Navigating Barriers to Utility Investment in Grid Modernization

Final Report

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List of Acronyms

ADMS	Advanced distribution management system
AMI	Advanced metering infrastructure
AUC	Alberta Utilities Commission
B2B	Business-to-Business
BCUC	British Columbia Utilities Commission
CAPEX	Capital expenditures
CEA	Canadian Electricity Association
CPUC	California Public Utilities Commission
CRTC	Canadian Radio-television and Telecommunications Commission
CSA	Carbon savings account
DER	Distributed energy resources
DERMS	Distributed energy resources management system
DPU	Department of Public Utilities
DRP	Distribution Resource Plan
DSI	Distribution System Inquiry
DSM	Demand side management
EAM	Earning Adjustment Mechanism
EE	Energy efficiency
EIMA	Energy Infrastructure Modernization Act
ERA	Emissions Reduction Alberta
GHG	Greenhouse gas
Guidehouse	Guidehouse Canada Ltd.
HQ	Hydro-Québec
ICC	Illinois Commerce Commission
LRAM	Lost Revenue Adjustment Mechanism
MOU	Memorandum of Understanding
MRP	Multi-Year rate plans
MW	Megawatt
NRCan	Natural Resources Canada
NWA	Non-Wires alternative
NYPSC	New York State Public Service Commission
O&M	Operations and Maintenance
OEB	Ontario Energy Board
OPEX	Operating expenditures
PBR	Performance-Based regulation

PUF	Public Utilities Fortnightly
RAM	Revenue Adjustment Mechanism
RECSI	Regional Electricity Cooperation and Strategic Infrastructure
REV	Reforming the Energy Vision
R&D	Research and Development
RRFE	Renewed Regulatory Framework for Electricity
SCADA	Supervisory control and data acquisition
TOTEX	Total expenditures
VAR	Volt/volt-ampere reactive

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Executive Summary

The electricity industry is undergoing significant disruption as it becomes cleaner, more distributed and more intelligent. This dynamic transformation is driven by trends that are clear across the sector, including increasing focus on climate change policy, evolving customer expectations, and advancing technology and innovation. These trends further emphasize the need for a more modern and aligned electricity grid. The primary objectives of this paper are to identify utility barriers to grid modernization investments and examine potential options to overcome these barriers using jurisdictional examples.

Utility Investment Barriers

Barriers to grid modernization manifest via two fundamental pivots, which are reinforced by an entrenched rate of return-based business model for most utility organizations. Thematic barriers are further contextualized with specified barriers in the figure below.

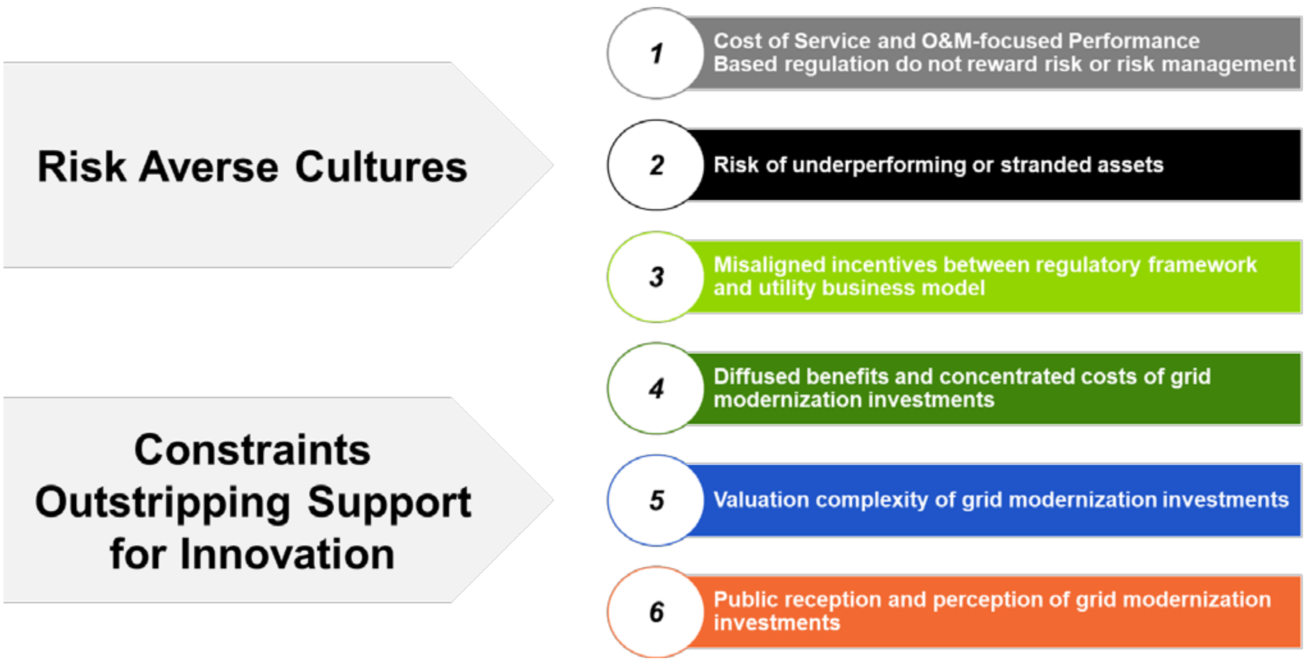

Figure ES 1 Summary of Utility Investment Barriers

The traditional cost of service utility model, with which most Canadian jurisdictions in some form regulate electricity supply and delivery, does not reward utilities to be innovative in response to sweeping market and technology disruption. Rate of return business models do not incentivize investment in non-infrastructure and non or low-capital assets. They tend to discourage operations and maintenance (O&M) expenses over capital investment. Innovative solutions such as cloud-based software-as-a-service and other non-infrastructure assets that could support transformation are typically considered O&M expenditure.

