

THE POWER TO CONNECT

Advancing Customer-Driven Electricity Solutions for Ontario



The Voice of Ontario's Electricity Distributors

February 2017

TABLE OF CONTENTS

Executive Summary	V
1. Introduction	9
1.1 Purpose	9
1.2 Industry Trends, Drivers, and Opportunities	9
1.3 Ontario Regulation and Policy	12
1.3.1 Green Energy and Green Economy Act, 2009	12
1.3.2 Climate Change Mitigation and Low-carbon Economy Act, 2016	13
1.3.3 Strengthening Consumer Protection and Electricity System Oversight Act (Bill 112) ...	13
1.3.4 Transfer Tax and Capital Gains Changes	13
1.3.5 Renewed Regulatory Framework for Electricity	14
1.4 LDCs Today	14
1.4.1 EDA Members Survey Results	155
1.4.2 LDC Innovation Case Studies	15
2. Cross Jurisdictional Research	18
2.1 Overview	18
2.2 New York	19
2.2.1 Technology and Innovation Projects	20
2.2.2 Key Takeaways from New York	21
2.3 California	21
2.3.1 Technology and Innovation Projects	22
2.3.2 Key Takeaways from California	22
2.4 Massachusetts	23
2.4.1 Technology and Innovation Projects	23
2.4.2 Key Takeaways from Massachusetts	23
2.5 Minnesota	23
2.5.1 Technology and Innovation Projects	24
2.5.2 Key Takeaways from Minnesota	24
2.6 Alberta	24
2.6.1 Technology and Innovation Projects	25
2.6.2 Key Takeaways from Alberta	25
2.7 Municipal Utility Regulation in the US	25
2.7.1 Technology and Innovation Projects	26
2.7.2 Key Takeaways from Municipal Utility Regulation in the US	26
2.8 Key Takeaways for Ontario	27
3. LDC of the Future Framework and Vision	29
3.1 DER Enabling Platform	30
3.2 DER Integration	32
3.3 DER Control and Operation	32
3.4 The Vision of the LDC of the Future	33
3.4.1 Fully Integrated Network Orchestrator	34
3.4.2 Alternative Regulatory and Market Framework	37
3.4.3 The Case for a Fully Integrated Network Orchestrator	38
4. LDC of the Future Evolution	41
4.1 DER Enabling Platform Evolution	44
4.2 DER Integration Evolution	44
4.3 DER Control and Operations Evolution	45
5. LDC of the Future Roadmap	47
5.1 Key Challenges	47
5.1.1 Regulation and Policy	47
5.1.2 Customers and Stakeholders	48

5.1.3 Technology	49
5.1.4 Operations	49
5.1.5 Business Models	50
5.2 EDA Initiatives	50
5.3 Conclusion.....	54
Glossary.....	55
APPENDIX A. LDC Case Studies.....	56
APPENDIX B. Jurisdictional Research	69
B.1 New York.....	69
B.2 California.....	71
B.3 Massachusetts	73
B.4 Minnesota	75
B.5 Alberta.....	77

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EXECUTIVE SUMMARY

The electricity grid is undergoing significant transformation to become clean, distributed and intelligent. This is evident in the disruptive triggers associated with technology and innovation, changing market demands, and regulatory and policy shifts. Declining costs of distributed energy resources (DER), digitalization, data analytics, rising customer empowerment, and climate change policies challenge the status-quo.

Local Distribution Companies (LDCs) have a unique opportunity to be at the vanguard of grid transformation by deploying enabling technologies and developing a service platform that provide new innovative offerings to customers and DER providers. The Ontario Energy Board has recognized the changing role of LDCs:

“The nature of electricity distribution has been changing for the past decade and will continue to change. Distribution companies have acted as a delivery route for power from the grid to consumers. In the future they will act more as a service platform offering services such as balancing, power quality, storage, and redistributing power from users connected to their systems.”¹

LDCs are the incumbent owners and operators of Ontario’s electricity distribution grid that interfaces with and integrates the transmission system and customers. By leveraging their existing customer relationships, expertise, brand recognition, and knowledge of their local distribution networks, LDCs are uniquely positioned as the most efficient and cost-effective service provider to lead the transition to a cleaner, more distributed and more intelligent grid.

The purpose of this paper is to present the EDA’s vision for the future role of LDCs, and in turn allow LDCs, government, agencies and interested other parties to better prepare for the challenges and opportunities that will arise in the rapidly changing energy landscape.

Business as usual is no longer an option as it does not sufficiently reflect policy goals and customer demands. This is true not only for LDCs, but for all players in the electricity market. The LDC’s traditional “poles and wires” model will become increasingly inadequate as the level of DER rises and markets become more competitive and complex. The changing energy landscape requires all market players to adapt new strategies to resolve challenges and position themselves for future growth. The roles and responsibilities of LDCs, as well as the government and its agencies, the Independent Electricity System Operator (IESO) and the Ontario Energy Board (OEB), must evolve in response to changing market conditions and market demands as DER penetration increases.

Ontario shares common goals with other jurisdictions to address climate change and facilitate the penetration of cost-effective DER. Ontario’s Climate Change Action Plan includes conservation, energy efficiency and fuel switching to reduce the use of fossil fuels and increase the use of clean electricity and clean fuels. The IESO’s Ontario Planning Outlook (OPO) reports electricity demand outlooks driven by different levels of electrification as a result of policy choices on climate change. The higher demand outlooks assume 2.4 million EVs on the road by 2035, which translates into 8 TWh of incremental energy.² LDCs are critical to enabling DER in Ontario’s energy system and to cost-effectively satisfy increased demand for electricity through electrification of transportation and fuel switching. While LDCs across Ontario are proactively innovating and expanding their capabilities within the current regulatory framework, a more flexible regulatory environment will be essential for LDCs to keep up-to-date with rapidly evolving market conditions. Moreover, public and worker safety and customer reliability will continue to be a priority as LDCs connect DER across their networks.

¹ EB-2015-0043 Rate Design for Commercial and Industrial Customers. OEB. 2015.

² Ontario Planning Outlook. IESO. September 2016.

There will still be a need for considerable investment in traditional distribution infrastructure, hence regulatory reform must be prudently balanced in order to ensure cost-effectiveness. One of the key challenges will be developing fair and transparent rules to achieve the appropriate balance between traditional regulated investments and those that enable and accelerate the development of new, competitive markets.

The EDA sees the LDC of the future as significantly different from current LDCs in three key dimensions:

- 1) *The extent to which an LDC provides a DER enabling platform*
- 2) *The degree of DER ownership by an LDC, and*
- 3) *The degree of control and operation of DER*

Specifically, the EDA sees the LDC of the future playing a key role in Ontario's energy transition as a Fully Integrated Network Orchestrator (FINO). As a FINO, the LDC of the future will potentially enable, control and integrate DER within its distribution service territory. Each LDC will evolve to a FINO at a different pace and to a different degree and there will need to be significant collaboration amongst LDCs related to DER enablement, control and integration as they evolve to become FINOs over the next ten to fifteen years and beyond.

To realize the Power to Connect vision, the EDA intends to:

1) Engage members on the Power to Connect vision.

In January 2017, EDA held two webinars for its members to discuss the Vision Paper. Member response was overwhelmingly positive.

2) Engage the Ministry of Energy in its development of the 2017 Long-Term Energy Plan.

LDCs are the incumbent owners and operators of Ontario's electricity distribution grid that interfaces with and integrates the transmission system and customers. Through the 2017 LTEP, the provincial government should support the modernization of the grid and DERs. The government should also recognize that LDCs are uniquely positioned to lead the transition to a cleaner, more distributed and more intelligent grid given existing customer relationships, brand recognition, and knowledge of local distribution networks.

3) Organize a working group to develop a plan to guide the Power to Connect vision.

A transparent, comprehensive approach is vital to fully addressing broader industry and business model challenges, changing customer needs, and adaptive regulatory structures. This starts with organizing a diverse team within the sector to develop a plan that will guide accomplishment of the Power to Connect vision.

4) Collaborate with external stakeholders on definitions, guiding principles, and essential regulatory changes to realize the Power to Connect vision.

This initiative will provide a basis for developing a strategy to carry out the Power to Connect vision, and give stakeholders opportunity to provide input. It will inform development of business strategies, a cost-benefit analysis framework, and regulatory changes including alternative regulatory frameworks. A potential task under this initiative would be undertaking a Line of Sight exercise to clearly map out the linkage between public policy objectives, enabling technologies and the evolving role of LDCs in our energy future. This exercise will also help to identify and clarify the foundational and conditional investments and capabilities that LDCs will require in the future.

5) Investigate regulatory changes and alternative regulatory frameworks that will incentivize LDCs to integrate DER, where doing so brings economic and/or system efficiencies.

The working group will need to investigate regulatory changes and alternative regulatory frameworks that will incentivize LDCs to integrate DER within their networks. The changes and alternative frameworks must modernize and augment the existing, regulatory framework for LDCs since investments in traditional distribution network infrastructure will continue. The goal is to create an adaptive regulatory structure that reduces barriers for LDCs to become Fully Integrated Network Orchestrators.

6) Develop a cost-benefit analysis framework for evaluation of DER and DER enabling technologies.

A cost-benefit analysis framework will be required to guide LDCs in evaluating DERs and enabling investments. The working group will need to identify the key parameters and inputs to be included in the cost-benefit framework including customer engagement, grid modernization and LDC business activities. In addition, the working group will need to identify the methodology for determining and updating parameter values and an approach to applying the framework to LDCs across Ontario. The framework should also be adaptive to evolve with market conditions, and new products and services as they become available.

7) Facilitate collaboration amongst LDCs, third party DER providers and energy solutions vendors to accelerate efforts for cost-effective deployment of DER and enabling technologies.

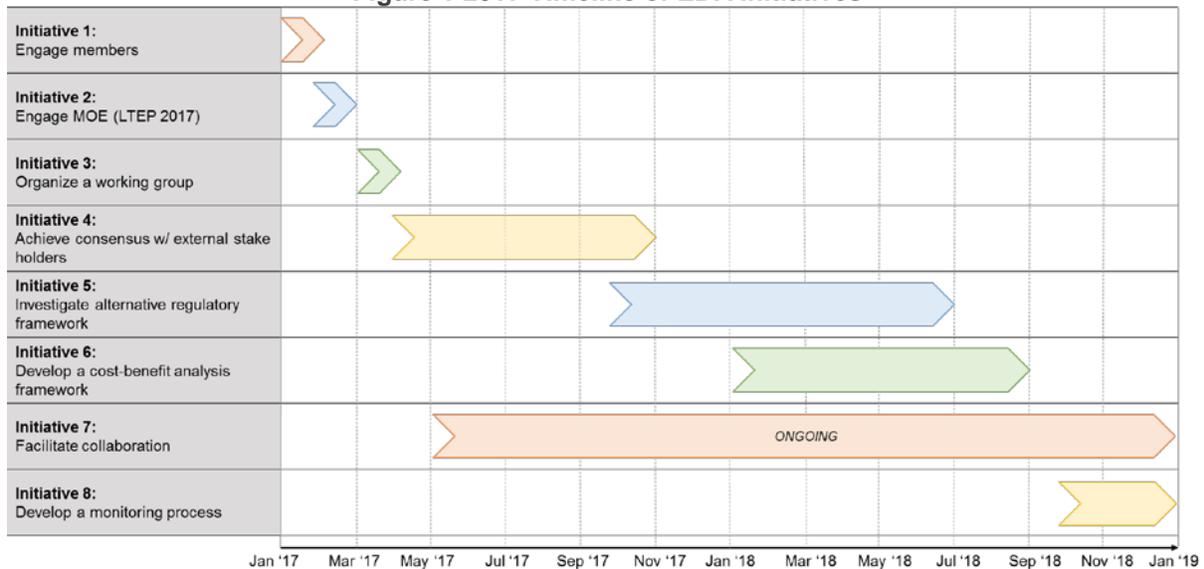
The diversity of LDCs in Ontario presents an opportunity to share unique experiences and lessons learned from the many innovative projects that LDCs are pursuing. LDCs should share information beyond operational or technical knowledge, including their experiences and insights on new business models. LDCs could accelerate their efforts to create economies of scale by investigating potential areas for shared services or joint ventures with other LDCs. Collaboration with third party DER providers and energy solutions vendors can accelerate these efforts and enhance interoperability.

8) Work with the OEB and IESO to develop a process that will monitor the responsiveness of the regulatory framework to the energy grid transformation.

Market conditions will ultimately influence the pace of LDCs' evolution to FINOs. If more DERs emerge in the market faster than expected, then a more advanced and intelligent grid will be required sooner than expected. The working group should coordinate with the OEB to identify a process that would monitor and encourage flexibility in the regulatory framework as the market develops.

In a rapidly evolving market, LDCs and stakeholders must move quickly and be prepared to navigate an increasingly complex energy landscape. The initiatives identified above should commence immediately to begin the discussion on the most appropriate policy and regulatory changes and implementation plan for Ontario. Figure 1 illustrates a proposed timeline for these initiatives over a two-year period. The transformation of the electricity sector will require proactive support from government, regulators, customers, and other stakeholders. Through effective collaboration, Ontario's electricity sector can resolve key challenges and fully realize the benefits of a cleaner, more distributed, and more intelligent electricity system.

Figure 1 2017 Timeline of EDA Initiatives



1. INTRODUCTION

1.1 Purpose

The purpose of this paper is to present the EDA's vision for the future role of LDCs, and in turn allow LDCs, government, agencies and interested stakeholders to better prepare for the challenges and opportunities that will arise in the rapidly changing energy landscape.

The electricity grid is undergoing significant transformation, shifting from the one-way flow of power to a clean, decentralized and intelligent system. This is evident in the integration of new technology and innovation, changing market demands, and regulatory and policy shifts. The status quo continues to be challenged by declining costs of distributed energy resources (DER), digitalization, data analytics, rising customer empowerment, and climate change policies.

Ontario's Climate Change Action Plan (CCAP) includes conservation, energy efficiency and fuel switching initiatives that are designed to reduce the use of fossil fuels and increase the use of clean electricity and clean fuels. LDCs are critical to enabling DER into the system in order to meet future energy demand as a result of electrification and fuel switching. The roles and responsibilities of LDCs, as well as government and its agencies (IESO & OEB), will need to be clearly defined as DER penetration increases.

New strategies, to maximize opportunities and resolve challenges, will be required for LDCs to maintain their valuable role in the market as well as adapt to the changes. There are new opportunities for growth across the value chain, particularly in distributed and behind-the-meter resources. By leveraging their existing customer relationships, expertise, brand recognition, and knowledge of their local distribution networks, LDCs are uniquely positioned as the most efficient and cost-effective service providers to lead the transition to a cleaner, decentralized and more intelligent grid.

1.2 Industry Trends, Drivers, and Opportunities

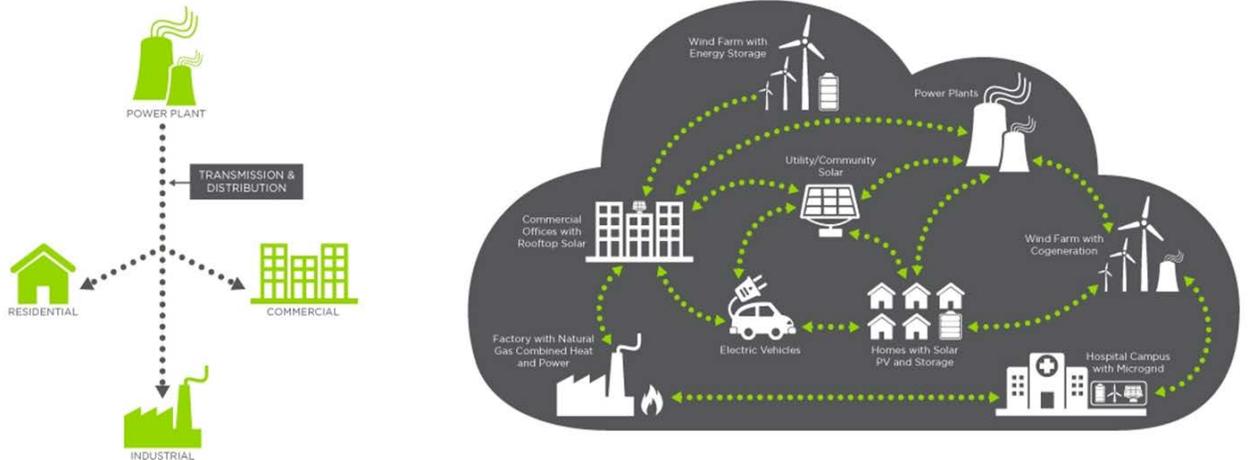
Over the last decade, the electricity sector in Ontario has undergone significant changes that have impacted the roles and responsibilities of electricity distributors. Key drivers of such changes include:

- *Green Energy and Green Economy Act, 2009*
- Conservation and Demand Management (including Ontario's principle to put "Conservation First")
- *Strengthening Consumer Protection and Electricity System Oversight Act, 2015*
- Changes to Transfer Tax and Capital Gains
- Climate Change Action Plan
- Renewed Regulatory Framework for Electricity

Looking to the future, there will continue to be significant changes in the energy landscape that will continue to transform the utility business model. There will be a shift away from the largely one-way power system relying principally on large centralized generation plants and conventional transmission and distribution (T&D) infrastructure toward a highly networked ecosystem of two-way power flows and digitally enabled intelligent grid architecture. This global electricity trend is depicted in Figure 2. This rapidly unfolding energy landscape will present challenges as well as opportunities that will require new strategies and approaches.

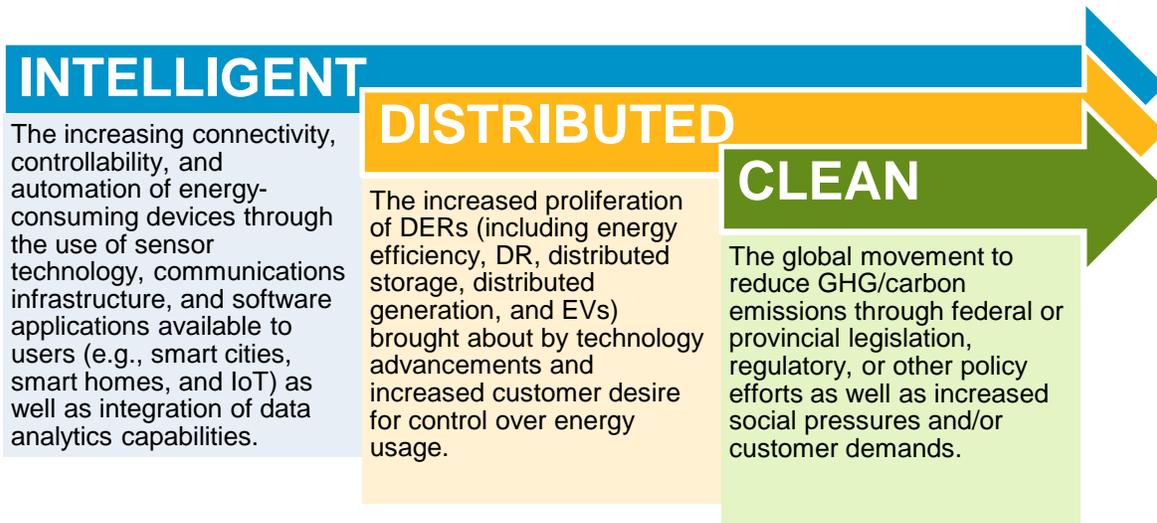
Figure 2 Global Electricity Trends

TODAY: Central, One-Way Power System	EMERGING: Distributed, Two-Way Power Flows
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The transformation reflects an accelerated transition towards a cleaner, more distributed and intelligent energy system (Figure 3).

Figure 3 Electricity Transformation



Source: Navigant Consulting

The shift towards a clean, decentralized and intelligent electricity grid impacts five key industry areas: customers, regulation and policy, technology, operations, and business models.

- 1) Customers: Utilities are continuing to shift their focus towards end-use customers and strengthening their relationships with transmission system operators, as well as new third party service providers.

- 2) Regulation and Policy: The energy future requires a strong regulatory and policy framework supporting renewables, emission reduction, distributed energy resources (DERs) and grid digitalization.
- 3) Technology: Advanced and affordable technologies are enabling development of two-way communications, data analytics, demand-side management, DERs, and aggregation.
- 4) Operations: Information technology and operations are converging towards a more integrated approach to asset management and system optimization. Utilities will need to expand their technical and commercial capabilities in order to thrive in the future energy landscape.
- 5) Business Models: Utilities will evolve towards a distributed system platform business model and will play a central role in enabling a decentralized energy system.

