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Too Smart to Ignore:

How flexible demand can help build a cleaner, more cost-effective electricity system

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Rapid change in electricity supply and demand is putting pressure on Canada's aging electricity grids. Those pressures can create costs for utilities, governments, and ratepayers. Yet increasing the flexibility of electricity systems can significantly reduce those costs, helping to protect the affordability and reliability of electricity in Canada.

On the demand side, growing reliance on electricity for heating and transportation—uses that vary during the day and throughout the year—risks driving more intense and frequent periods of peak demand. This, in turn, can increase system costs and strain grid capacity.

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On the supply side, utilities are integrating more low-cost renewable generation such as wind and solar. But the types of generation that utilities use to meet peak demand are typically the most expensive resources, like gas-fired peaker plants or hydro imports. Abrupt and significant changes in peak demand can thus have an outsized impact on system costs, which over time can put upward pressure on electricity rates. Higher electricity rates can worsen energy affordability. It also hampers the speed of the energy transition. Using more clean electricity is at the heart of decarbonization, and that switch can happen faster when electricity is more cost- effective than fossil fuels.

System planners can respond to higher peaks by adding generation capacity, for example by building new gas plants. Costs are then recouped through customer rates. However, adding new generation capacity takes time and money. Depending on the supply it can also put upward pressure on emissions. Some new investment in electricity supply is unavoidable to meet anticipated growth in electricity demand. But attention to the demand-side of the electricity system—including efforts to use less electricity at peak times—could help meet electricity needs more cost-effectively, with shorter lead times to implementation.

New tools to make demand more flexible can help. Demand-side management, such as energy conservation programming, has long been deployed to reduce system-wide costs by making electricity use more efficient. But new technologies—such as smart meters, electric vehicles (EVs), and household batteries—widen the realm of what demand-side solutions are possible, including more flexibility for the timing of consumer demand, even for small electricity consumers like households and small businesses.

Less "peaky" demand patterns, with a smaller difference between average electricity demand and the height of demand peaks, is more affordable to operate. By shifting demand to off-peak periods and reducing peak loads, demand-side management (DSM) that focuses on flexible demand can help balance supply and demand more efficiently, reducing or delaying the need for costly infrastructure investments and improving overall grid reliability. Flexible demand can help right-size the additional expansion needs of the system by optimizing the use of the existing system. However, despite proven benefits, flexible demand tools remain underused throughout the country.

This scoping paper explores the challenges facing the electricity system, the drivers behind the growing potential for flexible demand, and the benefits of complementing supply-side with demand-side approaches, in particular: demand flexibility from small electricity consumers, such as households and small businesses. It then identifies barriers to greater adoption of flexible demand and makes the case for various policy changes that could yield a more cost-effective, reliable, and smarter electricity system.

A changing grid creates new opportunities for demand-side solutions

Reducing costs by managing electricity demand is a long-standing, well established idea. Demand-side management encompasses a range of solutions, including traditional energy efficiency measures—such as building insulation, and high-efficiency lighting and appliances—that reduce overall electricity use at all times, including at peak times. But with new technologies, such as smart meters and household energy storage, new opportunities for DSM are emerging that can make demand patterns more flexible, reducing overall system costs.

Electricity systems are changing in ways that make demand-side solutions particularly valuable: growing electricity demand, higher demand peaks, and increasing complexity in managing supply and demand. Taken together, these trends threaten to raise electricity costs. This section explores these trends and highlights the growing opportunity for demand-side solutions like flexible demand to support a more affordable, reliable, and resilient grid.

Demand for power is growing rapidly

The clean energy transition in Canada will come with massive growth in electricity demand. The Canadian Climate Institute projects that Canadian electricity demand will grow 1.6 to 2.1 times higher by 2050 on a net zero pathway, requiring generation capacity to grow by 2.2 to 3.4 times (Dion et al. 2022). This aligns with projections from Electricity Canada, which estimates that annual Canadian electricity demand could more than double, from approximately 600 terawatt hours (TWh) per year to over 1200 TWh per year (Electricity Canada 2025a). Globally, electricity demand is also expected to rise steadily, growing 2.4 to 3.5 per cent annually through 2050 (IEA 2024).

Already, provincial electricity planners across Canada are adjusting up their load forecasts. Earlier in 2025, the Ontario Independent Electricity System Operator (IESO) revised its demand forecast upward by 15 per cent from the prior year’s estimate. The province now projects total electricity demand to rise from 151 TWh to 262 TWh by 2050, a 75 per cent overall increase (IESO 2025a). Hydro-Québec expects a 25 TWh increase (~13 per cent) in electricity demand and a 4,000 MW (~9 per cent) increase in capacity by 2032 (Hydro-Québec 2022). Manitoba Hydro expects that electricity demand in Manitoba could more than double in the next 20 years (Manitoba Hydro 2025). Many other provinces, including Newfoundland and Labrador and New Brunswick, are also planning for significant load growth in the coming decades, particularly under scenarios involving industrial expansion, electrification of buildings and transportation, new large sources of demand such as data centres, and increasing clean energy exports.

Provinces and territories are wrestling with how to cost-effectively address higher system peaks

Peak demand refers to the highest level of electricity consumption reached in a given period, typically daily, seasonally, or annually. Growing peak demand isn't necessarily problematic as long as the electricity system has enough capacity to meet it. However, issues arise when peak demand grows faster than average demand. In a relatively peaky system—one with a low average-to-peak demand ratio—a larger share of infrastructure is more frequently idle but must still be procured and maintained. This drives up system costs, which are then recovered over fewer kilowatt-hours of delivered electricity, ultimately increasing rates for consumers. Where fossil fuel plants are dispatched to meet peaks, this also leads to higher emissions intensity during those periods.

Managing peak demand has always been a fundamental challenge for electricity systems, and utilities have long built infrastructure to ensure they can meet the highest points of electricity use, even if those peaks occur only a few hours per year. However, as electrification of building heat accelerates and more frequent heat waves drive peakier periods of cooling demand, weather-driven demand swings intensify. Many jurisdictions are already seeing sharper peak increases relative to average demand, raising new concerns around system efficiency, affordability, and emissions.