Uncertainty and stranded asset risk make utilities less inclined to invest in grid modernization. Key challenges exist as we transition toward a clean, distributed, intelligent and secure energy grid. Balancing the pace of investments while aiming to position the utility business for long-term growth and financial resiliency becomes critical, as focus is targeted to mitigate rate increases and support customer needs.

Many non-traditional and beneficial distribution system investments reduce a utility's capital expenses and increase operating expenses, thus there is less revenue opportunity as utility profit is largely based on return on capital assets. Reducing or eliminating the bias towards capital expenditure could encourage utilities to opt for the most cost-effective solutions regardless of the expenditure type.

Grid modernization investments generally deliver a range of benefits (e.g., reliability improvements, operational performance improvements, reduction in system energy losses, reduced consumption, deferred traditional network reinforcement, more productive workforces, carbon emission reductions, etc.), across the multiple segments of the industry (generation, transmission, distribution, end-user, and society). However, grid modernization costs are disproportionately borne by the distribution segment and/or its ratepayers, with an unattractive risk-reward profile in comparison to traditional utility assets.

It is also challenging to quantify both the magnitude and timing of benefits and multiple value streams that could result from grid modernization investments. The lack of data to draw from, particularly on more leading-edge technologies, makes it difficult to develop a compelling business case and benchmark expected returns. This also makes it difficult to allocate costs and benefits of implementing grid modernization infrastructure across rate classes.

Grid modernization investment decisions can be nuanced and dynamic, and regulators must keep the public interest in focus. This is a particular challenge in jurisdictions where electricity is relied upon as a primary heating source for many homes and businesses (e.g. New Brunswick). The challenge can be compounded during times of severe economic downturn, when electricity customers are having trouble paying their bills, and utility rate increases are delayed to provide relief to homes and businesses. Factoring in uncertainties related to the quantification and timing of grid modernization benefits, along with the rate of new technology development, regulators and utilities are further challenged to determine the best time to invest in a particular grid modernization initiative for their specific jurisdiction.

Lastly, the general lack of public awareness and understanding of the smart grid, or the contemporary grid for that matter, increases the likelihood of confusion, misinformation and opposition to grid modernization investments. Customers are price sensitive but will need to be engaged and made aware of aging grid infrastructure which requires crucial reinvestment and replacement. The benefits of grid modernization would need to be tangible for customers, whether this is through alternative price plans, new products and services, and/or tools to help them understand and manage their energy use. Upgraded technologies and assets will allow customers and utilities to take advantage of technology pace of change and the benefits that continue to be provided.

Lessons can be taken from the domain of energy efficiency. For several decades utility incentive mechanisms have been tested and amended to drive adoption of and investment in demand side management programs and demand response. At the same time, amended incentives address the barrier created by reducing the fundamental means for utility revenues - electricity sold.

Potential Options to Address Barriers

How jurisdictions respond to the disruptive forces transforming the sector manifest at various paces and scales due to different priorities and unique policy contexts, political and demographic characteristics, market design and regulatory structures. The diverse nature of provinces and territories across Canada means that there is no one size fits all response and each jurisdiction will require a tailor-made approach for addressing barriers, and leveraging the opportunities of a modern grid without creating undue economic losses within a system of publicly funded assets.

Updating regulatory and policy frameworks could allow utilities to pursue innovative and non-traditional solutions and business models, while ensuring that consumers are protected and can reap the benefits of a modern grid. Collaboration and partnerships between stakeholders could help effectively manage risks and balance the pace of grid modernization.

Guidehouse summarizes potential options to help alleviate utility investment barriers identified as part of this study.

Table ES 1 Potential Options to Alleviate Utility Investment Barriers

Barriers Addressed	Potential Options
1 2 3 4 5 6	a) Align regulatory frameworks to encourage shifts in utility cost of service remuneration models that would help achieve desired public policy goals and grid modernization objectives.
1 2 6	b) Encourage utility and private sector partnerships to shift risk away from ratepayers and maximize value to customers, while fostering innovation and potential returns for investors.
5 6	c) Develop more strategic and fulsome guidance on the process for the development, review, approval and monitoring of grid modernization investments.
2 4 6	d) Develop standardized data and methodologies to address locational benefits and costs of grid modernization investments within the system, to help minimize risks and ensure the right investments are made.
6	e) Promote customer engagement and education on the benefits of a modern grid and enhanced participation.

1. Introduction

The Canadian and global economy is dependent on the safe, affordable, and reliable delivery of electricity. Organizations within the electricity sector agree that grid modernization is required to support this need. This section provides contextual background and examines the core drivers that are accelerating the need for modernized electricity systems. Additionally, it provides a definition of the modern grid and describes utility opportunities that facilitate investment in grid transformation. The evolution of the telecom industry and relevant key takeaways for the electricity sector are provided in Section 1.4 below.

Policy, regulation and markets guide change. Technologies offer opportunities and benefits for utilities, service providers and consumers. However, without robust leadership and a push towards innovation in the electricity sector, the current utility delivery model could impede changes necessary for meeting policy, consumer and societal objectives.

1.1 Drivers of Electricity Sector Transformation

The electricity system is in a period of dynamic transformation and becoming an increasingly clean, distributed, democratized and intelligent energy ecosystem. Changing market demand, advances in technology and innovation, and policy and regulatory shifts are evolving the centralized one-way power system towards a networked and dynamic ecosystem. The system is evolving to one where decentralization and diversification of supply offer customer choice, and system optimization technologies support higher productivity, cleaner energy, innovation and agility. This emerging landscape actively enables two-way power and information flows to integrate distributed energy resources (DER) alongside traditional electricity supply assets. It involves multiple inputs and relies on a high degree of communication and automation to support multi-directional energy flows.