The emergence of the distributed, two-way power flows driven by the changes in industry dimensions is outlined below:

Regulation and Policy

- *Carbon mitigation*: carbon pricing mechanisms, policies and investments (e.g. Ontario's Cap and Trade Program, Ontario's Climate Change Action Plan, Western Climate Change Initiative, The Paris Agreement/COP 21)
- *Shifting utility regulatory models*: incentive-based regulation (e.g. Renewed Regulatory Framework for Electricity, New York's Reforming the Energy Vision)
- *Flexibility*: promotion of distribution system operators, support for energy storage, support for intra- and international interconnection
- *Renewables promotion*: purchasing and/or production requirements (e.g. Green Energy Act, Long-Term Energy Plan), tax incentives (e.g., production tax credits, investment tax credits, accelerated depreciation)
- *DER adoption*: pricing mechanisms and policies (e.g. net metering, feed-in-tariffs)

Market Demand

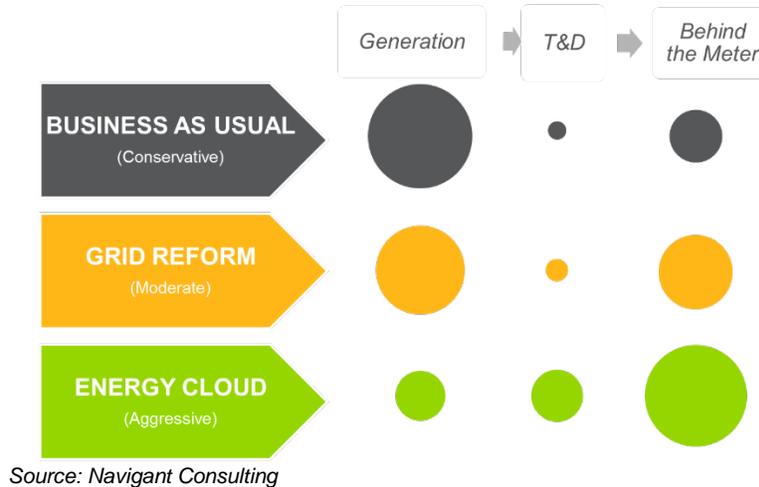
- *Control*: customers demanding control over their electricity usage and expenditure
- *Choice*: customers want the ability to purchase renewable power or self-generate and sell that power back to the grid
- *Sustainability*: businesses want to minimize the environmental impact of their energy use, as well as achieve marketplace differentiation and brand awareness
- *Accessibility*: more options available to greater share of end-use customers

Technology Innovation

- *Affordability*: declining cost of ownership for solar PV, energy storage, and other demand-side technologies
- *Digitalization*: lowering the barrier for entry for innovative solutions
- *Networking and data analytics*: harnessing distributed computing and data across the grid
- *Integration*: pairing of complementary disruptive technologies (e.g. solar + storage)

Since no two markets are alike, the transformation can vary depending on electricity prices, policies and regulations, customer demands, market structure (unbundled vs. vertically integrated), and adoption of new technologies. **Figure 4** depicts the relative revenue allocation across the electricity value chain for various scenarios projected for 2030.

Figure 4 Scenario Relative Revenue Allocation: 2030



As the transformation progresses, new revenue streams will be created through investments in new infrastructure, products, and services across the value chain. Furthermore, significant revenue growth is anticipated downstream towards the retail or behind-the-meter side, as the market evolves towards the distributed, two-way power flow scenario.

The value for T&D grows in each scenario. Since an increasing number of DERs will be connected to the distribution network, the distribution component will have a larger share of revenue compared to transmission. This presents opportunities for utilities to capture value in an evolving energy landscape.

1.3 Ontario Regulation and Policy

The growth of DERs will require a major shift in utility business models. The most important requirement for utilities to be able to aggressively pursue owning and operating DERs is an adaptive regulatory environment. Ontario's primary regulatory policies related to the electricity sector are highlighted in this section.

1.3.1 Green Energy and Green Economy Act, 2009

The *Green Energy and Green Economy Act, 2009* passed in May 2009 and established a renewable energy feed-in tariff (FIT) program, streamlined environmental approvals, gave renewable generation priority access to the transmission system, and reduced revenue uncertainty for renewable projects.

The Act gave the Minister of Energy the authority to direct the former Ontario Power Authority (OPA) to develop a FIT program with domestic content requirements. The FIT program targeted projects that can generate more than 10 kW of power, while a micro-FIT focused on smaller projects. These programs provide a guaranteed long-term pricing structure for biomass, biogas, landfill gas, wind, solar, and hydroelectric projects.

The Act required transmitters and distributors to connect renewable generators where capacity is available. Transmitters and distributors were permitted to recover costs related to renewable generation connection. The Act also permitted an LDC to own a renewable generation, combined heat power (CHP) generation, or an energy storage facility that does not exceed 10 MW.

Long-Term Energy Plan (LTEP)

In the 2013 Long-Term Energy Plan, Ontario committed to putting “Conservation First” in the electricity planning processes prior to building new energy infrastructure. The government also established a target of 20,000 MW of renewables by 2025 (including 10,700 MW of non-hydro renewables). Since 2005, over 6.5 GW of non-hydro renewable resources have been added to Ontario’s electricity system.³ The FIT program enables much of the distribution-connected renewable generation, which reached 3,000 MW by the end of 2015. The IESO has stated that “...policy decisions during the next LTEP will provide guidance on future embedded generation estimates.”⁴ The next LTEP is scheduled for release in 2017.

1.3.2 Climate Change Mitigation and Low-Carbon Economy Act, 2016

On May 18, 2016, the Government of Ontario passed the *Climate Change Mitigation and Low-carbon Economy Act, 2016*. The Act contains both emission reduction targets and the implementation of a Cap and Trade program. The Cap and Trade program will be an economy-wide approach that will cover:

- Electricity, including imports;
- Industrial and large commercial customers;
- Institutional customers;
- Transportation fuel; and
- Distribution of natural gas (e.g., heating fuels)

The Cap and Trade Program was implemented on January 1, 2017 with the first compliance period spanning from January 1, 2017 to December 31, 2020.

Climate Change Action Plan⁵

In June 2016, Ontario released a five-year Climate Change Action Plan (CCAP). The plan outlines the initiatives the government will use to transition Ontario to a low-carbon economy. The plan proposes to use conservation, energy efficiency and fuel switching to reduce the use of fossil fuels and increase the use of clean electricity and clean fuels. Specifically, it aims to increase the use of EVs by ensuring that charging infrastructure becomes widely available. Additionally, the plan intends to help homeowners purchase and install low-carbon technologies (e.g., geothermal, air-source heat pumps, solar thermal and solar energy generation systems) that reduce reliance on fossil fuels for space and water heating. LDCs will have a crucial role in accomplishing the fuel switching and electrification initiatives outlined in the CCAP.

1.3.3 Strengthening Consumer Protection and Electricity System Oversight Act (Bill 112)

Strengthening Consumer Protection and Electricity System Oversight Act, 2015 amended the Ontario Energy Board Act, 1998. This Act authorized an LDC to expand its business activity beyond distributing electricity, pending approval by the Ontario Energy Board (OEB). However, it remains unclear what test the OEB will apply in determining approval. Moreover, the types of business activity that a municipally-controlled distributor’s affiliates can pursue are no longer limited, thus creating opportunities for LDC affiliates.

1.3.4 Transfer Tax and Capital Gains Changes

³ Ontario Planning Outlook. IESO. September 2016.

⁴ Ontario Planning Outlook. IESO. March 2016.

⁵ Source: Ontario’s Five Year Climate Change Action Plan 2016-2020. Ministry of Environment and Climate Change. June 2016.

Through the 2015 Ontario Budget, to promote consolidation of the electricity distribution sector, the government announced a time-limited relief on taxes related to transfers of electricity assets for all municipally owned utilities, including transfers to the private sector. From January 1, 2016 until December 31, 2018, the transfer tax rate is reduced from 33% to 22%, and utilities with fewer than 30,000 customers will be exempt from the transfer tax, and capital gains from the departure tax.

1.3.5 Renewed Regulatory Framework for Electricity

The OEB implemented a Renewed Regulatory Framework for Electricity (RRFE) in 2014 to better align utility reliability and quality of service levels with customer expectations. It shifts the focus of rate setting for electricity distributors from costs and cost recovery to value for customers. RRFE monitors and uses a scorecard to measure LDC performance against defined outcomes including customer focus, operational effectiveness, public policy responsiveness and financial performance. Three incentive-based rate setting alternatives were also introduced to better accommodate the circumstance of each LDC:

- 1) 4th Generation Incentive Regulation Mechanism with initial rates set based on a forward test year cost-of-service followed by four years of incentive rate adjustments.
- 2) A Custom Incentive Regulation with rates set for the entire term based on a projected cost-of-service.
- 3) An Annual Incentive Regulation Index with rates adjusted by a simple price cap index formula.

Lastly, the RRFE takes an integrated approach to distribution network planning. It requires Distribution System Plans to integrate all investments and reflect good asset management practices and greater coordination between utilities on regional infrastructure planning.

1.4 LDCs Today

Currently, LDCs manage one-way energy flow with the obligation to connect customers and accommodate for distributed generation.

LDCs operate under a five-year regulatory rate mechanism with initial rates set based on a forward test year cost-of-service (COS) followed by incentive rate adjustments for the subsequent years. The OEB requires LDCs to file a Distribution System Plan (DSP) that includes smart grid and connections for renewable energy generation. Investments must be justified in terms of customer focus, operational effectiveness, public policy responsiveness, and financial performance. Existing performance standards and system reliability measures include minimum required service levels (SAIDI and SAIFI), customer satisfaction, billing accuracy, cost performance, and peak demand and cumulative energy savings. Collectively, LDCs are also responsible for planning and delivering Conservation and Demand Management (CDM) programs to achieve Ontario's target to reduce 7 TWh of electricity consumption by 2020.

On April 2, 2015, the OEB released a new policy on electricity distribution rate design. As a result, LDCs will transition to implementing fixed distribution charges for residential electricity consumers over four years. OEB is currently examining fixed commercial and industrial customer rates.

In addition, LDC affiliate activities cover areas such as street lighting, energy management services, and metering services. Many LDCs also undertake shared services and partnerships with other LDCs in areas of mutual aid or emergency arrangements, CDM, engineering standards, and joint purchasing.

1.4.1 EDA Members Survey Results

In June 2016, the EDA commissioned Ipsos Public Affairs to conduct a survey of its LDC members.⁶ The purpose of the study was to gather opinions on important issues facing LDCs, and to assist the EDA with longer-term planning and stakeholder relationships. The survey results demonstrate that the industry trends, drivers, challenges and opportunities outlined in Section 1.2 are evident in Ontario. LDCs are inherently aware of the importance of evolving to adapt to future changes.

Nearly all LDCs expressed the desire to expand their businesses. Some LDCs are more interested in shared service models, while others are more inclined towards joint ventures and offering new lines of business within their affiliated companies. The opinion is evenly split in LDC preference for public partnerships or private equity ownership structures as a means of achieving growth. However, some LDCs are more receptive to large amounts of private capital.

In light of the *Strengthening Consumer Protection and Electricity System Oversight Act, 2015* and Transfer Tax rule changes, most LDCs believe that expanded scope and services is the way of the future. They also agree that CDM should continue to be a core function for LDCs. With regards to pursuing new growth opportunities, opinion is varied on whether it should be through an affiliate or within the LDC.

As for scope expansion, utilities are keenly interested in owning renewable generation, energy storage, smart grid initiatives, EV charging infrastructure, and microgrid initiatives. Ownership of these new and emerging technologies is viewed by LDCs as being transformative. However, LDC executives cite regulatory ambiguity and challenges as the number one barrier to expanding their business scope. Similarly, in the US, a joint Public Utilities Fortnightly and Navigant survey found regulatory environment as the most important tipping point for utilities to aggressively pursue owning and operating DERs⁷.

LDCs agree that the future of distribution will be bigger in scale. Most LDCs are also interested in ramping up their scale through acquisitions and consolidation. However, opinion is varied on whether the size of the LDC is related to its ability to meet future challenges. The main barrier identified to expanding current business scale is limited capital (in contrast to regulatory barriers for expanding business scope).

When asked about the challenges facing LDCs in the future, the most cited challenges include:

- Regulatory framework
- Government policies and political priorities
- Customer expectations
- Technological changes

1.4.2 LDC Innovation Case Studies

Despite the challenges, LDCs are proactively testing and expanding their capabilities today by pursuing various technology and innovation projects. This section highlights several innovative projects, which are discussed in further detail in Appendix A.

Veridian Connections Tesla Powerwall

Veridian Connections unveiled the installation of two Tesla Powerwalls at its corporate headquarters in Ajax in June 2016. The first of its kind in Canada, it is part of an innovative microgrid project the utility launched earlier this year alongside Opus One Solutions. The project will integrate multiple sources of

⁶ Ipsos EDA Members Survey Report. June 2016

⁷ State and Future of the Power Industry, Navigant 2016

residential clean energy, while maximizing load efficiencies, energy utilization levels and providing backup power in case of grid outages.

Oshawa PUC Microgrid Research and Innovation Park at UOIT

OPUC provides the 2.4MW CHP plant and expertise on 13.8kV side of the microgrid while Panasonic's 500kW Li-ion battery storage system and 50kW solar PV system will provide power to critical first-priority loads at the UIOT campus through Power Conditioning System (PCS). Proper operation and load, storage and generation balancing of new renewable and storage sources with existing generation systems will be made possible by GE's microgrid controller and optimizer systems. The UOIT microgrid will also provide a facility for research and testing to improve and develop the microgrid concept for larger projects. Such projects include hospitals, military facilities, chemical processing plants and research facilities that require seamless power transition from the grid during power failures.

Niagara Peninsula Energy Inc. Innovation and boosting overall utility performance

Many LDCs are innovating by integrating GIS systems as part of their IT/OT systems. For example, NPEI's innovative integration of GIS has boosted overall utility performance and responsiveness. The system has had significant benefits around outage management as well as key infrastructure planning and asset management. NPEI is known for their ability to respond to the unique needs of their customers through such measures as their well-known Energy Concierge Pilot Program tailored to finding energy efficiency opportunities within the Niagara region's hotel and motel sector.

PowerStream MicroGrid/Virtual Power Plant

PowerStream, in partnership with the Korea Electric Power Corporation (KEPCO), officially launched a utility-scaled microgrid. At the heart of this cutting-edge solution is the Microgrid Distributed Energy Resource Automation System (MiDAS), an advanced microgrid controller that can operate autonomously and optimize the way in which power is delivered. In addition to providing backup power supply, resiliency and operational efficiency in a safe, secure way, MiDAS can also facilitate the use of renewable power sources to provide a lower carbon footprint and ultimately a cleaner environment.

PowerStream also has the POWER.HOUSE pilot program, Canada's first Virtual Power Plant using an aggregate fleet of 20 residential solar and energy storage systems located at customer homes that can be autonomously controlled through intelligent software to simulate a single, larger power generating facility.

COLLUS PowerStream Innovative Energy-Efficiency Program

In partnership with Opower, PowerStream and Collus, PowerStream are giving customers a more personalized experience and more control over their energy use. The partnership includes Opower's Home Energy Report program, which offers a series of customized tips to help customers identify easy ways to lower their consumption and save money. The reports pair behavioural science with Big Data analytics to provide useful information about whether a household's energy use is in line with homes of a similar size, the time of year, and local weather patterns.

Hydro Ottawa Zibi Project

The project includes eco-friendliness in all aspects of the building and design with goals of heightened consumer engagement, decreased carbon emissions, energy cost-savings, and increased resource efficiency. Sitting on the land of a large, former industrial site since the 1800s on the Ottawa River, Zibi has access to clean run-of-the-river generation with the potential for on-site solar generation, energy storage and support for electric vehicles. Windmill is currently building Zibi's first development on the Quebec side of the site. Hydro Ottawa and its partners are discussing concepts for the Ontario version, which involves hosting design charrettes that bring utilities, entrepreneurs, policymakers and project developers together to create change.

Entegrus Grid Edge Controls

As some utilities find themselves struggling because traditional grid management tools are unable to control voltages adequately, a new grid-edge management technology has been successfully installed by Entegrus to help improve voltage stability, customer satisfaction and energy savings on the electrical grid. The pilot, which is also being undertaken at London Hydro and Enwin Utilities, is showing that innovative controls, placed at the grid edge, can overcome these limitations.

Horizon Utilities Virtual Engagement Platform

Horizon Utilities recently launched *Take Charge·Save Energy·Earn Rewards*, an online conservation and demand management (CDM) pilot program that rewards residential customers with Air Miles® reward miles for reducing their household energy use. The program has already demonstrated how a virtual engagement platform can help customers manage their own electricity costs and support Horizon Utilities' overall CDM targets. This innovative program combines behavioural science and technology as a way to engage customers around energy conservation while providing them with tools to manage their own electricity costs.

Enwin UAV Technology

Windsor will be among the first cities in Ontario to benefit from unmanned aerial vehicles (UAVs), better known as drones, which are increasingly employed in the maintenance of hard-to-access infrastructure across North America. *ENWIN* has received a standing Special Flight Operations Certificate (SFOC) from Transport Canada, and is now fully licensed to employ the technology for infrastructure assessment and maintenance inspection. Longer-term benefits could include the early detection of potential electrical fires. Poor connections get hot, and drones equipped with infrared cameras are able to detect them and flag them for repair.

Although LDCs are currently involved with a variety of technology and innovative projects, Ontario has yet to tap into its full potential. There remains plenty of opportunities to further advance DERs in the market and to align public policy goals, customer demands and LDCs' business interests. LDCs are equipped to undertake a leadership role and be at the forefront of the changes in Ontario's energy landscape. Section 22 presents findings of a cross jurisdictional research, which provide valuable key takeaways for Ontario in its approach for the future.

2. CROSS JURISDICTIONAL RESEARCH

2.1 Overview

A cross jurisdictional research and review of developments can provide valuable insight on changes that can be expected in the short term, as well as different approaches in undertaking future challenges for utilities. Jurisdictions were selected based on activity level pertaining to advancing DERs, smart grid, and/or grid modernization initiatives. The five jurisdictions were New York, California, Massachusetts, Minnesota and Alberta. Since most electricity distribution utilities in Ontario are municipally owned, Austin Energy and Sacramento Municipal Utility District (SMUD) were also examined.

In most US states, municipal utilities and public utility districts are not subject to any economic regulation by the state utility regulator. Each jurisdiction has somewhat different approaches to utility regulation as summarized in Table 2-1.

Table 2-1 Overview of Current Regulatory Framework Across Jurisdictions

Mechanism	ON	NY	CA	MA	MN	AB
Capital Expenditure Tracker	Yes	Yes	Yes	Yes	Yes	Yes
Multiyear Rate Plan	Yes	Yes	Yes	No	Yes	Yes
Revenue Decoupling	Yes	Yes	Yes	Yes	Yes ⁸	No
Retail Formula Rate Plan	No	No	No	No	No	No
Forward Test Year	Yes	Yes	Yes	No	Yes	Yes

Although jurisdictions have varying regulatory frameworks and approaches to the evolving energy landscape, initiatives are guided by similar principles:

- Build and maintain a clean, resilient, and affordable energy system
- Achieve public policy objectives
- Enable greater customer engagement, empowerment, and options for energy services
- Facilitate comprehensive, coordinated, and transparent integrated distribution system planning
- Promote innovation and implementation of new technologies

A major challenge is defining the role of utilities and ensuring that regulatory and business models adapt to face the future. Sections 2.2 to 2.7 highlight initiatives, projects, and key takeaways from each jurisdiction. Further details for each jurisdiction can be found in Appendix B. Figure 5 highlights a variety of projects and initiatives across various jurisdictions.

⁸ Minnesota in pilot phase for revenue decoupling; Xcel is partially decoupled.

Figure 5 Projects and Initiatives across Jurisdictions



Source: Navigant Consulting, Inc.

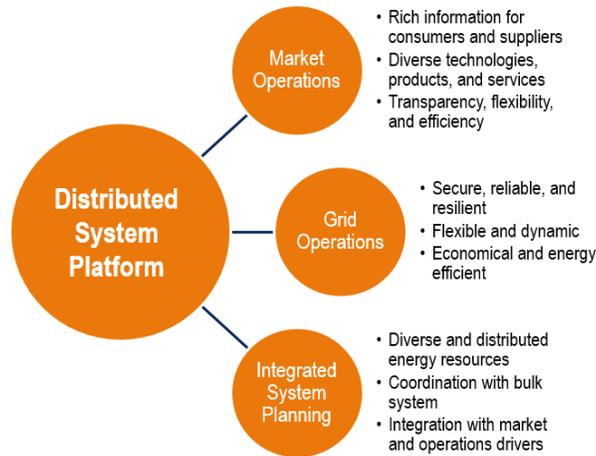
2.2 New York⁹

In 2014, Governor Cuomo launched New York’s energy policy, Reforming the Energy Vision (REV). REV is a comprehensive strategy that aims to build an integrated, clean, resilient and more affordable energy system. New York is not simply imposing a mandate, but is being proactive by acknowledging that the business model of utilities is changing, and in order to facilitate this transition the regulatory framework also needs to change.