How electricity demand fluctuates over time differs across Canada's provinces and territories. Some electricity systems, such as Alberta's grid, have flatter load profiles due to the dominance of large, steady industrial customer demand and limited use of electricity for building heat. Other systems are already relatively peaky, such as those with strong seasonal variations in heating and cooling demand. Quebec, for example, has long experienced sharp winter peaks due to cool winters and widespread use of electric baseboard heating. While the province is investing in energy efficiency measures, its available hydro surplus is shrinking as demand continues to grow, and the system is still expected to face growing strain on winter capacity.

Many provinces across the country are already anticipating substantial increases not just in overall electricity demand but, also, in peak demand. A few examples:

- In **Ontario's** 2025 Annual Planning Outlook, peak demand is projected to grow almost 60 per cent in 24 years, from ~23 GW in 2026 to ~37 GW in 2050. That's also an upward adjustment from 2024's outlook: the most recent demand projections are 3 GW (~ 6 per cent) higher in 2050 compared to the previous year's forecast. Currently, Ontario experiences its highest demand peaks in the summer, when demand for air conditioning spikes. By 2030, the IESO expects significant peaks in both summer (driven by demand for cooling) and winter (driven by demand for heating) (IESO 2025a).

> Strategies that can reduce, shift, or flatten peak demand will be increasingly important to maintain system reliability and affordability as Canada's electricity systems evolve.

- In **Alberta**, the Alberta Electricity System Operator (AESO) projected in its 2024 Long-Term Outlook that peak demand could grow 31 per cent over the next 20 years and as high as 63 per cent over that time period in a high electrification scenario (AESO 2024).
- Similarly, **Nova Scotia's** 2024 system outlook report, published in 2024 expects a rise in net system peak of 362 MW (from 2365 to 2727 MW) over the next 10 years, a 15 per cent increase (Nova Scotia Power 2024). If Nova Scotia built a new power plant to this growth in demand, it would be the second largest generating asset in the province.
- In **Yukon** Energy's 2023/24 general rate application filing, the territory noted that peak electricity demand increased 23 per cent between 2017 and 2022, and expects an additional 36 per cent increase in non-industrial peak by 2030 (Yukon Energy Corporation 2023).

Given these trends, cost-effectively managing growing peaks without overbuilding capacity remains a central concern for system planners. Strategies that can reduce, shift, or flatten peak demand will be increasingly important to maintain system reliability and affordability as Canada's electricity systems evolve.

Meanwhile, growing system complexity creates reliability and resilience challenges

While the electricity system is growing in size, it is also becoming more complex for system operators to manage. A significant share of recent supply additions have come from low-cost but variable sources like wind and solar (IEA 2024, DiGangi 2025). At the same time, the integration of emerging technologies, such as grid-scale energy storage, and the rapid growth of distributed energy resources (DERs), such as rooftop solar and household batteries, are reshaping how and where electricity is produced, delivered, and used.

In its latest reliability assessment, the North American Reliability Corporation (NERC) warned that most of the North American power system will face mounting challenges over the next decade due to surging demand growth and impending generation retirements (NERC 2024). These factors will lead to heightened blackout risks, increased reliance on expensive peaker plants, and rising transmission congestion.

The impacts of climate change also add risk and cost. In Canada, the costs associated with repairing electricity infrastructure from more frequent and severe storms are growing (Ness 2023). White navigating these changes, utilities, system operators, and regulators must maintain reliability, keep energy costs fair and reasonable for ratepayers, and reduce emissions.

Demand-side management, including tools to access flexible demand, can help address resource adequacy and affordability concerns

Traditionally, system planners have ensured grid reliability by pairing firm capacity, including baseload resources like nuclear and hydro, with flexible resources to manage changes in generation and shifts in demand. Dispatchable generation such as natural gas plants and flexible hydro can be called upon to meet peak demand, with a specific class of power plants called "peakers" denoted to illustrate their role in serving peak load.

To ensure enough supply, electricity planners rely on reserve margins, a reliability metric indicating the amount of excess capacity available above forecasted peak demand. For example, Saskatchewan maintains a reserve margin level of 15 per cent while Manitoba holds one at 12 per cent. In some provinces, booming load growth and upcoming power plant retirements and downtime for refurbishments, means utilities must procure new resources to maintain these standards.

For example, in its most recent long-term reliability assessment, NERC projects that the anticipated reserve margin level in Saskatchewan will remain stable around ~26 per cent out to 2035, indicating that no resource adequacy issues are anticipated in that period. However, it projects that Manitoba's anticipated reserve margin will fall from roughly 21 per cent to 4 per cent in the same time frame, indicating that additional measures will be required to reliably meet peak demand (NERC 2024).

Instead of dealing with growing demand peaks by focusing solely on supply expansion to meet resource adequacy needs, demand-side solutions can help by lowering projected peaks.

DSM is a broad energy management strategy that includes energy efficiency and other ways to reduce system demand instead of only relying on additional supply to meet consumer needs. A key subset of DSM is flexible demand-side resources, which are tools to adjust electricity consumption patterns to align with real-time grid needs. It also includes demand response programs, which enable consumers to adjust their energy consumption in response to information about grid conditions, price signals, or incentives.

Demand response programs for industrial ratepayers have been in place for decades, allowing large energy consumers to curtail or shift electricity use during peak periods in exchange for lower electricity costs. However, smarter grids, alongside emerging energy technologies, such as electric vehicles, heat pumps, and smart thermostats, are expanding the potential for demand flexibility from smaller electricity consumers. These new solutions allow consumers, both residential and commercial, to modify their energy use automatically in response to price changes or other signals. With new technology, substantial expansion of demand flexibility is possible, and the potential cost savings are significant.

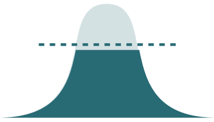
2 What are the potential benefits of more flexible demand?

As electricity demand grows, flexible demand can help manage peaks across multiple scales, from bulk system capacity to localized distribution constraints. This section focuses on how flexibility strategies can enable cleaner, more efficient grid operations, and reduce or delay the need for infrastructure upgrades. Drawing on Canadian and international examples, it underscores the significant economic and reliability benefits of scaling up demand flexibility, particularly through emerging technologies like smart EV charging and virtual power plants.