Guidehouse characterizes this new ecosystem as the Energy Cloud, shown in Figure 1-1.

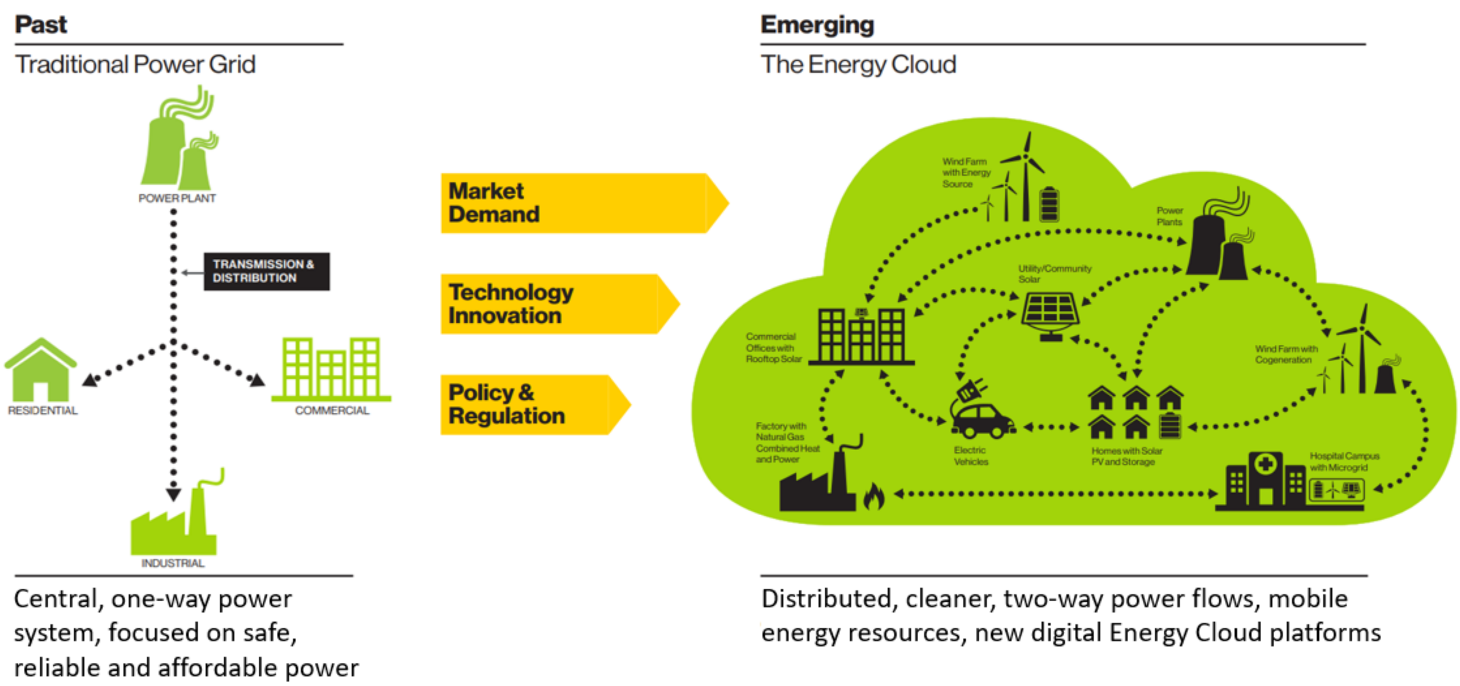

Figure 1-1 The Energy Cloud Transition

As evidenced from other industries, the confluence of three forces - technology innovation, changing market demands, and regulatory and policy shifts – continue to disrupt long-standing value chains. Innovative technology can slice through existing conventions, regulation, and business models, and connect consumers to the goods and services they seek in a more direct fashion than ever before.

The effects of these forces could play out fast or slow. However, they inevitably expose long-standing inefficiencies within an industry, leading to displacement of incumbent solutions and disruptions to the traditional value chain.

Guidehouse refers to the drivers of transformation as a disruption vortex, shown below in Figure 1-2.

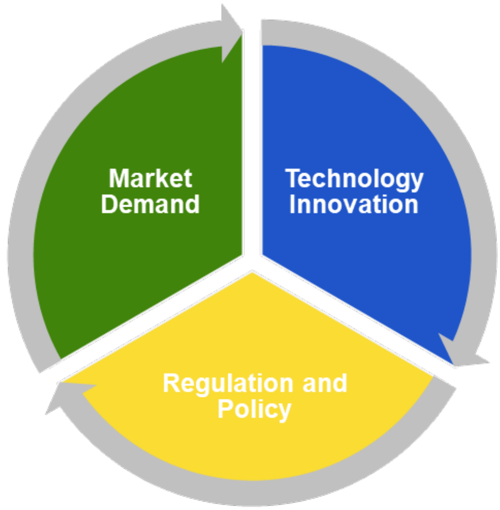

Figure 1-2 The Disruption Vortex

This disruption vortex in the utility industry is giving rise to multiple megatrends that are leading the transformation to a clean, intelligent, and distributed economy.

1. There is a growing market demand for cheaper, cleaner and more reliable energy sources. A growing number of customers are also demanding more choice in the type of energy from which they obtain electricity and choice in how they communicate with utilities. The ease of access to information is shifting customers from passive consumers to active prosumers. They also want more control and better understanding of their energy use, and some want to self-generate and sell excess electricity to the grid.[1] These trends are leading to marketplace differentiation and greater brand awareness for companies that can provide value-added solutions to a greater share of end-use customers. For example, Hydro-Québec offers a variety of products and service offerings such as consumption tracking tools, mobile apps, electricity management systems, net-metering etc.

