficiency, enabling new technologies, and better aligning customer bills with actual grid impacts. Each ARS approach entails trade-offs among fairness, cost reflectivity, customer comprehension, and complexity, necessitating careful design.

Effective ARS design must also recognize customer diversity. Large industrial users generally have the capacity to respond to complex pricing signals, whereas residential and small commercial customers prioritize simplicity, predictability, and affordability. Enabling technologies—such as smart thermostats and controllable EV chargers—can help smaller customers engage with ARS. Utilities and regulators must carefully balance infrastructure investments and customer engagement efforts required for ARS implementation against the anticipated benefits.

To inform EDTI, Power Advisory conducted a jurisdictional scan of emerging electricity distribution rate designs. The review highlights examples from other markets where utilities move away from traditional pricing models toward time-based, capacity-based, and customer-segment-specific rates with the aim of better reflecting system costs, aligning with policy imperatives, and promoting desired customer behaviours—while managing inherent trade-offs related to fairness, simplicity, and predictability. Experiences from North America and Europe illustrate both the opportunities and challenges of ARS, underscoring the importance of enabling infrastructure, robust customer engagement, and alignment with complementary price signals and policies. Overall, lessons from other jurisdictions emphasize that no single ARS design fits all contexts; local system needs, policy objectives, and customer profiles should guide choices.

Successful ARS implementation depends on multiple interrelated factors tailored to a jurisdiction's operational, regulatory, and customer environment. Drawing on international experience and Alberta's evolving market context, seven critical factors have been identified to ensure ARS are practical, effective, and aligned with broader system and policy goals:

1. Alignment with Government Policy: ARS should be clearly aligned with decarbonization, electrification, and grid modernization objectives to provide direction and foster adoption, while misalignment can undermine trust and effectiveness.

2. Regulatory Readiness: Flexible, innovation-friendly regulatory frameworks with well-defined objectives and phased implementation enable utilities to develop and refine advanced rate designs successfully.

3. Utility Capabilities and Enabling Infrastructure: Advanced metering, data management, and system monitoring platforms are essential to accurately measure consumption, bill customers, and tailor rates based on system conditions.

4. Customer Adoption of Technologies: Broad uptake of enabling technologies—such as smart thermostats and EV chargers—increases customers' responsiveness to price signals, enhancing ARS effectiveness.

5. Customer Engagement and Education: Ongoing, targeted education and clear communication foster customer understanding, trust, and willingness to adapt to new rate designs, supported by tools and advisory services that simplify decision-making.

6. Complementary Use of Price Signals and Incentive Programs: Integrating ARS with DSM programs, rebates, and automation reduces customer burden, improves acceptance, and maximizes behavioural and system benefits.

7. Market Dynamics and the Role of Retailers: Collaboration among utilities, retailers, and system operators is vital to harmonize multiple price signals, simplify customer experience, and enable retailers to offer innovative, value-added products supporting ARS objectives.

Overall, ARS present significant opportunities to align electricity costs with usage more accurately, influence customer consumption behaviours to reduce infrastructure costs, and advance policy goals. That said, selecting and designing ARS involves making trade-offs between simplicity, fairness, and responsiveness, and require substantial investments in technology and customer engagement that must be justified by tangible benefits. Recognizing the varying capabilities across customer segments—and supporting smaller customers through enabling technologies and complementary programs—is essential to equitable and effective adoption. Targeted ARS designs can address specific system challenges, such as EV charging and distributed energy resource (DER) integration, enhancing overall efficiency and fairness. For EDTI, advancing ARS implementation should begin with broad, coordinated sector engagement, followed by careful, evidence-driven approaches that may include phased or small-scale implementation with select customer groups—where feasible and aligned with broader objectives—while recognizing that billing system constraints may delay such approaches until future system upgrades. Ongoing collaboration among stakeholders will be crucial to ensuring practical, supported outcomes. Ultimately, ARS are one tool among many, and their success depends on thoughtfully matching design choices to specific system needs, customer profiles, and policy goals.

1. BACKGROUND AND PURPOSE

As Alberta's electricity system evolves, interest is growing in more modern, cost-reflective pricing approaches. Across many jurisdictions, *Advanced Rate Structures* (ARS)—such as demand-based billing and time-of-use (TOU) rates—are being introduced to align customer bills more closely with system costs, reduce peak demand, and support new technologies like distributed energy resources (DERs).

This report supports EPCOR Distribution & Transmission Inc. (EDTI) in evaluating the potential for implementing ARS for residential and small commercial customers. Its purpose is to inform EDTI by providing strategic insights and evidence-based analysis tailored to Alberta's deregulated electricity market, where competitive retailers manage most customer billing relationships.

The report outlines the rationale for ARS, drawing on regulatory filings, literature, and case studies from other jurisdictions. It identifies key success factors—such as policy direction, regulatory readiness, utility capabilities, and customer engagement—and assesses how these apply in the Alberta context.

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

The report includes the following:

- Strategic context for ARS
- A discussion of ARS and their objectives
- A typology of rate designs
- Jurisdictional examples
- Lessons learned and key implementation factors
- Strategic implications for EDTI

These insights aim to support EDTI in navigating rate design discussions and identifying its role in enabling a more modern, efficient, and customer-focused electricity system.

2. STRATEGIC CONTEXT FOR ADVANCED RATE DESIGN

ARS must be considered within a clear strategic context that reflects both local and broader system priorities. In Alberta, the competitive retail market, evolving decarbonization policies, and the roles of distributors, retailers, transmitters, and the Alberta Electricity System Operator (AESO) create a distinctive backdrop for rate design decisions. As a key demand-side management (DSM) tool, ARS can help address emerging challenges—such as peak demand growth, electrification, and DER integration—while supporting affordability, fairness, and system efficiency. Understanding the strategic drivers behind ARS, and how they align with Alberta's regulatory and operational realities, is essential to ensuring rate designs are targeted, effective, and aligned with long-term energy objectives.

2.1 Alberta's Context

When considering ARS in Alberta, it is important to understand the distinct roles that retailers, distributors, and transmitters and the AESO play in rate design and implementation—and how these roles ultimately shape customer bills. Like other deregulated markets, this context adds nuance when considering shifting rate design of one or more elements of a customer bill, particularly when compared to implementing ARS in jurisdictions with vertically integrated utilities.

Alberta's market structure includes regulated Distribution Facility Owners (DFOs) with assigned geographical service territories and competitive retailers who can sell electricity contracts anywhere in the province. Electricity commodity and delivery rates are established as follows:

1. Commodity: Electricity rates are determined by retailers, and customers can choose their preferred retailer and pricing plan. Many retailers correlate their electricity rates with the average pool price. Customers that do not select a competitive retailer are enrolled in the Rate of Last Resort (ROLR).

2. Distribution (delivery): The Alberta Utilities Commission (AUC) has regulatory oversight of both the distribution system costs and the distribution tariff design for each DFO.

3. Transmission (delivery): The AUC has regulatory oversight of transmission facility owner (TFO) costs. Transmission tariffs are developed by the AESO and are subject to AUC approval.

Retailers are responsible for preparing and issuing electricity bills to customers, including the pass-through of distribution and transmission charges (i.e., distribution and transmission tariffs). The sample residential electricity bill below illustrates how total electricity costs are allocated and presented to customers. In this example, energy commodity (retail) charges make up 41% of the bill, while distribution and transmission delivery charges account for 24% and 16%, respectively. Notably, delivery charges appear as a single line item, with no breakdown of the underlying rate design.

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**

While implementing ARS may be feasible in Alberta, the effectiveness of the rate design will largely depend on customer understanding and their willingness to adjust consumption in response to price signals. Since distribution delivery charges typically represent only about a quarter of a residential customer's total electricity bill, changes to distribution rates alone may not generate a strong enough price signal to drive meaningful shifts in energy use. Therefore, any changes to distribution rate design should be guided by clearly defined outcomes and assessed in the context of how they interact with both retail and transmission rates. Misalignment across these components could result in conflicting signals to customers. Given these considerations, it is also important to explore other demand-side solutions—particularly those aimed at influencing customer behaviour and supporting broader system objectives.

2.2 Demand Side Management

DSM refers to a suite of programs and initiatives designed to influence how consumers use electricity, helping to optimize grid operations and reduce the need for additional supply resources. Rather than simply expanding supply to meet peak demand, DSM encourages customers to modify their usage patterns, particularly during periods when the grid is under stress.