Flexible demand can make electricity demand less peaky

Flexible demand can lower peaks by curtailing electricity use at peak times (peak shaving) or by shifting electricity use to off-peak times (load shifting).

Peak shaving



The goal of peak shaving is to reduce electricity consumption during high-demand periods. Utility-controlled devices, like smart thermostats and heat-pump water heaters, can be programmed to use less electricity during peak periods. Customers benefit from lower energy costs and may also receive incentive payments for their participation. For example, Yukon Energy provides households with financial incentives to participate in a smart thermostat demand response program that allows the utility to temporarily reduce electricity use for heating in periods of peak demand (Yukon Energy Corporation 2025).

Load shifting

The goal of load shifting is to move electricity use from peak periods to times of lower demand. For example, smart EV chargers can adjust charging times based on grid conditions, reducing strain during peak periods while still ensuring vehicles are charged when needed. Time-varied pricing can also help encourage consumers to charge vehicles or use appliances at off-peak times.

> As electricity demand continues to rise and place pressure on the existing infrastructure, demand flexibility can be deployed more rapidly than new generation and transmission.

As electricity demand continues to rise and place pressure on the existing infrastructure, demand flexibility can be deployed more rapidly than new generation and transmission, providing immediate relief while buying time for the construction of additional supply capacity.

Traditional DSM measures like energy efficiency have long contributed to peak demand reduction by lowering overall consumption. These remain important, and can be implemented in tandem with distributed flexible demand, including technologies that can shift or curtail usage in response to grid conditions.

Studies suggest that flexible demand could greatly lower electricity system costs

Globally, there is increasing evidence of large-scale benefits derived from ramping up the magnitude of flexible load. In Australia, modelling commissioned by the Australia Renewable Energy Agency (ARENA) estimated the net benefit of increased demand flexibility to be $8 billion to $18 billion, and this benefit increases as the share of renewable energy grows (Briggs et al. 2024). In the United States, a report from the Brattle Group estimated that New York state's 2040 grid flexibility potential is more than six times the state's current capability, equating to roughly 25 per cent of the 2040 net system peak demand. Achieving this level of grid flexibility by 2040 could avoid nearly $3 billion per year in power system costs, much of which could be used to compensate participants, with a portion retained as cost savings for all ratepayers (Hledik et al. 2025). Similarly, a Brattle Group Demand Response Potential study for Colorado found 537 MW of cost-effective winter demand response potential in 2030, roughly double the existing capability in 2022 when the report was published (Hledik et al. 2022).

An important use case of flexible demand is in the building sector, where an increasing share of at-home charging and electrified heating and cooling may create strain on the local and bulk power grid. The Rocky Mountain Institute (RMI) has estimated that in the residential sector alone, widespread implementation of demand flexibility can save 10 to 15 per cent of potential grid costs, and customers can cut their electric bills 10 to 40 per cent (Dyson et al. 2015). RMI estimates that residential demand flexibility can avoid $9 billion per year of forecast U.S. grid investment costs, more than 10 per cent of total national forecast needs, and avoid another $4 billion per year in annual energy production and ancillary service costs. Analysis of two appliances, air conditioning and domestic water heating, shows that ~8 per cent of U.S. peak demand could be reduced while maintaining comfort and service quality (Dyson et al. 2015).

Among the various flexibility solutions, virtual power plants (VPP) have emerged as a tool for peak demand reduction and cost savings. A VPP is a term for an aggregation of flexible loads and distributed energy resources (DERs) that can act as a co-ordinated unit as if they were a single, larger power plant (VP3 2023). By orchestrating many small, distributed assets to respond in real-time, VPPs can deliver grid services traditionally provided by centralized generation without requiring new physical infrastructure.

American studies have shown that deploying 80 to 160 GW of VPPs by 2030 (enough to serve 10 to 20 per cent of peak load in the United States) could support rapid load growth while reducing overall grid costs (DOE 2025). By 2030, VPPs could reduce peak demand in the United States by 60 GW, and potentially more than 200 GW by 2050. Moreover, a recent RMI study found that VPPs can help reduce annual power sector expenditure by $17 billion in 2030 and offset or provide 14 per cent of U.S. peak electric power demand in 2050 (Brehm et al. 2023).

Furthermore, a Brattle Group report prepared for Google found that a 60 GW VPP deployment could meet future resource adequacy needs at a net cost that is $15 to $35 billion lower than the cost of the alternative options over the next decade (Hledik et al. 2023). In California, more than 7,500 MW of VPP capacity could be deployed cost-effectively by 2035, higher than both the capacity of the largest power plant in California, and the total system peak demand of Los Angeles. This could create consumer savings of ~$550M per year by 2035 (Hledik et al. 2024).

A rapid deployment of these resources is expected to take place in the United States. Currently, the United States Department of Energy has a high-end DER deployment target of 160 GW, and a recent Wood Mackenzie report projects that the U.S. will add 217 GW of DER capacity through 2028, vastly exceeding the target (Martucci 2024). Flexible resources are projected to make up approximately 50 per cent of this capacity, with distributed solar and energy storage making up the remainder (Martucci 2024).

While less research specific to flexible demand has been published in Canada, existing studies highlight strong potential

Canadian provinces are beginning to pay attention to the potential benefits that demand-side interventions can provide to the system. A few examples:

- In **Ontario**, a 2022 study found that there is sufficient cost-effective capacity from distributed energy resources (DER), including demand response, to meet or exceed forecasted increases in electricity demand across various future scenarios (Dunsky 2022a). Once factoring in real-world conditions, the report finds that the achievable potential of DERs can satisfy a significant portion of the province's energy needs, from five to 14 per cent of peak summer demand by 2032 (Dunsky 2022a).
- In **P.E.I.**, the total achievable savings from demand response range from 11 to 31 MW, which represents between 3.1 to 8.8 per cent of the overall forecasted electricity demand peak in 2030 (Dunsky 2021). Demand-side solutions may be particularly valuable in P.E.I., given the small province's growing integration of renewable energy and limited local generation capacity.
- In **Nova Scotia**, a Joint Energy Efficiency and Demand Response Potential Study found that the total cost-effective achievable peak demand response potential is approximately 80 MW by 2027, stabilizing around 70 MW from 2035 onwards. Direct load control and critical peak pricing were estimated to play the largest role (Navigant 2019).