2. Technology innovation is resulting in declining DER costs, thus strengthening the business case for encouraging adoption. For example, the unsubsidized cost of solar and wind have decreased 89% and 70%, respectively, from 2009 to 2019.[2] Advances in communications, controls and sensor technologies are also increasing connectivity, controllability, automation and data availability. These trends are increasing technology affordability and enabling the pairing of complementary disruptive technologies (e.g. solar and storage) to provide unique service offerings.

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[1] CEA. *Vision 2050: The Future of Canada's Electricity System*, pg. 28-29., 2014.

[2] Lazard. *Lazard's Levelized Cost of Energy Analysis – Version 13.0.* Accessed September 2020.

3. Policy and regulation is increasingly focused on addressing climate change, transitioning towards a low carbon economy, and further integrating other sectors of the economy with the electricity industry. Policy and regulation changes have led to increased renewables capacity. For example, Canada's cumulative installed capacity in wind and solar has grown from 460 megawatts (MW) to 15,857 MW from 2005 to 2018.[3] Every Canadian province and territory has targets and/or are making investments in energy efficiency, and almost all jurisdictions have set greenhouse gas (GHG) emission reduction and renewable energy generation targets (see 1.4Appendix A for jurisdictional profiles).

The backbone of the Energy Cloud is a modern electricity transmission and distribution system - a smart grid. A smart grid, secured against emerging cyber and physical threats, would allow utilities to integrate and optimize use of renewable energy and DERs, improve reliability, drive operational efficiencies, and enhance security, resiliency and flexibility.

Guidehouse defines grid modernization as investments in the transmission and distribution systems that include intelligent equipment, automation capabilities, sensors, operation systems and data analytics, as noted in the table below. These technology underpinnings are combined with processes and organizational design that more productively deliver enhanced reliability, resiliency and operability. Along with improved communications between utilities and customers, this constitutes grid modernization and offers customers an array of benefits.Table 1-1 lists the assets and/or components of a modern grid.

[3] Canadian Energy Regulator. *Renewable Energy Facts.* Accessed September 2020.

Table 1-1 Components of a Modern Grid

Component Category	Description
Advanced Metering Infrastructure (AMI)	AMI is capable of two-way communication and recording consumption data in near real-time. It enables remote meter reading, remote connection/disconnection, improved fault location, and more accurate and granular systems operational data. AMI provides the necessary information for utilities to improve operational efficiency and for customers to make decisions regarding energy efficiency and DER investment.
Non-Wires Alternative (NWA)	NWA, including DERs such as solar, battery storage, electric vehicles, and demand response, can be aggregated and managed by utilities in a smart grid to defer investments in traditional transmission and distribution grid infrastructure, such as substation and line upgrades.
Distribution Automation	A mixed variety of sensors and monitoring devices, mechanical and intelligent electronic devices, switches and communication devices, and supervisory control and data acquisition (SCADA) system, allow for more effective monitoring to support optimized asset utilization and integrated resource planning. It also reduces congestion in communication networks through the deployment of more distributed control architecture.
Advanced Communications and Data Analytics	Increased frequency and amount of communications amongst DER, smart devices and the central control server will require greater bandwidth and lower latency networks. Advanced data analytics will allow deeper analysis of the grid at an increasingly granular level to enable coordination of DER, and supply and demand.
Control & Management Systems	Use of advanced distribution management systems (ADMS) for distribution network management and/or DER management systems (DERMS) to monitor and control DERs on the network.

1.2 Defining Grid Modernization

Jurisdictions around the world are examining the challenge of how best to approach grid modernization. Efforts manifest at various paces and scales across jurisdictions due to different priorities, unique policy contexts, political and demographic characteristics, market design and regulatory structure. Although the definition and efforts on grid modernization vary by jurisdiction, desired outcomes and objectives converge along similar themes, shown in Figure 1-3.

A modern grid enables utilities to improve capital efficiency by better utilizing existing assets, enhancing security, reliability, resilience, affordability and flexibility in terms of resource management, and by providing greater customer choice. It also promotes sustainability and facilitates the integration of renewables and DERs into the grid, as well as enables implementation of demand-side management initiatives. The emphasis on these grid modernization objectives may vary depending upon the priorities and characteristics of a jurisdiction.

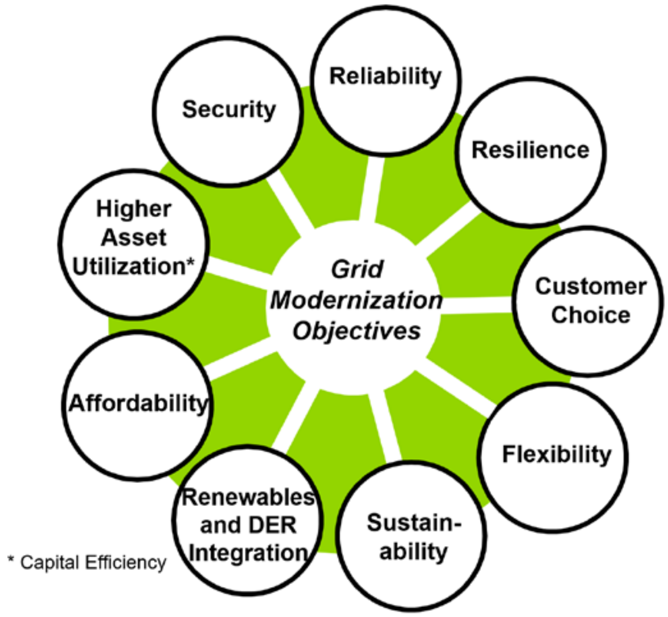

Figure 1-3 Key Objectives of Grid Modernization

For the purposes of this paper, grid modernization is defined as the process of implementing digital and physical energy infrastructure needed to ensure access to electricity, while cost-effectively supporting aging asset replacement, diversification of generation sources, climate change adaptation and resilience of infrastructure. Other characteristics of a modernized grid are that it: improves security and resiliency, motivates and includes the consumer, providing power quality for 21st century needs, accommodates and optimizes existing and new electricity generation and storage options, enables markets, optimizes assets and operates efficiently.