DSM programs typically include:

- Demand response programs: Financial incentives are offered to customers who agree to reduce or shift their electricity use during peak periods or grid emergencies, helping to maintain system balance.
- Energy efficiency funding and rebates: Incentives support customers in upgrading homes or buildings with high-efficiency equipment and appliances, lowering overall consumption.
- ARS: Innovative pricing approaches, such as TOU rates or demand-based rates, encourage customers to shift usage to off-peak times with the aim of deferring or avoiding future system expansion costs.

DSM can be thought of as a flexible toolkit — different tools or combinations of tools can be deployed depending on the specific system objectives and customer needs. ARS are an increasingly important component of DSM, as they are designed to influence customer behaviour through price signals.

Rate design plays a central role in how utilities recover costs, how customers interact with the grid, and how broader policy goals — such as decarbonization, electrification, and integration of DERs — are achieved. As the electricity system evolves, ARS will need to continue balancing a diverse set of objectives, navigating trade-offs between cost recovery, fairness, simplicity, and system efficiency.

2.3 Strategic Drivers

The evolution of distribution rate design in Alberta will depend on several factors, including the technical capabilities of utilities, the regulatory framework, policy objectives and incentives, the availability of customer-facing utility programs, customer adoption of new technologies, and levels of customer education and engagement.

Policy, regulatory, and economic drivers are expected to continue placing downward pressure on rates. As a result, optimizing the use of existing distribution infrastructure will become increasingly important. This underscores the growing relevance of DSM tools—such as ARS—that can help manage load more efficiently. At the same time, customer adoption of technologies like EVs and battery storage is accelerating. Many of these technologies have the potential to support the grid, either by reducing demand during peak periods or by shifting consumption to off-peak times.

Avoiding costly capacity investments will depend on the ability to achieve predictable and reliable load reductions—or increases—at specific times and locations. In this context, rate design and targeted customer programs will play a critical role in creating the right incentives and compensation mechanisms for customers to respond to system needs.

Given this complex and evolving landscape, decisions around when and where to implement ARS in Alberta are not straightforward. While this report focuses on ARS, it is essential to recognize that they represent just one option within a broader suite of DSM tools. The choice of which DSM measures to apply—including ARS—should be guided by the specific system challenges being addressed, the characteristics of the customer segments involved, and the trade-offs among simplicity, fairness, efficiency, and cost-effectiveness.

The following section provides an overview of ARS, their key features, and how they can be adapted to meet the changing needs of the electricity system and its customers.

3. OVERVIEW OF ADVANCED RATE STRUCTURES

As metering and other grid technologies — such as smart meters, sensors, load controls, and data analytics — have advanced, utilities have increasingly adopted more innovative rate structures to charge electricity customers (residential, commercial, and industrial) for distribution costs, moving beyond traditional fixed-fee, energy-based, or demand-based rate structures.

This section defines ARS and highlights their key objectives, including improving cost recovery, promoting efficient consumption, supporting reliability, enabling customer choice, and advancing policy goals like electrification and DER integration.

3.1 What are Advance Rate Structures?

ARS represent a shift from traditional, one-size-fits-all electricity pricing toward more tailored designs that reflect the true costs and demands placed on the grid. Common rate structures that have traditionally been used by electricity distributors include:

- Fixed monthly fee (i.e., $/month),
- Flat energy-based rate (i.e., $/kWh), and/or
- Flat demand-based rate ($/kW).[1]

ARS often include time-based or demand-based components to better reflect that distribution utility costs are largely determined by the infrastructure required to serve peak demand. Examples include, TOU energy rates, critical peak pricing (CPP), real-time pricing (RTP), and TOU demand rates. The evolution of rate design has resulted in a spectrum of approaches, ranging from simple, traditional structures to more sophisticated ones that better reflect grid and system needs. Each structure varies in how charges are derived, how it signals usage patterns, and how it incentivizes customer behaviour, with different degrees of complexity and responsiveness to system conditions.

Table 1 summarizes key traditional and ARS designs, highlighting their pricing basis, typical applications, and intended benefits.

Table 1. Traditional and Advanced Rate Structure Designs

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)

[1] Demand-based rates are common for commercial and industrial customers and not commonly applied to residential customers.

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.

Traditional rate structures may offer simplicity and predictability but may not fully reflect the underlying cost drivers of the distribution system, particularly those related to peak demand. In contrast, ARS are designed to send more precise price signals that align customer behaviour with system needs, improve utilization of existing infrastructure, and support emerging priorities such as electrification, integration of DERs, and demand flexibility. The next section explores ARS in greater detail, examining their design features, benefits, and implementation considerations.

3.2 Objectives of Advanced Rate Structures

ARS offer utilities new methods to better align electricity prices with the true costs and value of energy supply, delivery, and consumption. By moving beyond traditional flat energy rates and fixed fees, ARS can improve system efficiency, support the integration of technologies (i.e., DERs, EVs, etc.), and enable customers to manage their energy use more effectively. Successful implementation depends on clear objectives that balance the needs of utilities, customers, and policy goals. Key rate design objectives include:

- Cost Reflectiveness: Prices match the actual cost of energy and grid use.
- Fairness and Equity: Allocate costs fairly based on usage and demand.
- Revenue Stability: Ensure the utility recovers its costs reliably.
- Affordability and Predictability: Keep bills manageable and stable.
- Efficiency and Load Optimization: Encourage energy efficiency as well as shifting or reducing usage during peak times.
- Customer Understanding: Make rates clear and easy to understand.
- Support Electrification: Align rates to promote clean energy technologies.
- Enable DERs: Supports integration of solar, storage, and demand response.
- Operational Feasibility: Be practical and cost-effective to implement.
- Policy Alignment: Support government priorities and energy goals.

These objectives guide the development and evaluation of ARS to ensure they deliver value across the electricity system. However, designing rates that balance all these goals often involves trade-offs. For example, increasing cost reflectiveness can improve efficiency but may reduce bill predictability and customer acceptance. Similarly, promoting demand flexibility can enhance grid reliability but requires more complex technologies and customer engagement efforts. A simplified view of these trade-offs is shown in Table 2.

Implementing more ARS often requires utilities to invest in enabling infrastructure such as smart meters, data systems, and customer engagement tools. As a result, the selection of rate design options—and the level of complexity introduced—should be aligned with the expected benefits in terms of system efficiency, cost recovery, and customer value. Utilities and regulators must carefully assess whether the benefits of a given rate structure justify the associated costs and implementation requirements.

When designing ARS for residential and small commercial customers, several important considerations arise. Unlike large industrial customers — who often have dedicated energy managers and are already familiar with demand-based rate components — smaller customers typically have less visibility into their consumption patterns and more limited ability to actively manage their load. Simplicity and predictability in billing are highly valued, making it important to balance accurate price signals with customer understanding and acceptance. Equity and affordability concerns are also paramount, as some households and businesses may face higher bills if they are unable to change their behaviour in response to time-based or demand-based rates, due to factors like building characteristics, appliance efficiency, or occupancy patterns. Enabling technologies (e.g., smart thermostats, home energy management systems, smart EV chargers, etc.) can help smaller customers respond more effectively, but adoption remains uneven and often depends on income and awareness. Careful communication, education, and complementary programs are essential to ensure ARS are fair, effective, and broadly accepted, including rebates for enabling technologies, opt-out designs, or bill protections.

Table 2. Overview of Pros and Cons of Rate Design Options

Rate Design	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
PTR	Non-punitive; rewards load reduction	Less effective if customers don't respond
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
TOU Demand Charge	Charges are more aligned with system peaks; fair costs allocation	Some complexity for customers, can cause bill volatility
Demand Subscription	Promotes predictable demand; supports planning	Penalties may deter customers; complexity in setting limits
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
DLMP	Provides precise cost signals by location and time	High complexity; requires advanced grid monitoring

While the above shows a high-level view of the trade-offs, it is useful to look at how other jurisdictions are navigating these decisions. Some ARS have been widely implemented, while others are still novel, with limited deployment or pilot experience. The case studies examples discussed in the next section provide insights into how utilities and regulators are balancing complexity, cost, and customer impact. Importantly, some rate structures are better suited to commodity pricing, while others are more appropriate for recovering transmission and distribution costs, depending on the specific goals of the rate design.

4. JURISDICTIONAL REVIEW OF ADVANCE RATE STRUCTURES

To inform EDTI, Power Advisory conducted a jurisdictional scan examining advanced distribution and transmission rate designs implemented or under consideration in other markets. The findings from this review provide insights into the range of design options available, the practical challenges of implementation, and emerging best practices. These insights will inform EDTI's consideration of rate design alternatives, ensuring they are evaluated in the context of Alberta's regulatory, system, and customer environment. The following literature review summarizes key findings from this jurisdictional scan to help guide EDTI's approach to cost-reflective, equitable, and forward-looking rate design.