Under REV, utilities will expand their roles as Distributed System Platform providers, functioning as integrated system planners, grid operators, and market operators (Figure 6). Utilities submitted Distributed System Implementation Plans (DSIP), describing their strategies over a five-year period for identifying system needs and developing their capacities as a platform.

⁹ Source: NY PSC Case 14-0101, Order Adopting a Ratemaking and Utility Revenue Model Policy Framework

Figure 6 NY REV Distributed System Platform



Source: New York Public Service Commission

In May 2016, NYPSC issued an order adopting changes to the ratemaking and utility revenue model policy framework. The new framework builds from the traditional cost-of-service approach and adds a combination of market-based platform earnings and performance-based earning opportunities.

There will be four ways for utilities to achieve earnings under REV:

- 1) Traditional cost-of-service earnings
- 2) Return on DER investment in lieu of capital investment
- 3) Market-based earnings as platform providers
- 4) Monetized performance metrics

All earnings opportunities under REV will continuously be reevaluated as the market develops.

2.2.1 Technology and Innovation Projects

The NY REV demonstration projects are designed to be a test of new business models, partnerships and revenue sources.



Building Efficiency Marketplace – ConEd is building a platform for small commercial customers to enable clean energy project origination, bidding, and to facilitate technical support and financial options.



Community Energy Coordination - Iberdrola partners with a consulting firm to aggregate local demand for clean energy technologies, target outreach to areas where DER can provide the greatest system benefits, and orchestrate a bulk purchase from third party providers on behalf of customers to lower costs and increase benefits.



Buffalo Niagara Medical Campus Distributed System Platform Engagement Tool - National Grid aims to use the campus as a test-bed for platform functionalities, coordinating and optimizing DER throughout the campus.

2.2.2 Key Takeaways from New York

- A critical challenge is creating a regulatory environment in which a utility will naturally pursue solutions that simultaneously increase its earning opportunity, create consumer savings and facilitate technology innovation.
- Since market and technology evolution pace is unpredictable, the regulatory environment needs to be flexible and adaptable.
- Adding new market-based revenue for utilities is in the public interest since it can help mitigate rate pressure for customers and maintain quality of service.
- There will still be considerable utility investment in conventional rate-based infrastructure, hence regulatory reform must be prudently balanced in order to be cost effective.
- Positive incentives should be used to stimulate a market in the early stages, and negative adjustments can be imposed as required to accelerate progress.
- A fair cost allocation method needs to be established for competitive activities that is made possible by a combination of ratepayer funded infrastructure and at-risk operated expenses.
- Determining DER localized pricing is a rigorous and complex process.

2.3 California¹⁰

California has been a vanguard of energy policy for more than a decade, but in contrast to New York, it is focused on establishing goals and mandates and less on the business model and regulatory framework. A myriad of mandates and market incentives for renewables, distributed solar, energy storage and electric vehicles has significantly reshaped the distribution grid landscape (see Appendix B2 for further details).

California's DRP proceeding required utilities to file resource plans that will identify optimal locations for DER deployment. CPUC is authorized to modify as appropriate any plan to minimize the overall system costs and maximize customer value from DER investments.

¹⁰ Source: California Public Utilities Commission

In its Integrated Distributed Energy Resources (IDER) proceeding, CPUC is working to establish an integrated regulatory framework for the guidance, planning, and evaluation of DER. There are a variety of IDER-related efforts underway, including updating a DER cost-effectiveness calculator and developing the framework for how to source DER to meet grid reliability needs. Moreover, there is a proposal for a regulatory incentive mechanism pilot which would offer an incentive for DER deployment that displaces or defers a utility expenditure based on a fixed percentage of the payment made to the DER provider.

2.3.1 Technology and Innovation Projects



Interconnection Maps - The DRPs require California's three IOUs (PG&E, SCE and SDG&E) to connect developers with the system data needed to enable strategic DER siting



Borrego Springs Microgrid – San Diego Gas & Electric's (SDG&E) microgrid uses solar, energy storage, and automated switching



Qado Energy's GridUnity – Pacific Gas & Electric (PG&E) and SCE are using an advanced distribution system analytics platform to do planning, forecasting, and cost calculations for high DER penetrations.

2.3.2 Key Takeaways from California

- Successive targets and mandates around renewable generation, energy efficiency and DER broadly are reshaping the distribution grid and the utilities that own and operate them.
- Distribution planning should start with a comprehensive, multi-stakeholder planning process that standardizes data and methodologies to address locational benefits and costs of DER.
- Mandates can be written such that utilities are allowed to play, but not dominate the market. For example, utilities in California are allowed to own energy storage provided they “do not unreasonably limit or impair the ability of non-utility enterprises to market and deploy energy storage systems.”¹¹

¹¹ California Assembly Bill 2868

2.4 Massachusetts¹²

Massachusetts has been a progressive stalwart for more than a decade placing a very strong emphasis on energy efficiency, renewable energy and DER development, all centered around a goal to address the effects of climate change. Like California, Massachusetts' emphasis has been on statewide goals and mandates that have catalyzed a robust business environment for energy efficiency providers, distributed renewable sources and demand response solutions. In recent years the Massachusetts Department of Public Utilities (MDPU) has embarked on a policy and operational examination of grid modernization to begin the reshaping of utility grid operations in response to a changed grid landscape.

MDPU's process sought to identify the grid technologies and capabilities that have become foundational for operating a distributed grid environment and providing the means to achieve state policy goals. A taxonomy of grid modernization capabilities was developed and from that the MDPU determined that all utilities should seek offer analysis and plans to offer customer Advanced Metering Functionality (AMF). Rather than prescribe Advanced Metering Infrastructure (AMI), the regulators established a set of benchmarks in terms of functional capability that utilities would address in ten-year Grid Modernization Plans (GMP) that would establish investment priorities backed by cost-benefit analyses.

2.4.1 Technology and Innovation Projects



EVERSOURCE
ENERGY

New Bedford Microgrid - Eversource plans to undertake an energy storage project in New Bedford for voltage smoothing to accommodate high solar PV penetration.

2.4.2 Key Takeaways from Massachusetts

- There is long term commitment to addressing climate change, and fostering DER development at the community and customer level.
- Focusing on grid modernization investments helps address the changing distribution grid operating environment but does not fully address broader industry and business model challenges. Massachusetts opted to maintain the traditional cost-of-service mechanism for cost recovery of investments.
- There is a need for collaboration to enhanced research, development and deployment efforts and budgets, which are typically less than 1% of utility revenues¹³.

2.5 Minnesota¹⁴

Minnesota's e21 put forth recommendations regarding incentive-based ratemaking, customer option and rate design reforms, planning reforms, regulatory process, and distribution grid planning. e21

¹² MA DPU 12-76, Raab Associates, Ltd. & Synapse Energy Economics, Inc. – Massachusetts Electric Grid Modernization Stakeholder Working Group Process, July 2013

¹³ MA Grid Modernization: Detailed Review of Utility Proposals, December 2015 http://acadiacenter.org/wp-content/uploads/2015/12/Acadia-Center_MA-Grid-Mod-Plans_Review-of-Utility-Proposals.pdf

¹⁴ Source: E21 Initiative Phase 1 Report. Great Plains Institute. December 2014.

recommends an optional multi-year, incentive-based framework wherein utilities shall file a comprehensive five-year business plan, describing grid modernization investments, how it will meet performance metrics, and how costs will be allocated and recovered. e21 is currently developing the next level of detail necessary for implementation of its framework recommendations, integrated system planning and grid modernization.

2.5.1 Technology and Innovation Projects



Belle Plain Project - Xcel Energy is planning a solar and energy storage pilot project in the city of Belle Plain to defer a traditional substation upgrade.

2.5.2 Key Takeaways from Minnesota

- With the changes anticipated for the grid over the next decade and the general pace of utility investment decisions (as well as rate cases), it may be challenging for the distribution utility to keep up-to-date in the fast turnaround time of the market.
- Conceptualizing a new utility business model should occur in parallel to prioritizing action items to enable their achievement.
- A holistic approach would be most beneficial for ensuring investments are made in a cost-effective manner.
- Ensuring the safety of the existing distribution grid should not be forgotten in grid modernization processes. The safety of existing infrastructure, including asset management, maintenance, and replacement schedules may warrant additional attention, especially as utilities seek to install advanced technologies across their networks.

2.6 Alberta¹⁵

The Alberta Utilities Commission (AUC) was directed by Alberta's Department of Energy to undertake an official smart grid inquiry in 2010. The purpose was to inform policy development supporting smart grid technology to achieve Alberta's provincial energy strategy goals linked to clean energy production, wise energy use and sustained economic prosperity.

Smart grid development in Alberta has been primarily driven by the industry. Utilities have implemented control and monitoring system applications such as SCADA, outage management systems, workforce management systems and graphical information systems. Utilities are also investing in projects that include communication system upgrades and integration of control and protection devices, and intelligent electronic devices, in order to achieve automation. For example, ENMAX deployed a major distribution automation project to improve the reliability of its distribution system in Calgary. FortisAlberta, and the cities of Medicine Hat and Lethbridge have installed smart meters in their service areas.

¹⁵ Source: Alberta Smart Grid Inquiry. Alberta Utilities Commission. January 2011.

In November 2016, the government of Alberta announced changes to its electricity market to ensure power supply as it phases out coal-fired power plants. Alberta's electricity market will transition from the existing deregulated energy-only system towards a regulated capacity market starting in 2021.¹⁶ Transmission and distribution will remain fully regulated by the Alberta Utilities Commission (AUC) based on a cost-of-service model.

2.6.1 Technology and Innovation Projects



ENMAX's Smart Grid vision - ENMAX Energy partnered with Cisco to advance projects on building energy management, residential energy management, data centre readiness, system security and renewable energy optimization. ENMAX and Cisco are working together to enable automated demand-response management with commercial and industrial customers.

2.6.2 Key Takeaways from Alberta

- When Alberta deregulated in 2001, PPAs allowed existing utility owners to continue to own and operate their facilities, but auctioned the dispatch rights of the associated energy to new buyers. Market rules will need to be clarified since a future role wherein LDCs serve as a distributed system operator may present a conflict of interest in terms of market operations.

2.7 Municipal Utility Regulation in the US

In contrast to Ontario, most municipally owned utilities in the US are not subject to state regulatory oversight and have greater flexibility to act on policy reforms. Municipal utilities in Austin and Sacramento demonstrate innovation in tackling the same realities faced by other providers in a landscape of evolving technology, infrastructure needs and consumer demand.

Austin Energy

The City of Austin has long been in the vanguard in terms of their energy policies centered on renewable supply and combatting the effects of climate change. Austin has advanced these efforts through its municipal utility, Austin Energy and the Pecan Street Project, a public-private partnership to model the modern grid with demonstrations of smart grid technologies, electric vehicles (EV) and home automation solutions.

Austin Energy currently has a Plug-in Everywhere program that offers PEV owners a rebate of 50% of the cost of the purchase and installation of a Level 2 charging station. In addition, its EV360 Pilot Program allows customers to take advantage of a fixed, time-of-use rate that includes unlimited charging anywhere on the Plug-In Everywhere network and unlimited off-peak charging at home. Austin Energy operates the Plug-in Everywhere network powered by renewable energy and will continue to expand Austin's EV charging network, targeting retail premises, work places and multifamily sites.

Residential customers are eligible for rebates and can also earn a Value-of-Solar credit on their monthly bill for every kilowatt-hour of electricity their solar system produces. Commercial customers can qualify for a performance-based incentive, calculated based on the total electricity generated (regardless if it were consumed on site or sent to the grid) and a pre-determined rate locked in for a 10-year term.

¹⁶ Source: Alberta Electric System Operator

Moreover, Austin Energy implemented its GreenChoice program, allowing residential and commercial customers to meet their electricity needs by opting to pay a premium for 100% renewable Texas wind power. Austin Energy has the exclusive right to sell electricity in its service area, hence Power Purchase Agreements (PPAs) are not permitted.

Sacramento Municipal Utility District (SMUD)

SMUD has a number of programs supporting renewable energy. Greenenergy is an opt-in program wherein customers can pay a monthly premium to support a mix of different types of renewable energy resources such as solar, wind and hydro. SolarShares gives customers the opportunity to benefit from solar energy when installing a rooftop solar system is not possible. A portion of the solar power produced at a local solar farm will be credited to the customer's monthly SMUD bill. Finally, renewable projects up to 5MW can qualify for a FIT rate, and projects larger than 5MW can have opportunities in SMUD's periodic request for offers for renewable energy.

SMUD's SmartSacramento Project involves consumer behavioral studies, system-wide deployment of AMI integrated with IT systems as well as partial deployment of automated control and operation capabilities on the distribution grid assets. The project also empowers customers through systems that provide energy usage and cost information.

As part of SmartSacramento, SMUD has issued an in-home display check-out program allowing customers to learn about their whole house consumption with real-time data for two months, and then returning the devices to SMUD or a public library. SMUD is engaging customers via dynamic websites, text messages, social media, energy usage data on a web portal and educational videos.

2.7.1 Technology and Innovation Projects

	<p>Austin SHINES - Austin Energy is piloting a technology platform that integrates solar power, energy storage (lithium-ion batteries), smart inverters, forecasting tools, market signals, advanced communications and a software optimization platform.</p>
	<p>Solar EV Charge Port- SMUD has implemented EV fast chargers allowing drivers to charge up to 80% of their car's battery in less than 30 minutes, thus giving drivers the range confidence to fully realize the potential EVs offer.</p>

2.7.2 Key Takeaways from Municipal Utility Regulation in the US

- Municipal utilities can be at the vanguard of change, deploying new technologies and offering new innovative offerings to their customers, sometimes empowered by a motivated local governance structure.
- It is important to develop tools that make it easy for customers to enroll in and exit programs, and marketing materials that describe offerings and answer questions. These give customers the option to be a consumer or a prosumer.

2.8 Key Takeaways for Ontario

Ontario shares goals with the other jurisdictions to address climate change and enhance the penetration of DERs. Listed below are key takeaways from the above jurisdictions which LDCs, government, its agencies and other interested stakeholders in Ontario can apply to guide their own energy transformation efforts:

- A transparent, holistic approach is vital to fully addressing broader industry and business model challenges, changing customer needs, and adaptive regulatory structures.
- LDCs can be at the vanguard of change, deploying new technologies and offering new innovative offerings to customers.
- With the changes anticipated for the electricity grid over the next decade, and the general pace of rate cases and investment decisions, a flexible regulatory environment will be essential for LDCs to keep up-to-date.
- Ensuring the safety of the existing distribution grid should not be overlooked in grid modernization processes. The safety of existing infrastructure, including asset management, maintenance, and replacement schedules may warrant additional attention, especially as LDCs seek to install advanced technologies across their networks.
- There will still be considerable investment in conventional rate-based infrastructure, hence regulatory reform must be prudently balanced to be expedient and cost effective.
- One of the key challenges for the OEB will be achieving a balance between regulated and competitive markets. Transparent and fair market rules will need to be developed.
- Positive incentives should be used to stimulate a market in the early stages, and negative adjustments can be imposed as required to accelerate progress.
- Adding new market-based revenue for LDCs is in the public interest since it can help mitigate rate pressure for customers and maintain quality of service.
- DER planning will be more predictable and cost-effective with LDC market participation, thus more certainty in achieving public policy goals.
- Distribution planning should start with a comprehensive, multi-stakeholder planning process that standardizes data and methodologies to address locational benefits and costs of DERs.
- Appropriate price signals are needed so that investments and operations behind-the-meter are economic for both the customers and the entire system.
- A future role wherein LDCs own DERs and have capabilities as a distributed system operator may present a conflict in terms of market operation. Transparency in the development of market rules will be integral.
- It is important to develop tools that make it easy for customers to enroll in and exit programs, and marketing materials that describe offerings and answer questions. These give customers the option to be a consumer or a prosumer.

- Collaboration amongst LDCs is necessary for efficient DER research, development and deployment.

Based on the current state of the distribution sector in Ontario, coupled with the lessons learned from other jurisdictions, Section 3 presents EDA's vision of the "LDC of the future" and provides a potential path forward to realize the benefits of a cleaner, more distributed and more intelligent electricity system in Ontario.

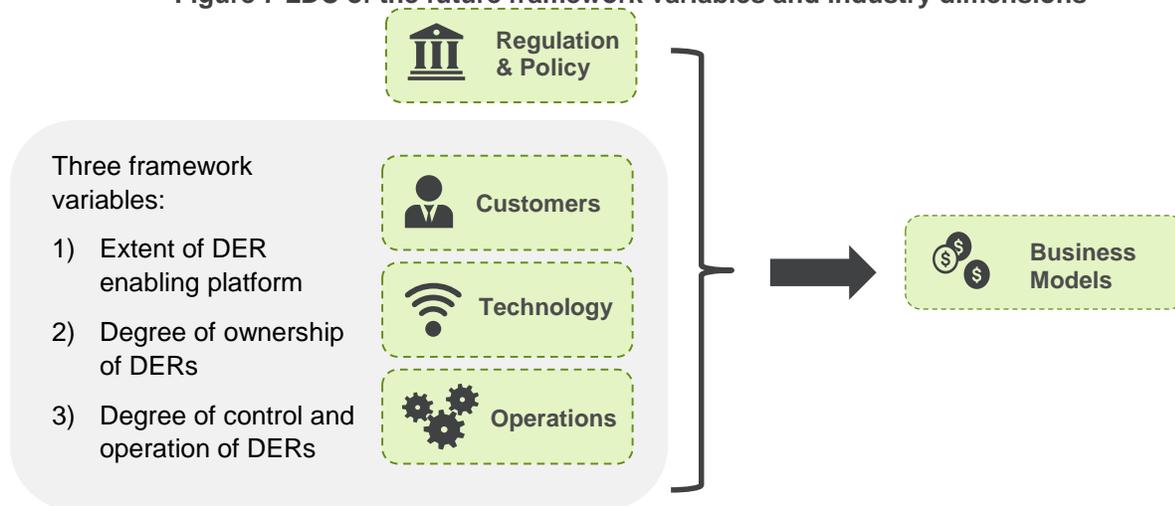
3. LDC OF THE FUTURE FRAMEWORK AND VISION

This section discusses the LDC of the future framework. The EDA sees three variables that will impact the LDC of the future:

- extent to which LDCs provide a DER enabling platform;
- degree of ownership of DERs; and
- degree of control and operations of DERs.

Each of these variables is directly associated with the industry dimensions of customers, technology, and operations. The LDC of the future framework, along with regulation and policy, will influence LDC's future business models (Figure 7).

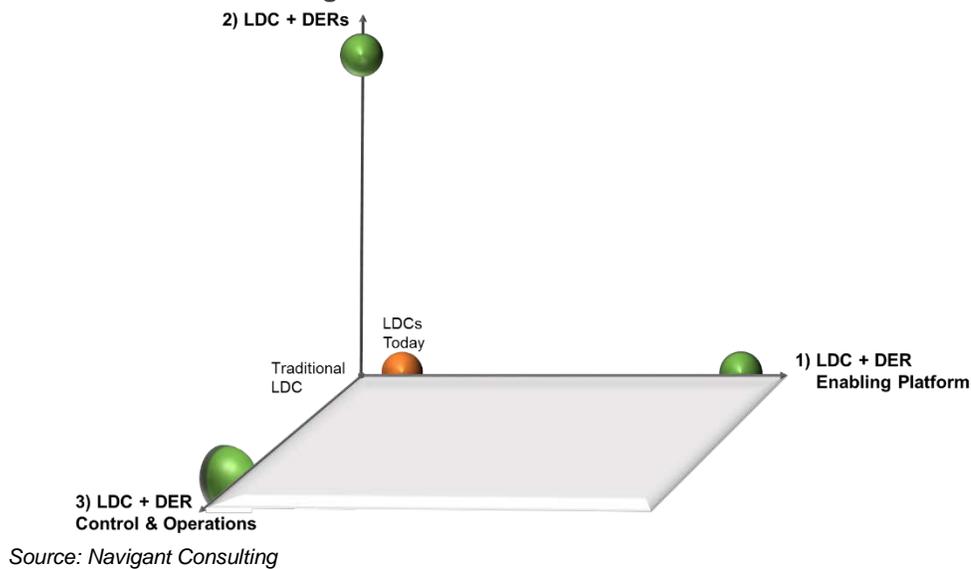
Figure 7 LDC of the future framework variables and industry dimensions



Source: Navigant Consulting

The role of the LDC of the future will be a combination of the shifts towards providing a DER enabling platform, owning DER assets, and controlling and operating DERs. Figure 8 combines the three framework variables into a 3-D graphical representation in which the LDC of the future role will evolve.