1.4Appendix A highlights grid modernization initiatives across Canadian provinces and territories, along with policies and other initiatives that are enabled by grid modernization, or are supportive of and integrated with the grid modernization definition and objectives discussed above. Policies and initiatives across Canadian jurisdictions related to GHG emissions reduction, renewables, energy efficiency and energy storage align with the core tenets of grid modernization and the objectives of sustainability, renewables and DER integration, reliability, customer choice and flexibility.

The diversity of provinces and territories across Canada means that there is no one size fits all response and each jurisdiction would develop their own approach for addressing barriers and leveraging the opportunities of a modern grid without creating undue economic losses within a system of publicly funded assets. Unique jurisdictional market needs will dictate the pace and the specific direction of change of their electricity sector.

1.3 Utility Opportunities in a Modern Grid

As the energy landscape transforms, there is an increasingly competitive environment for utilities. Revenue growth opportunities are anticipated to grow downstream, closer to the customer or behind-the-meter. This would reduce revenue opportunities from the efficient operation of a centralized system that moves commodity products unidirectionally from supply to load.

Declining costs of DER and consumer-enabling technologies—e.g., smart thermostats, building energy management systems, and machine learning heating and cooling systems etc.—would point to an even greater deployment of technology and infrastructure at the edge of the grid.

The potential for revenue from distribution utilities' core business is declining due to increasing energy efficiency and increasing adoption of DERs, constrained by regulatory and business models based on system throughput. To address any disincentive for utilities to promote conservation demand management resulting in lost revenues from utilities' core business, the Ontario Energy Board (OEB) has compensated utilities for reduced consumption due to conservation programs using a lost revenue adjustment mechanism (LRAM).[4] With an LRAM, a distribution utility can recover revenues it has lost in the past due to a conservation demand management program lowering customers' consumption levels.

Figure 1-4 illustrates the value shifting downstream towards the customer. This may lead to the core network and centralized investments becoming partially, if not fully, financially stranded with utilities unable to increase consumer electricity prices to generate sufficient revenue to cover costs. Assets would continue to be required during periods of peak system load. The core business and utility role as the owner and operator of the "highway of electrons" would prevail. However, there are financial and operational risks that utilities may be exposed to at varying degrees as the sector continues to transform.

Several approaches could be applied to mitigate these risks. These include exploring new business models and revenue streams, pursuing opportunities for innovation, and making investments in digital and intelligent assets to better facilitate and pace the transition. Leveraging smart grid technologies and on-system innovation, greater use of demand side management and demand response opportunities can further accommodate deferring of capital assets, smoothing of rate impacts and delivering reliable service. Utility organizations, regulators and consumers would share the risks and rewards of modernization.

[4] OEB. *Conservation and Demand Management Requirement Guidelines for Electricity Distributors* EB-2014-0278, updated 2016.

