ONTARIO'S ELECTRICITY SYSTEM'S DELIVERABILITY RISKS REQUIRE INNOVATIONS IN THE DISTRIBUTION SYSTEM

Power Workers' Union (PWU), September 2024

This fourth and final paper outlines the PWU's views on better ways for Ontario to meet its growing electricity demand with lower carbon emissions and in a more reliable, affordable and timely manner.

POWER WORKERS' UNION

The People Who Help Keep The Lights ON.

INTRODUCTION

The first three discussion papers described how systemic reliability risks in the face of growing demand require a radical rethink of Ontario's electricity system planning and procurement approach which necessitates an urgent focus on developing the long-lived baseload generation assets Ontario needs to power its growth. The papers also described how the lack of accountability for over-all affordability in Ontario's electricity system planning and procurement processes is unnecessarily driving up rate payer and taxpayer costs. This paper considers that the delivery system infrastructure will be equally challenged to meet the growing demand and advances policy ideas to support a reliable and cost-effective transition of Ontario's electricity system as demand grows and the baseload bulk system supplies are developed.

EXECUTIVE SUMMARY

A transition plan is required to identify an affordable and achievable pathway for improving the infrastructure of Ontario's electricity system to respond to demand growth and the province's increasing dependence on natural gas fired generation. Such a plan would maximize the use of the capacity of Ontario's existing distribution and transmission components while deferring the need to upgrade them. This would "buy time" to better optimize timing and development of the required delivery system infrastructure as well as the bulk system baseload generation assets.

This energy transition strategy would help optimize the use of existing delivery infrastructure by maximizing the transfer of baseload power from the grid to the distribution system by migrating the provision of variable demand smoothing and flexible supply solutions to the latter i.e., "as close to load as possible".

Instead of relying on IESO-advocated market-based mechanisms, the optimal approach would employ regulated-rate designs to incent consumer behind-the-meter (BTM) technology adoption choices that support grid performance and enabling AI-powered aggregated demand side management (DSM).

Embracing such innovations is critical given that the rapid growth in electricity demand exceeds the system's ability to build the necessary infrastructure, a fact recognized across North America.[1] This pace risk requires proactive and aggressive mitigation – and the opportunities for necessary mitigation exist in the distribution system.

[1] Canada Faces Crunch in Electrical Supply, Energy Now, Aug 17, 2024; New York encourages electrification with new grid planning process, affordability pilot, Utility Dive, Aug 21, 2024. "The rate at which consumers are electrifying buildings and vehicles has the potential to outpace the existing grid planning processes," the New York Public Service Commission said.

The pace of demand growth is challenging the delivery system

The PWU's discussion paper on mitigating reliability risks drew on the IESO 2024 Annual Planning Outlook (APO), planning references from the Toronto Region, and available net zero studies for Ontario. This analysis showed that the planned growth and electrification of Ontario's economy will lead to approximately 150% increase in system capacity over the 25-year period from 2025 to 2050. These findings did not reflect the impact of the Honda factory announcement (over 300 MW) or the trend in requests for AI-driven data centers (could range from 350 MW to 3000 MW by 2030). These alone represent a 10% increase in the peak load in Ontario by 2030 that is not currently being addressed.[2]

The pace of electricity demand growth presents challenges not only for procuring required new generation resources but also for new infrastructure in the delivery system. The delivery system represents about 30% of the total cost of electricity or almost half of the cost of generation[3]. While generation can be located with a finite selection of sites, the delivery system is ubiquitously spread across the province and is managed by 60 local distribution companies (LDCs),[4] as well as the transmitters, including Hydro One which serves most of the province. Upgrading the transformer stations, wires and distribution transformers to meet demand growth represents a major challenge while maintaining reliability and meeting consumer demand.

The Electrification and Energy Transition Panel (EETP) report clearly described this critical challenge, stating: *"Importantly, increases in the demand for electricity must be paced in a way that aligns with the capabilities of the energy delivery system for power and gas."* This highlights the need for an energy transition strategy to achieve a NZ economy by 2050 – not everything can be built everywhere, all at once.