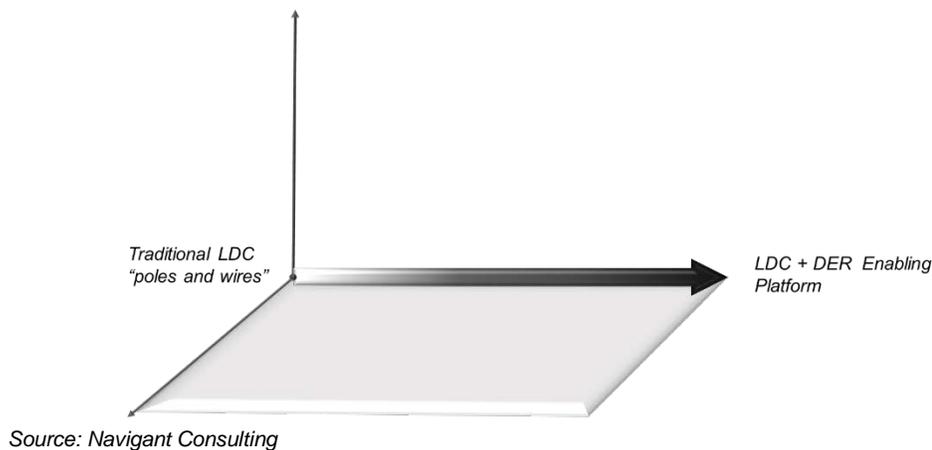
Figure 8 LDC of the future framework



3.1 DER Enabling Platform

With increased proliferation of DERs on the distribution grid, the LDC will be key in facilitating and enabling DERs. The DER Enabling Platform refers to the extent to which LDCs will provide an intelligent platform where DER third party providers and customers can “plug-n’-play.” Part of an LDC’s role will be to ensure that the distribution network can accommodate DER connections, while maintaining the stability and reliability of the grid.

Figure 9 Extent of DER Enabling Platform



An LDC’s role as a traditional “poles and wires” provider will be expanded to include the provision of a DER enabling platform as depicted in Figure 9. To facilitate this development, distribution network control and automation, AMI, smart inverters, two-way communication, and an Advanced Distribution Management System (ADMS) will need to be deployed.

Distribution network automation upgrades could include implementation of Intelligent Electronic Devices (IEDs) such as remote terminal units (RTU), digital recloser controller, digital fault recorders, programmable logic controllers (PLCs), remotely controlled voltage regulators, and automatic transfer schemes. IEDs are microprocessor-based controllers of power system equipment, such as circuit breakers, transformers and capacitor banks, which can also make two-way digital communication possible with other devices.

Smart inverter technologies permit generation management, static voltage support through reactive power management, and/or dynamic grid support during contingencies via fault ride-through. As communications and smart grid infrastructure improve, central coordination and control of these support strategies will be enabled.

ADMS is an emerging grid technology innovation that unifies operational and engineering data for state analysis, switching, outage management, planning, and providing a single, more efficiently managed platform for operating the distribution network. Recent trends in ADMS development encompass the full integration of all IT/OT systems, including meter data management and asset management systems. Vendors are also starting to incorporate capabilities of DER management systems and demand response management systems. ADMS technology is still on a steep learning curve; one of the market challenges for ADMS is the lack of experiential proof that it can provide solutions that are appropriate for unique LDCs or distribution grids.¹⁷

Advancement in communications and IT, including data analytics, will support the application of existing and future smart devices on the grid. Access to a ubiquitous, high bandwidth, low latency network is needed to provide transport for grid intelligence and enable the management and automation of two-way power flows, transactive energy markets, and other energy services. A communications platform can be built using public or private options, and both wired and wireless options. For example, purchasing or leasing a private licensed spectrum, creating a fibre-to-the-premises, and possibly fifth generation wireless technology if an LDC is willing to partner with public carriers. Advanced distribution technologies are highly dependent on the availability of high speed telecommunication systems. In addition, the cost of upgrading communication systems or purchasing new systems may be restrictive.

There are numerous other tools and activities that would promote and facilitate DER connections to the distribution network, including web-based interconnection tools for project origination, optimal DER siting, application tracking and evaluation. Grid cyber security and technical and operational standards can mitigate risks and ensure safety and reliability with increased DER adoption.

LDCs must provide DER enabling technologies due to operational and planning practicalities. Their knowledge and experience with the distribution network will give insights for optimal DER siting and help maintain system integrity and reliability as DER penetration increases. AMI is also already widely implemented across the grid in Ontario, placing LDCs at an advantage to serve as an enabling platform.

A variety of DER enabling platform projects are underway both in the US and Ontario. In Ontario, Oshawa PUC is improving its analytical capabilities by leveraging smart meter data to understand their customers' energy usage patterns and tailoring energy efficiency programs to meet customer needs. PowerStream launched a utility-scale microgrid with an advanced microgrid controller that can operate autonomously and optimize the way in which power is delivered. In New York, Con Edison proposed a "Building Efficiency Marketplace" demonstration project to streamline connections between customers and a network of solution providers. The platform will use interval meter data to identify high potential projects that can be placed in the market for project origination. PG&E in California

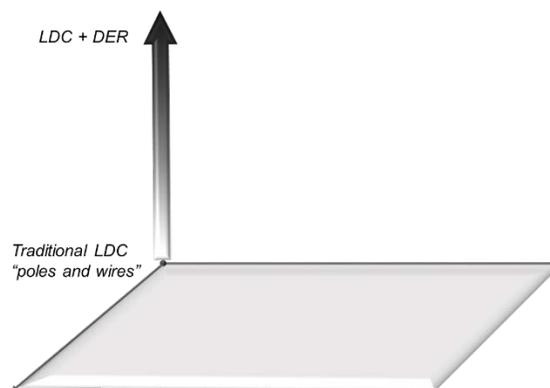
¹⁷ Grid Edge Intelligence for DER Integration. Navigant Research. 2015.

started deploying smart inverters in the field earlier this year, along with a DERMS to allow for DER control and monitoring. A number of utilities in the US such as Austin Energy, CenterPoint Energy (Illinois), SDG&E, Duke Energy and PG&E, have implemented ADMS.

3.2 DER Integration

The DER Integration variable refers to the degree of DER asset ownership by LDCs in their scope of business (Figure 10). DERs could include solar, wind, energy storage, EV charging infrastructure, CHP, fuel cells, demand response, and conservation and demand management. The extent of DER integration will vary for each LDC given the diversity in size, location, and hosting capacity.

Figure 10 Degree of ownership of DER



Source: Navigant Consulting

LDCs are well positioned to stimulate the DER market development. As regulated entities, LDCs can modestly invest in areas where a private company might not be able to earn an immediate return on investment. DER Integration by LDCs does not necessarily mean that market innovation will be dampened or that customer choice will be limited. LDCs may contract out many services, and these contracts can lead to development of new energy solutions, ideas and services. DER Integration does not preclude other market players from owning and operating DERs. Further, DER planning will be more predictable compared to an exclusively market-based structure, thus there is more certainty in achieving public policy goals.

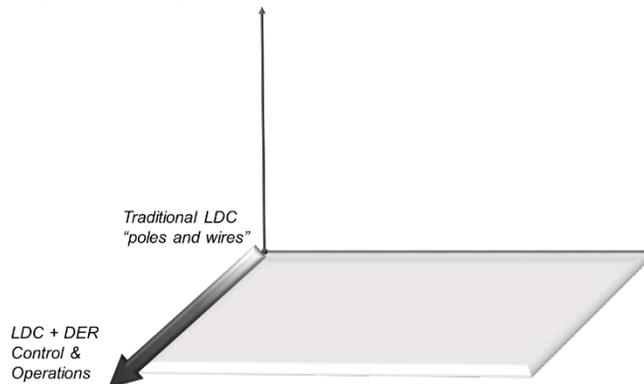
LDCs in Ontario have already started integrating DERs into their networks. PowerStream's POWER.HOUSE project uses a fleet of solar PVs and energy storage systems to form a virtual power plant that can be controlled to simulate a single, larger power generating facility. Veridian Connections has collaborated with Opus One Solutions on a microgrid project integrating Tesla Powerwalls.

3.3 DER Control and Operation

DER Control and Operation refers to the degree to which LDCs control and operate DERs that are connected to their distribution networks. It is within the capacity of LDCs to serve as a distributed system operator or a mini-IESO. Through operations and interaction with DERs, LDCs can optimize the value of DERs to the larger system and to all customers. Elements associated with DER Control and Operation include real-time visibility, DER price signal, and new products and services such as virtual power plant aggregation, load management, and grid services. As with the previously discussed variables, DER

Control and Operations will be in addition to the traditional LDC “poles and wires” model, as depicted in Figure 11.

Figure 11 Degree of control and operation of DER



Source: Navigant Consulting

One of the critical building blocks for DER Control and Operations is a DER Management System (DERMS). DERMS capabilities typically include real-time network visibility, asset monitoring and control, scheduling and dispatch, active and reactive power import and export control, voltage control, forecasting, resource valuation and optimal demand response.¹⁸

Another fundamental element is the implementation of DER price signals. Appropriate price signals are needed so that investments behind-the-meter are economic for both the customers and the entire system. DERMS and DER price signals will enable LDCs to dispatch DERs to maximize value and ensure efficient use of both centralized and distributed resources. LDCs will continue to procure power at low cost, in large part from centralized resources. However, they would also be empowered to incorporate a wider variety of technologies and DERs alongside centralized generation. Coordination between IESO and LDCs will need to be enhanced to utilize DERs efficiently.

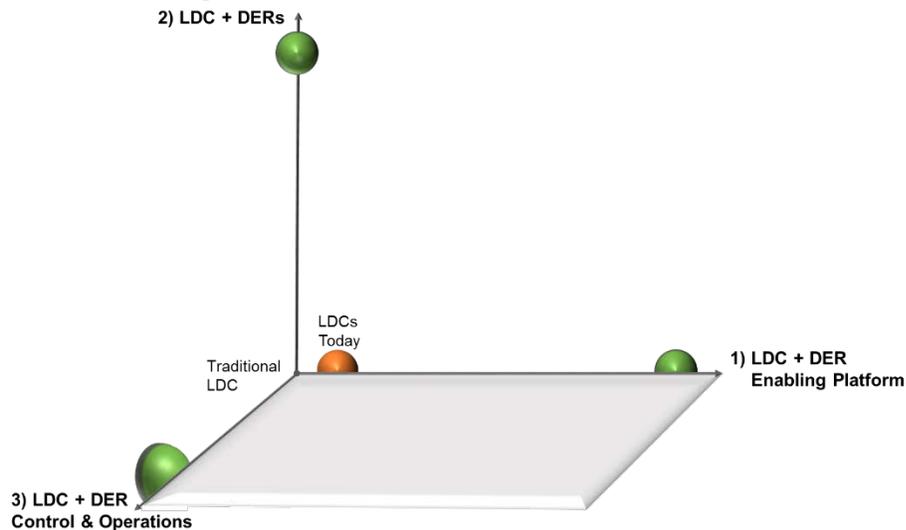
Niagara Peninsula Energy Inc. (NPEI) is one of the few LDCs in Ontario to have its Geographic Information System (GIS) fully integrated with other operating systems, creating a tool that not only enables quick power restoration, but also effective infrastructure upgrades and planning. A fully integrated GIS is a step in the right direction for achieving real-time visibility of the distribution grid. Through a software management system, PowerStream's POWER.HOUSE allows for the aggregation of DERs into a virtual power plant, providing operators with the capability to deliver grid-scale energy services.

3.4 The Vision of the LDC of the Future

The EDA sees the LDC of the future role to be a combination of providing a DER enabling platform, owning DER assets, and controlling and operating DERs. Figure 12 combines the three framework variables previously discussed into a 3-D graphical representation of the LDC of the future role.

¹⁸ Grid Edge Intelligence for DER Integration. Navigant Research. 2015.

Figure 12 LDC of the Future Framework



Source: Navigant Consulting

Figure 12 depicts the potential role of the LDC of the future, depending on the extent to which LDCs can pursue each variable. Today, LDCs largely operate under the traditional “poles and wires” model and as such are depicted near the origin in Figure 12.

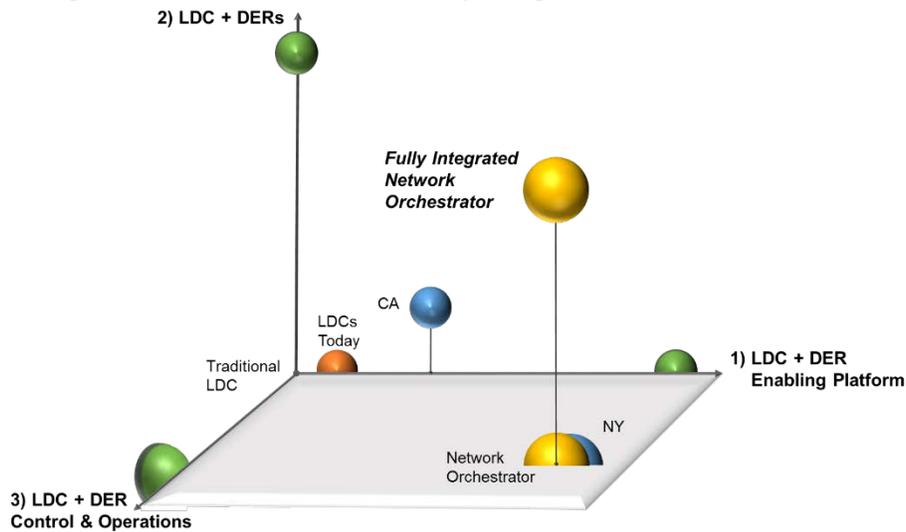
Considering the diversity in size, location, resources, and capabilities of LDCs in Ontario, each LDC’s evolution will vary as there is no one-size-fits-all future role. Under any future role, LDCs would retain all current responsibilities to ensure the safe, reliable, and affordable operation of the distribution grid.

3.4.1 Fully Integrated Network Orchestrator

In general, a network orchestrator creates a network in which the participants interact and share in the value creation. They may sell products or services, build relationships, collaborate, co-create and more. Examples of network orchestrators include Uber and AirBnB. Uber and AirBnB are transforming the transportation and hotel industry without owning the physical assets. Without physical assets, this model is the easiest to scale up, and is therefore potentially the most profitable. In Ontario, DER asset ownership by LDCs will be necessary to stimulate the market.

A Fully Integrated Network Orchestrator (FINO) ventures into the DER Enabling Platform, DER Integration, and DER Control and Operations variables in the LDC of the future framework as shown on Figure 13. The objectives of this role are to increase customer choice and value, enable diverse DER integration, maintain and improve grid reliability, improve overall efficiency, and facilitate a DER market.

Figure 13 LDC of the Future - Fully Integrated Network Orchestrator



Source: Navigant Consulting

Aspects of the NY REV model parallel a network orchestrator model, hence its placement on Figure 13. Under NY REV, utilities are not to own DER projects except under limited circumstances where DER investments are made in lieu of capital investments. However, to stimulate the market in the early stages, utilities will manage the grid through planning and procuring similar to current processes. Nevertheless, New York intends to transition towards a greater market-based competitive system.¹⁹ In contrast to New York, California permits some DER ownership by the LDCs. For instance, LDCs are allowed to own energy storage provided they “do not unreasonably limit or impair the ability of non-utility enterprises to market and deploy energy storage systems”.²⁰

A challenge under this model will be to balance the LDCs’ market power. As a provider of the enabling platform, there is a potential conflict of interest with connecting and dispatching LDC-owned DERs versus other suppliers. Rules surrounding interconnection and market operations will need to be clearly established.

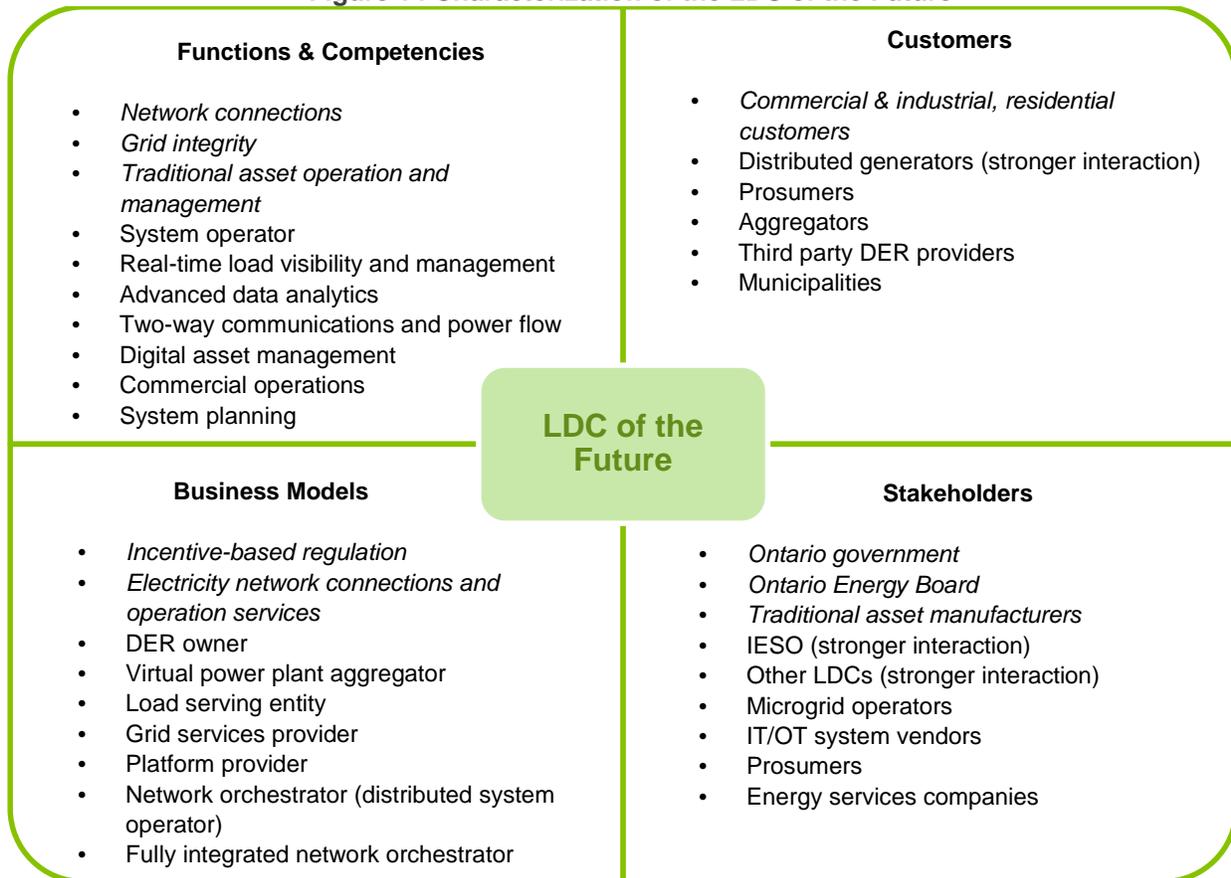
Since Ontario does not have a retail market for electricity, LDCs are the most effective means of bringing DERs to the market. They can leverage existing customer relationships, service facilities, brand recognition, and their experience with the distribution network will allow LDCs to streamline interconnection management. Increased customer choice through a FINO will result in new relationships between customers and DER third party providers and/or vendors, instead of solely with the LDC.

An additional service that an LDC could provide would be bill management for customers from a variety of DER third-party providers. Other platform services could include data analysis, customer online portals, and web-based interconnection tools for streamlining DER applications. As an LDC’s functions and capabilities evolve, its relationships with customers and stakeholders would expand and become more complex. Figure 14 characterizes the LDC of the future in terms of functions and competencies, customers, business models and stakeholders.

¹⁹ NYPSC 14-M-0101 Order Adopting Regulatory Policy Framework and Implementation Plan. February 2015.