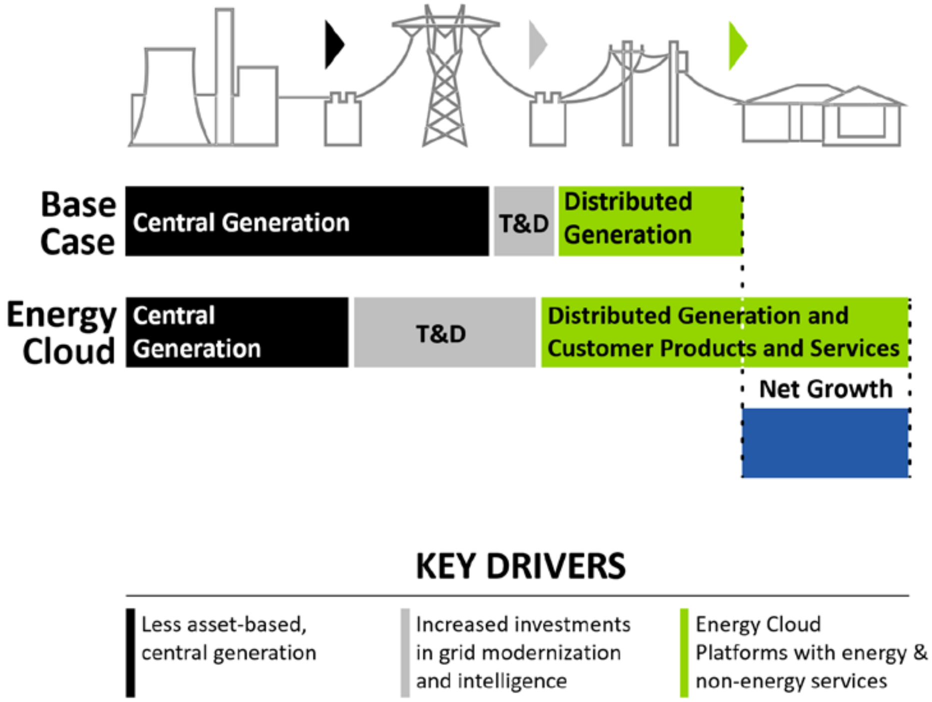

Figure 1-4 Value Chain for Base Case to Energy Cloud

In a recent annual survey of North American utility companies published in *Public Utilities Fortnightly (PUF)*, utilities recognize the importance of new business models in an environment with growing DER penetration. As shown in Figure 1-5, 47% indicated network orchestration roles, such as building transactive energy platforms and facilitating third-party participants, as the most attractive new business model.[5] Utilities have the opportunity to play a key role in providing an intelligent secure platform where third-party providers and customers are enabled to engage and exchange information, products or services. A core intelligent network is essential to facilitate these markets. Examples of products and services may include but are not limited to distributed generation, behind-the-meter energy storage, EV charging services and hardware, energy management services, and building or transportation to grid services.

Utilities could invest in new revenue opportunities beyond their traditional service offering, including technologies and infrastructure that support innovation. This could include managing multi-directional flows and data transactions and orchestrating distributed and dynamic, customer-based systems.

[5] Public Utilities Fortnightly. Annual Pulse of Power Survey, 2020.

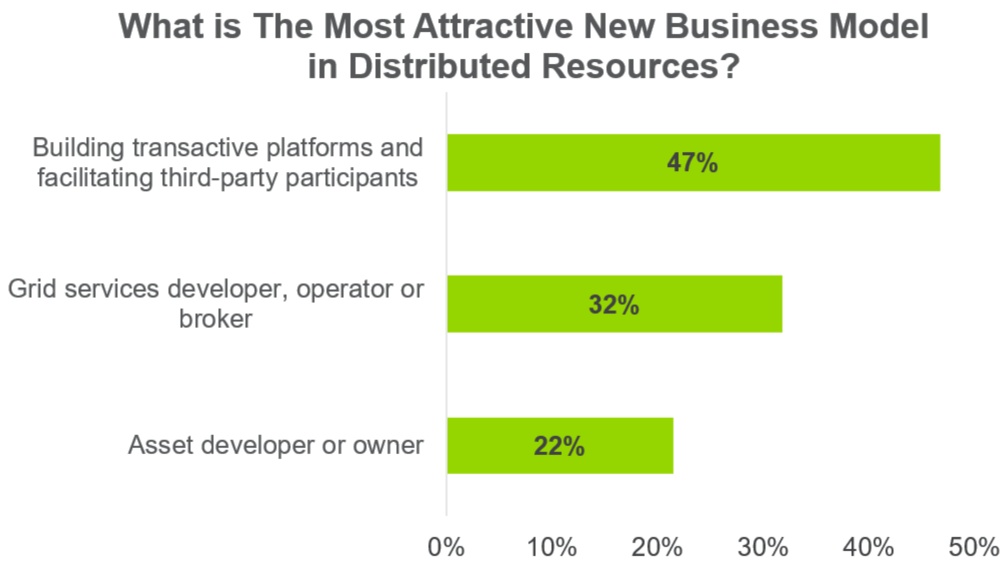

Figure 1-5 Utility Survey on New Business Models

It will be a challenge to identify how the electricity sector can navigate and capture opportunities in this transforming environment. Specifically, for utilities, the challenge will be identifying how to pursue new business models, while ensuring they meet their obligation to deliver electricity in a safe, reliable, secure and affordable manner. Adapting the market and regulatory framework can allow for utilities to be able to monetize their value-add through new business models. For regulators, it will become harder to balance what constitutes a business that should be funded by rates, and what should be a competitive business. Regulators are also already challenged in making decisions in the public interest relating to grid modernization investments. This is a particular challenge in jurisdictions where electricity is relied upon as a primary heating source for many homes and businesses (e.g. New Brunswick). The challenge is also compounded by economic downturns requiring further mitigation of rate increases to provide relief to consumers and businesses.

The subsequent section will discuss how the telecom industry navigated through their sector transformation, to provide some inspiration for the electricity sector.

1.4 The Telecommunication Industry Through Transformation

For several decades now, the telecom industry has gone through a transformation resulting in significant impacts to the overall structure of the industry and the growth in services provided. The impacts observed from telecom's transformation are a useful case study for the electricity sector, due to the historically monopolistic nature and tight regulatory origins of both telecom and electrical utilities. For many years, like with electric utility poles and wires assets, landline telephony was heavily regulated on a cost of service basis and required by customers as an essential service. However, as the pace of technology innovation accelerated and enabled more opportunities for new and diverse services on a cellular platform in the 1980s and 1990s, a continual retraction of regulation and restructuring of the industry allowed technology to flourish. This has led to an extremely high pace of change, adoption of new technology and reinvestment in infrastructure to enable faster, more efficient, more resilient and more diverse service.

Cellular, to fibre optic, to the forthcoming 5G, the industry continues to reinvent itself and serve evolving customer demands in a value-based competitive landscape.

The following sections will discuss the telecom industry's transformation through the lens of policy and regulation, customer demand and technology innovation.