Innovations are emerging that can enable an achievable pace of development and reduce reliability risks. The average capacity usage of the delivery system is about 35%. If the daily peak demand variations from the LDCs can be reduced, in favor of relative increases in baseload, the utilization of the delivery system assets could be doubled to 70%, reducing the required growth in capacity. This strategy could buy time for building delivery capacity on the path to 2050, potentially deferring the risk of

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[2] Strapolec analysis: Honda estimated based on VW media reports, IESO representative verbal statement of 350 MW of AI connecting requests, analysis of 2024 EPRI study suggests Ontario demand form AI data centers could grow by 2.5 to 3 GW by 2030.

[3] 2019 statistics published by Ontario's Auditor General, quoted from https://www.lifebynumbers.ca/cost/electricity-service-costs/, stating: The total system service cost for providing electricity to Ontario consumers approaches $23 billion according to a 2019 audit of the Independent Electricity System Operator (IESO). The cost breakout is 68% for electricity, 17% for distribution, 7% for transmission, 4% for wholesale market charges, and 4% for regulatory and all others.

[4] https://www.eda-on.ca/FOR-CONSUMERS/Ontarios-Local-Hydro-Utilities#:~:text=LDCs%20distribute%20power%20from%20transmission,60%20LDCs%20operating%20across%20Ontario.

distribution and transmission system-induced bottlenecks and local blackouts for many years.

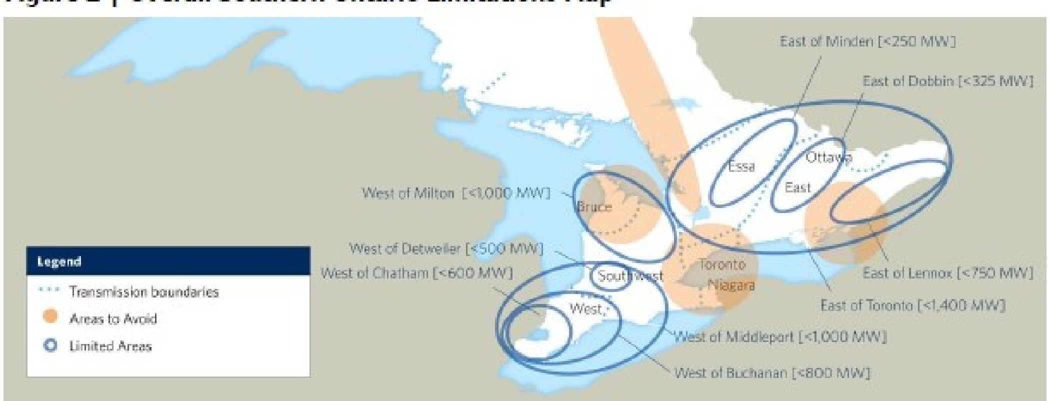
Ontario's bulk system grid → all roads lead to the distribution system

The previous papers explored the factors related to total system costs and the transmission system's contribution as well as the zonal structure of the bulk system and the localized emerging supply gaps. The papers argued for a transition plan that can optimize the pace of developing long-term infrastructure and the cost-effective development of required baseload generation by leveraging existing bulk system assets. The analysis concluded that locating new generation within each zone, where possible, would minimize the broader Ontario bulk system transmission development challenge.

The previous papers recognized that the IESO's 2024 APO forecast demand growth is primarily for baseload supply. However, there is a need to address Ontario's variable supply needs as well, in particular reducing the province's reliance on flexible natural gas generation. The IESO's procurement of flexible supplies continues to rely on outdated market mechanisms. Analyses have shown that procuring 3000 MW of new grid-connected storage could fully meet Ontario's need even in 2050 in the Net Zero scenario. However, the new storage and other resources are being acquired by the IESO in less-than-optimal locations, increasing transmission costs and exacerbating the need for the grid to accommodate peaking supply.

The IESO's preliminary guidance on new resource connections for its LT2 RFP,[5] shows that they should be connected away from the province's peak demand centers. This approach exacerbates the delivery system development challenge by continuing to place peaking generation outside of load centers. Many of these may become stranded when the more cost-effective baseload supplies are developed.

Figure 2 | Overall Southern Ontario Limitations Map



[5] IESO, Preliminary Connection Guidance for Long-Term 2 RFP, April 16, 2024.