- The Government of **Manitoba** assessed the market potential for electric demand response programs and EVs in 2022. The results were used as inputs to a larger DSM study but the demand response results are not publicly available (Dunsky 2022b).

While the above studies provide a valuable snapshot of the technical and economic potential of flexible demand across Canadian provinces, they likely only scratch the surface. Additional work is underway at the utility and community levels, much of which may not yet be publicly available.

In addition to the provincial-scale work, many local utilities and distribution companies are actively exploring demand-side solutions through internal planning, project-based partnerships, or early-stage pilot programs. However, insights from these efforts often remain proprietary or unpublished. As interest in flexible demand continues to grow, greater transparency and dissemination of findings will be critical to building a fuller understanding of its system-wide value and scalability in different provincial contexts.

How flexible demand can unlock lower electricity bills

PARTICIPANT BENEFITS:

- ✓ **Reduced energy bills:** Customers who deploy DSM technologies like smart thermostats, automated lighting, and demand response programs help shift electricity usage to off-peak hours or efficiently manage power consumption. By reducing peak demand, utilities avoid expensive infrastructure upgrades (e.g., new power plants or transmission lines). These cost savings are passed down to consumers through lower electricity rates over time.
- ✓ **Incentives:** Customers who participate in demand response programs can receive incentive payments in addition to the energy savings benefits associated with smarter electricity consumption. These demand reductions provide value to the grid by reducing the need to ramp up expensive peak generation and avoid grid congestion.
- ✓ **Avoided demand charges and higher time-of-use rates:** Businesses using energy management systems (EMS) can optimize their energy use and reduce overhead expenses by avoiding costly demand charges. Large-scale electricity users typically pay a demand charge based on the quantity of electricity consumed during periods of peak demand, such that managing peak consumption, not just total consumption, is particularly important for their electricity bills. DSM adoption helps businesses meet net-zero targets, improve sustainability scores, and comply with corporate ESG requirements.

RATEPAYER BENEFITS: Flexible demand can help avoid or defer system upgrades, meaning that the total system remains cheaper to operate. As a result, even those that elect not to adopt or participate in demand response or other DSM programs that enable flexibility stand to benefit from lower bills. Ultimately, the benefits of a more cost-effective set of system investments trickles down to all ratepayers.

2.2 Flexible demand can be particularly valuable to distribution systems, and help delay or avoid costly upgrades to local infrastructure

As electrification accelerates, local distribution systems face growing pressure. Through peak shaving and load shifting, flexible resources can help defer or avoid traditional distribution infrastructure upgrades such as transformers, feeders, and substations.

For example, in Saskatchewan, a joint study by SaskPower and the University of Regina demonstrated that controlled EV charging could keep peak demand within transformer capacity limits, whereas uncontrolled charging pushed demand to 244 per cent of rated capacity (El-Hendawi et al. 2025).

Studies from utilities around the world are also uncovering significant potential—and acting on it:

- In the **United States**, Con Edison, a local distribution company in Brooklyn, New York, received regulator approval to spend up to $200 million on demand-side resources to avoid a $1 billion substation upgrade. (New York State Public Service Commission 2014; Walton 2016). As of 2024, the project was operating well below budget.
- In the **United Kingdom**, projections show that uncontrolled charging from 10 million EVs would increase evening peak demand by 3 GW by 2035—but only by 0.5 GW with smart charging (AER 2018).
- In **China**, the government has set a target for 60 per cent of EV charging to occur off-peak by 2025, starting with five pilot cities (NDRC 2023).

Beyond cost savings, demand-side resources offer practical advantages in accelerating customer connections in constrained areas. Demand-side solutions can often be deployed faster and reduce the strain on utility capital budgets, workforce, and supply chains, especially in the face of rapid load growth. New York's Joint Utilities recommend lead times of just 18 to 24 months for demand-side projects costing $300,000 to $1 million, far shorter than typical infrastructure build-outs (Frick et al. 2021; Hrab et al. 2024).

3 Where do we stand on implementing flexible demand in Canada?

Canada has started to use more demand-side resources but progress is uneven and far below potential. Some provinces, such as Ontario, British Columbia, Quebec, and Nova Scotia, are making strides through updated frameworks and targeted programs. This section examines where progress is being made, where gaps remain, and what's at stake if deployment continues to lag.

Certain jurisdictions are making meaningful progress

While the general pace of adoption is slow, there are some encouraging early initiatives in certain provinces. Efforts in a few provinces are worth highlighting:

ONTARIO

In January 2025, the Government of Ontario announced a new 12-year electricity DSM framework, and the IESO published a program plan that specifies an energy savings target of 4.6 TWh, peak demand savings target of 900 MW, and a budget of $1.8 billion for the initial three years of the new framework spanning 2025 to 2027 (IESO 2025b). The DSM framework has a wide variety of programming, including both small- and large-load demand response programs.

One of the most successful programs has been the IESO's Peak Perks, enrolling more than 200,000 Ontario residents and achieving an estimated maximum one-hour peak demand reduction of 187 MW in summer 2024. The program has since grown even further and the program was expected to deliver more than 200 MW of peak demand reduction for summer 2025 (IESO 2025c). The Peak Perks program results exceeded expectations and recently expanded to include small businesses (IESO 2024a).

The Ontario Energy Board (OEB) is also taking action at the level of the distribution system. In 2024, the OEB introduced a cost-benefit assessment framework (OEB 2024a). This framework includes a mandatory test for distribution-system investments exceeding $2 million, requiring infrastructure projects to be assessed against non-wires alternatives, such as demand-side solutions.

BRITISH COLUMBIA

In British Columbia, recent action has included legislative amendments to the Clean Energy Act (Government of British Columbia 2022) to require BC Hydro to consider demand-side solutions and develop and report annually on DSM plans (e.g., BC Hydro 2024a). BC Hydro's 2024 Energy Efficiency Plan included a target of 400 MW of capacity savings from demand response programs and time of use rates by 2030 (BC Hydro 2025b). These plans historically centred on energy efficiency but increasingly include wider DSM measures.