A summary of rate structures reviewed is provided in Appendix B.

4.1 Rationale for Advanced Rate Structure Designs

The energy transition, including policy mandates to decarbonize through electrification and increasing amounts of DERs, has resulted in an increasing interest in the design of electricity rates. The energy transition is expected to result in a significant increase in electricity consumption and demand, requiring a significant expansion of supply resources and grid expansion and reinforcement investments to meet that demand. Many jurisdictions at a national and sub-national level have policy mandates to reduce emissions and/or achieve a net zero economy, which involves significant increases in electricity generation and grid infrastructure.

As discussed earlier, a foundational objective of ARS, as well as rate design more generally, is to design prices that reflect underlying system costs, recover system costs, and provide a signal to customers to use (or not use) electricity. For example, with regards to electricity generation, having energy prices ($/kWh) reflect the cost of power, which varies over time according to the supply mix and demand-supply balances. With respect to distribution network costs, which are traditionally considered predominantly representing fixed costs (i.e., the costs do not vary based on energy consumption), demand-based ($/kW) charges are used to reflect the need to build the network to meet maximum peak system demand.

On rate design more generally, commentators have argued that "predominant volumetric electricity rates with a constant price per kWh for withdrawals provide insufficient incentives to reduce energy consumption during hours of scarce supply and grid congestion while cross-subsidizing distributed generation."[2]

As a result, current rate structures are being re-examined with a focus on designing rates that better influence consumer behaviour (e.g., incentives to reduce peak and/or shift-use to off-peak periods, adopt DERs, fuel-switch to lower carbon transportation and heating equipment, etc.) such that network

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[2] David Ribo-Perez, Christine Gschwendtner, Christian Winzer, Sigurd Bjarghov, Tim Schittekatte, Selin Yilmaz, "Future electricity tariffs: designing electricity rates fit for the energy transition," *Energy Policy*, Volume 202, 2025: https://www.sciencedirect.com/science/article/abs/pii/S030142152500103X

infrastructure expansion costs can be deferred and/or reduced.[3] For example, much attention is being paid towards designing energy and network charges to facilitate the efficient integration of EVs.[4] For example, Green Mountain Power (GMP) in Vermont offers innovative EV-specific rates designed to encourage electric vehicle adoption and optimize charging behaviour. Customers purchasing EVs can claim a free Level 2 charger incentive, which requires them to enroll in one of two EV rates. The first option is a TOU energy rate with an off-peak period between 9 PM and 9 AM on weekdays, incentivizing customers to charge during low-demand hours. The second option is a managed charging rate, where GMP is allowed to curtail charging up to five times per month to reduce peak demand. GMP reported that 80% of customers purchasing EVs claimed the free charger incentive and enrolled in one of these EV rates, demonstrating the effectiveness of pairing financial incentives with targeted rate designs to promote EV adoption and reduce strain on the grid.

4.2 Review of Distribution Rate Structures

ARS for energy consumption have received much attention and study (i.e., retail energy TOU/RTP/CPP options), the application of more varied and dynamic rates for distribution rates, especially low volume customers, has received less attention until recently. Further, while demand-based distribution and/or transmission charges have historically been associated with larger electricity customers, there has been increasing attention to applying such charges to low volume customers.[5]

Further, the European Union Agency for the Cooperation of Energy Regulators (ACER) in its most recent report on network tariffs observed a "gradual shift towards more power-based [i.e., demand-based] charges."[6] In most instances, residential customers are exposed to contracted (or subscription-based) demand charges rather than measured demand. In fact, for some European countries subscription-based rates for residential customers, have been in place for decades. However, some countries, such as Norway, have only recently started to mandate utilities to make use of demand-based charges for low volume users, giving utilities flexibility in whether to charge households on a subscription or measured-demand basis.

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[3] Matthias Hofmann, Sigurd Bjarghov, Hanne Sæle, Karen Byskov Lindberg, "Grid tariff design and peak demand shaving: A comparative tariff analysis with simulated demand response," *Energy Policy*, Volume 198, 2025: https://www.sciencedirect.com/science/article/pii/S0301421524004956

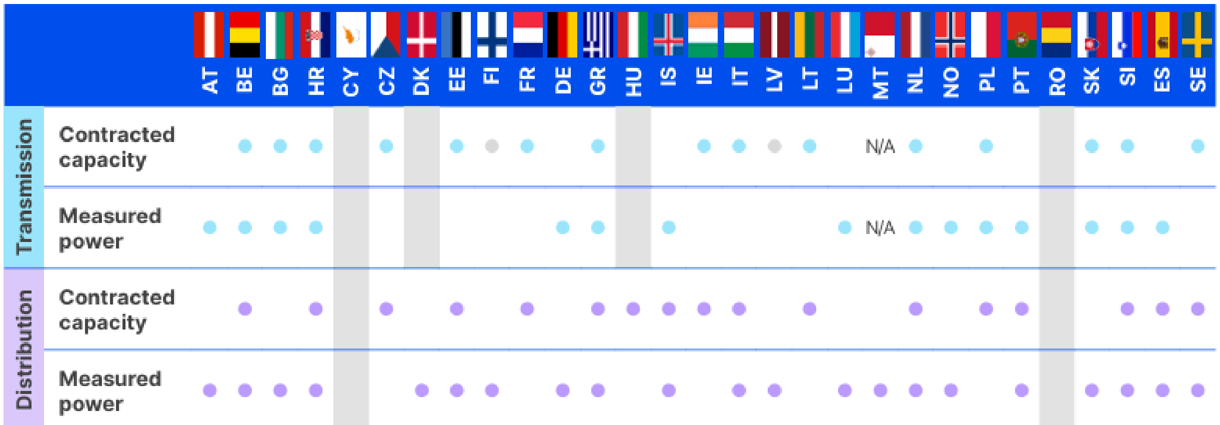
[4] Turk Graham, Tim Schittekatte, Pablo Dueñas Martínez, Paul L. Joskow, and Richard Schmalensee (2024), "Designing Distribution Network Tariffs Under Increased Residential End-user Electrification: Can the US Learn Something from Europe?" MIT CEEPR Working Paper 2024-02, January 2024: https://ceepr.mit.edu/workingpaper/designing-distribution-network-tariffs-under-increased-residential-end-user-electrification-can-the-us-learn-something-from-europe/

[5] Note, demand-based charges are also referred to as capacity-based charges or power-based charges in other jurisdictions.

[6] European Union Agency for the Cooperation of Energy Regulators, Getting the signals right: Electricity network tariff methodologies in Europe: ACER report on network tariff practices, March 27, 2025, p. 17: https://www.acer.europa.eu/sites/default/files/documents/Reports/2025-ACER-Electricity-Network-Tariff-Practices.pdf; for details see ACER (2025) pp. 29-25.

In addition to demand-based distribution pricing, some European jurisdictions have TOU pricing for distribution (and transmission) tariffs on energy ($/kWh) basis and/or a demand ($/kW) basis.[7] These TOU charges typically incorporate one or more features, such as on- and off-peak periods, seasonal variations, and designating weekends/holidays as off-peak.

Figure 2. Demand-Based Transmission and Distribution Charges in Europe



Note: In Belgium's Brussels region a lump sum charge applies which is based on an installed capacity threshold of ≤13kVA. The 'grey-marked dot' means that the country applies installed (connected) capacity-based charges. No capacity/power-based charges apply in four countries (CY, DK, HU, RO) at the transmission level and in two countries (CY, RO) at the distribution level. Malta has no transmission network.

Source: ACER (2025), p. 34.