Optimizing the bulk system development and timeline costs requires understanding the drivers of demand: from large, baseload-drawing, directly connected industries; and, from the residential, industrial, and commercial loads within local distribution company (LDC) territories. In fact, the APO shows that most of the demand growth stems from loads within the distribution system. The solution to grid cost optimization is not to construct large scale grid-connected storage, but to smooth the demand variability with smaller distributed energy storage capacities as close to the loads as possible.[6] New grid connected storage would optimally be co-located with transmission system transformer stations at the bulk-system grid interface to the LDCs, specifically on the LDC side of the connection. This approach would smooth demand and minimize peaks at the transformer stations permitting greater utilization of the bulk system assets and the deferral of their upgrades – an underpinning pretext for the value of demand side management (DSM) of distributed energy resources (DER).

The optimization of this cost-effective approach to the development and use of the bulk system transmission and baseload generation assets would critically rely on additional DSM implementation within the distribution system to minimize the operational challenges of grid scale storage and flexible supplies.

Importantly, state of the art distribution system DSM is sufficiently well advanced and should figure prominently in the IESO's resource adequacy framework, but it is not.

A Paradigm Shift is required to optimize deliverability through distribution system innovations

The nature of consumer demand and the tools available to manage it are conducive to a radical rethink of how the distribution system's costs and capacity could be optimized.

a) *The electricity system does not need to invest in empowering consumers with choice, but rather ensure that infrastructure can be cost effectively delivered as consumers make whatever choices they desire.*

The EETP report overstates the degree to which "e*mpowering customers with choices is integral*". It is not established how important it is to cater to " '*prosumers' who can both produce and consume electricity and actively provide grid services, not just consume them*." There has been much hyperbole in the sector on the degree to which DERs have been adopted. However, this adoption has arisen from inadequately

[6] Strategic Policy Economics, Distributed Energy Resources in Ontario, 2018.

designed and overly generous incentives that shift DER costs to other rate payers (e.g. net metering and the Industrial Conservation Initiative).[7]

While the EETP report provided no quantified assessment of costs related to its recommendations, it did qualitatively emphasize the importance of understanding cost. It states that "*Any mechanisms adopted by the government should be rigorously analyzed for cost-effectiveness and must transparently consider both costs and benefits to individual customers and to the overall system, for example peak electricity demand impacts*."

To this end, the OEB has been advancing the important work of developing a benefit cost analyses (BCA) approach to fill this data gap for decision makers.[8]

While understanding the benefits and costs of DERs are critically important for decisions that allocate costs to rate payers, the OEB BCA framework does not address mitigating schedule constraints on resource development and other priority areas such as ensuring that Ontario's lights will not go dark.

b) Dogmatic reliance on market-based procurement mechanisms is a barrier to innovation.

The EETP report stated that: "*Well-regulated competitive markets can significantly advance customer choice and should be combined with convenient and accessible information about options, including up-front and operating costs*." While this is an important ambition, it is not an achievable reality with respect to procuring future non-emitting supply resources. Markets rely on innovators to leverage market price arbitrage-based schemes. In the absence of fossil-fuel-dominated electricity markets, the approach is not sustainable as there are no possible market-based signals that can capture the implication of full system cost and the greater imperative need to build out quickly.[9] The EETP report cautioned that *"new technical capabilities raise a myriad of challenges concerning not only the physical management of the energy system, but also pricing and the entry of non-traditional market participants."* The EETP report also stated that "*market models and regulatory frameworks by which the distribution sector is managed, and the ways in which the bulk electricity system is planned and managed, will need to evolve."*

Growing the distribution system is a physical/engineering management challenge, not a market price optimization challenge.