BC Hydro is prioritizing the deployment of demand flexibility locally to address grid constraints at the distribution level, starting with high-value locations (BC Hydro 2020). Behind-the-meter efforts in B.C. include peak-saving incentives for lowering consumption in response to an alert in advance of upcoming peak periods, with over 130,000 customers participating since 2022, and newly increased incentives for enrolling batteries, EV chargers, and other smart devices. (BC Hydro 2025c). BC Hydro is also applying a geographically targeted approach to use demand-side resources as a non-wires alternative to defer or fill in for what would otherwise be needed reinvestment at specific feeders and substations (BC Hydro 2025b).

In the B.C. context, these initiatives are moving beyond pilot studies to a more general practice of investigating demand-side alternatives (BC Hydro 2022). Recently, BC Hydro also announced a residential VPP-based service (BC Hydro 2025a).

QUEBEC

Quebec has started to integrate demand flexibility as part of its broader strategy to meet rising electricity demand and support decarbonization. Hydro-Québec has launched a comprehensive smart home energy management service called Hilo, which enables residential customers to reduce electricity consumption during peak winter periods by enrolling smart thermostats, EV chargers, and other connected devices in automated demand response events. Customers are rewarded for participation, with average payouts of $205 during the 2024–2025 winter season (Hydro-Québec 2025a).

In parallel, Hydro-Québec has deployed time-varying rate structures such as Rate Flex D, which incentivize residential customers to shift usage away from peak hours by offering discounted rates for the majority of the winter season and elevated prices during high-demand events (Hydro-Québec 2025b). These programs are complemented by dynamic pricing pilots, which have demonstrated peak demand reductions of up to 22 per cent during winter events (Sergici 2024). In the 2024–2025 season alone, more than 400,000 households participated in Hilo or these rate schemes, contributing to a combined flexible capacity of 2,330 MW (Hydro-Québec 2025a).

Recent policy developments have further embedded demand flexibility into Quebec's long-term planning. Bill 69, which came into force in June 2025, mandates a 25-year Integrated Energy Resource Management Plan and streamlines regulatory processes to support energy transition projects, including demand-side resources (Rolland et al. 2024). Building on this policy foundation, Hydro-Québec's Action Plan 2035 outlines a $10 billion energy efficiency initiative aimed at reducing electricity consumption by 10 per cent. The plan includes the distribution of over one million smart thermostats and financial incentives for efficient technologies (energynews 2025). These initiatives are expected to double customer energy savings and free up 3,500 MW of system capacity, reinforcing Quebec's commitment to leveraging demand-side resources, including DSM that enables flexible demand, as a critical tool for reliability and decarbonization.

NOVA SCOTIA

In Nova Scotia, Efficiency Nova Scotia has operated as a dedicated efficiency utility since 2009, with demand savings targets mandated and overseen by the provincial regulator. Demand response is treated as a legitimate system resource, and Nova Scotia Power's 2020 Integrated Resource Plan (IRP) called for 81 MW of demand response capacity deployed by 2045 (EfficiencyOne 2022). In 2024, EfficiencyOne programming achieved 172.8 GWh of electricity savings and 30.7 MW of demand savings, both exceeding their respective targets (EfficiencyOne, 2025).

In collaboration with Nova Scotia Power and other partners, Efficiency Nova Scotia is actively expanding its demand response portfolio. In 2023, it secured 2.4 MW of demand response capacity, which grew to 8.1 MW in 2024 (EfficiencyOne, 2025). The current 2023–2025 DSM program cycle has a target of 17.9 MW by 2025, 7.1 MW from the EcoShift residential program (e.g., battery control, behavioural demand response, peak pricing, smart EV charging) and 10.7 MW from the Smart Synergy business, non-profit, and institutional program (e.g., curtailment, direct load control, critical peak pricing) (EfficiencyOne 2022). These efforts aim to help manage growing electricity demand while advancing the province's clean energy transition (ClearResult 2024).

MANITOBA

In 2025–26, Efficiency Manitoba, working closely with Manitoba Hydro, is beginning to pilot demand response offers to market. They are currently collaborating on a launch of a commercial or industrial curtailment pilot and a residential smart thermostat pilot (Efficiency Manitoba 2025). Manitoba›s newly published net zero strategy promises to increase efficiency savings through new programming on demand response and beneficial electrification (Government of Manitoba 2025)

Flexible demand solutions are under-deployed in Canada

While studies have shown promising technological potential, actual deployment remains low. For example, in 2022, a study by Dunsky found that under the incentives and structure in place at the time, Ontario could be missing out on up to 2.8 GW of economically viable summer capacity from demand-side resources by 2032, resources that could help reduce peak demand and lower overall system costs (Dunsky 2022a). Prince Edward Island and Nova Scotia studies echo this trend: while assessments show significant cost-effective opportunities for efficiency and demand response, actual uptake remains limited (Dunsky 2021; Navigant 2019).

This pattern leaves demand-side resources under-deployed even though DSM programs that enable flexible demand have been proven to be cost-effective, scalable, and beneficial for grid reliability. Should this gap continue, provinces risk missing an opportunity to keep rates low, improve reliability, and decarbonize the sector cost-effectively. Enhancing the deployment of DSM technologies will help avoid the overbuilding of supply and ensure that the value on the table is captured for ratepayers.

While some demand-side resources are more straightforward to implement, such as energy efficiency and text-based customer notifications, real-time data and advanced forecasting tools would unleash more value from flexibility.

4 What’s standing in the way of more flexible demand?

Adoption of flexible demand in Canada faces persistent barriers. Grid limitations, misaligned incentives, and limited recognition of DSM as a core resource have slowed progress. This section outlines what’s holding back deployment from achieving levels that could unlock its full value.

Electricity systems were not designed for decentralized participation

Electricity systems in Canada were originally designed, built, and regulated around one-way electrical flow from large centralized power plants to be transmitted and then distributed to end users through wires and poles. This centralized system was designed for supply resources to respond to demand rather than have consumer demand change in response to wider grid conditions in real time (Powell et al. 2024).