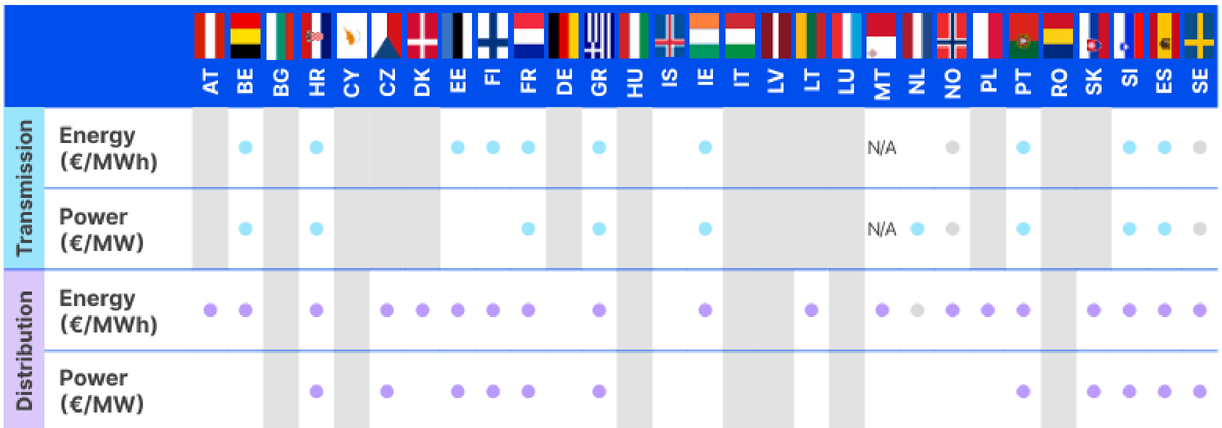
Table 3. Types of demand-based distribution charges

Types of Demand-Based Distribution Charges: Measured Demand
Customer's annual peak (i.e., Non-Coincident Peak)
Customer's monthly peak or average of multiple individual peaks during month (i.e., Non-Coincident Peak)
Customer's peak during system peak hours (i.e., Coincident Peak)
Energy consumption during peak hours converted into demand (i.e., Coincident Peak)

Source: Adopted from ACER (2025).

[7] See ACER (2025), pp. 82-87.

Figure 3. Time-of-Use Transmission and Distribution Charges in Europe



Source: ACER (2025), p. 85.

While ARS for energy consumption have been widely implemented, more innovative approaches to distribution charges — especially for low-volume customers — have only recently gained attention. European jurisdictions offer useful examples, from long-standing subscription-based demand-based rates to newer measured-demand pricing and TOU features layered on both energy and demand components. These developments illustrate how distribution pricing is evolving to better reflect costs and customer behaviour. The next section examines pilot projects in North America that are exploring different rate design options holistically, considering both policy objectives and customer adoption and implementation challenges.

4.3 Innovative Rate Design Pilot Programs in North America

Across North America, utilities and regulators are piloting ARS to better align customer behaviour with system needs, improve grid efficiency, and support decarbonization. These pilots reflect a growing recognition that traditional, static rates are poorly suited to managing the increasingly dynamic and distributed electricity grid.

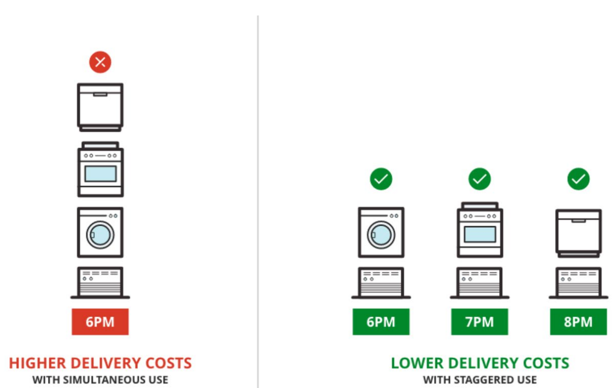


Figure 4. ConEd's depiction of their Smart Energy Plan

One notable example is Consolidated Edison’s (ConEd) Innovative Pricing Pilot in New York. This pilot features seven time-variant, demand-based rates, offered under the Smart Energy Plan and Fixed Delivery

Billing Plan. These innovative designs include options such as time-variant demand delivery rates, TOU supply pricing, demand subscription delivery rates, and a hybrid delivery rate combining volumetric and time-variant demand components. The goal is to encourage customers to space out the use of electric devices, shift consumption to off-peak hours, and align their energy use with grid needs — thereby reducing peak demand and improving overall system efficiency. ConEd describes the pilot as akin to "a cell phone data plan personalized based on the average amount of data a customer used over the past year," offering customers tailored, predictable plans that fit their unique energy needs while providing flexibility and supporting grid reliability and decarbonization goals.[8]

Another example is from the California Public Utilities Commission's CalFUSE Framework (California Flexible Unified Signal for Energy) represents another ambitious approach. CalFUSE provides a policy roadmap and retail rate strategy designed to address grid challenges and optimize the integration and operation of DERs. The framework proposes dynamic retail prices based on real-time locational marginal prices demand charges that reflect real-time utilization of local distribution infrastructure. Additional features include bi-directional prices for both importing and exporting energy, subscription-based options that offer customers predictable bills based on historical usage patterns, and transactive elements that enable energy trading at predetermined prices. Together, these elements aim to send more granular and locationally accurate price signals to customers, fostering efficient and flexible participation in grid operations while supporting the state's clean energy objectives.[9]

These pilots demonstrate the potential for innovative rate designs to improve customer engagement, enhance grid performance, and accelerate the energy transition. As results from these pilots become available, they will offer valuable lessons for regulators and utilities across jurisdictions looking to modernize electricity pricing structures.

4.4 Lessons Learned and Best Practices

The decision-making process for rate design is not simply choosing a mix of energy-based, demand-based, and fixed charges that recover and reflect costs. Research and commentary on advanced distribution rate design (and ARS design more broadly) is that setting rates to address multiple objectives, such as fairness, efficiency, cost reflectivity, acceptability, predictability as well as revenue sufficiency and stability is a complex task, involving making trade-offs between objectives rather than achieving all objectives. As one study notes: "It is quite common to see policymakers bundle together a wide range of appealing features

[8] See ConEd's website for information about their rate pilots: https://www.coned.com/en/accounts-billing/smart-energy-plan

[9] See CPUC Staff white paper on Advanced Demand Flexibility Management. https://www.cpuc.ca.gov/-/media/cpuc-website/divisions/energy-division/documents/demand-response/demand-response-workshops/advanced-der---demand-flexibility-management/ed-white-paper---advanced-strategies-for-demand-flexibility-management.pdf

that range from "efficiency" and "cost-reflectivity" to "predictability" and "simplicity," a checklist that is virtually impossible to fully satisfy."[10]

Many challenges have been identified in recent studies that reduces the effectiveness of measure demand-based rates. For example, recent analysis of Norway, where the regulator has mandated the phasing-in of demand-based rates (with discretion left to utilities on the specific tariff) 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 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."[11]

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.[12] 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 am to 7pm. 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.[13]

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 4pm to 9pm 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

[10] 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

[11] 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/

[12] 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

[13] Gohary et al. (2023).

> customers and retailers, *we consider the potential impact on small customers of default 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*."[14] (emphasis added)

These examples and others illustrate clearly that rate design is easier in theory than in practice. Further, the challenges of implementing ARS will be driven not only by the general technical challenges of rate design, but utility and/or jurisdictional context, such as grid conditions (e.g., amount of congestion, penetration of DERs, and/or demand-supply balance), whether the ARS are opt-in or opt-out, and even general economic conditions.

A consistent issue raised in the literature is potential for ARS to create new peaks rather than reducing peak demand (i.e., peak shifting rather than peak-reduction). For example, this challenge has been identified when a customer's individual peak demand is the basis for the demand-charge rather than maximum system demand, such 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."[15] (emphasis in original)

Other literature notes that setting rates is becoming a more complex exercise as the energy transition continues to change how energy is produced and consumed. For example, one study examined distribution rate design notes that system conditions (the degree to which grid investments need to be made versus are already sunk), the degree and type of DER penetration (i.e., solar photovoltaic (PV) vs. battery storage), mix and portion of consumers with DERs, locational circumstances, retail energy pricing, and public policy all play a role in rate design, including ensuring efficiency, cost reflectivity and fairness: "More granular network tariffs could become increasingly important to limit the efficiency-loss. Overall, the interaction between network tariff design, retail energy pricing, public policies (e.g. energy efficiency and DER subsidies) and taxation deserves further analysis.[16]

Similarly, some research suggests that ARS should be paired with a variety of other programs and measures (including non-price-based options), such as energy efficiency measures that reduce demand on an enduring basis, information, as well as expanding automated load controls which "can significantly reduce the effort required to respond to more complex and dynamic grid tariffs, thereby increasing daily

[14] 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

[15] Gohary et al. (2023).