²⁰ California Assembly Bill 2868

Figure 14 Characterization of the LDC of the Future

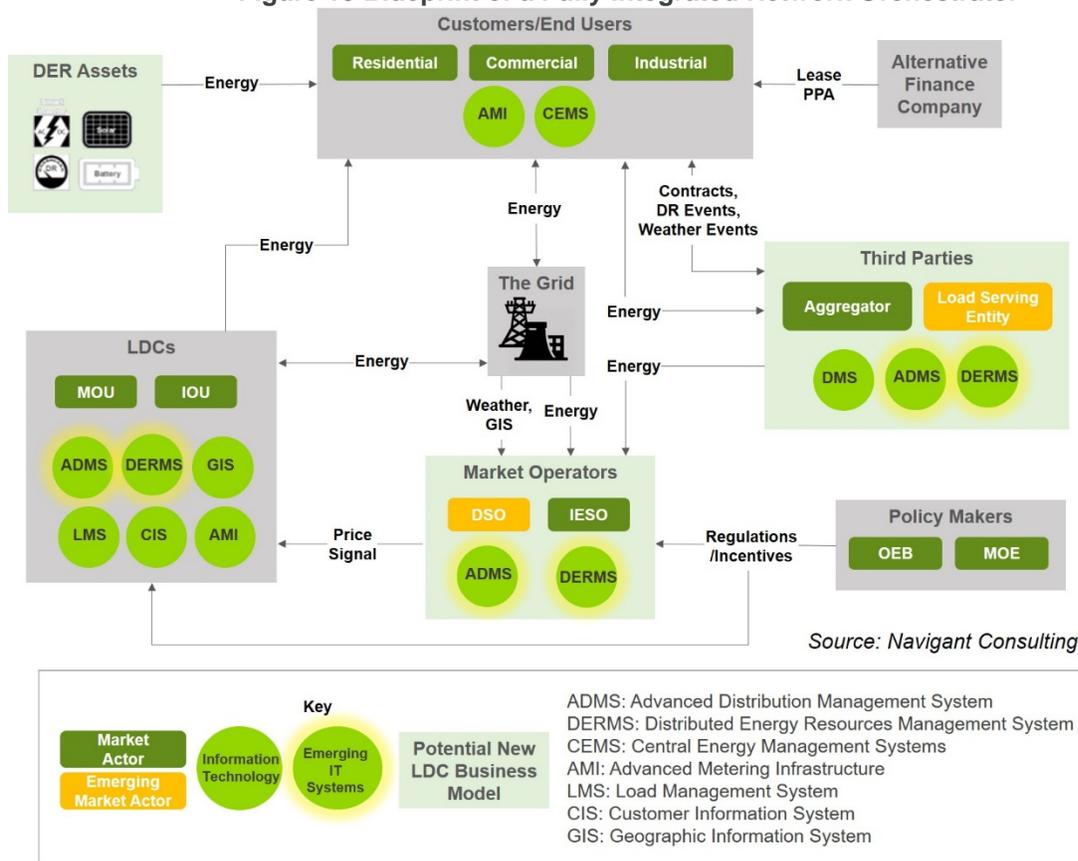


Key: *Exists Today*
Emerging

Source: Navigant Consulting

Figure 15 provides a blueprint for the LDC's role as a FINO and illustrates the future energy grid in which it will operate. It describes a market in which LDCs, customers, third parties, IESO and policy makers work in conjunction to fully integrate DERs across operations, energy markets, and system planning. Critical information, operations, and communications systems will support real-time DER management. Ideally, there would be appropriate DER price signals and policy makers would establish incentives for LDCs to advance DER and provide behind-the-meter energy solutions to customers. In addition to owning DER assets, LDCs may also provide services as a virtual power plant aggregator combining DERs into a reliable grid resource and selling electricity to the wholesale market. LDCs may essentially become load serving entities.

Figure 15 Blueprint of a Fully Integrated Network Orchestrator



3.4.2 Alternative Regulatory and Market Framework

The Ontario Energy Board's traditional Cost-of-Service (COS) rate-setting model is considered insufficient because it relies on sales growth and asset acquisition, both of which contradict Ontario's energy conservation policies. As the level of DERs increases and markets become more competitive, electricity sales volumes will decline, thus increasing the risk of stranded assets. For publicly-owned utilities, the burden of these stranded assets would fall on the ratepayers, as governments would take a loss on the investment. For an investor-owned utility, stranded assets pose a risk for current investors, and can also deter future investors from becoming shareholders.

Fixed distribution charges can potentially mitigate the risk of stranded assets in the immediate future. The OEB introduced fixed distribution charges for residential customers. The OEB has also expressed intent to introduce a new rate policy for commercial and industrial customers, but this is not yet available. In the long-term, Ontario needs regulatory and market incentives that align customer value, policy goals and LDCs' financial interests.

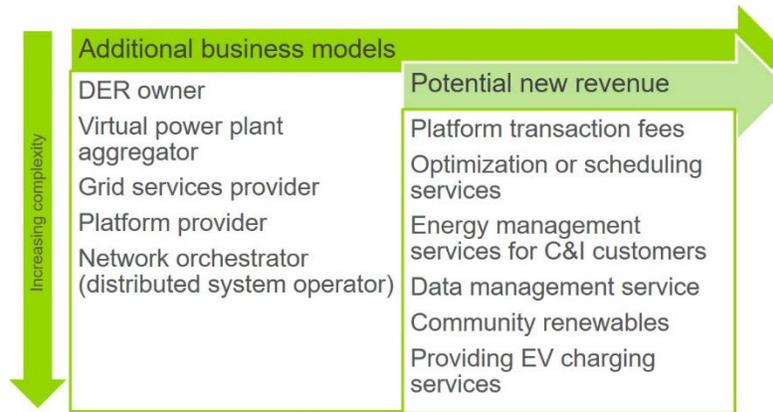
One option is to introduce a use-of-system charge for prosumers that choose to implement DERs for self-generation. A use-of-system charge would compensate LDCs for enabling DERs on their distribution networks as well as reduce cross subsidization by regular consumers.

LDCs must be incentivized to use operating resources or third party assets in lieu of capital investment, where it is more cost-effective. For example, NY REV is implementing a reconciliation mechanism

wherein LDCs are allowed to keep a portion of the difference between planned capital expenditure and the more economical solution. An alternative regulatory framework could make the LDC indifferent between capital and operating expenditures, provided the latter brings more customer value. Further, LDCs will have to manage more digital assets that require continuous upgrades, which are treated as operational expenditures under the current framework. LDCs can be compensated either through a separate rate case application or a fee-for-service. The OEB needs to consider the customer's total delivered cost of electricity as opposed to focusing only on distribution costs in its review of DSPs.

Lastly, LDCs may also earn additional revenue from market-based activities. There is opportunity to increase revenue by serving as a platform for customers and DER third-party providers. For instance, LDCs can charge for access to data and information identifying the best locations for investment, pricing signals that indicate the real-time value of the investment, and other services that help reduce transaction costs. This would encourage LDCs to support access to enabling platform provided it brings value to end-users. Figure 16 summarizes new business models and potential new revenue streams that can augment the existing cost-of-service model. These emerging business models would require a fair cost allocation methodology that recognizes both rate based and competitive activities and allocates costs accordingly.

Figure 16 Additional Business Models and Potential New Revenue Streams



Source: Navigant Consulting

3.4.3 The Case for a Fully Integrated Network Orchestrator

LDCs are the incumbent owners and operators of Ontario's electricity distribution grid that interfaces with and integrates the transmission system and customers. LDCs are well positioned to play the critical role of a FINO to ensure the future energy grid empowers customers, stimulates DER market development, and achieves public policy goals while maintaining the reliability and safety of the grid as DER penetration increases.

Customer Empowerment

A FINO will coordinate both centralized and distributed resources to maximize value to the grid. Customers want choice and are increasingly demanding products and services tailored to their needs and goals. An important part of an enabling platform is facilitating third-party energy solutions. An enabling platform not only ensures diverse products are offered, but also their accessibility to a greater share of end-use customers. Businesses are increasingly conscious of the environmental impact of their energy use and are incorporating sustainability plans into their business strategies. A FINO will help customers achieve sustainability through their enabling platform or by providing the products and/or services themselves. LDCs can empower customers effectively by serving as a FINO and leveraging existing customer relationships, expertise, brand recognition, and knowledge of local distribution networks.

Regulation and Policy

The OEB recognizes the changing role of LDCs. As part of the rate design discussions for Commercial and Industrial Customers, the OEB notes: “The nature of electricity distribution has been changing for the past decade and will continue to change. Distribution companies have acted as a delivery route for power from the grid to consumers. In the future they will act more as a service platform offering services such as balancing, power quality, storage, and redistributing power from users connected to their systems.”²¹

LDCs are already required to include Smart Grid and connections for renewable energy generation in their DSPs. The OEB requires DSP investments to be justified in terms of customer focus, operational effectiveness, public policy responsiveness, and financial performance. These terms are fundamental in a FINO model. The DSP is an opportunity to put forward a plan and “paint the picture”, using line of sight (Figure 17), to present a long term plan that reflects evolving policy goals and being an enabling platform.

Ontario’s Climate Change Action Plan includes conservation, energy efficiency and fuel switching to reduce the use of fossil fuels and increase the use of clean electricity and clean fuels. The IESO’s Ontario Planning Outlook (OPO) includes various electricity demand outlooks driven by different levels of electrification. The higher demand outlooks assume 2.4 million EVs on the road by 2035, which translates into 8 TWh of incremental energy.²² LDCs are pivotal to enabling DERs and to cost-effectively addressing increased demand for electricity through electrification of transportation and fuel switching.

A FINO encourages fuel switching and energy efficiency through the provision of an enabling platform, integration of DERs and delivery of new products and services such as EV charging, grid services, load management, and optimization or scheduling services.

As summarized in Figure 17, the role of a FINO supports key policy, business, and regulatory drivers. The line of sight alignment shows the rationale and linkages behind investing in enabling technologies. LDCs are the incumbent owners and operators of Ontario’s electricity distribution grid that interfaces with and integrates the transmission system and customers. LDCs can leverage their existing customer relationships, expertise, brand recognition, and knowledge of local distribution networks to streamline interconnection management.

²¹ EB-2015-0043 Rate Design for Commercial and Industrial Customers. OEB. 2015.

²² Ontario Planning Outlook. IESO. September 2016.

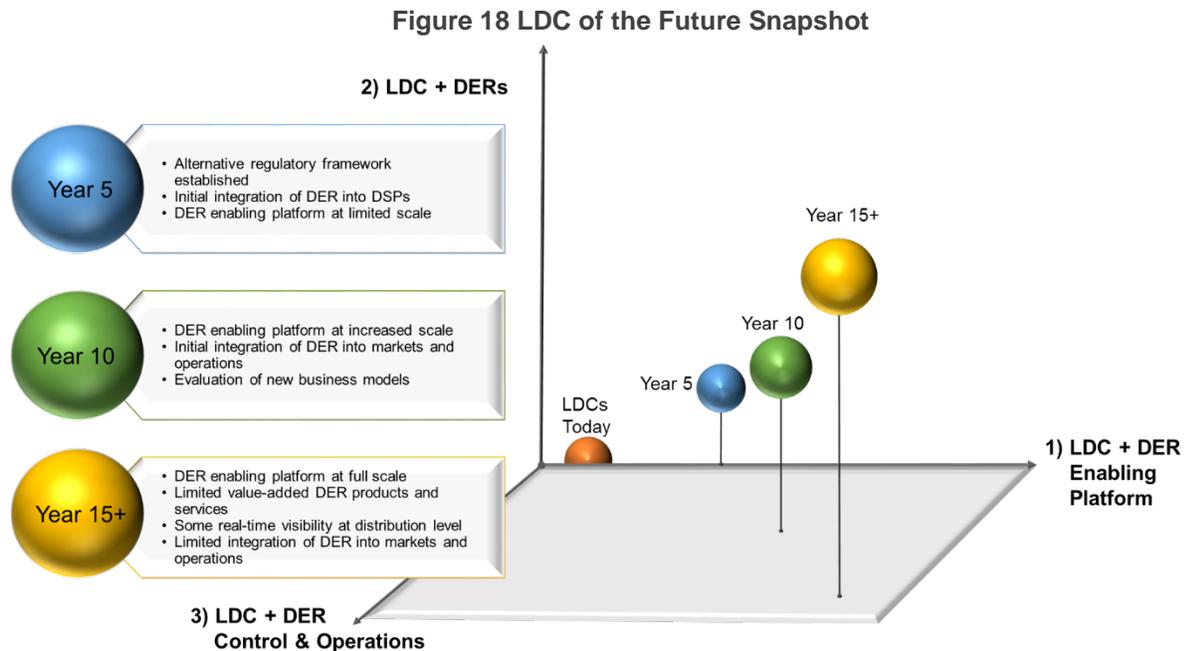
Figure 17 Line of Sight Alignment



Source: Navigant Consulting

4. LDC OF THE FUTURE EVOLUTION

The evolution towards a Fully Integrated Network Orchestrator (FINO) and the milestones over a fifteen-year timeframe are illustrated in Figure 18. The progression from LDCs Today to Year 5, demonstrates that LDCs will need to build an enabling platform to accommodate DER growth prior to obtaining capabilities to control and operate them by Year 10 and beyond. Figure 18 portrays an LDC with the resources to pursue an aggressive approach to transform into a FINO. Ideally the alternative regulatory framework would be established by Year 5, and an enabling platform would be fully deployed by Year 15.



Source: Navigant Consulting

Figure 19 shows the FINO development over a fifteen-year period. There will be different degrees to which LDCs transform into a FINO as portrayed by the range of functionality within the curve in Figure 19. The functionality of individual LDCs as a FINO can be anywhere on the curve and will depend on market conditions and each LDC's unique circumstances. The upper bound represents an LDC with an aggressive strategy to transition into a FINO. EDA Initiatives, which are further discussed in Section 5.2, are ideally early actions that should occur within two years to ensure challenges and obstacles are addressed to enable LDCs to evolve into a FINO in a cost-effective manner. Foundational investments, classified as technologies necessary to enable DERs, will need to be prioritized and should start in the near-term. Conditional investments are optional items that would depend upon market conditions and each LDC's unique situation. Table 4-1 classifies and describes the functionalities of foundational and conditional investments.

Figure 19 FINO Development Timeframe



Source: Navigant Consulting

Table 4-1 Foundational and Conditional Investments

Investment	Function
AMI	Smart meters capable of two-way communication and recording consumption data in near real-time. It allows for remote meter reading, remote connection/disconnection, improved fault location, and more accurate and granular data. Metering data can be used to integrate DER and optimize voltage and reactive power.
Smart inverters	Inverters that can manage supply and demand within microgrids, provide voltage support through reactive power management, and provide control options to the consumer based on near real-time electricity information obtained from an LDC via AMI.
Distribution and substation automation	A mixed variety of sensors and monitoring devices, mechanical and intelligent electronic devices, switches, reclosers, protective relays, and communication devices are used for distribution and substation automation. It allows for more effective monitoring to support optimized asset utilization and integrated resource planning. It also reduces congestion in communication networks (to and from central control server) through the deployment of more distributed control architecture.
Advanced communications and IT, including advanced data analytics	Increased frequency and amount of communications amongst DERs, smart devices and the central control server will require greater bandwidth and lower latency networks. Advanced

Foundational Investments	Advanced Distribution Management System (ADMS)	<p>data analytics will allow deeper analysis of the grid at an increasingly granular level to enable coordination of DERs, and supply and demand.</p> <p>Unifies operational and engineering data for state analysis, switching, outage management, and planning, providing a single, more efficiently managed platform for distribution network management. ADMS has centralized functions for coordination with legacy SCADA, transmission systems, power marketing, and situational awareness that cannot be achieved through distribution control and automation alone.</p>
	DER Management System (DERMS)	<p>DERMSs capabilities typically include network awareness, asset monitoring and control, scheduling and dispatch, active and reactive power import and export control, voltage control, constraint management, forecasting, resource valuation and optimal DR. DERMS can enable new business models around DER-based energy services, grid operation optimization, peak load management, and microgrid integration.</p>
	DER	<p>Distributed energy resource investments will vary based on customer demands, location, price signal and overall market conditions. See Section Table 4-3 for a complete list of DERs.</p>
Conditional Investments	New products and services	<p>New products and services may include virtual power plant aggregator, ancillary grid services, load management, customer data analysis, energy web portals, and DER interconnection tools. The types of products and services will depend on customer demands and market conditions.</p>

One of the biggest concerns is the scale of investment required to make FINO a reality. Each LDCs' unique circumstances will ultimately determine how it evolves into a FINO. Some LDCs can potentially collaborate on shared services as a means towards their FINO evolution. Regional system planning may also play a part, where it makes economic sense. Further, market conditions may drive the pace at which LDCs adapt and build DER capabilities. If DERs materialize in the market quicker, LDCs must react accordingly with enhanced grid sophistication.

Sections 4.1 to 4.3 discuss the various stages of development at five, ten, and 15-years for elements of the LDC of the future framework variables. The future stages of development described below represent an LDC under a flexible regulatory framework with an aggressive approach in its transformation as a FINO.

4.1 DER Enabling Platform Evolution

The technological gap and need for grid modernization is evident when comparing the state of deployment for today and the future on Table 4-2. AMI, smart inverters, distribution and substation automation, communications and ADMS are considered to be foundational investments that must be pursued in the near-term. These enabling technologies are complimentary and utilizing them concurrently can maximize investment benefits throughout the network. For instance, ADMS has centralized functions for coordination with legacy SCADA, transmission systems, power marketing, and situational awareness that cannot be achieved through the use of distributed control and automation alone. The deployment of these technologies will need to be undertaken in the next three to five years to accommodate DER growth in the market. The sequence of deployment will depend upon each LDC's current state and level of development in terms of DERs, automation, and communication capabilities. AMI is already fully deployed in Ontario, placing LDCs at an advantage for DER integration.

Table 4-2 DER Enabling Platform Evolution

Elements	Today	Year 5	Year 10	Year 15
AMI*				
Smart inverters*				
Distribution and substation automation*				
Communications & IT*				
Advanced Distribution Management System (ADMS) *				
Grid cybersecurity, technical and operational best practice				

* Foundational

None/pilot Limited deployment Wide scale deployment

Grid cyber security, and technical and operational best practices for DER interconnection is under continuous improvement both in Ontario and other jurisdictions. The OEB issued a notice in early 2016 announcing a consultation to review cyber security of the distribution network and associated systems that could impact the protection of personal information and grid security.²³

4.2 DER Integration Evolution

The pace of DER integration by an LDC is dependent upon the availability of an enabling platform. Table 4-3 presents DER deployment within an LDC's regulated business. EVs and charging infrastructure deployment is accelerated in order to align with the fuel switching policies based on Ontario's Climate Change Action Plan. The government committed to work with LDCs in implementing an optional time-of-day EV charging program, with the goal of lowering overall electricity bills for homes that charge vehicles. In general, the province wants to ensure charging infrastructure is widely available.

²³ EB-2016-0032 Protecting Privacy of Personal Information and Reliable Operation of the Smart Grid in Ontario. OEB. 2016.

Table 4-3 DER Integration Evolution

Elements	Today	Year 5	Year 10	Year 15
Renewables				
Energy storage				
EVs and charging infrastructure				
CHP				
Fuel cells				
Demand response				
CDM				

None/pilot
 Limited deployment
 Wide scale deployment

Although CHP is a mature technology, it has similar market barriers as fuel cells; high upfront costs and carbon price for the fuel. Demand response (DR) enables customers to reduce their electricity consumption in response to price signals and system demand. The IESO has ongoing efforts to expand DR capabilities through auction and pilot projects. LDCs must coordinate DR with the IESO as the grid moves towards decentralization. Smart building and home energy management system solutions are rapidly maturing and can be deployed by LDCs to their customer base as a means to expand the impact and effect of price responsive demand. LDCs are already responsible for planning and delivering CDM programs to achieve Ontario’s target to reduce 7 TWh of electricity consumption by 2020.

LDCs will need to evaluate the potential for DER growth over time to perform cost-benefit analyses and develop a roadmap for implementation. The actual deployment of DERs will be influenced by future policy and market developments.

4.3 DER Control and Operations Evolution

Table 4-4 demonstrates the large gap between today and the future in LDCs’ capability as a distributed system operator. A foundational capability of a FINO is real-time visibility on the network and ability to dispatch DER, thus requiring an advanced control system such as DERMS. One of the most rigorous tasks will be developing DER price signals that capture the full value of DER to the system and enable investments and operational decisions. Price signals will be necessary for developing business models associated with new products and service platform offerings. The amount and diversity of these offerings may vary depending on an LDC’s service territory.

Table 4-4 DER Control and Operations Evolution

Elements	Today	Year 5	Year 10	Year 15
DER dispatch and real-time visibility*				
DER price signal*				
New products and services				

* Foundational

 None/pilot
  Limited deployment
  Wide scale deployment

5. LDC OF THE FUTURE ROADMAP

The previous section presented the LDC of the future evolution and emphasized that each LDC will face unique challenges to its FINO evolution. Section 5.1 discusses current challenges impeding the electricity sector to realizing the LDC of the future in terms of the industry dimensions of regulation and policy, customers and stakeholders, technology, operations, and business models.