The shift towards widespread grid flexibility requires operational, technological, and market adjustments. One major challenge is co-ordination. Making consumer demand more flexible and responsive to grid conditions requires more information flow and change in response to that information from diverse consumers and participants such as distribution utilities, system planners, and businesses, making implementation more complex.

Integrating new technologies into the operating system provides challenges for system operators as well. Different systems, devices, and software from technology like smart thermostats, EV chargers, and distributed storage, do not necessarily communicate and exchange information seamlessly and effectively. This lack of standards for interoperability adds an additional layer of complexity for the integration of the technologies with utility control systems (Trabish 2024). While some demand-side resources are more straightforward to implement, such as energy efficiency and text-based customer notifications, real-time data and advanced forecasting tools would unleash more value from flexibility.

Existing incentive structures do not reward the full value of flexible demand

Existing utility regulations, and the incentive structures they create, were not designed with demand-side flexibility in mind. While flexible demand can provide multiple value streams, including grid reliability, avoided costs of distribution upgrades and new generation, and emissions reductions, these benefits are not yet fully captured in current regulatory or market frameworks. As a result, the full system value of flexible demand remains undervalued by both utilities and system planners.

In most Canadian jurisdictions, regulated utilities are permitted to earn a return on capital expenditures like new infrastructure but DSM programs are typically treated as operating expenses. This accounting treatment, while not universally applied, can reduce the financial attractiveness of DSM investments, even if they represent the most cost-effective solution. A report from Guidehouse evaluating utility regulatory frameworks found that this incentive structure has led to risk aversion when it comes to grid modernization (Guidehouse 2020).

The heterogeneity of regulatory environments across the country adds an additional layer of complexity in planning and determining appropriate compensation for making demand more flexible. In some provinces, DSM budgets are allocated by governments through separate mechanisms rather than by regulators (e.g., British Columbia), resulting in parallel but sometimes competing objectives and planning processes. In other cases, value streams from demand-side flexibility cross jurisdictional lines, for example, between regulated transmission and distribution systems and deregulated generation sectors (as in Alberta), making it difficult to attribute and compensate system-wide benefits consistently.

The incentive misalignment problem also extends to end users. Households and businesses that shift EV charging to off-peak hours or install smart thermostats contribute to system-wide benefits, such as avoiding system peaks, reducing infrastructure costs, and lowering emissions for everyone, but are often compensated only for a smaller portion of the value they create. The Brattle Group's New York Grid Flexibility Potential study identified the complexity of programs and difficulty in monetizing the full value of grid flexibility as a major barrier impeding deployment for flexible resources (Hledik et al. 2025).

Finally, consumer price signals remain weak in many provinces. Time-varying pricing, demand response incentives, and other incentives could help align customer behavior with system needs, but these tools are inconsistently deployed. Unlocking the full potential of demand flexibility will require reforms that not only clarify the value streams associated with flexible demand, but also align the incentives of regulators, utilities, and customers within jurisdictions.

Perceived risk and procurement barriers undermine the integration of flexible demand into resource planning

Flexible demand is often treated as a complementary tool rather than a primary grid resource, largely because it has not been widely demonstrated at scale and requires customer adoption outside the direct control of utilities. Some jurisdictions, such as British Columbia and Nova Scotia, have existing mechanisms to ensure that cost-effective DSM is considered a resource, but even in those places, the existing framework has not yet unlocked the full potential of flexible demand resources.

In most provinces, DSM is included in integrated resource planning (IRP) frameworks but often treated as a passive reduction to forecasted load rather than an active grid resource. This limits the investment, planning priority, and market access DSM receives relative to conventional supply. Studies have shown however, that DSM can provide similar capacity benefits to other supply sources. For example, a Brattle Group study modeled the economics of a residential VPP for a representative utility system in 2030 and found that it could perform as reliably as a gas peaker and utility-scale battery at 40 to 60 per cent of the cost, without counting societal benefits (Hledik et al. 2023).

Furthermore, jurisdictions that estimate capacity savings from DSM often underestimate their potential due to methodological shortcomings, outdated avoided costs assessments, and the use of total resource costs to screen out measures (Haley et al. 2025). When DSM programs that enable flexible demand significantly outperform expectations, such as Ontario's recent experience, it's another sign that the resource is likely underestimated. In the absence of proper valuation methodologies and incentive mechanisms, DSM remains sidelined in planning and investment decisions, and will likely result in continued underutilization.

Regulators, system planners, and utilities prioritize reliability and predictability for good reasons—they have mandates to ensure prudential investments on behalf of ratepayers and reliable service (Guidehouse 2020). The perception of DSM as a less dependable investment comes in part from uncertainty around timing and scale. Even for traditional DSM, which has established accounting mechanisms and decades of proven performance, utilities are hesitant to depend on its performance. For example, in the most recent Integrated Resource Plan, Manitoba Hydro notes:

> *One of the main considerations with energy efficiency measures as a resource option is that even with regulation and legislation, achieving energy reductions is dependent upon customers' actions. The energy savings potential used by Manitoba Hydro is estimated by Efficiency Manitoba and is based on a variety of assumptions including technological development, anticipated customer energy usage/savings, and market cost projections. As a result of these factors, uncertainty surrounding expected savings from energy efficiency measures is fundamentally different from the uncertainty and risk associated with traditional forms of resource supply options (Manitoba Hydro 2023).*

Unlike dispatchable power plants that can be turned on and off at will, DSM depends on voluntary customer participation, making its availability less predictable in the eyes of system planners. For example, demand response programs depend on customer technology adoption and voluntary participation, making their scale, adoption rate, and responsiveness less predictable than dispatchable generation in the absence of long-term performance data at scale. This has led to conservative adoption strategies, where DSM is used in pilot projects but not fully integrated into capacity planning or resource adequacy frameworks.

A recent report from Efficiency Canada found that no utility in Canada treats demand-side resources on par with supply-side options in planning processes (Haley et al. 2025). Notably, no utility made the full suite of demand-side resources available as selectable inputs in long-term capacity planning models.