[16] Tim Schittekatte, Leonardo and Meeus,, "Least-cost distribution network tariff design in theory and practice," The Energy Journal, 41(5), 2020: https://journals.sagepub.com/doi/10.5547/01956574.41.5.tsch

demand flexibility."[17] Similarly, other research suggest that non-price-based measures and more precisely and sparingly targeted system peak pricing mechanisms (e.g., CPP) need to be considered because "peaks are not solely caused by the generic consumption patterns and rhythms of users, which take place on a day-to-day basis. Instead, they are mainly driven by temperature and weather conditions."[18]

4.5 Rate Design in Restructured Markets

In many jurisdictions, electricity markets have been restructured and rates unbundled into individual components: generation/commodity, transmission, distribution, and others (e.g., taxes and regulatory charges). The implication is that while customers likely receive a single bill, the bill contains separate line items that are managed and set independently from one another, yet customers are expected to modify their behaviour in response to these multiple price signals at the same time.[19] These different rates may not necessarily be aligned; it is likely that they are not in many cases.

For example, a recent study highlighting this issue noted in the case of a consumer being on a real-time retail electricity rate and having a demand-based distribution rate notes that:

> "Selecting ideal response behaviours that are optimized for both tariffs requires keeping track of two moving targets – the hourly spot price and hourly consumption – both of which change daily. A user needs to check the hourly spot price, anticipate their load profile and somehow find an optimal between these two variables. They then need to repeat this exercise every single day, rendering the task of responding to price signals into an endeavour that is complex and cumbersome."[20]

Perhaps more importantly, such misalignment between rates is likely to frustrate customers and "risks inducing a backlash that could erode users' trust in utilities and system operators [and regulators]."[21] In other cases, rate misalignment can result in additional system costs. For example, research indicates that misalignment between wholesale energy prices and distribution network charges could result in EV charging causing an increase in local system peaks and needed distribution grid upgrades.[22]

Ontario is an example of a jurisdiction with a restructured market that has implemented TOU rates for the electricity commodity portion of the bill for residential and small business customers; this was introduced

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[17] Matthias Hofmann, Sigurd Bjarghov, Hanne Sæle, Karen Byskov Lindberg, "Grid tariff design and peak demand shaving: A comparative tariff analysis with simulated demand response," *Energy Policy*, Volume 198, 2025: https://www.sciencedirect.com/science/article/pii/S0301421524004956

[18] Gohary et al. (2023).

[19] Britt Stikvoort, Fouad El Gohary, Anders Nilsson, Cajsa Bartusch, "Serving two masters – How dual price signals can undermine demand flexibility," *Energy Policy*, Volume 185, 2024.

[20] Stikvoort et al. (2024).

[21] Stikvoort et al. (2024).

[22] Graham et al. (2024)

by legislation concurrent with the deployment of advanced metering infrastructure (AMI) in the 2010s. TOU rates were mandatory for over ten years before prolonged customer dissatisfaction led the government to allow customers to choose between TOU and tiered pricing. Under a separate policy initiative, distribution charges for residential-class customers are fully fixed.[23] Importantly, Ontario's restructured electricity market means TOU rates applies only to the electricity commodity portion of the bill, while delivery charges — which combine distribution and transmission costs on a single line item — remain largely fixed for distribution and volumetric for transmission. As a result, customers' actual monthly "delivery" charge still varies from month to month, since transmission charges are determined volumetrically.

4.6 Overall Findings from the Jurisdictional Scan

The evidence to date does not indicate a clearly preferred ARS option. One conclusion is that the traditional reliance on fixed monthly charges and static, energy-based charges for recovering distribution system costs is being increasingly re-examined as the energy transition advances and customer production and consumption behaviours become more complex.

As a result, more factors will determine the best rate option for a given jurisdiction and even within a given utility's service territory. This indicates that even under an advanced distribution rate regime that a combination of fixed, energy-based, and demand-based charges will be used. Further, rates will need to be complemented with other measures, such as automated load control.

Table 4 summarizes the main findings from other jurisdictions. Ultimately, the mix, specific form, and how charges are applied to different aspects of electricity costs and across different users requires careful consideration, taking into account not only the needs of the distributor and other line items, such as retail energy pricing, but also other public policy goals and programs to ensure alignment (i.e., ensure initiatives do not work at cross-purposes) and achieve the collective desired outcomes of customers, utilities, regulators, and government.

Table 4. Key findings from Jurisdictional Scan

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.

[23] 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

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.
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,	Plan is intended to incentivize customers to lower their demand during on-peak hours. Pilot program – customers can opt in. May require a meter

		November-April: weekdays 5-9am and 5-9pm).	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, October-April)	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.

The jurisdictional review demonstrates that advanced rate designs can offer significant benefits, but their success hinges on thoughtful, context-specific implementation. Experience from other markets underscores the need to align designs with policy objectives, customer preferences, and utility capabilities. The next section examines the key factors that support effective and practical implementation.

5. FACTORS FOR SUCCESSFUL IMPLEMENTATION OF ADVANCED RATE DESIGN

While experience in other jurisdictions with ARS offers valuable lessons, the successful implementation of such approaches is dependent on local context. Factors such as regulatory frameworks, customer characteristics, technology adoption, and utility readiness vary significantly across jurisdictions. For EDTI, any exploration of ARS must be grounded in the unique features of the Alberta electricity market, including its competitive retail structure, unbundled billing framework, and evolving policy and regulatory environment in addition to the utility's technical capabilities, including planning, operating, and billing.

The following section identifies key factors that influence the successful implementation of ARS. These factors are considered in relation to EDTI's specific operational, regulatory, and customer context to ensure any proposed rate changes are practical, effective, and aligned with broader system and policy objectives.

5.1 Alignment with Government Policy

A strong alignment between ARS and overarching government policies—particularly those related to decarbonization, electrification, and grid modernization—is a critical enabler of successful implementation. Jurisdictions that have effectively introduced new rate structures often did so in the context of clear policy direction, either through legislation or explicit mandates.

One of the key lessons from other jurisdictions is that clear policy mandates can accelerate adoption of ARS. For example, Norway and Sweden have both introduced demand-based distribution charges for residential customers as part of broader national decarbonization and electrification goals. In these cases, regulatory requirements provided a clear signal to utilities and the public, removing ambiguity. Similarly, the European Union, through the Agency for the ACER, has encouraged member states to adopt network tariffs that better reflect actual usage patterns and grid needs, aligning tariff reform with the European Union's energy and climate goals.

Misalignment between rate structures and government policy can undermine trust and effectiveness. As highlighted in the literature, when rate designs are poorly coordinated across electricity bill components or misaligned with customer expectations and public objectives, they may confuse customers or even be perceived as punitive. This is especially true in restructured markets where multiple price signals (e.g., real-time commodity pricing and demand-based network charges) may not be aligned. Such misalignment risks customer backlash and may erode trust in utilities, regulators, and the broader energy system.

Based on public information from 2023, Alberta's decarbonization policies include the aspiration to achieve a carbon neutral economy by 2050 with near term targets of 30% renewable energy by 2030.[24,25] At the same time, the Alberta government has publicly rejected the federal government's 2035 net-zero electricity target and made significant revisions to renewable development regulations, resulting in the

[24] See Renewable Electricity Act (2020) https://open.alberta.ca/publications/r16p5.

[25] See Emissions Reduction and Energy Development Plan (2023) https://www.alberta.ca/emissions-reduction-and-energy-development-plan.

cancellation of many large scale wind and solar projects in the province, slowing the transition towards emission reduction from the grid supply. There are currently no energy efficiency or electrification strategies included in government policy, although the government has included measures to support consumers to generate their own electricity and manage energy demand in their Emissions Reduction and Energy Development Plan from April 2023.

From a municipal government perspective, the City of Edmonton has a target to become a carbon-neutral community by 2050, along with a 2030 target to reduce energy consumption by 35% per person (compared to 2005 levels). They have been delivering on various initiatives to support energy savings such as deep energy retrofits, building energy benchmarking, district energy systems, and EV charging infrastructure.

There is little misalignment between provincial and municipal governments when looking at targets. However, when looking at near term priorities and creating clear pathways for investment decisions, there is more clear action at the municipal level that would begin to set the political direction for more complex rates.

5.2 Regulatory Readiness

Across jurisdictions, the literature consistently shows that where regulators provide clear guidance, demonstrate openness to innovation, and enable flexibility in rate design, utilities are better positioned to implement and iterate on more sophisticated rate designs. Conversely, where regulatory frameworks are outdated, overly prescriptive, or risk-averse, rate design innovation can stall—even when utilities are technically and operationally prepared to proceed.

Jurisdictions with successful implementation often benefit from well-articulated regulatory objectives—such as promoting cost reflectivity, fairness, system efficiency, and enabling decarbonization—which serve as a foundation for evaluating rate proposals. For example, European regulators have increasingly encouraged tariff reforms that shift from energy-based charges to demand-based models, often explicitly referencing system cost drivers and policy goals as justifications.