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[7] PWU Submission to MENDM on "Changes to Ontario's Net Metering Regulation to Support Community-Based Energy Systems", November 2020.
[8] Ontario Energy Board, Framework For Energy Innovation: Setting a Path Forward for DER Integration, January 2023; Ontario Energy Board, Benefit-Cost Analysis Framework for Addressing Electricity System Needs, May 16, 2024.
[9] Strategic Policy Economics, Electricity Markets in Ontario, 2019.

c) *The potential for Distributed Energy Resources (DERs) to help address the system needs is not being clearly communicated and misinforms decision makers.*

The EETP report states that *"Technology for the distributed generation and management of electricity is evolving quickly in maturity and cost-competitiveness, with the potential for disruptive change in the distribution sector in the near future."*

However, the potential contribution of DER is optimistically conveyed in the EETP report that "*it would be possible to cost-effectively meet all incremental system needs with DER capacity*." This has not been confirmed by analyses. The EETP founded their conclusions on an IESO-funded study.[10] Analysis shows that the study conclusions, particularly around the role of solar that figured prominently in the findings, were based on contrived analyses and serve to misinform decision makers, like the EETP.[11] As a result, the PWU found it appropriate that the EETP report "watered down" support for DER by stating: "*The assessment of the achievable potential of DER technologies therefore must be complemented <u>with rigorous analysis</u> to understand how evolving (utility) business models and design of the wholesale market can enable DERs*."
The PWU suggests that DERs cannot in fact help address the problem of accelerating capacity buildout except where DER technologies can improve distribution asset utilization. Specifically, this requires mitigating not only peak demand but demand variability in general.

The real strategic issue → Demand drivers and delivering the required supply

Smoothing demand and thereby optimizing the utilization of existing distribution infrastructure is the critical strategic issue for buying time during the transition. The EETP report identified that "*There is an urgent need to advance the regulatory environment to enable effective participation of DERs and eliminate barriers. A delay will mean that potentially cost-competitive solutions located at the distribution level cannot effectively compete during a time when Ontario will be investing in the expansion of the electricity grid to satisfy increased demand from electrification*."

Much attention has been given to the promise of smart grid technologies, much of which is associated with enabling two-way flows across the distribution systems to accommodate DERs. While the technology innovations from smart grid initiatives hold promise, the answer is not market-based pricing signals and two-way flows across the grid. A smart grid in this sense is not what is needed, but rather smart energy consumption by the end users. The objective is to smooth demand on the distribution system connection points and ultimately to the transformer station supplying the feeder that connects a consumer. Enabling two-way flows represents a costly exercise

[10] Report to the IESO, Ontario's Distributed Energy Resources (DER) Potential Study, Sept 2022.
[11] PWU Submission to the IESO on the DER Potential Study, October 28, 2022.

that can be deferred and potentially obviated by the innovations discussed here. The answer lies in understanding the drivers of demand growth.

Demand growth is emerging from two sources: new economic growth/development; and the electrification of the economy. Economic growth impacts population and new business, both of which lead to distribution system expansion for new connection requests (e.g. new subdivisions or industry such as greenhouses or auto sector manufacturing). Electrification of the economy results in increasing demand from existing loads and is ubiquitous throughout the province's distribution systems. Planning for new loads, e.g., economic growth, is not new, albeit the pace of growth in Ontario may be higher than previously experienced. The electrification of the economy, however, is a new phenomenon that entails unprecedented growth for existing infrastructure.

The implications of electrification on demand from existing loads can be viewed from two perspectives:

1. ***Industrial load growth***: Increased load from existing large consumers translates directly into requests for higher service levels from the distributor and/or transmitter. Related investment decisions are implemented within a planning framework with scheduled upgrades developed accordingly.

2. ***Residential/commercial and other buildings***: Consumer adoption of non-emitting options to fuel switch away from gasoline and natural gas are occurring in many areas and are organic based on public opinion. The most commonly discussed innovations are electric vehicles and heat pumps for building heating and cooling. But electrification of appliances is also occurring. This ubiquitous growth across all LDCs impacts the existing distribution system infrastructure.

In all cases, the impacts will be felt through the need for distribution system feeder and transformer upgrades. Managing the development of existing feeders is the daunting problem – How can asset utilization be maximized and distribution system upgrades deferred? This is an important question as the required infrastructure cannot all be built across the entire distribution system at the same time.

Opportunity:
Emerging Distribution level Demand Side Management tools

The EETP report states that: "*Ontario must explore ways that implementation can proceed quickly while other regulatory and market reforms are underway.*" The distribution system offers opportunities for balancing growth on and across feeders. The process starts with smoothing demand within a feeder, then across feeders from a common substation, then across substations connected to a transformer station, etc. Solutions in DER Management Systems (DERMS) are helping utilities meet their current needs and scale for the future by improving hosting capacity, reducing the need for grid upgrades, and delivering financial gains and grid support.[12] DERs that can be most effective at achieving this objective fall into two categories: LDC load management DERs; and, consumer adopted fuel switching technologies suitable for integrated load profiles management.