> Despite demonstrated benefits, existing technical, economic, and regulatory barriers inhibit the use of flexible demand at scale.

The political and regulatory environment plays a critical role in determining the financial viability of pursuing DSM. While regulators are tasked with protecting consumers, they are also responsible for enabling utilities to earn fair returns, essential for attracting investment, financing debt, and ensuring long-term financial stability. When regulators decide what expenditures can be included in the rate base, they consider fairness to ratepayers and utilities.

Regulator decisions on approving DSM investments vary across the country. In Alberta, regulators have been hesitant to include the cost of DSM investments in rates. A recent report from the Pembina Institute notes that three of the four Alberta distribution utilities included DSM in their 2023 rate applications, but apart from one managed EV-charging pilot, the regulator denied their requests (Hyde et al. 2025). In contrast, regulators in British Columbia and Ontario have actively encouraged DSM investments, supported by broader government policy goals related to energy efficiency and system decarbonization.

Despite demonstrated benefits, existing technical, economic, and regulatory barriers inhibit the use of flexible demand at scale. As the imperative for reducing peak continues to grow, the role and potential of flexible demand will grow further, and provinces without supportive regulatory environments may risk missing out on an opportunity to adopt a viable, cost-effective resource.

5 How might demand flexibility achieve its full potential?

Realizing the full potential of flexible demand will require co-ordinated action across governments, regulators, utilities, and consumers. This section outlines four enablers of scale: modernizing provincial regulations and planning, fairly compensating adopters, expanding public investment, and enabling third-party participation. Together, these actions can help move demand flexibility from the margins to the mainstream, unlocking system value, reducing costs, and accelerating the clean energy transition.

Provincial reforms to utility regulation and energy system planning could help utilities and other participants uncover and unlock the value of demand flexibility

Greater co-ordination and role clarity within provinces among utilities, system planners, and regulators could help them act together to capture the value that exists from demand flexibility. Where flexible demand benefits ratepayers, but current rules—including how utilities can generate a rate of return on investment—do not make it a good business investment to utilities or other electricity system actors, that misalignment demands resolution.

In some instances regulator mandates may need clarification or enhancement to better position regulators to enact rules that incentivize utilities and/or other actors to deploy flexible demand resources when they are the most cost-effective option for ratepayers. This could come in the form of greater use of performance-based incentives, reforms that help align utility incentives with outcomes such as energy efficiency, peak reduction, or emissions mitigation. Alberta, for example, has implemented a form of performance-based regulation for distribution utilities, and Ontario is currently exploring similar mechanisms through public consultation (AUC 2023; OEB 2025).

Provincial policymakers can also empower regulators to require that utilities consider non-wires alternatives during planning processes. For example, the Ontario Energy Board's Distribution System Code now mandates that utilities conduct a cost-benefit assessment of non-wires alternatives for any distribution investment over $2 million, an important step in embedding DSM into core utility planning (OEB 2024b).

In deregulated markets such as Alberta and, to some extent, Ontario, provincial governments can support regulators to clearly define roles and responsibilities relating to the deployment of flexible demand resources as well as DSM more broadly. Alberta is currently the only province in Canada without utility-led DSM, resulting in less stable and fragmented government-led energy efficiency and retrofit programs (Hyde et al. 2025).

Provincial governments can also equip system planners and utilities with the planning capacity, analytical tools, and data access necessary to identify where flexible demand can deliver the greatest value. Robust cost-benefit analysis, long-term energy roadmaps, and improved integrated planning processes can support this. Making high-quality information accessible across the electricity value chain can help demonstrate the business case for flexible demand, guiding smarter investment and co-ordination decisions.

At the distribution level, utilities can demonstrate the potential value of flexible resources by focusing first on high-value locations such as overloaded transformers and feeders. By targeting these constrained areas, utilities can measure and showcase the full range of benefits, from cost savings to grid reliability, enabled by flexible demand. This locational approach has proven effective in illustrating how flexible demand can help defer or avoid costly distribution system upgrades. For example, in 2020, Minnesota-based Xcel Energy and the Center for Energy and Environment piloted a geotargeted demand response program aimed at deferring a new transformer and feeder reconfiguration. The program successfully met its goals for both energy efficiency and demand reduction, ultimately eliminating the need for the planned infrastructure upgrade (Frick et al. 2021).

Provincial policymakers, utilities, and regulators can develop new ways to compensate participating customers for the value they provide to the grid

Better alignment between system-level benefits and consumer-level incentives would enable more widespread adoption of demand flexibility resources.

Individual incentives should align with the benefit that demand-side participants provide to the grid. Potential consumer participants should be able to see clearly how their participation benefits them directly. If the financial return or convenience doesn't match the cost and effort involved, adoption will remain limited. However, many provincial market structures do not fully account for the value or provide a platform to provide rewards for the adoption of flexible demand.

In addition to adequate financial incentives, clarity and ease of the participant experience matters. For example, researchers at the University of Calgary and Stanford conducted a field experiment with residential electricity customers to evaluate how the ease of participation affects program effectiveness, comparing utility-initiated versus customer-initiated demand response. For utility-initiated households, the demand response action was done remotely, without any action from the household. In the household-initiated group, the participant pushed a button on an app to initiate a demand response action. Utility-initiated households reduced consumption by an average of 26 per cent while customer-initiated households reduced by only 5 per cent, demonstrating the impact that program design can have on uptake (Bailey et al, 2024).

Clearer and more consistent planning, targets, and energy roadmaps that make explicit the need for and benefit of flexible demand resources can help.

Consumer participation can also be secured through time-varying rates and other pricing schemes, which should also have adequate financial benefits and be easy enough to attract participants. Smart pricing can incent customers to reduce electricity use during periods of peak demand. However, in some regions without widespread smart meter adoption, customers lack the tools and data necessary to engage in time-based pricing or demand response programs.

Ultimately, refining programs and pricing schemes to simplify customer options and incorporate the full value of grid flexibility is critically important to unlock more grid flexibility (Hledik et al. 2025).