The literature also highlights the importance of regulatory discretion and staged implementation, particularly when introducing unfamiliar rate structures. In Norway and Sweden, regulators mandated the adoption of demand-based charges for residential customers but allowed utilities some latitude in how they designed and phased in the new tariffs (e.g., measured vs. subscription-based). This flexibility has helped utilities tailor solutions to local grid needs and customer profiles while meeting overarching regulatory requirements.

However, the experience in these jurisdictions also underscores a common challenge: mandates alone are not enough. Studies from Norway indicate that the early implementation of new tariffs has had limited impact on household behaviour, due in part to weak price signals, customer confusion, and the absence of enabling technologies.. These findings suggest that regulatory approval should not only enable ARS designs but also include expectations or guidance on complementary measures (e.g., customer education and communication, automation technologies, or DER integration).

Ultimately this speaks to the need for a thoughtful integration of various DSM strategies, not just rate design. In reference to trade-offs, it is important that regulators provide guidance in terms of goals or outcomes that DSM or rate design programs should achieve – even better if there is a prioritization framework– this would create the clarity utilities need to put in the effort to design and apply for DSM programs such as ARS design. In Alberta, utilities have had no clear direction to invest in DSM from the regulator and have been denied DSM program funding on multiple accounts.

5.3 Utility Capabilities and Enabling Infrastructure

While policy direction and regulatory support are critical, the practical delivery of more complex and dynamic pricing models depends on a utility's ability to monitor and measure customer demand and energy consumption. The literature clearly points to the importance of having foundational systems and technologies in place to support these functions.

AMI is the most frequently cited enabling technology. AMI allow for granular measurement of consumption and demand, which is a prerequisite for the accurate billing of TOU or demand-based rates. Without interval data, utilities cannot reasonably track the timing or magnitude of individual customers' peak usage, nor can they implement rate designs that encourage peak shifting or reduction.

The near real-time data collection of new AMI (often called AMI 2.0) enables utilities to monitor consumption patterns and power quality more accurately and opens the door to more complex rate designs based on discrete real-time conditions. Some meters include real-time load disaggregation and data processing tools, such as the Sense module option in Revelo meters. The Sense module and customer-facing app provides benefits for utilities and customers through detail energy usage details for specific devices or device types. When considering the future of ARS design, this feature could play an important role in dynamic and targeted rates to specific customers based on the technologies in their homes and their discrete usage habits. Beyond rate design, the Sense app enables customers to access information beyond real-time power usage in their home or business by including details on electricity usage for discrete devices, and the scalability to included advanced demand response or rewards programs for specific customer behaviours.

Beyond metering, data management systems and analytics capabilities are essential to interpret usage patterns, determine customer billing determinants, and assess the impacts of new rate structures. Utilities must invest in platforms that can not only manage large volumes of data but also extract insights to inform rate design, system planning, and customer engagement strategies.

The utility's ability to model and monitor system conditions—including local congestion, DER penetration, and the timing of peak demand— also ensures rate structures align with underlying cost drivers. For example, if distribution investment needs are concentrated in certain substations or feeders, location-specific pricing or targeted load management initiatives may offer more precise tools for cost mitigation than broad-based pricing changes. This level of precision requires enhanced system visibility and situational awareness, underscoring the need for advanced distribution management systems (ADMS) and DER management systems (DERMS).

EDTI has made foundational investments in the systems needed to eventually deliver on more complex rate design including AMI 1.0, ADMS, DERMS, and EDTI's Data Insights Portal. Many of these systems are scalable, meaning that functionality can be added over time, to utilize increased amounts of available data. However, EDTI's current AMI systems (typically described as AMI 1.0) are expected to require significant modifications and investment to be capable of demand based and TOU billing, as well as potential approvals from Measurement Canada. Implementing complex rate designs beyond these two advanced measurement and billing structures may be technically feasible based on metering and communications infrastructure but may be cost prohibitive and face other limitations such as bandwidth requirements, data granularity and processing, and customer awareness and engagement. This is highly dependent on the detailed data needs, which is a combination of which measurements are collected, in what interval, and how often data is communicated to the head-end system.

5.4 Customer Adoption of Technologies

As DER and EV penetration increases, traditional rate designs may become less effective in aligning customer behaviour with system requirements. Without appropriate pricing mechanisms, there is a risk that increased adoption could contribute to peak demand growth, underutilization of assets, and cross-subsidization among customer classes. ARS—such as time-varying rates, demand-based charges, or dynamic pricing—can help mitigate these risks by providing clearer economic signals to customers regarding the timing and magnitude of their electricity consumption.

Experience in other jurisdictions supports this conclusion. For example, in Vermont, GMP's EV charging program combines off-peak pricing with automated load control, resulting in high program participation rates and measurable system benefits. This illustrates how targeted rate designs, when paired with enabling technologies, can support customer electrification.

Customer response to price signals, however, depends not only on the rate structure itself but also on the availability and adoption of enabling technologies. Smart thermostats, programmable water heaters, and home energy management systems allow customers to automate their usage in response to price signals, thereby supporting their ability to respond effectively to time-varying or demand-based rates. Without such tools, customers may face barriers in adjusting their consumption in ways that align with system needs.

Evidence from other jurisdictions indicates that where enabling technologies are not widely adopted, the responsiveness of customers to ARS designs is limited. For example, studies in Nordic countries found that demand-based charges did not lead to significant changes in consumption behaviour unless accompanied by automation or stronger price differentials. Overall, this demonstrates the importance of aligning rate reform with strategies that promote the adoption of enabling technologies.

While overall adoption rates are important indicators, it is equally crucial to understand the specific locations and technical characteristics of these emerging technologies. For example, research shows both EVs and solar PV have higher adoption rates in affluent communities[26,27] and that further clustering can occur on specific streets or neighbourhoods as customers purchasing choices are influenced by those of

[26] See for example, Davis, L. W. (2019). Evidence of a homeowner-renter gap for electric vehicles. Applied Economics Letters. Vol 26, No 11, 927-932. Available online: https://faculty.haas.berkeley.edu/ldavis/Davis%20AEL%202019%20Gap.pdf

[27] See for example, Forester, et al. (2023) Residential Solar-Adopter Income and Demographic Trends: 2023 Update. Berkley Lab. Available online: https://emp.lbl.gov/publications/residential-solar-adopter-income-2

their neighbours[28,29]. ENMAX completed an early study prior to the Distribution System Inquiry to understand the impacts of EVs on residential transformers in Calgary and found that less than 3 EVs on a single residential transformer could cause overload conditions. Further, EDTI completed a study in 2021 to extrapolate the potential system impacts of unmitigated EV adoption and charging, noting significant system investments would be needed without the integration of controlled EV charging. ARS designs, along with controlled EV charging (which has been successfully piloted by FORTIS) may prove to be a successful combination in Alberta to manage peak growth demands cause by the growing adoption of EVs. Given the current capabilities of EDTI's systems, this combined approach appears to be feasible and could be included in small-scale deployments for EV owners within its service territory in future years (near term).

Solar PV can either function as a grid support mechanism by absorbing load or providing power quality support,[30] or a strain to the grid by high volumes of reverse power flow when load is low and production is high. This dynamic capability lends itself well to dynamic (yet complex) rate design or customer programs where utilities can utilize the characteristics of real-time solar production to enhance the functionality of the distribution system.[31]

5.5 Customer Engagement and Education

Proactive engagement and education are necessary to ensure that customers understand the rationale for rate design changes, the opportunities available to them, and how to respond to price signals effectively. A key objective of customer engagement is to build trust and increase awareness of how new rates will impact electricity bills and usage patterns. Research from jurisdictions that have implemented time-varying or demand-based rates indicates that customers are more likely to accept and respond to new pricing structures when they are supported by timely, transparent, and easily accessible information.

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[28] See for example, Graziano, Marcello & Gillingham, Kenneth. (2014). Spatial patterns of solar photovoltaic system adoption: The influence of neighbors and the built environment. Journal of Economic Geography. https://www.researchgate.net/publication/266624878_Spatial_patterns_of_solar_photovoltaic_system_adoption_The_influence_of_neighbors_and_the_built_environment.

[29] See for example, Zukowski, D. (2022). EV adoption is higher where consumers see more electric vehicles, studies show. Smart Cities Dive. Available online: https://www.smartcitiesdive.com/news/electric-vehicle-EV-influencer-buy/626795/#:~:text=The%20NCST%20report%20assessed%20the,public's%20adoption%20of%20electric%20vehicles.