1. *LDC load management innovation opportunities*

LDCs have three load optimization options that could be leveraged by DERMS: Addition of community scale storage at transformer stations; working with large evening charging loads; and, optimizing the operations of electrolytic hydrogen production facilities. These options could provide MWs of flexible load.

- Distribution stations are an opportunity to locate Front of the Meter (FTM) community scale storage.

  Locating storage on the load side of distribution stations is the most direct mechanism for smoothing load originating on a feeder and minimizing the variability presented upstream to the rest of the grid. Studies have shown that using storage to smooth load is the most cost-effective use of storage capacity.[13] While community scale storage (1-5 MW) is almost double the cost of grid storage (100 MW),[14] it can provide delivery system load smoothing benefits. In contrast, the IESO has procured grid-scale transmission connected storage to mimic the flexible operations of gas-fired generation. Grid connected facilities offer no benefit for optimizing transmission infrastructure and in fact increase costs given the need to connect them and not co-locating them with demand which incurs losses. However, a direct cost comparison may not be the relevant consideration. The benefit of community scale storage is its potential to defer the distribution system capacity upgrades and support a more cost-effective transition plan.

- Commercial and Municipal transportation electrification offer overnight load balancing

  Loads arising from electrification of commercial delivery fleets and public bus and rail could represent increased overnight loads. This would help smooth overall diurnal distributions system load and, by utilizing utility DERMS, could smooth demand more locally and at further upstream transformer stations where feeders converge.

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[12] https://resources.industrydive.com/manage-ders-at-scale-and-unlock-more-value-for-customers?utm_source=UDLM&utm_medium=BlastMay24&utm_campaign=SmarterGridSolutions; It's time to stop fretting about load growth and get serious about demand-side solutions, Utility Dive, Aug 6, 2024.
[13] Strategic Policy Economics, Distributed Energy Resources in Ontario, 2018.
[14] Lazard, Levelized Cost Of Energy, June 2024.

- Electrolytic hydrogen offers distributed flexible load and demand response The potential for hydrogen as an alternative fuel for heavy-duty transportation and for blending into the natural gas system to reduce its emissions could be distributed across the province's distribution system. Electrolyzers have rapid flexible load control when producing hydrogen. Electrolytic hydrogen production could be incented for nighttime operations and/or used as demand response.[15]

2. Consumer technology adoption offers controllable load profiles

Residential and consumer adoption of heat pumps and EVs offers the ability to manage loads on a feeder. Unmanaged, large and coincident peaks could compromise the distribution system. Much work has been done to demonstrate that the smart charging of EVs, in response to rate programs for example, can help smooth new peak loads. The IESO assumed this benefit in its 2024 APO. Additional technology innovations offer greater benefits. Hybrid dual fuel heat pumps, bidirectional EV chargers and home storage (e.g. powerwalls) can provide tools to help smooth demand all year long, reduce peaks and increase the utilization of delivery system capacity.

Enbridge, with the support of Natural Resources Canada (NRCan), managed a Hybrid Home heating program from 2021 to 2024.[16] This program met with success.[17] Natural Resources Canada has been supporting DERMS pilots as part of its Smart Grid Funding.[18] Several pilot programs are seeing success using bidirectional EV chargers.[19] Finally, the value of home energy storage is growing. California recently reduced the guaranteed payments under net metering for solar PV owners.[20] The result has been an uptick in installed home storage for shifting solar output to more optimal times. It is important to note that using storage to smooth demand is far more cost effective and efficient in Ontario than in smoothing the output from intermittent renewables.

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[15] Green Ribbon Panel, Clean Air, Climate Change and Practical, Innovative Solutions Policy Enabled Competitive Advantages Tuned for Growth, 2020, identified how hydrogen can be used in a "Made In Ontario" Integrated solution as demand response to reduce system costs; Strategic Policy Economics, Electrification Pathways for Ontario, 2021, quantified those benefits.

[16] https://www.enbridgegas.com/sustainability/clean-heating/hybrid-heating.