This section also identifies an approach that the EDA could lead to address some of these challenges, to avoid missed opportunities and to support LDCs. Stakeholders will need to collaborate to develop implementation plans to achieve the Power to Connect vision.

5.1 Key Challenges

5.1.1 Regulation and Policy

Regulatory Framework

The regulatory structure in Ontario will need to be flexible to allow LDCs to adapt. LDCs cite the existing regulatory framework in Ontario as the principal barrier to expansion of business scope. Although the *Strengthening Consumer Protection and Electricity System Oversight Act, 2015* enabled the OEB to authorize an LDC to expand business activities beyond electricity distribution, it remains unclear what test the OEB would apply in determining approval.²⁴ The regulatory process for evaluating infrastructure investments makes it difficult for LDCs to propose and get approval for DER enabling investments. For example, the OEB only considers the impact on distribution rates in its DSP review, not the impact on overall system costs. There is also a lack of mutual understanding of the benefits and risks involved with grid modernization investments. The RRFE Performance Scorecard “customer focus” based measures are related only to service quality, results of customer satisfaction surveys, and billing accuracy. Performance measures should be designed to encourage LDCs to address *future* customer needs and those of third parties who will rely on the enabling platform. LDCs are not encouraged to include technologies beyond the traditional network expansion and asset replacement under the existing regulatory framework.

There are limited mechanisms for LDCs to monetize the value of benefits that DERs would bring under the current framework. Regulation must allow for some risks to enable investments in new technologies. If LDCs are compensated for implementing DER solutions that maximizes value in the system, whether it be through incentives or cost recovery, economies of DERs can be achieved earlier and LDCs can earn revenue.

California recently addressed regulatory challenges in a Southern California Gas case, which offers useful insights for Ontario. CPUC created a DERS tariff which allows SoCalGas to provide CHP services and include the investment in rate base. The CPUC decision found that “*DERS Tariff is in the public interest because it meets untapped demand in underserved markets for smaller customers who would benefit from CHP, offers additional choices to customers, and supports innovative business partnerships.*”²⁵

To avoid anti-competitive impact, the tariff was designed with numerous requirements. For instance, service would be limited to underserved markets below 20 MW; the new tariff must be promoted only through the SoCalGas website through the use of “competitively neutral scripts”; the website must outline other service providers who offer similar services; the provision of DERS Tariff service must not be tied to

²⁴ BLG Electricity Markets Group Bulletin, July 2015.

²⁵ 15-10-049 Decision Granting SoCalGas' Application to Establish a DER Services Tariff with Modifications. CPUC. 2015.

any other SoCalGas service; SoCalGas must submit market development reports; and lastly, there is a ten-year time limit on the tariff, which would help CPUC evaluate impact from the new service. The tariff creates a clear and well defined offering for customers, thus increasing customer access.

A regulatory framework should reward LDCs that build their capacity as a DER enabling platform. A potential solution could be to adopt Earnings Impact Mechanisms (EIMs) tied to performance as a platform provider, facilitating the market, and advancing policy goals. Metrics can include peak reduction, energy efficiency, customer engagement and information access, affordability, and timely interconnection. EIMs would supplement LDC earnings and can be reevaluated as the market develops and market-based earnings become a stable source of revenue.

5.1.2 Customers and Stakeholders

Mitigating customer rates, supporting customer expectations, and coordinating with other LDCs and the IESO are some of the challenges facing LDCs.

Meeting Customer Expectations

A key challenge for transitioning into a clean, distributed and intelligent energy grid is balancing the pace of investments with increasing electricity rates and customer needs. Creating an enabling platform and facilitating the DER market will require significant investments. Therefore, LDCs should prioritize opportunities and gain an understanding of what capabilities are vital to maximize customer value. Such activities can include examining whether distribution assets are fully optimized or whether the LDC could lower costs by investing in data analytics instead of a physical asset. LDCs can also consider which areas of the business would benefit from a shared services model with other LDCs. The goal is to prioritize and balance the pace of investments to improve the business while also positioning for new growth.

Meeting the growing set of customer choices and changing demands while continuing to serve their core customer base will be a challenge for LDCs. Market segmentation analyses may be needed to target and customize new product and service offerings. There is also risk of failing to attract and retain end-use customers for these new products and services, which emphasizes the need for sharing experiences and lessons learned from DER pilot projects amongst LDCs.

Coordination with Stakeholders

As DERs develop in the marketplace, seamless coordination between distribution and transmission networks will be required to manage the overall system. Given the pace of change, transmission, and distribution companies should work closely to ensure a coordinated approach to planning, operation and investments. Issues requiring whole system coordination can be identified at an early stage to ensure they are addressed efficiently.

A FINO's capability to serve as a distributed system operator presents a challenge on coordinating grid operability with the IESO. The IESO's role and responsibilities must evolve in response to changing market conditions and market demands as DER penetration increases. There will be greater interactions between LDCs and the IESO as LDCs build their capabilities to become a distributed system operator, coordinating both DER control and operations.

The IESO is in the midst of developing a grid-LDC interoperability framework to identify future collaboration opportunities to enhance the reliability and efficiency of the grid. Some areas of opportunity include embedded generation visibility, solar variable generation forecast, coordination of load transfers, and improved understanding of customer consumption patterns.

5.1.3 Technology

Maturing Technology

Half of LDCs in Ontario characterize their approach to future innovation as gradual and incremental, although some LDCs tend to consider themselves as early adopters or pioneers.²⁶ The relative immaturity of the enabling technologies leads to high capital costs, evolving functionality, and performance risks. LDCs must balance reliability and safety requirements with the challenges of integrating new technologies.

Lack of Interoperability

Interoperability across new equipment and between new and existing legacy systems is another issue that will need to be considered by LDCs. The lack of interoperability standards may lead to additional system integration costs, extended timelines, and risk of vendor or technology lock-in. A decision to invest in a particular technology today could deter LDCs from taking advantage of new solutions or equipment at a later date. Interoperability between systems from different vendors would be ideal to leverage their functionalities and maximize the value of the investments. Standardization is increasingly necessary for efficient development of the future energy grid.

Many capabilities and functionalities of a FINO build on existing systems. This will be a particular concern for LDCs that do not have systems such as GIS and outage management, or have legacy systems that are in need of investment. IT/OT systems can be an area of investigation for a shared services model amongst LDCs.

5.1.4 Operations

Business Processes and Cultural Adaptation

Introducing new technologies presents challenges to business processes, cultural adaptation, and workforce constraints. New policies and procedures will need to be developed in response to these disruptive technologies. Sharing operational knowledge and best practices amongst LDCs can help ensure that investments are maximized. Leadership and support for innovation are necessary to allow for time to make changes, adjust, and gain understanding of the technology.

²⁶ Ipsos EDA Members Survey Report. June 2016

Workforce Constraints

The distribution network is becoming more complex with the increasing use of intelligent sensors and devices, convergence of IT/OT systems, and data-driven machine-learning functionality across the grid. This increasing complexity requires a different skillset than what some LDCs currently employ. In most cases, adopting emerging technologies will require some degree of training or new roles to support deployment. LDCs may need new competencies and skills in data analytics, communications, machine learning, cyber security, and digital asset management. Some LDCs may not have the resources required to expand their labour force or contract out these services to others. This may result in not fully capturing the value that these advanced technologies and grid modernization may bring to the grid. LDCs may wish to consider sharing IT resources amongst themselves.

5.1.5 Business Models

Financial Constraints

Transitioning the fundamental role of LDCs in the electricity system towards a FINO brings a complex set of challenges such as financial constraints and risks with competitive activities. Although there is opportunity to coordinate and replace aging infrastructure with new technologies that will transform how LDCs operate, LDCs are already financially constrained. Aging infrastructure requires significant capital, which could potentially defer earnings of municipal and provincial shareholders. Insufficient new incremental capital makes it difficult for LDCs to expand the scale of the business and carry out investments to build an enabling platform.

Building an enabling platform will require significant economies of scale, and may be challenging for some smaller LDCs. The lack of scale will negatively impact the cost-effectiveness of DER investments, and would likely require shared services, joint R&D and pilot projects amongst LDCs as a means towards a FINO.

Financial Risk with Competitive Activities

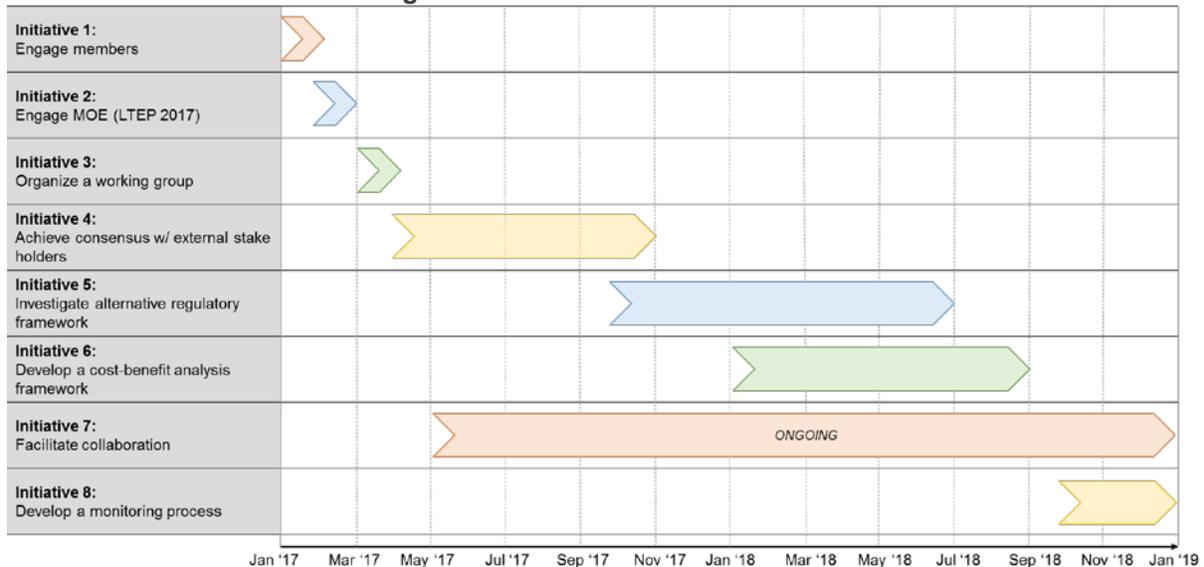
LDCs will need to manage the inherent financial risk linked to non-regulated or competitive activities. Facilitating a competitive market by providing a service platform will expose a portion of LDC revenue market risks, whereas the majority of LDC revenues are currently regulated. It will take time to develop and evaluate new products and services in the market, and determine whether they are viable sources of revenue. The significant difference between the roles of an LDC today with a FINO could result in transitional challenges in the competitive market.

Pilot projects are important not only to provide a test bed for technology evaluation, but also to provide opportunities for LDCs to evaluate changes to business processes, test new business models, build their capabilities as a FINO, and evaluate an alternative regulatory framework. LDCs can also assess how they can accelerate the introduction to market of new service options, products, and technologies.

5.2 EDA Initiatives

As presented in the previous sections, LDCs must be at the forefront of the grid transformation to capture value in an energy grid that is becoming clean, distributed and intelligent. It is imperative for the previously discussed challenges to be addressed to realize the benefits of the EDA's Power to Connect vision. The initiatives outlined in this section are intended to begin the discussion on necessary policy development, regulatory changes and implementation. These EDA initiatives are early actions that should ideally occur within the next two years as portrayed on Figure 20.

Figure 20 Timeline of EDA Initiatives



1) Engage members on the Power to Connect vision.

Challenges Addressed: Coordination with Stakeholders

In January 2017, EDA held two webinars for its members to discuss the Vision Paper. Member response was overwhelmingly positive.

2) Engage the Ministry of Energy in its development of the Ontario’s 2017 Long-Term Energy Plan.

Challenges Addressed: Regulatory Framework, Coordination with Stakeholders

LDCs are the incumbent owners and operators of Ontario’s electricity distribution grid that interfaces with and integrates the transmission system and customers. Through the 2017 LTEP, the provincial government should support the modernization of the grid and DERs. The government should also recognize that LDCs are uniquely positioned to lead the transition to a cleaner, more distributed and more intelligent grid. The goal of this initiative is for the provincial government and LTEP to acknowledge that by leveraging their existing customer relationships, expertise, brand recognition, and knowledge of their local distribution networks, LDCs are uniquely positioned as the most efficient and cost-effective service provider to lead the transition to a cleaner, more distributed and more intelligent grid.

3) Organize a working group to develop a plan to guide the Power to Connect vision.

Challenges Addressed: Regulatory Framework, Coordination with Stakeholders

A transparent, comprehensive approach is vital to fully addressing broader industry and business model challenges, changing customer needs, and adaptive regulatory structures. This starts with organizing a working group, within the sector, that will focus on developing a plan that will guide accomplishment of the Power to Connect vision. The working group should be diverse, consisting of representatives from the Ministry of Energy, LDCs, OEB, IESO, Advanced Energy Centre and other interested ministries and stakeholders. Identifying other groups or stakeholders with overlapping mandates may also provide opportunities to leverage efforts in addressing the challenges of the future energy grid in Ontario.

4) Collaborate with external stakeholders on definitions, guiding principles, and essential regulatory changes to realize the Power to Connect vision.

Challenges Addressed: Regulatory Framework, Coordination with Stakeholders

This initiative will provide a basis for developing a strategy to carry out the Power to Connect vision, and give stakeholders opportunity to provide input. It includes establishing common definitions and baseline knowledge linked to grid modernization; achieving mutual understanding of the economic costs and benefits of DERs to the system; and exploring changes needed in the regulatory framework as a result of new business models. Another potential task under this initiative would be a Line of Sight exercise to map out the connections between public policy objectives and enabling technologies. This exercise can also help reach consensus on foundational and conditional investments and capabilities that LDCs will require in the future.

This initiative will inform development of DER cost-benefit analysis framework, alternative regulatory framework, LDCs' business strategies, and ensure alignment with public policy goals. Business model parameters should be defined as well to help clarify relationships with other stakeholders.

5) Investigate regulatory changes and alternative regulatory frameworks that will incentivize LDCs to integrate DER, where doing so brings economic and/or system efficiencies.

Challenges Addressed: Regulatory Framework

The working group will need to investigate regulatory changes and alternative regulatory frameworks that will incentivize LDCs to integrate DER within their networks. This may include use-of-system charge, an alternative reconciliation mechanism, and monetized performance metrics. Changes to the DSP review criteria should be considered to encompass impact on overall system costs, as opposed to only distribution rates. The changes and alternative frameworks must modernize and augment the existing regulatory framework for LDCs since investments in traditional distribution network infrastructure will continue. The goal is to create an adaptive regulatory structure that reduces barriers for LDCs to become Fully Integrated Network Orchestrators.

6) Develop a cost-benefit analysis framework for evaluation of DER and DER enabling technologies.

Challenges Addressed: Regulatory Framework, Coordination with Stakeholders

A cost-benefit analysis framework will be required to guide LDCs in evaluation of DERs and enabling investments. The working group will need to identify the key parameters and inputs to be included in the cost-benefit framework including customer engagement, grid modernization and LDC business activities. In addition, the working group will need to identify the methodology for determining and updating parameter values and an approach to applying the framework to LDCs across Ontario. The framework should also be adaptive to evolve with market conditions, and new products and services as they become available.

7) Facilitate collaboration amongst LDCs, third party DER providers and energy solutions vendors to accelerate efforts for cost-effective deployment of DER and enabling technologies.

Challenges Addressed: Maturing Technology, Lack of Interoperability, Business Processes and Cultural Adaptation, Workforce Constraints, Financial Constraints

The diversity of LDCs in Ontario presents an opportunity to share unique experiences and lessons learned from the many innovative projects that LDCs are pursuing. LDCs should share information beyond operational or technical knowledge, including their experiences and insights on new business models. LDCs could accelerate their efforts to create economies of scale by investigating potential areas for shared services or joint ventures with other LDCs. Collaboration with third party DER providers and energy solutions vendors can help accelerate these efforts and enhance interoperability.

The EDA may be able to promote collaboration efforts, whether it be through a forum or an online project database to exchange ideas and solutions.

8) Work with the OEB and IESO to develop a process that will monitor the responsiveness of the regulatory framework to the energy grid transformation.

Challenges Addressed: Regulatory Framework, Financial Risk with Competitive Activities

Market conditions will ultimately influence the pace of LDCs' evolution to FINOs. If more DERs emerge in the market faster than expected, then a more advanced and intelligent grid will be required sooner than expected. The working group should coordinate with the OEB to identify a process that would monitor and encourage flexibility in the regulatory framework as the market develops.

5.3 Conclusion

LDCs are eager to drive the modernization of the grid, make cost-effective investments in DERs and enabling technologies, such as microgrids, energy storage, and advanced grid-edge controls that support reliability and enhance resiliency. Embracing a culture of innovation and flexibility is essential for LDCs who want to maintain their role as leaders and who want to proactively pursue new business models, new products and service offerings, and network facilitation.

The EDA sees the LDC of the future role as a Fully Integrated Network Orchestrator. There will be different degrees to which LDCs evolve into this role as a result of developing market conditions and each LDC's unique circumstance. LDCs are the responsible owners and operators of Ontario's electricity distribution grid that interfaces with and integrates the transmission system and customers. By leveraging existing customer relationships, expertise, brand recognition, and knowledge of local distribution networks, LDCs are uniquely positioned as the most efficient and cost-effective service provider to lead Ontario's transition to a cleaner, decentralized and more intelligent grid.

The increasing focus on fuel switching and electrification will result in greater demand for distributed sources of clean energy. LDCs are pivotal to achieving Ontario's Climate Change Action Plan, particularly in ensuring the wide availability of EV charging services.

In a rapidly evolving market, stakeholders must move quickly and be prepared to navigate an increasingly complex energy landscape. The initiatives identified above should commence immediately to begin the discussion on the most appropriate policy and regulatory changes and implementation plan for Ontario. The transformation of the electricity sector will require proactive support from government, regulators, customers and other stakeholders. Through effective collaboration, Ontario's electricity sector can resolve key challenges and fully realize the benefits of a cleaner, more distributed, and more intelligent electricity system.

GLOSSARY

ADMS:	Advanced Distribution Management System, a software platform that integrates numerous utility systems and provides automated outage restoration (FLISR), and optimization of distribution grid performance, conservation voltage reduction, peak demand management, volt-VAR optimization, and real-time load visibility and management.
DER:	Distributed Energy Resources, smaller-scale power sources (<10MW) that can be aggregated to provide power necessary to meet demand (e.g. solar, storage, demand response, fuel cells, EVs, microturbines etc.)
DERMS:	Distributed Energy Resource Management System, a software platform for managing a variety of interconnected DER, enabled through bidirectional exchange of information; could have functions such as the ability to provide, exchange, and respond to market price/cost signals.
Digitalization:	The use of digital technologies to change a business model and provide new revenue and value-producing opportunities; in the energy grid context, it is the application of smart connected technology to enable efficient operation, improved reliability, system planning and DER integration.
IEDs:	Intelligent Electronic Devices, microprocessor-based controllers of power system equipment, such as circuit breakers, transformers and capacitor banks, etc. that can communicate with other devices.
Microgrid:	A group of interconnected loads and DER within clearly defined electrical boundaries that acts as a single controllable entity with respect to the grid, and connects and disconnects from such grid to enable it to operate both in parallel and in island mode.
Network Orchestrator	Creates a network of peers in which the participants interact and share in the value creation without owning physical assets; they may sell products or services, build relationships, collaborate, co-create etc.
Shared Services Model:	Consolidation of business operations that are used by two or more LDCs; it is more cost-efficient since it centralizes back-office operations and eliminates redundancy; for example, LDCs could share IT resources and contracted staff.
Smart Grid:	An electricity network that uses two-way digital communications allowing for real-time monitoring, analysis, control and communication within the electricity supply chain; helps improve system efficiency, reduce energy consumption and cost.
Virtual Power Plant:	A system that relies upon software and a smart grid to remotely and automatically dispatch retail DER services to a distribution or wholesale market via an aggregation and optimization platform.

APPENDIX A. LDC CASE STUDIES

Building a resilient electricity distribution system with microgrids and innovations in energy use: Veridian Connections Inc.

Veridian Connections Inc. (“Veridian”), a utility showing great interest in accommodating new technologies and service models that provide increased value to their customers, is part of a groundbreaking, multi-phased microgrid pilot project that leverages the latest technology, including the Tesla Powerwall battery. The pilot project integrates multiple sources of residential clean energy, while maximizing load efficiencies and provides backup power in case of grid outages – helping to create a resilient grid. The purpose of the project is to test and gain experience with microgrid integration, ensuring that Veridian’s distribution system and operating protocols are ready to accommodate an expected proliferation of these systems.