[30] As of 2023, all new solar PV micro-inverters in Alberta must comply with the IEEE 1547 standard, as specified in EDTI's interconnection requirements. This standard defines grid-supportive functionalities that an inverter must provide, including voltage regulation (e.g., volt–VAR control), frequency response (e.g., fast frequency response), active power curtailment, ride-through capabilities (remaining connected during brief voltage or frequency disturbances), and the ability to receive grid-support commands from the utility.

[31] For example, on a feeder with high air conditioning load peaking in summer, solar PV generation can coincide with peak load, reducing strain on the grid. ARS designs could help monetize such valuable peak reductions. Similarly, smart inverters with pre-programmed reactive power (Volt/VAR) control to sustain voltage at their point of connection provide additional grid support that could also be recognized through advanced rate design.

Moreover, communications should be tailored to account for differences in customer needs, energy literacy, and access to enabling technologies.

Customer education is particularly important when the effectiveness of a rate design depends on behavioural response. For example, TOU or CPP schemes rely on customers being able to understand and act upon the price differentials. Enabling technologies, such as smart thermostats or EV chargers with load-shifting capabilities, can support this objective, but their value is only realized if customers are aware of how to use them in conjunction with new rate structures.

A robust customer engagement strategy should also include:

- Clear communication of benefits and protections: Customers need to understand how new rate designs align with broader policy goals (e.g., affordability, sustainability, system efficiency) and how any transitional impacts will be mitigated.
- Ongoing education and support: Education should not be viewed as a one-time activity. As technology adoption and rate structures evolve, continuous updates, training, and customer service support is required.
- Customer care and advisory support: This includes providing access to trained representatives who can explain rate plan options, interpret usage data, and offer recommendations tailored to a customer's consumption profile, household characteristics, or technology adoption.
- Tools to support rate plan selection: To empower informed decision-making, utilities should offer tools such as online rate comparison calculators, personalized bill impact projections, and user-friendly interfaces that help customers understand which rate plan best meets their needs. These tools should be accessible, mobile-friendly, and designed to serve customers with varying levels of digital literacy.

Given the deregulated nature of Alberta's market, where customers have choice of retailers and not their distributors, customer engagement is expected to be of utmost importance, particularly when compared to fully integrated utility jurisdictions such as neighbouring British Columbia. Customer understanding of electricity distribution rates in Alberta is already limited—even before introducing the added complexity ARS. Line items currently include distribution charge, transmission charge, balancing pool allocation, rate riders, administration fees and of course the energy charge at their chosen retail rate. With all these components, it is difficult for a customer to understand how their behaviours would impact each line item, and most importantly, the total bill.

To further exacerbate this issue in Alberta, until recently, many Albertans where either not aware that they had their choice of retailer or simply were indifferent and decided not to choose. These customers were automatically enrolled in the previous default rate which is now the ROLR. Alberta's transition to ROLR included a provincial government funded campaign educating customers on their retail choices, and funding customer care supports to assist them in transferring from ROLR to a retail contract of their choice. This is important context in Alberta as it showcases the early stages of customer education when it comes to electricity rates and customer choice. It is also an example of provincially funded electricity programs that are beneficial for all Albertans, instead of leaving it up to competitive retailers or regulated distributors that must recover those costs from their customers.

Beyond customer bills, it is important to note that many jurisdictions utilize customer apps to educate their customers on how rate design changes, combined with customer choices lead to bill savings.

When it comes to providing customers with information about electricity usage and costs to shift consumer behaviour, bills are typically the least effective. Customers are looking for a minimum of real-time information on their electricity usage (through apps or in-home energy monitors), but further value is unlocked once predictive analytics is integrated where specific recommendations are tailored to the customers' usage and in-home/building devices. This is where there is an emerging role for AI to play in customer education and engagement as technology advances and becomes more widely integrated into utility or retailer services.

5.6 Complementary Use of Price Signals and Incentive Programs

Evidence from multiple jurisdictions suggests that price signals alone are often insufficient to achieve widespread behavioural change or technology adoption. This limitation arises due to several factors, including customer awareness and understanding of complex rate structures, variability in customer ability to respond to dynamic prices, and the relative strength of price signals compared to other economic incentives customers face.

To bridge this gap, many utilities, such as GMP in Vermont, have adopted complementary DSM programs alongside new ARS. These programs typically provide direct financial incentives, rebates, or non-price interventions aimed at encouraging customers to adopt enabling technologies—such as smart thermostats, EV chargers, energy storage, and demand response automation—that enhance their ability to respond to price signals.

Beyond technology incentives, complementary DSM programs also include customer education, energy efficiency initiatives, and automated load control systems. These measures reduce the effort required by customers to engage with complex and dynamic tariffs, increase overall demand flexibility, and mitigate the risk of unintended consequences such as new peak formation due to load shifting. Further, integrating DSM incentive programs with rate design can improve customer acceptance.

Incentive programs have been assessed in various DFO service territories in Alberta particularly for shifting residential EV charging load through customer choice or utility control. Additional DSM programs have yet to be assessed or implemented in Alberta, despite the efforts of DFOs. In the 2023 Rebasing Proceeding, ATCO Electric and FortisAlberta all applied for funding for DSM programs, and all were denied except the EV charging pilot for FortisAlberta.

Leveraging DSM programs alongside rate design is possible in Alberta once there is clarity of a regulatory process for utilities to do so and/or there is a monetary benefit for retailers to offer these programs to customers. In addition, regulations currently restrict DFOs and retailers from partnering on customer programs. This lack of coordination is likely to result in a slower adoption of DSM or incentive programs in Alberta than seen in fully integrated jurisdictions. Removing this barrier in Alberta would presumably not only impact the pace and scale of consumer adoption, but also customer experience and engagement. If retailers could lead customer programs that were coordinated with value-add service to distributors, customers could sign up for a program with their retailer, keeping the point of contact consistent and streamlined, rather than connecting directly with their distributor to sign-up for distributor led DSM programs.

5.7 Market Dynamics and the Role of Retailers

While utility rate structures provide price signals to guide customer behaviour, the broader market environment and retailer offerings can significantly influence how these signals translate into meaningful consumer actions. In many restructured electricity markets, the unbundling of electricity services has created competitive retail markets where customers can choose among multiple electricity suppliers, each offering differentiated products and services. Retailers serve as intermediaries who can bundle price signals with other products, flexible contracts, and services.

Jurisdictional experience highlights that retailers can amplify the impact of ARS designs. For example, retailers may offer bundled packages that combine dynamic pricing with home energy management tools, or demand response enrolment incentives that complement utility demand charges.

However, the literature and case studies reveal several market challenges that affect this complementary relationship. The coexistence of multiple price signals—wholesale energy prices, distribution tariffs, transmission tariffs, and retail contract prices—can create complexity and potential misalignment. Customers may find it difficult to understand and respond to these signals if they are not coordinated across market layers.

To address these challenges, some jurisdictions have explored regulatory frameworks and market designs that promote alignment between wholesale market signals, retail pricing, and distribution rate structures. For instance, enabling two-way price signals that reflect both energy consumption and export (from DERs). Market mechanisms that facilitate automated demand response allow retailers and customers to respond in near real-time, enhancing system flexibility and reducing peak demand stress.

Moreover, the jurisdictional scan underscores the importance of clear roles and responsibilities among utilities, retailers, and system operators to ensure seamless customer experience and effective signal delivery. Collaborative efforts are essential to provide transparency, customer education, and access to enabling technologies.

There is a meaningful opportunity to develop value-added customer programs through retailers that support grid reliability, reduce customer bills, and enhance long-term affordability—but realizing this potential will require collaboration between competitive and regulated entities around shared objectives.Enabling this type of coordination or collaboration in Alberta would require explicit clarity from the AUC, most likely initiated by policy change or provincial government direction.

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

6. CONCLUSION

ARS offer a means to strengthen cost causation, influence customer electricity consumption in ways that reduce infrastructure costs and support broader policy goals. However, ARS also introduce trade-offs that must be carefully weighed—such as simplicity and accuracy, fairness and efficiency, and predictability and responsiveness. Each rate design option carries distinct benefits and drawbacks, and there is no single solution that meets all objectives equally well.