[17] https://sustainabletechnologies.ca/home/heating-and-cooling/air-source-heat-pumps/smarter-home-heating/london/#:~:text=Overall%2C%20the%20analysis%20showed%20that,electricity%20demand%20of%20the%20homes.

[18] https://natural-resources.canada.ca/sites/nrcan/files/environment/Smart%20Grig_E_2021_accessible.pdf

[19] From Vehicle-to-Grid To DIY Home Powerwalls, Hackaday, Aug 18, 2024; In a first, electric Ford F-150 trucks are powering homes in Baltimore, Canary Media, Aug 1, 2024; Sunrun, BGE launch first US electric vehicle-to-home virtual power plant, Utility Dive, Jul 25, 2024.

[20] https://support.opensolar.com/hc/en-us/articles/6037827371919-Understanding-California-s-NEM-3-0-Latest-Modifications.

Optimizing the use of these technologies to support the development of electricity infrastructure requires a distribution system performance signal, not a market price signal. In fact, the optimal intent of load smoothing would be to have a constant load that would not have material price differences over the day. Strong wind on a cold winter day may provide a low HOEP on the grid, but it won't change the overloading of the distribution system wires when the heat pumps ramp up. NRCan describes the dual fuel heat pump controls as "*Wi-Fi–enabled smart switching controls that automatically send a signal to the system to switch to the furnace or the heat pump … The smart system takes into account various factors: natural gas and electricity prices, time of use, outdoor air temperatures, performance of the natural gas furnace and performance of the heat pump.*"[21] Crucially, it requires more information than just the electricity wholesale market price and could be configured to "understand" the load interaction with the distribution system.

3. *The advent of AI enables internet-based consumer load optimization*

Google hosted a National Electricity Roundtable in Montreal in June of 2024.[22] A key message was that Artificial Intelligence (AI) is far more mature than most people think and represents another industrial revolution. Google is already working actively with the IESO on its Save On Energy Peak Perks™ program and with Alectra on other projects.

The Peak Perks program has received North American attention with over 100,000 Ontario residents allowing their utility to adjust the homeowner's WiFi enabled smart thermostat up to two degrees to save power during events such as heat waves. This is described by the energy industry as a virtual power plant (VPP).[23] The IESO has partnered with the Energy Hub, a leading North American provider of DERMS. Several smart thermostats are supported, including Google's NEST. The Peak Perks program is currently focussed on avoiding the top peak demand hours during the summer air conditioning season.

Google has incorporated NEST functionality into Google Home. Expanding the notion of Peak Perks to incorporate bi-directional EV charging, dual fuel heat pumps and home energy storage on a 24x7 basis that can leverage such internet-based cloud services, such as Google Home, is not a technology "stretch".

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[21] https://natural-resources.canada.ca/simply-science/the-future-home-heating-hybrid-home-heating-systems-offer-energy-savings-and-reduce-g/22236.

[22] https://static1.squarespace.com/static/65c13565c669a1195a8adfef/t/6658ca1d9c2a3e6860bb420c/1717094942079/Agenda.pdf.

[23] What if you got paid to use less power during heat waves?, CBC News, Jul 28, 2024; EnergyHub Helps Ontario's IESO Build Canada's Largest Residential Virtual Power Plant in Just Six Months, February 1, 2024 - The Financial Post; How an Ontario virtual power plant enrolled 100,000 homes in just six months, Utility Dive, Feb 5, 2024.

The potential for VPPs hinges on the ability to aggregate consumer behaviour. AI is already able to identify and locate where EVs are just using meter data. Its readiness is illustrated by Maryland's regulations that will require utilities to integrate bidirectional EV charging with VPPs.[24] Key VPP players agree that advanced operational software, communications standards and customer compensation can scale VPP size and services, cut system and customer costs and enhance reliability.[25] Studies have shown that this approach could improve the cost effectiveness of Ontario's delivery system.[26]

The first step could be to enable energy management within buildings and then link buildings on a feeder etc. Aggressively adopting these passive low-cost solutions that require no delivery system infrastructure development could buy the time required to optimize the capacity utilization of the delivery system while its expansion and that of the bulk system baseload resources are being planned. The next step of advanced bi-directional power flows from buildings to the grid may be an unnecessary costly distraction. Many utilities are appropriately focusing their development efforts on capacity expansion, not risky bidirectional applications.