Canada’s first two Tesla Powerwalls were installed at Veridian’s corporate headquarters in Ajax in June 2016 for phase one of the pilot project. The units are located in the lobby, offering visitors and customers an opportunity to learn about the capabilities and benefits of battery storage systems. The second phase of the project involves the addition of a solar powered carport canopy with electric vehicle charging stations at the company’s corporate headquarters. The final phase will see the deployment of two potential residential microgrids involving two homebuilders – managed and operated by Veridian’s 24/7 grid operations system control centre and controlled by Opus One’s GridOS® Microgrid Energy Management System. The pilot project supports electric vehicle technology, and will exhibit how the growing deployment of such systems will benefit the environment through reduced air pollution and GHG emissions.

Veridian’s microgrid is adding flexibility by allowing more distributed generation to come on line – providing customers more choice in meeting their energy needs. Perhaps more importantly, Veridian is gaining experience with a technology that will enhance the resiliency of its grid. Greater risks of extreme weather events from climate change can increase power vulnerability, as seen with Hurricane Sandy in 2012, the ice storm in 2013 and flash flooding in Greater Toronto in 2013. Several utilities, in addition to Veridian, are starting to see microgrids as a solution for mitigating customer impacts of power outages in extreme weather events.

As the province moves to net zero carbon emission new homes by 2030 and many more electric vehicles, Veridian and its partners are leading the work to try and optimize the home environment and functionality for customers while optimizing the electricity grid of the future. The optimal sizing and location of components and new technologies will provide a greater likelihood of meeting GHG reduction targets, reducing customer costs and increasing the overall quality of service.

Veridian President and CEO Michael Angemeer says, “Our goal is to demonstrate and evaluate the benefits of microgrids, battery storage, renewable energy and electric vehicles for our residential customers, and make progress towards net-zero carbon emission homes and eventually virtual power plants – providing direct benefits and expanded services to our customers.” He added “It is important to test out flexible systems in the home or business and connections to our 24/7 System Control Centre from a technical and customer interface perspective to allow the optimal sharing of benefits between the customer and the utility.”

Veridian will continue to conduct pilot programs, sharing its learnings and best practices with the industry and customers.

Transforming into “Utility 2.0” – Oshawa PUC

Oshawa PUC, a mid-sized utility serving 55,000 customers, recognizes the need to change the way it does business to address increasing customer expectations and electricity costs, frequent severe weather events, and aging infrastructure. It must also do so while being lean and nimble.

The utility is making significant headway in its efforts to become the community’s “Utility 2.0” by concurrently improving its analytical capabilities and developing new energy efficiency programs and distributed energy resources. The utility has already integrated multiple systems and leveraged new technology to pinpoint outages more effectively and restore power faster, even without a 24/7 control room.

With new systems in place, Oshawa PUC is also leveraging the power of smart meter data to understand their customers’ energy usage patterns and tailoring their energy efficiency programs to meet individual customer needs. For example, the utility’s Bidgely HomeBeat App, which identifies and tracks the major appliances in the home, is providing customers with personalized tips for saving energy and money. Preliminary results of the program show increased customer satisfaction and engagement with the utility, as well as positive behavioural changes and energy habits. Through its efforts 24 per cent of customers have signed up for e-billing, changing the customer experience and interaction with Oshawa PUC

Oshawa PUC has also established innovative partnerships with Japanese company Tabuchi Electric and Panasonic Eco Solutions to launch one of the largest microgrid projects in Canada. Thirty homes will be equipped with solar panels and batteries free of charge, and switched to net metering contracts. The utility aims to demonstrate how an efficient solar energy management system enhances reliability through the creation of connected, self-sufficient and energy-secure communities that provide back-up power supply and shift demand from on-peak to off-peak periods.

For Oshawa PUC, the way of the future lies in behind-the-meter generation and energy storage. All these efforts are building an interconnected system with many moving parts that create two-way power flows – a departure from the traditional LDC business model-- that can improve system operations and deliver on customer expectations.

Doing business better – Niagara Peninsula Energy Inc.

For Niagara Peninsula Energy Inc. (NPEI), innovation is about doing business better. The utility has the third largest service territory and the second highest number of agricultural electricity customers in the province, as well as a large group of commercial customers in the centre of Niagara Falls. Like other utilities in Ontario, NPEI is also contending with different preferences in customer service among its diverse customer base. While younger generations want information readily available online or through their mobile app, other customers who are not as comfortable using technology, or who live in areas with a low rate of broadband, want to deal with their utility on the phone or in-person. Quite evidently, flexibility in customer service models is a necessity for NPEI.

NPEI's innovative efforts have focused on offering specialized services that meet their customers' needs. As a first step, the utility undertook a market segmentation study to understand these very different customer segments. The study uncovered multiple barriers faced by the hospitality sector in accessing conservation incentives. This led to NPEI launching an 18-month conservation pilot program known as the Energy Concierge for Hotels and Motels, which ran until January 2017. This program focused on space heating and cooling – a major priority identified by hotels and motels – and offered customers a three-year energy management plan complete with technical assistance and financial incentives for certain types of upgrades to significantly boost energy efficiency.

Agricultural customers also benefit from having access to specialized incentives to address their energy needs. NPEI offers these customers access to audit funding, retrofits, small business lighting and high-performance. In addition, NPEI is collaborating with Hydro One, subject to approval from the Independent Electricity System Operator, to launch in the spring of 2017 a joint High Efficiency Agricultural Pumping Program. This program is being designed to increase the uptake of high performance, smarter pumping systems by local farmers through financial incentives for these pump sets, as well as education about the equipment in order to influence the stocking practices of this equipment by suppliers and contractors.

NPEI has also undertaken various system upgrades to ensure the utility operates as efficiently as possible. The utility is one of the few in the province to have its geographic information system integrated with other operating systems, creating a powerful business intelligence tool that not only enables quick power restoration, but also effective infrastructure upgrades and planning.

Efficiency is key. As a mid-sized utility, NPEI has to consider resource implications when developing new programs or procuring services. One solution to broaden its purchase power is to pursue cooperative business models, which it is doing through its membership in the GridSmartCity Cooperative.

For Brian Wilkie, President and CEO of NPEI, establishing and maintaining a high-caliber team is also critical to achieving excellence and driving innovation. It is the people behind the programs, services and campaigns that contribute to NPEI's positive reputation within its community and in the industry.

"A local utility is not just a service provider – it is part of the community. That is what drives us in our daily efforts to deliver even better services to our customers," says Brian.

A next generation utility – PowerStream

PowerStream is transforming from a local distribution company into an integrated, innovative, energy solutions provider that plans, designs and implements on and off-grid energy services. PowerStream's new business strategy is driven by the need to respond to the challenges imposed by rising electricity bills, increasing carbon dioxide emissions, frequent weather disturbances, grid congestion, new technologies and integration of renewable electricity generation. PowerStream's existing work on residential solar-storage technology, EV integration, pricing models and utility-scaled microgrids is helping the utility build smart communities, supported by a strong, flexible grid and customized energy services and programs for consumers. This work has earned PowerStream a place among the top 10 Smart Grid Solution Providers by Energy Insights Online.

POWER.HOUSE

POWER.HOUSE is a state-of-the art technology that collects solar energy through solar panels and converts it into electricity, and then sends that energy to a battery backup, the customer's home, or the grid, depending on what's best for the customer. The program offers customers a no-worry system as PowerStream controls the entire process through a software management system. POWER.HOUSE provides customers with many other benefits, including immediate backup in case of an outage, savings on the electricity bill and the ability to earn bill credit for exporting excess electricity back to the grid. Units are installed "behind-the-meter" (i.e. directly in a customer's home); however, they are owned and operated by the utility. This ownership structure allows the utility to aggregate the resources into a "Virtual Power Plant" (VPP), providing operators with the capability to deliver grid-scale energy services using a collection of residential-scale assets.

PowerStream recently received an Innovation Award from Energy Storage North America in the category of Distributed Storage for the project – a clear sign that programs such as POWER.HOUSE offer added value to consumers and can be replicated by distributors elsewhere. The project also earned a CanSIA Game Changer award.

Other utilities have expressed interest in testing this technology, evidenced by Thunder Bay Hydro signing a partnership agreement with PowerStream to introduce the technology to Thunder Bay customers.

EV Integration

PowerStream identified electric vehicles as a major opportunity for sustainable mobility in late 2010 and purchased the first two Nissan LEAF electric vehicles ever delivered in Canada. It was the first in North America to demonstrate a vehicle to grid technology, which is connected to its head office microgrid. The utility continues to lead the charge for better and wider access to charging infrastructure, with DC fast chargers at its head office and in Markham. PowerStream's continued leadership in promoting electric vehicles earned it the Canadian Electricity Association's inaugural Tom Mitchell Electric Vehicle Leadership Award in 2016.

Advantage Power Pricing

The first of its kind in Canada, PowerStream's Advantage Power Pricing is a technology enabled, voluntary dynamic pricing pilot program for residential customers in which the daily on-peak price varies in response to overall provincial demand for electricity.

Participating customers pay a low price for off-peak electricity use (5.9 cents per kilowatt-hour), while peak use, from 3:00 to 9:00 p.m. on weekdays, consists of three variable rates set at low, medium and high. These daily prices are sent to customers the day before to help them schedule their electricity

consumption. Participating customers are mailed a monthly report summarizing their energy consumption and costs, and have the option to be equipped with an intelligent thermostat and a ZigBee-enabled smart meter that can automatically adjust their heating and cooling in response to the peak price. Customers pay the lower of the Advantage Power Pricing rate or the regular Time-of-Use rate, and so at the end of every six months of the pilot, customers whose participation resulted in cost savings receive a cheque in the mail (to a maximum of \$500).

The program has shown some very good results. A recent survey showed that 83 per cent of participants felt that the program helped them to develop lasting energy-saving behaviours and habits at home, and 87 per cent said they would likely recommend it to friends. This unique approach to delivering added value to consumers and applicability to the sector earned PowerStream an EDA Innovation Excellence Award in 2016.

KEPCO Microgrid and MiDAS

In partnership with the Korea Electric Power Corporation (KEPCO), PowerStream officially launched a utility-scale microgrid which has the capacity to provide several hours of backup power supply to 400 customers in Penetanguishene. At the heart of this cutting-edge solution is the Microgrid Distributed Energy Resource Automation System (MiDAS), an advanced microgrid controller that can operate autonomously and optimize the way in which power is delivered. In addition to providing backup power supply, it reinforces the existing grid by increasing resiliency and operational efficiency in a safe, secure way. MiDAS can also facilitate the use of renewable power sources to provide a lower carbon footprint and ultimately a cleaner environment.

ENWIN's leading edge UAV technology will benefit customers and first responders

Windsor will be among the first cities in Ontario to benefit from unmanned aerial vehicles (UAVs), better known as drones, which are increasingly employed in the maintenance of hard-to-access infrastructure, across North America.

While many local electricity utilities are exploring the potential for this equipment in assessing and maintaining electrical infrastructure, *ENWIN* Utilities Ltd. has received a standing Special Flight Operations Certificate (SFOC) from Transport Canada, and is now fully licensed to employ the technology for infrastructure assessment and inspection.

The utility can now begin to use the small flying machines routinely, to check transformers, power lines and other infrastructure necessary to maintain the safety and reliability of the local distribution system.

If the power does go out, the utility can use the unassuming mini-copters to locate and assess the cause, without the time and expense of sending out a crew and a truck. This will also improve response times, and help avoid potential emergency situations.

Longer-term benefits could include the early detection of potential electrical fires. Poor connections get hot, and drones equipped with infrared cameras are able to detect them and flag them for repair. Helga Reidel, CEO of *ENWIN* Utilities, anticipates that this could also benefit the City's Emergency Management team.

SmartMAP – Collus PowerStream’s swiss army knife for access to data

With the implementation of Smart Meters, there is an overabundance of data that can help drive decisions, but this data can also be the cause of frustration. By providing the data in a useable format, a model of the distribution network can be created to allow for a view into real time operations. SmartMAP provides Collus PowerStream with the data needed to better serve its customers.

SmartMAP is a new innovative software solution that has improved outage restoration and operational efficiency, decreased system expansion costs, reduced theft of power, energy savings, and improved customer service for Collus PowerStream. SmartMAP has been designed for the utility with end-use electricity customers as a number one priority. This comprehensive solution gives Collus PowerStream useful insight into the state of their system, and extends this information into an outage management system, customer energy reports, web portals, asset management tools and engineering analysis giving utilities the power to effectively perform all of their tasks in one application.

For Collus PowerStream the direction was clear—become a 21st Century Utility. By acquiring this innovative technology, the utility has been able to:

- Leverage technology to make better, more informed decisions
- Eliminate waste
- Drive value to the ratepayer
- Prevent failures
- Minimize reactive work and become proactive
- Improve service reliability and quality
- Extend life of its assets
- Respond to an outage from the software, not from customer call

Grid-edge controls: A Canadian first

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Ontario's electrical grid is at a historic turning point, as renewable energy and grid modernization gain traction. Under these new conditions, some utilities find themselves struggling because traditional grid management tools are unable to control voltages adequately within this new framework. Now a new technology, the first of its kind in Canada – introduced as a pilot project – has been successfully installed to help improve voltage stability, customer satisfaction and energy savings on the electrical grid. Underway at Entegrus in Eriean, a picturesque community on the shore of Lake Erie, the pilot is showing that innovative controls, placed at the grid edge, can overcome these limitations. Many factors are contributing to the changing grid conditions and the need for new tools. One key factor is Ontario's significant commitment to the integration of PV solar and wind distributed generation (DG) systems. The increase in DG is producing two-way power flows along with new power quality issues, such as voltage and load dynamics.

Drawbacks among traditional control tools in the presence of DG

Several tools located on the medium voltage side of the distribution grid have traditionally been relied on by LDCs for voltage control. Among these tools are load tap changers – at both high and lower power utility sub-stations, which adjust the voltage delivered from these sub-stations. Other tools include line voltage regulators that adjust voltages to compensate for line droop, and capacitor banks. All of these tools are still used to provide basic voltage control, but through modernization efforts, they are being integrated with more complex controls to automate voltage management. Helpful as these tools are, their distance from the grid edge – where residential customers are connected – makes them unable to adequately control lower system voltages. They also do not act fast enough to respond to and regulate dynamic voltage variations because of their location far from the grid edge as well as equipment reliability constraints that limit the number of control operations per day.

The case for better voltage control in Eriean

Eriean, a community of about 420 people served by Entegrus, presents nearly perfect conditions for a community that will benefit the most from grid-edge voltage control technology because of its distance from the transformer station and the presence of renewable generation. Eriean would experience voltage variations when customers connected between its location and the main power source at the transformer station varied their loads. Similarly, voltage variations also occurred when the power being injected into the grid from secondary power sources such as renewable generators would vary. During the summer in Eriean, it was traditionally challenging to maintain Canadian Standards Association voltage standards during both peak and light load conditions. The presence of wind DG further complicated the situation. Customers were experiencing significant voltage fluctuations throughout the day as feeder conditions changed. Entegrus regularly received concerns about dimming lights and commercial customers complained of premature equipment failures. Since Hydro One owns many of the transformer stations in the province where voltage adjustments are made, Entegrus has had to rely on Hydro One to make voltage adjustments. Given the changing feeder operating conditions, this manual voltage control by Hydro One made it difficult to provide consistent and timely adjustments to maintain steady voltage levels.

Pilot testing grid-edge control technologies

Entegrus was introduced to and embraced an opportunity to evaluate an innovative grid-edge management technology, offered by Varentec™, called the Varentec Grid Edge Management System™ (GEMSTM) platform. The Eriean feeder was an ideal candidate to evaluate the GEMSTM system

because of the distance from the distribution and transformer stations, and the presence of DG systems. Entegrus is the first to deploy this technology in Canada through a demonstration project sponsored by Ontario's Ministry of Energy and funded in part through its Smart Grid Fund initiative, Hydro One, and the technology company. Pilot testing is ongoing on the Erieau feeder, as well as in two other utilities in Ontario.

The GEMSTM system deploys multiple, fast-acting and autonomously controlled voltage regulators, called Edge of Network Grid Optimization™ or ENGO™ devices. These devices are installed in parallel with the output windings of distribution transformers along a feeder (these distribution transformers convert the high voltages supplied by the substation to the low voltage levels used by customers). The aggregate impact of the multiple devices flattens the voltage profile along the entire feeder, enabling utilities to provide voltage support, improved power quality, enhanced integration of wind and PV solar, and integrated voltage control.

Another potential benefit of the GEMSTM system is providing utility-side demand management through conservation voltage reduction. This system would enable utilities to realize as much as five per cent energy savings on a feeder, which could ultimately offer them a utility-controlled mechanism for significantly accelerating the time frame for meeting conservation targets.

The Entegrus deployment and early results

For the Erieau pilot, Entegrus deployed 35 ENGO-V10 devices. Installation was accomplished in under two weeks and the system was commissioned and operational in one day. The early results are very encouraging. In addition to improved voltage conditions, Entegrus has already observed a reduction of customer concerns in Erieau and attributes this improvement to the GEMSTM platform. Based on these early results, Entegrus has several other feeders under consideration for deployment of this technology. The Smart Grid Fund Project that is sponsoring the Entegrus pilot will run through the first quarter of 2016, and results will be reported to the LDC community.

Proving that innovation contributes to better customer service

This story was originally published in the EDA's 2015 fall issue of "The Distributor" magazine.

Horizon Utilities Corporation believes that effective communication with customers is the first step in building relationships. Continuously improving engagement to ensure a genuine focus on its customers is part of the Horizon Utilities culture. But in order to be truly innovative, the utility is adopting creative methods to be an industry leader in customer service.

Horizon Utilities recently launched Take Charge·Save Energy·Earn Rewards, an online conservation and demand management (CDM) pilot program that rewards residential customers with Air Miles® reward miles for reducing their household energy use.

The online pilot program, funded by the Independent Electricity System Operator (IESO) and Simple Energy, will wrap up this October. The program has already demonstrated how a virtual engagement platform can help customers manage their own electricity costs and support Horizon Utilities' overall CDM targets.

This innovative program combines behavioural science and technology as a way to engage customers around energy conservation while providing them with tools to manage their own electricity costs.

Customers enrolled in the program receive a personalized weekly energy insight email to help them better understand their household energy consumption and provide customized insights based on smart meter data and usage comparisons to similar households. Participants are incentivized with Air Miles® reward miles when they complete energy-saving tips and record other actions on their customer dashboard.

The project dovetails another recent award-winning customer engagement campaign – Just Ask Us. Horizon Utilities received the Gold MARCOM award for its customer engagement initiative designed to encourage customers to be proactive in energy conservation. Horizon Utilities' customers were encouraged to call on their energy savings experts to help find solutions to reduce energy use and save money.

Similar to the online pilot project currently underway, the Just Ask Us campaign focused on personal interaction with in-house conservation experts. As part of its commitment to environmental sustainability, conservation experts continue to work with residential and business customers to deliver value to customers.

Innovation often requires the use of proven methods while employing new technologies and techniques. This is why Horizon Utilities continues to expand its focus on self-serve 24/7 options that offer customers convenience at the click of a button through online channels.

Customers are realizing the benefits of information at their fingertips through smartphones, tablets and computers. Horizon Utilities offers its customers online or in-person options to view transactions and account balances, manage their accounts and even view daily usage. With an emphasis on 24/7 service – Horizon Utilities has ensured customers can be hands on in their own energy saving efforts.

Horizon Utilities has increased its focus on the use of electronic communications vehicles such as social media to ensure broader reach for its customers. While these communications mediums are great for providing information and updates during power outages, they also provide additional tools for promoting new CDM initiatives beyond a website presence.

Horizon Utilities believes that innovation in all aspects of its business is contributing to greater value and customer satisfaction. This was evident according to the results of the 2015 UtilityPULSE Electrical Utility Customer Satisfaction Survey where Horizon Utilities received a 92 per cent overall customer satisfaction rating, well above the Ontario average of 86 per cent.

In fact, the annual customer satisfaction survey indicated Horizon Utilities' commitment and innovative approach to customer service is paying off with an increase of five per cent from 2014.

Diligent research and communication have provided a greater understanding of where customers turn to for information. Horizon Utilities is continuously looking at new ways of embedding innovation into all aspects of customer service to ensure recent satisfaction success continues to improve.

Hydro Ottawa – Building North America’s First-Ever District Utility

Imagine living in a brand new, green, and technologically-advanced community – one where sustainability is seamlessly integrated into your way of life. Your home is an ultra-modern condominium overlooking the picturesque Ottawa River, with electric vehicle charging stations in the garage, a net Zero-Carbon heating and cooling system, and real-time home energy monitoring through a mobile app.