Transformation through Policy and Regulation

In recent years, governments have been keen to develop fibre-optic networks, and oftentimes smart discrete regulations that enhance markets can be effective, even in a competitive marketplace like telecom. Rural and remote communities across Canada have recently benefited from several investments by governments in the telecom industry. In 2016, the Canadian government, along with the Province of Ontario, invested $180 million to deploy fibre-optic cables that allow for high-speed broadband internet. The Government of Canada also committed to investing $500 million over five years to extend and enhance this broadband service. [6] Municipal governments have also applauded telecom companies' sizable investments into fibre-optic development in urban areas. For example, Telus has invested a total of $75 million to connect homes and businesses directly to its fibre-optic network in the city of North Vancouver. This investment is part of Telus' commitment to invest $4.7 billion throughout BC between 2017 and 2020.[7]

Telecom firms are also being obliged, by the Canadian Radio-television and Telecommunications Commission (CRTC) and federal government, to share their fibre-optic infrastructure with smaller carriers in order to ensure a competitive marketplace. The CRTC allows the big telecoms to charge fees for sharing their fibre-optic network in order to profit on their capital asset investments.[8] This is analogous to the idea that arose under New York's Reforming the Energy Vision (REV) of electric utilities, expanding their roles as platform orchestrators. New York Utilities can earn platform service revenue by enabling the integration of third-party DERs and stimulating DER market development.

The above examples showcase how government regulation and policy can shape the direction and or velocity of the development of new utility markets and business models, such as encouraging utilities to act as platform providers and encourage third-party participants and transactions.

[6] CBC News, 2016. Accessed September 2020.

[7] Telus Media Release, 2019. Accessed September 2020.

[8] CBC News, 2015. Accessed September 2020.

Transformation through Customer Demand

The push for deployment of fibre-optic technology is driven by increasing customer demand for higher internet speeds and greater bandwidth, as shown in Figure 1-6. In competitive urban areas, rival telecom companies have undertaken sizable investments to bring fibre-optic cables directly to residents' homes in order to optimize speed and bandwidth. As of 2018, 89% of households have subscribed to internet service with the average monthly download usage for high-speed subscribers reaching 210 GB, a 25% increase over the previous year.[9]

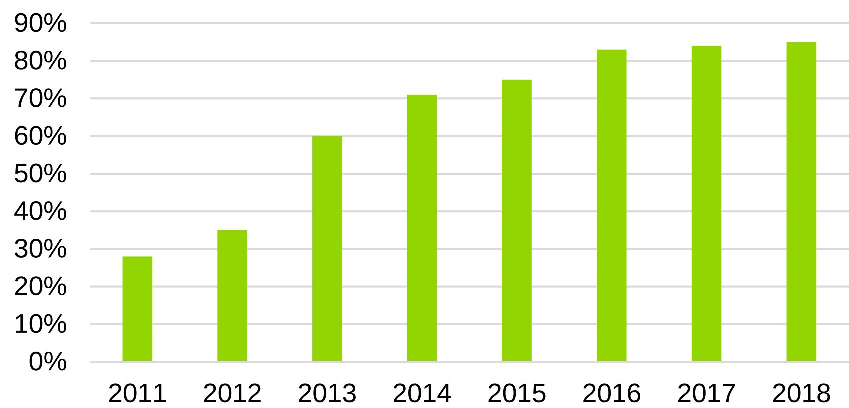

Figure 1-6 Percentage of Canadian households with access to ultra-high-speed broadband[10] (>100 Mbps)

Moreover, the pandemic has accentuated the need for better internet and wireless network access. For example, Rogers supported health-care providers by deploying temporary cell sites on wheels, increased capacity to hospitals, ran fibre in parking lots and fields and extended fixed wireless to create new COVID-19 testing centres. They have also provided more Wi-Fi for hospitals, senior's homes and homeless shelters. Most telecom companies committed not to disconnect customers and waive fees for low-income families and students in need during the pandemic.[11]

Telecom companies were able to meet increased and evolving customer demand by investing in reliable infrastructure. The above example emphasizes how important it is to have a customer-centric approach, to anticipate the needs of the market, and to ensure that the requisite technologies are implemented before the existing system becomes overburdened or obsolete. Similarly, within the context of the electricity sector, customers are playing a key role in the transformation as their preferences evolve and as they demand new and different services from their utilities.

Extensive infrastructure investment can also lead to higher costs for customers. In a recent Canadian Radio-television and Telecommunications Commission survey of 28,000 cell phone users, it was found that 45% of customer are dissatisfied with their current provider, and >85% of respondents cited the cost/price of service and/or data as the reason for their

[9] CRTC. *Communications Monitoring Report, 2019.*

[10] CRTC. *Communications Monitoring Report, 2016.*, CRTC. *Communications Monitoring Report, 2019.*

[11] Global News, 2020. Accessed September 2020.

dissatisfaction.[12]In the electricity sector, utilities and regulators will need to work together to avoid customer dissatisfaction by clearly communicating and demonstrating the benefits of grid modernization investment, especially where costs of such investment are passed on to consumers.

Transformation through Technology Innovation

Fibre-optic cables are succeeding copper wire as the standard in communications technology as they provide faster upload and download speeds, suffer less signal degradation over long distances, significantly increase bandwidth potential and have a lower total cost of ownership. Telecom firms recognize that the existing copper wire network will not be able to support future demand, so they are expanding their fibre-optic cable networks to stay competitive despite the high cost involved. For example, Bell invested $1.14 billion in broadband fibre connections in Toronto.[13] In the telecom industry, a full overhaul of the existing infrastructure was needed. For the electricity sector, the market need is dictating a change in direction.

As the industry pushes forward, new technologies will also arrive and compete with fibre optic. 5G is again expected to be a step change, offering fully wireless connectivity with greater bandwidth and productivity. As a platform, 5G will likely unleash another wave of innovation for network users, consumers and technology developers who will enhance and expand services that the telecom ecosystem provides for and enables.

Over the past two decades, the demand for landline telephones has significantly decreased with the adoption of mobile phones. Although some demand for landlines still exist, the share of Canadian households that own one or more mobile phones has continued to rise, while fewer and fewer households own landlines, as shown in Figure 1-7. While some demand for landlines is almost certain to remain for the foreseeable future, it will make up a decreasing portion of telecom companies' business. Telecom companies are relying increasingly on their mobile, wireless and broadband services, which are becoming increasingly lucrative as consumers demand more from their internet plans.