4. *Electricity rates designed for synergy with AI and aggregation can enable delivery system capacity enhancements*

The need for Conservation and Demand Management programs to evolve beyond peak reduction to demand smoothing cannot be achieved using market mechanisms. However, consumer electricity rate programs designed for synergy with AI and aggregation could.

Rate programs can be effective enablers of AI-based aggregator solutions given their predictability. Time of use rate programs provide incentives to shift demand away from system peaks to off peak times, every day. The recently introduced ultralow overnight rate might be sufficient to motivate overnight EV charging. Addressing whether aggregators can use it for more than just EV charging and how demand profiles evolve requires optimizing local peak demand on feeders. The IESO has recognized that moving away from simple time-bound frameworks may better leverage CDM as a resource that responds to evolving system, market and customer needs.[27]

Key features for new rate designs are that the offers must be clear and predictable. As home energy management system integration becomes more sophisticated, more

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[24] Bidirectional EV charging, VPP bill passes Maryland Assembly, heads to governor's desk, Utility Dive, Apr 8, 2024.

[25] Tackling 3 key issues can help scale virtual power plants and spur a wave of benefits, analysts say, Utility Dive, Apr 23, 2024.

[26] Strategic Policy Economics, Electrification Pathways for Ontario, 2021.

[27] IESO, Demand Side Management Update - Presentation for the Strategic Advisory Committee, June 26, 2024.

sophisticated rate incentives could be developed that encourage the end objective. Rate programs can be designed to encourage a smooth demand profile to approximate as much as possible a constant load 24x7.[28] This could be presented as a challenge to aggregators to achieve smoothing over feeders etc. Enabling aggregators with aligned consumer incentives could accelerate adoption at a much lower cost by creating scale.

With such a rate program, AI-enabled aggregators will be able to achieve the performance objectives needed to ease Ontario's delivery infrastructure development challenge.

The Answer to Optimizing Distribution System Load: Policies to regulate consumers and incent the private sector support

Philippe Dunsky, the Chair of the recent Canada Electricity Advisory Committee (CEAC) suggested at the OEA/APPrO Sept 2023 conference that it may be time to not rely on markets but instead require customers to implement demand side management. This theme came through in the CEAC report that recommended federal support should prioritize demand management.[29] The report notes that these programs should address demand flexibility and related distribution grid modernization technologies; and, ensure that electricity-consuming entities and project aggregation entities are eligible proponents.

Ontario needs an energy transition strategy rooted in what is achievable where and when. That strategy should consider options for influencing demand growth, demand profile evolution and the need to expand the delivery system. The pace of demand growth can be influenced by policy that helps moderate the increase. While defining an appropriate pace of demand growth acceleration will be controversial, the path forward will in large part be determined by realistic development timelines and acceptable costs. The PWU offers the following policy recommendations that it believes can enable demand side management schemes to moderate demand growth and facilitate and accelerate the delivery system's ability to meet the growing demand cost effectively.

1. LDCs should be mandated to minimize load variability on Ontario's bulk electricity system.

The EETP report strongly encouraged the OEB to enable LDC autonomy in support of innovations within the distribution system. The EETP report stated that: *Where private sector participation lags and markets fail to adopt or proliferate valuable innovations,*

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[28] Informal feedback provided to the OEB on Class B rate designs, February 2021.
[29] Canada Electricity Advisory Council Final Report, Powering Canada - a Blueprint For Success, May 2024.

LDCs should be empowered to step into the breach, in the interest of enabling the energy transition and protecting customers. LDCs should be allowed to include storage facilities located at transformer stations as part of the rate-based infrastructure costs where those assets are needed to optimize station performance. An additional criterion the OEB should include in its BCA should be mitigation of risk associated with the schedules for the development of required distribution infrastructure given the rapid ubiquitous demand growth across the system. It may be appropriate to prioritize the delivery system development schedule as a criterion for procuring both bulk and distribution system assets.