While developments around the world can boast some of these characteristics, Ottawa’s Zibi²⁷ community will be the first to bring these features and more together in one place. And a new business model – a district utility – will serve as the hub for operating, managing, monitoring and reporting on the sustainability of the community’s energy system.

Hydro Ottawa is partnering with the Windmill Development Group, Dream Unlimited and the MaRS Advanced Energy Centre to make this vision a reality. The ultimate goal is to ensure Zibi becomes a One Planet Community – the first of its kind in Canada, and only the tenth such community worldwide. To be certified to the “One Planet Standard”, Zibi must achieve zero-carbon, zero-waste, and eight other principles within its lifetime²⁸ – all of which will ultimately make sustainable living easy and affordable for everyone in the community.

The partners have worked together on this project since late 2014, making important progress in refining the vision for Zibi’s energy systems and developing strategic plans. On May 2015, the Advanced Energy Centre, in partnership with Hydro Ottawa, convened a group of urban planners, entrepreneurs, investors, industry leaders, as well as policy and regulatory experts for an intensive planning session, called a design charrette.

After defining the ideal human experience, the group brainstormed new solutions at the distribution edge that could enable a net-zero carbon energy system at Zibi. The group focused on ideas for new utility business models and methods for achieving sustainability targets. For example, the district utility could offer a community aggregated demand response. It could also share the community’s progress on sustainability, energy demand and other measures through visualization tools, such as an electronic community billboard.

Another idea is the Digital Sustainability Concierge, which would provide residents and businesses with access to data on the community’s energy usage, including consumption data for each suite or business. It would allow customers to easily compare their energy usage with others within the community. The Concierge could also issue rewards and incentives, push carbon intensity or pricing notifications to customers, and enable them to remotely control their smart energy devices. In addition, it could use the One Planet Community framework to give personalized targets to customers based on the framework’s principles as well as ways to better manage their energy usage and save money.

Following the design charrette, the Zibi project leaders defined high-priority utility business opportunities. These include the district’s heating and cooling system, its electrical distribution, billing services, lighting, green generation, the energy “Internet of Things” infrastructure, the customer experience, and telecom services.

²⁷ "Zibi" means "river" in the Algonquin language and this new development is located on the banks of the Ottawa River in both the City of Ottawa and the City of Gatineau in Quebec. In Ottawa, Zibi is just west of the downtown core and consists of the Chaudière and Albert Islands, which are surrounded by the Ottawa River. In Gatineau, the lands are in the city's downtown area.

²⁸ The eight other One Planet principles include sustainable transport, sustainable material, local and sustainable food, sustainable water, land use and wildlife habitats, culture and community, equity and local economy, and health and happiness.

Then in late April 2016, representatives from Hydro Ottawa, Windmill Developments, and the MaRS Advanced Energy Centre participated in the Electricity Innovation Lab (eLab) Accelerator event hosted by the Rocky Mountain Institute. This invitation-only, four-day working meeting brought together teams from across North America that are working on high impact and innovative projects in electricity distribution.

Through structured sessions designed to accelerate progress, the Zibi project team worked on the business model for the district utility including its asset ownership, rate structures, investment strategy, and operations plan. It explored options for what a new district utility for the Zibi community could look like, narrowing these down to two potential ownership structures. The first was a “business as usual” model where Hydro Ottawa would only participate in the community’s electrical distribution. The second was a “New Co” model where a joint venture between Hydro Ottawa and Windmill Developments would act as the community’s complete energy provider.

At the eLab Accelerator event, the Zibi team also detailed the timeline for achieving the key energy-related milestones in the community over the next few years, especially those that must be in place for early 2018 when Zibi will be ready to welcome its first residents. Much of the discussion focused on Zibi's heating and cooling system, which is the linchpin in the district's energy system. There's an opportunity to develop an eco-friendly system reusing heated process water from a nearby paper mill, instead of typical forms of energy such as electricity or gas. That would go a long way in ensuring that Zibi is carbon neutral.

Now, the project team is refining its strategic plans and working with stakeholders to more clearly model how Hydro Ottawa or the New Co would operate. This work will inform the project team's recommendations, which will then be presented to the internal stakeholders of each of the partner organizations for approval.

Located in the heart of our Nation's capital, Zibi is an ambitious development project that presents an unprecedented opportunity for Hydro Ottawa and its partners to explore ground-breaking technologies, tools and services that will engage customers, reduce carbon emissions and enhance the efficient use of resources.

Bryce Conrad, President and Chief Executive Officer of Hydro Ottawa, believes that: “This partnership is a natural fit for Hydro Ottawa as we continue to drive for performance excellence, while furthering our goal to be Canada’s leading electricity company of tomorrow.”

APPENDIX B. JURISDICTIONAL RESEARCH

B.1 New York²⁹

Regulatory oversight to New York's utilities is provided by the New York Public Service Commission (NYPSC). New York has a basic performance based model, where only a small portion of the revenue allowance is intended for incentives. Most incentives are mainly for energy efficiency and the rate plan also includes the potential for negative revenue adjustments related to customer service, reliability, and stray voltage.

Regulatory plans include an earnings sharing mechanism, with the earnings in excess of an established return-on-equity (ROE) cap to be shared by shareholders and ratepayers. Furthermore, an expense reconciliation mechanism included in the plans permit utilities to defer increases in certain expenses given that the company's earned ROE remains below specified thresholds. NYPSC typically applies a productivity adjustment of 1% in rate proceedings to encourage operational efficiency improvements of utilities.

REV is aligned with New York's State Climate and Community Protection Act, which requires the state to reduce greenhouse gas emissions to 80% from 1990 levels by 2050, and obtain at least 50% of its electricity from clean energy by 2030.

The REV proposal was divided into two tracks: Track 1 focuses on a policy framework and processes moving forward; Track 2 focuses on ratemaking and utility revenue model. In July 2015, New York Department of Public Service released a white paper entitled Benefit-Cost Analysis Framework in REV Proceeding. This is critical to address the marginal costs and benefits of DER versus traditional utility investments and expenditures to be proposed in near term DSIPs and tariff development.

Market-based earnings (MBEs) are designed to engender an entrepreneurial approach by the utility as the Distributed System Platform to cultivate ancillary revenues that can augment and offset the role of ratepayer funds. Platform Service Revenues (PSRs) are a new form of utility revenue associated with operation and facilitation of distribution-level markets. PSRs are anticipated to leverage the platform's capability to offer value-added services to the marketplace. Additionally, Earnings Impact Mechanisms (EIMs) are regulated incentives tied to prescribed outcomes that flow from operating the platform in ways that facilitate the market and advance policy goals. Utilities are also expected to displace conventional infrastructure projects with non-wires alternatives, utilizing DER to serve customers and balance the system. Utilities have the opportunity to benefit by sharing in the cost savings of deferral and under certain conditions a return on owned DER assets. The intent of the mechanism is to build a market oriented platform environment, so the goal is to reduce the role of EIMs over time as the market matures, and the portion of a utility's revenue that is market-based will increase.

A process will need to be established for a fair cost allocation of competitive activities that are made possible through a combination of ratepayer-funded infrastructure and at-risk operated expenses. The approval process and pricing of products and services that could generate new revenue must be defined as well. Services could include a customer online portal, data analysis, transaction and/or platform access fees, optimization services, energy services, financing, and microgrid engineering services.

In general, utilities are not permitted to invest in DER to facilitate market entry and participation of third parties. Third party providers and unregulated utility affiliates are permitted to participate in the marketplace to gain access and information on optimal locations and pricing signals that indicate real-time value for investments, and other services that may help reduce transaction costs. Establishing

²⁹ Source: SNL Financial

distribution locational marginal pricing is a challenging effort that New York is currently tackling. The transition from government incentives to market price signals will be a difficult process. Adding to the complexity is the fact that distribution locational marginal pricing can either be positive or negative depending on the circumstances.

Monetized performance metrics are intended to provide incentives to build market activity, generate consumer savings, and achieve public policy goals. The performance metrics may be linked to customer engagement and information access, peak reduction, interconnection, affordability and greenhouse gas reductions. The performance metrics are viewed as a transitional component to New York's regulatory reform until market-based revenues are available in scale and can contribute significantly to utilities' revenue streams.

Scorecards can also be utilized for performance outcomes that cannot be monetized directly in order to monitor the progress of achieving REV objectives.

B.2 California³⁰

Investor-owned utilities in California are regulated by the California Public Utilities Commission (CPUC). California operates under a largely traditional electric regulatory framework. The current rate plans enable utilities to receive annual awards equal to 5% of actual energy efficiency portfolio expenditures, and a performance bonus of up to an additional 1% depending on each utility's performance.

California's approach for advancing DER uses industry reshaping mandates that include:

- Assembly Bill 32 (2006):
 - Required California to reduce its GHG emissions to 1990 levels by 2020; a reduction of approximately 15% below emissions expected under a "business as usual" scenario
- Senate Bill 350 (2015):
 - Directed utilities to procure 50% of electricity from renewable resources by 2030
 - Directed utilities to develop multi-year programs accelerating the adoption of EVs in order to reduce reliance on petroleum, meet air quality standards, and achieve greenhouse gas reduction to 40% below 1990 levels by 2030 and to 80% by 2050
- Assembly Bill 327 (2013):
 - Directed California's jurisdictional investor-owned utilities to submit a Distribution Resources Plan (DRP)
 - Established 33% by 2020 Renewable Portfolio Standards obligation as floor, rather than a ceiling
 - Called for a shift from the state's four-tier rate structure into a two-tier monthly rate structure, with much less price difference between the two
 - Allowed jurisdictional investor-owned utilities to charge flat fees of up to \$10 per month to every customer, regardless of how much power they consume³¹
 - Required the CPUC to develop a future Net Energy metering tariff prior to reaching the cap by 2017, and to ensure that the total benefits of the tariff to all customers and the electrical system are approximately equal to the total costs
- Assembly Bill 2514 (2010):
 - Enacted an energy storage procurement goal of 1.3 GW by 2020 for utilities, with only a portion to be owned by utilities and with installations required no later than the end of 2024
- Assembly Bill 2868 (2016):
 - Allowed California's three largest utilities, Pacific Gas & Electric, Southern California Edison, and San Diego Gas & Electric (PG&E, SCE and SDG&E), to procure an additional 500 MW of energy storage capacity
- Assembly Bill 1637 (2016):
 - Doubled the size of CPUC's Self-Generation Incentive Program funding (75% allocated for energy storage, 25% for generation), and extended net energy metering for fuel cell resources
- Assembly Bill 2861 (2016):
 - Authorized CPUC to create a resolution process for DER interconnection disputes
- Assembly Bill 33 (2016):
 - Directed the CPUC and California Energy Commission to evaluate and analyze the potential for all types of long duration bulk energy storage, such as pumped hydro, to help integrate renewable generation into the grid

³⁰ Source: SNL Financial

³¹ Greentech Media, "California' Major Residential Rate Reform: A Mixed Bag for Solar Economics," <https://www.greentechmedia.com/articles/read/californias-major-residentia-rate-reform-a-mixed-bag-for-solar-economics> April 24, 2015

California has also introduced new wholesale market rules to advance DER deployment.

In late 2015, CPUC launched its Demand Response Auction Mechanism (DRAM) pilot program to allow demand response providers to get compensated today for energy reduction they promise to deliver the following year. DRAM opens the state's wholesale grid market to DER such as solar PV, energy storage, plug-in EVs, smart thermostats and other energy management devices, aggregated into units of at least 100 kW. California's big three IOUs (PG&E, SCE and SDG&E) announced 82 MW worth of DRAM contracts for 2017.

To further promote demand response in California, CPUC adopted policies for implementation of direct participation demand response, thus creating opportunities for third party demand response providers, aggregators and customers. CPUC issued a proposed decision setting the first budgets and targets for how the state's big three IOUs will bring customers, as well as recover costs for technology platforms and business processes that could make direct participation in demand response possible. Moreover, recent California Independent System Operator (CAISO) tariff revisions allow distributed, non-generator resources to be compensated at market rates when it is used as an alternative to generation.

CPUC's Electric Tariff Rule 21 sets a standard defining how DER can connect to the grid. It establishes greater transparency on the potential costs associated with interconnection, and limits the cost overruns a developer is liable for. CPUC also identified the development of advanced inverter functionality as an important strategy to mitigate the impact of high penetrations of DER. As a result, a working group was formed which is developing autonomous functions that all inverter-connected DER in California will be required to perform; default communications protocols between IOUs, DER, and DER aggregators; and additional advanced inverter functionality that may or may not require communications.

B.3 Massachusetts³²

Utilities in Massachusetts are regulated by the Massachusetts Department of Public Utilities (MDPU). The current regulatory framework of Massachusetts follows a mainly traditional regulatory model, wherein the rate plans are short term and available incentives are limited. Incentives are primarily associated with energy efficiency programs, earnings sharing, and long-term renewable energy contracts. Utilities are required to file energy efficiency plans every three years, and it must include a proposed performance incentive mechanism and a cost-recovery framework. Massachusetts utilities have become skilled and effective at delivering efficiency programs to customers that have allowed them to not only recover their program costs but earn performance incentives.

Legislation calls upon utilities to obtain 7% of their historical peak power demands, and 4% of their annual load from renewable generation via long-term contracts procured by end of 2016. Utilities are eligible to receive an annual incentive equal to 2.75% of the annual value of the contract for the additional 4% requirement. Of the incremental resources to be procured, 10% must be reserved for newly developed small, emerging, or diverse energy generation.

Massachusetts legislation also outlines a number of goals including: (1) meeting at least 25% of the state's total electric load with demand-side resources by 2020; (2) providing at least 20% of the state's total electric load from new, renewable and alternative energy resources; and, (3) developing a plan to reduce the state's total energy consumption by at least 10% by 2017 through the Green Communities program³³.

Global Warming Solutions Act 2008 also requires greenhouse gas emission reductions of 25% below 1990 levels by 2020, and 80% by 2050.

As part of the Grid Modernization proceeding, different regulatory frameworks were considered by stakeholders. A performance-based model, which included a longer rate plan, revenue allowances based off of future test data, enhanced performance incentives, and ROE indexed by incentive performance, was proposed. MDPU adopted important aspects of the program such as long term utility implementation plans that, once approved, would be deemed recoverable in rates via a special capital tracker. The MDPU chose not to adopt some enhanced recovery mechanisms for utilities such as "future test year", or outcome based financial incentives. Monitoring of grid modernization progress will be via non-monetized performance metrics.

Consistent with the MDPU order in 12-76, in 2014 utilities submitted their GMPs wherein they proposed short-term and long range grid- and grid modernization investments. The nature of the grid modernization investment varied based on what capabilities utilities already had in place, territory specific challenges and strategic approach of management. National Grid proposed investments in distribution automation technology; AMI; advanced distribution management and monitoring; measures to improve distributed generation application processing, system analysis and planning; online tools for customers; and targeted system upgrades. Eversource proposed an incremental approach to AMI while focusing on distribution automation capabilities that would enhance reliability and support increasing integration of DER two-way power flow.

Massachusetts uses both net metering and solar incentives to encourage the development of solar, although a cap is placed on solar net metering and utilities can charge a minimum bill to cover fixed costs.

³² SNL Financial

³³ Green Communities strives to help all 351 Massachusetts cities and towns find clean energy solutions that reduce long-term energy costs and strengthen local economies through provision of technical assistance and financial support for municipal initiatives to improve energy efficiency and increase the use of renewable energy in public buildings, facilities and schools.

An online tool is available for enabling customers to apply for and reserve space for a planned system under the established aggregate program cap. Lastly, Massachusetts policy allows neighbourhood net metering, a shared renewable-energy arrangement, and third-party ownership of systems.

B.4 Minnesota³⁴

Utilities in Minnesota are regulated under a traditional framework by the Minnesota Public Utilities Commission (MPUC).

State legislation has established greenhouse gas reduction targets of 30% below 2005 levels by 2025, and 80% below by 2050. Electric utilities are also required to generate or procure their power from renewable sources in percentages corresponding to the last two digits of the indicated year: 20% by 2020; 25% by 2025. In addition, Minnesota aims for 10% of the retail electric sales to be generated by solar energy by 2030.

Statutes established a goal for all Minnesota utilities to achieve annual energy savings equal to 1.5% of retail sales and must invest at least 1.5% of their gross operating revenues on energy conservation programs. Minnesota also created a value-of-solar tariff (VOST), a mechanism for taking multiple grid impacts of distributed solar PV into account when pricing its value to utilities and customers. However, application of VOST by utilities today is limited.

Every two years, utilities must file an Integrated Resource Plan (IRP), which must include a detailed 15-year load forecast and an analysis of supply-side and demand-side management options available to meet the forecasted demand. When planning a large energy facility (transmission or generation), utilities must also evaluate non-wires alternatives, such as energy efficiency, peak load reduction, demand side resources, and DER.

Several of the state's utilities have adopted pilot revenue decoupling mechanisms. Additionally, subject to MPUC approval, capital costs would be recoverable based on a formula, forecast, or fixed escalation rate, while operation and maintenance expenses would be recoverable based on a price index or formula. Distribution system costs associated with grid modernization would be eligible for recovery under an adjustment rider.

Some stakeholders disagree with MPUC placing new utility business models in the third phase of the grid modernization proceeding since the current business model make it challenging to accomplish some of the action items. Items for near-term consideration include integrated distribution planning, smart inverters, distributed generation interconnection, and hosting capacity analysis.

MPUC also addressed issues piecemeal as they arose, such as alternative rate design and third party aggregation of DER. However, several parties are advocating for a more holistic approach to grid modernization to ensure that investments are made in a cost-effective manner.

There are two on-going initiatives associated with grid modernization in Minnesota. The first is the e21 Initiative, a consensus-based, multi-stakeholder effort aiming to develop a more customer-centric and sustainable framework for utility regulation that better aligns how utilities earn revenue with public policy goals, new customer expectations, and changing technology landscape. The e21 Initiative commenced in February 2014 and is facilitated by the Great Plains Institute, in partnership with Xcel Energy, Minnesota Power, Center for Energy and Environment and other stakeholders.

The second initiative in Minnesota is MPUC's Grid Modernization proceeding initiated in May 2015. Minnesota is a vertically integrated state, wherein utilities own the generation, transmission and distribution assets. This adds complexity for creating opportunities and aligning interests for all stakeholders. To help set priorities, MPUC set up a three phase grid modernization framework:

- Phase 1: adoption of definitions and principles

³⁴ Source: SNL Financial

- Phase 2: prioritize potential action items, direct additional studies for on-going discussion
- Phase 3: adopt long-term vision for grid modernization, including new utility business and regulatory models

Minnesota's Grid Modernization proceeding is currently in Phase 2. ³⁵

³⁵ Source: Staff Report on Grid Modernization. Minnesota Public Utilities Commission. March 2016.

B.5 Alberta³⁶

Alberta's electricity market is unique in Canada since it has never owned or operated a crown corporation. Distribution systems throughout Alberta are mostly owned and operated by municipal governments and/or their public utilities. With the exception of EPCOR and ENMAX, the Alberta Utilities Commission (AUC) does not regulate municipally-owned utilities. Deregulation of the electricity market was introduced in 2001 to encourage efficiencies through competition in the generation sector. PPAs allowed existing utility owners to continue to own and operate their facilities, but auctioned the dispatch rights of the associated energy to new buyers. Transmission and distribution are fully regulated, whereas retail is a mix between regulated and deregulated.

Alberta currently supports DER through its micro-generation policy. The Electric Utilities Act Micro-generation Regulation came into effect in 2009 and allows customers to receive credit for any excess power they send to the grid. Micro-generation is defined in Alberta as small scale renewable electricity generation of 1 MW or less. The regulation gives customers and energy retailers the option to decide the terms of compensation for surplus electricity.

Industrial and large commercial customers are typically equipped with smart meters allowing for time variable pricing and real-time meter reading. Alberta requires sites with a peak demand greater than 2MW to have a smart meter. However, utilities began to establish lower smart meter installation thresholds in part due to customers' requests for more detailed information on their consumption and to improve operation efficiency and bill accuracy. Currently, sites with demand as small as 150 kW are being equipped with smart meters.

The Alberta Municipal Solar Program provides financial rebates to Alberta municipalities who install solar PV on municipal facilities or land and complete public engagement for the project. ENMAX offers a Home Solar 15-year lease financing program and is currently developing other programs to take advantage of the role solar will play in Alberta's future energy grid.

In its Climate Leadership Plan, Alberta committed to phasing out coal-fired power plants and 30% of electricity from renewables by 2030, implementing a new carbon price on GHG emissions, capping oil sands emissions to 100 megatons annually, and reducing methane emissions by 45% by 2025.

³⁶ Source: Alberta Utilities Commission



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