Consideration of ARS should start with a focus on the broader Alberta context, ensuring engagement across the electricity sector—including other DFOs, retailers, the AESO, and the AUC—to build alignment and coordination. Decisions about when and where ARS are appropriate are not black and white. ARS are one of many DSM tools available to utilities and policymakers, and their suitability depends on the specific problem being addressed, the customer segment targeted, and the broader system context. Careful analysis is needed to define the objectives—whether reducing peak demand, integrating DERs, supporting electrification, or improving cost recovery—and to evaluate whether ARS are the most effective and equitable means of achieving them. By starting with a clear understanding of the problem to solve, and aligning rate design with policy goals, customer capabilities, and system capabilities and needs, utilities can ensure ARS are deployed where they deliver the most value.

Deploying ARS requires enabling infrastructure to be in place — such as advanced metering, communications and billing systems, along with data analytics platforms, and customer-facing engagement tools. These utility systems require significant capital investment and come with operational implications, the costs of which are unlikely to be justified by ARS alone. Once these systems are in place, the data collected can provide helpful insights into segmented customer electricity usage patterns and assessing discrete local system issues, enabling the utility to analyse where and how ARS may be a useful too.

When it comes to implementation, the selection of rate design options and the level of complexity introduced should be aligned with the expected benefits, considering system efficiency gains, customer value, and the utility's capacity to implement and sustain the changes. Utilities and regulators must evaluate whether the costs of a given rate structure are justified by its ability to deliver measurable benefits, both to the grid as a whole and to individual customers.

The design of ARS must also recognize differences between customer segments. Large industrial customers are generally more capable of responding to complex price signals, often employing dedicated energy managers and already accustomed to demand-based charges. By contrast, residential and small commercial customers typically have less visibility into their consumption patterns, less control over their load, and higher sensitivity to bill volatility and complexity.

To support smaller customers in adapting to ARS, enabling technologies (e.g., smart thermostats, energy management systems, and controllable EV chargers) and complementary programs (e.g., education campaigns, rebates, opt-out designs, or bill protections) can play an essential role. Utilities and regulators should ensure ARS designs for this segment are accompanied by robust customer engagement and support to foster understanding, trust, and equitable outcomes.

Building on this, targeted ARS can also be designed to address specific system challenges or policy priorities within particular customer segments. For example, EV-specific rates, especially when coupled with managed charging programs, can encourage off-peak charging and mitigate distribution system impacts from clustered EV adoption. Similarly, rates that reward customers with distributed solar and storage for providing grid-supportive services (e.g., voltage regulation or peak shaving) can help integrate DERs more effectively. These targeted approaches not only align customer behaviour with system needs but also enhance the value of enabling technologies already adopted by customers. Thoughtfully segmenting customers and offering optionality through differentiated rate designs allows utilities to address distinct needs and capabilities while promoting overall system efficiency and fairness.

In addition, throughout the ARS design and implementation process, meaningful stakeholder engagement, customer education, and regulatory collaboration will be essential to ensuring ARS designs are practical, effective, and broadly supported. The targeted approach, mentioned above, may offer a small-scale starting point for utilities introducing ARS to specific customer segments, reducing the complexity of these factors. It is important to note, however, that reducing complexity of stakeholder engagement, customer education, and regulatory collaboration does not mean reducing the technical complexities or the system needs for the utility when it comes to implementing ARS. The same fundamental utility system capabilities must be in place to implement ARS.

In conclusion, there are many complex factors that must be considered when determining if, when, and how ARS would be the most useful DSM tool to meet various objectives, often with necessary trade-offs. Implementation of ARS should be guided by clearly defined policy objectives, utility goals and infrastructure capabilities, robust data and cost-benefit analysis, and an understanding of how unique customer behaviour can support system constraints.

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: RATE STRUCTURES REVIEWED

Jurisdiction	Rate Structure	Eligibility	Description	Comments
Spain[32]	Contracted demand	Customers with demand <15 kW; mandatory participation	Two-period €/kW demand charge for distribution component charge Peak period: weekdays from 8:00 am to midnight Demand is contracted in increments of 0.1 kW and contract can be adjusted annually	Exceeding demand generally trips breaker in meter, leading to outage. Rates and design parameters set out in legislation
France *(EDF)*[33]	Contracted demand	Customers with demand <36 kVA; mandatory participation	Flat monthly demand charge that increases in 3 kVA increments. Customers with contracted demand of 9+ kVA must pay TOU energy prices	Longstanding rate structure. Exceeding demand generally trips breaker in meter, leading to outage
Norway *(Elvia)*[34]	Measured demand	Residential customers; mandatory participation	Ten-tier kronor/kW distribution charge (tier determined monthly based on average of the three highest	Demand charges are mandatory in Norway as of early 2020s; distributor has flexibility in rate design and

[32] Comisión Nacional de los Mercados y la Competencia, *Resolución de 4 de diciembre de 2024, de la Comisión Nacional de los Mercados y la Competencia, por la que se establecen los valores de los peajes de acceso a las redes de transporte y distribución de electricidad de aplicación a partir del 1 de enero de 2025*, https://www.boe.es/diario_boe/txt.php?id=BOE-A-2024-26218, December 2024

[33] EDF, *Grille de prix de l'offre de fourniture d'électricité « Tarif Bleu »*. https://particulier.edf.fr/content/dam/2-Actifs/Documents/Offres/Grille_prix_Tarif_Bleu.pdf, February 2025

[34] Elvia, *Standard nettleietariff for forbrukerkunder*, https://www.elvia.no/siteassets/dokumenter/priser/2025/1-april-2025/tariffblad_1_0_standard_tariff_privat_20250401.pdf April 2025

			demand periods in the month) combined with two-season, two-period kronor/kWh distribution charge. Peak period: 6:00 am to 10:00 pm; Seasons: January-March (lower-priced); April-December (higher-priced)	can bill based on measured or contracted demand. Norway has large number of distributors; rate described at left is for Elvia (serving Oslo and surrounding counties)
Sweden *(Ellevio)*[35]	Combination of contracted demand and measured demand	Residential customers living in detached homes/with direct connection to the distribution network; mandatory participation	Flat monthly demand charge based on maximum breaker size (4 increments), plus a kronor/kW demand charge. Measured demand charge is determined based on average of the three highest-demand hours in the month. For peak demand billing calculation purposes, demand incurred between 10pm and 6am is recorded at 50%	Swedish distributors must introduce demand-based distribution charges by 2027, and some have already begun instituting them. Subscription level can be adjusted annually. Residents of multi-unit buildings pay only the monthly subscription fee (only a single tier is offered) and are billed on measured demand.
Arizona *(Salt River Project)*[36]	Measured demand – bundled rate (i.e., not solely	Residential customers, excluding sub-	Bundled rate charged on a three-period TOU	SRP currently offers a different residential

[35] Ellevio, *Elnätspriser* https://www.ellevio.se/globalassets/content/priserabonnemang-pdf/2025/privat/sakr-250101.pdf January 2025

[36] Salt River Project Agricultural Improvement and Power District, *Standard Electric Price Plans* https://www.srpnet.com/assets/srpnet/pdf/price-plans/2024/2025-Ratebook.pdf, effective November 2025

	distribution charges)	metered customers	demand basis, in addition to a fixed monthly service charge. On-peak hours: weekdays from 5:00 pm – 10:00 pm Super off-peak hours: 8:00 am – 3:00 pm Off-peak hours: all other hours (e.g., overnight, late afternoon, etc.) Billing demand is average of the daily maximum thirty-minute demand that occurs during on-peak period of billing cycle	demand rate with a bundled three-tier demand charge, with billing demand based on peak demand during seasonally varying peak periods (2-8pm in summer, 5-9am and 5-9pm in winter). This rate is being phased out as of 2027 in favour of the one described at left.
New South Wales *(Essential Energy)*[37]	TOU distribution charge based on volumetric energy consumption; measured demand as an optional adder	Residential and small business customers; demand billing not mandatory	Default is three-period $/kWh TOU distribution charge. Customers may opt in to a $/kW + three-period $/kWh TOU distribution charge (calculated on maximum demand in one half hour period within the month; for the residential tariff, this half hour period must be	Australian distributors must offer TOU and/or demand-based distribution rates to residential and small business customers. TOU rates are generally the default rate option, with either a pure demand charge or a demand + TOU distribution charge offered on an opt-in basis

[37] Essential Energy, *Network Use of System Charges* https://www.essentialenergy.com.au/-/media/Project/EssentialEnergy/Website/Files/About-Us/2024-29-Revised-Indicative-NUOS-Price-Schedule.pdf

		within 5pm – 8pm on weekdays) Customers may opt out to a flat $/kWh distribution charge