All orders of government can scale up ambition for demand flexibility in targets, system planning, and funding

Creating a grid of the future that benefits the wider public is part of the project of modernizing energy infrastructure, in which public investment can play a constructive role. In 2024, the Canadian Electricity Advisory Council advised the federal government to prioritize support for demand management by refocusing funding toward demand-side solutions such as energy efficiency, demand flexibility, and grid modernization (NRCan 2024)

Policymakers can further catalyze change within the electricity sector by creating policy certainty about the deployment of flexible demand resources, alongside other demand-side investment. If regulatory integration is weak and DSM relies on government budgets, volatility in political priorities can create boom-and-bust cycles. Regulatory systems tend to be more resilient to political change, offering a stable foundation for cost-effective, enduring implementation. Ideally, a blended approach may be needed to combine ramp-up speed with regulatory durability.

Clearer and more consistent planning, targets, and energy roadmaps that make explicit the need for and benefit of flexible demand resources can help. British Columbia's Clean Energy Act, for example, already requires BC Hydro to consider demand-side solutions and develop and report annually on DSM plans (Government of British Columbia 2022). Several provinces, including Manitoba, Quebec, Prince Edward Island, and New Brunswick, have imposed energy efficiency savings targets to spur action and to facilitate adoption of DSM, including flexible demand (Efficiency Canada 2025).

Targeted government support can facilitate the scaling of pilots to permanent programs. Following initial successes and upward estimates on load forecast, the Ontario Government increased the budget of the 2021–2024 Conservation and Demand Management Framework, with an initial budget of $692 million to $1 billion (IESO 2024b). Ontario's new DSM framework significantly expands electricity demand-side management in the province with a 12-year, $10.9 billion budget.

Programs can also be developed with scalability in mind. Yukon's Peak Smart Program started as a home demand response demonstration project funded by the federal government's Smart Grid Program over the winters of 2020 and 2021 (Yukon Energy Corporation 2024; NRCan 2021). Due to the success of the program, the Peak Smart Home program has become a permanent mainstay and now users can receive rebates for the purchase and installation costs of eligible thermostats and hot water heaters. The Government of Canada's Energy Innovation Program Smart Grid stream embodies this view, focusing explicitly on providing support for technology, market, and regulatory innovations that address barriers to scale pilot projects into grid-wide deployments (NRCan 2025).

Participation of third parties could ease administration burden and promote knowledge sharing

Third-party operators can play a role in advancing flexible demand that aggregates the benefit of multiple users, such as virtual power plants.

Dedicated third parties that are more focused on flexible demand resources could help bridge the gap between utilities, regulators, and consumers. More entrepreneurial structures could be better suited to facilitate communication, innovate better program design, and share learning. In doing so, they can improve customer service and drive down costs through competitive service offerings. Recently, the flexible demand service provider EnergyHub partnered with FLO chargers to help North American utilities scale participation in managed EV charging demand response programs (EnergyHub 2025).

The evolving landscape of emerging technologies and underutilized flexible demand resources offers fertile ground for business innovation and new market entrants. For instance, BluWave-ai recently partnered with Hydro Ottawa to deliver Canada's first AI-driven demand response events across multiple EV manufacturers, illustrating how third parties are finding new ways to aggregate flexible demand resources and support utility operations (BluWave-ai 2024). However, many still face high entry and informational barriers, and unclear compensation pathways, limiting market growth. They may also face regulatory restrictions that prevent third parties from participating in electricity service provision.

Nonetheless, where third parties are permitted, pilot programs have demonstrated their potential involvement in program administration of DSM that enables flexible demand. For example, Ontario's IESO successfully partnered with EnergyHub to deliver the Peak Perks program, which achieved high levels of customer engagement (EnergyHub 2024). Similarly, Alectra, a local distribution company, piloted a market-based approach where aggregators and direct participants competed in local capacity auctions, with price caps based on the costs of traditional infrastructure investments. Winning bidders received contracts from Alectra. The pilot exceeded targets, proved technically and economically viable, and raised no operational concerns. However, it also revealed systemic limitations, such as inaccessible value streams, that continue to hinder efforts to access flexible demand resources at scale under current regulatory structures (IESO 2024c).

Conclusion

As Canada's electricity system evolves, rising peak demand, accelerating electrification, and growing system complexity are creating both challenges and opportunities. Flexible demand offers a cost-effective, scalable solution to reduce strain, improve reliability, and contain system costs. Realizing its full potential will require policy change, including regulatory reform, better incentives, and co-ordinated action across governments, utilities, and market actors. But unlocking this untapped value will pay off in a cleaner, smarter, more affordable electricity grid.

Glossary

Advanced Metering Infrastructure (AMI)

An integrated system of smart meters, data management systems, and communication networks that enables a two-way flow of information between utilities and customer meters. (Electricity Canada)

Demand-side Resources (DSR)

Demand-side resources meet resource adequacy needs by reducing load, which reduces the need for additional generation. Typically, these resources result from one of two methods of reducing load: energy efficiency or demand response/load management. (US DOE)

Demand-side Management (DSM)

Demand-side management involves programs and strategies that help people and businesses reduce energy waste and use energy at times that are better for the grid. (Efficiency Canada)

Demand Response (DR)

Refers to balancing the demand on power grids by encouraging customers to shift electricity demand to times when electricity is more plentiful or other demand is lower, typically through prices or monetary incentives. (IEA)

Distributed Energy Resources (DER)

Distributed Energy Resources refers to energy resources that are directly connected to the electricity distribution system, or indirectly connected to the distribution system behind a customer's meter; and generates energy, stores energy, or controls load (Dunsky). Energy efficiency measures are excluded from the definition of DER because their performance is not dynamically variable. (IESO)

Demand Flexibility

The capacity of demand-side loads to change their consumption patterns hourly or on another timescale. (Berkeley Lab)

Non-wires Alternatives

Solutions that defer or avoid the need for traditional transmission or distribution system upgrades. (IESO)

Smart Grid

A suite of technologies that facilitate information flow so that the utility can deliver and manage electricity more economically and efficiently. (Electricity Canada)

Virtual Power Plants (VPP)

A grid-integrated aggregation of many individual DERs that act as a co-ordinated unit as if they were a single, larger power plant. (VP3)

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