2. Examine the need for the IESO's ongoing procurement of grid scale storage.

As previously noted, analysis has shown that if properly located, Ontario has already procured sufficient grid scale storage assuming the DSM approaches discussed in this paper are adopted. Ongoing procurement of grid scale storage should prioritize optimal locations, such as in transmission stations to moderate demand flows on the upstream grid. This need may be better addressed by transmitters not the IESO.

3. Provide the OEB with a new mandate and criteria for rate design.

The OEB should have the authority to design rates for options that will support innovation from aggregators of BTM consumer DERs. As mentioned earlier, there are rate design approaches to help optimize the smoothing consumer loads.

4. The government should prioritize fuel switching technology adoption incentives.

The EETP report recommended that*: "The provincial government should explore mechanisms to support broad adoption of fuel switching, decarbonization and supportive technologies such as electric vehicles, storage and heat pumps to support its clean energy economy objectives, foster change at the needed pace and scale.* The reference to "needed pace and scale" represents an important caveat.

Burdens on the system can be minimized while achieving emission reductions by managing adoption incentives that moderate local demand and encourage DSM. The government should incent:

- bidirectional EV chargers more than unidirectional chargers; and,
- dual fuel heat pumps or heating modes more than regular heat pumps, where consumers have existing natural gas connections.

The government should further incentivize aggregator program participation when consumers utilize the subsidies for purchasing heat pumps or EVs.

Based on California's experience, net metering requirements should mandate that any new PVs be paired with storage and must be managed to smooth the load on the feeder and not require bi-directional flows to the distribution or transmission systems (i.e. peak output should be less than the coincident peak demand of the building).

5. Transitioning off natural gas and accelerating a hydrogen strategy

EETP report recommended that: *"In order to provide clarity to utilities, investors and customers, the Ministry of Energy should provide policy direction on the role of natural gas in Ontario's future energy system … and consider the various roles natural gas plays across the energy system."* The EETP report further stated that "*The outcome should be to manage the system optimization and fuel switching necessary to achieve a clean energy economy at a pace that maintains affordable, reliable and resilient energy service*." The report suggested several approaches including renewable natural gas and clean hydrogen for the natural gas system.

Effective policy can help manage the synergies between the natural gas system and the hydrogen economy to create the infrastructure required to help mitigate system peaks while achieving emission reduction by incenting hydrogen fueled trucking and charging stations and gas system down blending with hydrogen.[30] Supporting the development of large-scale centralized hydrogen production in southwest Ontario and distributed electrolysis stations throughout province can provide demand side management services.

LDCs mandated to smooth demand as recommended above, could put constraints on new connection requests for EV fleet charging and hydrogen electrolysis installations, requiring that customers must participate in demand management services. Making connections conditional on participant behavior is being advanced by the OEB DER Connections Working Group.

CLOSING

Ontario can mitigate its delivery system development risks through regulated rate designs, incentivizing consumer behind-the-meter (BTM) technology adoption that support grid performance, and enabling AI-powered aggregated demand side management (DSM) of those capabilities.

[30] The IESO and Enbridge have been operating a successful hydrogen to natural gas pilot in Markham.

This paper described the delivery system development challenges including the pace of demand and its drivers, the solutions that exist in the distribution system, the need for a paradigm shift in approach, and the opportunities presented by the emergence of DSM and AI. Supportive policy recommendations for government include expanding the mandates for the LDC, IESO and OEB and for optimal incentives that achievably accelerate the adoption of emission reducing technologies.

Without embracing these new innovations in Ontario's future supply mix, procurements, and delivery system planning, the province will be unnecessarily exposed to both the significant risk that its delivery system will be outpaced by demand growth as well as a greater need for transition bulk system assets that will get stranded.

For over seventy years, the men and women of the PWU have played a critical role helping to keep the province's lights on. The PWU remains a strong supporter and advocate for the prudent and rational reform of Ontario's electricity sector and recognizes the importance of planning for low-cost, low-carbon energy solutions to enhance the competitiveness of Ontario's economy. The PWU has a successful track record working with other energy stakeholders to strengthen and modernize Ontario's electricity system. The PWU is committed to the following principles: Create opportunities for sustainable, high-pay, high-skill jobs; ensure reliable, affordable, environmentally responsible electricity; build economic growth for Ontario's communities; and, promote intelligent reform of Ontario's energy policy.