[12] CRTC. *Online Consultation on Mobile Services in Canada Final Report, 2020.*

[13] Bell Canada Enterprises, 2015. Accessed September 2020.

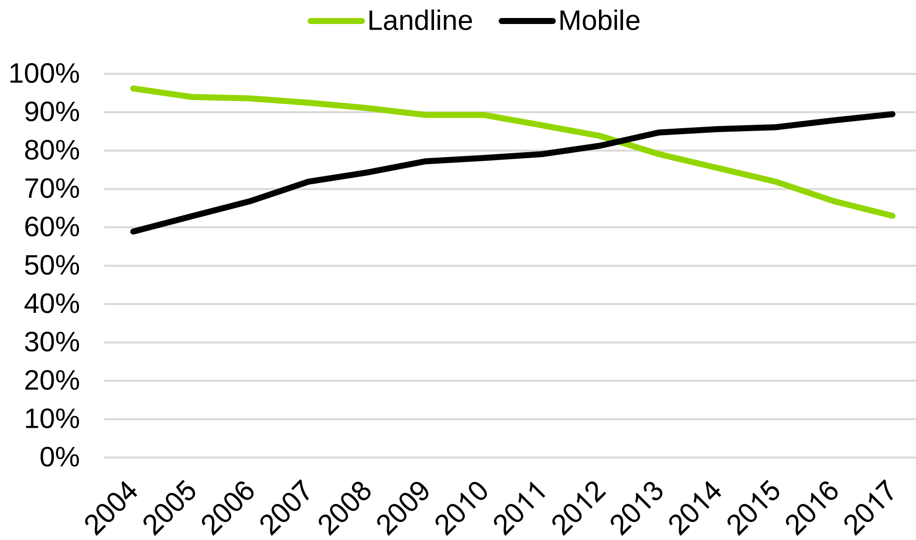

Figure 1-7 Percentage of Canadian Households with Landline and Mobile Subscriptions[14]

In the electricity sector, although centralized generation is unlikely to disappear completely with increasing adoption of DERs, utilities are seeing a decrease in demand from their core business. As seen from the telecom example, a diversified product portfolio can keep a company competitive and relevant as technology transform its business.

Key Takeaways for the Electricity Sector

- Government regulation (or deregulation) can drastically impact the direction of a market.
- It is crucial to be proactive in anticipating the needs of the market and implementing the requisite technologies before the existing system becomes overburdened or obsolete.
- The market need is dictating the change in direction of technology investments.
- Where grid modernization investment costs are passed on to consumers, the electricity sector will need to educate and demonstrate benefits to customers.
- With increasing adoption of DERs and energy efficiency, utilities will see a decrease in demand of their core business.
- A diversified product portfolio can keep a company competitive and relevant as technology transforms its business.
- Utilities can remain relevant by accommodating the shifting market expectations and evolving towards new business models.

[14] CRTC. *Communications Monitoring Report, 2019.* Figure 1.2 Household subscriptions to landline and mobile services (per 100 households).

2. Utility Investment Barriers

Section 2.1 discusses barriers to utilities investing in infrastructure that would help achieve grid modernization objectives.

2.1 Identified Barriers

Although the need for modernizing the grid is widely recognized by the electricity sector, there remains barriers that manifest via two fundamental pivots:

- Risk averse cultures reinforced by an entrenched cost of service – rate of return-based model
- Constraints outstripping support for innovation

The traditional regulatory compact between regulators and utilities has established a risk averse culture, leading to a misalignment between value-based decision making and cost-based decision making. Through this traditional regulatory compact, utilities can earn a rate of return in exchange for taking the financial risk on capital investments and being obligated to serve all customers. The return on investment allowed for is well understood and entrenched, resulting in the expectation for utility shareholders of a near risk free return in exchange for reasonable levels of reliability and production efficiency on a predictable and dependable basis.

The most common rate designs recover the fixed cost of the electricity system via volumetric rates. Therefore, the recovery is dependent upon the volume or kilowatt-hours of electricity delivered to customers. In a transforming energy landscape where there is increasing energy efficiency and adoption of DERs, utilities are less inclined to take the risk of investing in the distribution grid in order to meet customer expectations, increase flexibility, and integrate DERs. The traditional regulatory framework, which was designed many decades ago, cultivates an expectation of low risk and guaranteed returns for utilities. In an evolving energy landscape, utilities exist in an increasingly competitive environment wherein their risk appetite may need to change, and business models may need to be augmented to be more flexible and accommodating to change. This institutional desire for stable revenue streams, long-term investments, and outlook predictability is no longer a reality in today's utility landscape. As a result, the risk averse culture that has developed in both the regulator and electricity utility industry will require a fundamental disruption to unsettle.

Regulators' risk attribution is rooted in their mandate of protecting consumers and making decisions that serve the public interest by ensuring production cost efficiency and cost prudence. When it comes to electricity utilities, especially in Canada where we have enjoyed relatively low power costs and resource abundance, consumers themselves are also risk averse. This is likely due to a lack of awareness and understanding of how grid modernization impacts them personally, beyond their monthly bills. Canada's relatively low electricity rates makes it challenging to convince consumers and political representatives to invest in grid modernization infrastructure, or to invest in change at all – *a don't fix something that works very well mindset*.

Innovation requires testing unproven concepts and technologies, taking risks, and pursuing ideas that often fail. The obligation of utilities to serve, avoid risks to ensure safety, reliability and security and the regulators' mandate to ensure cost efficiency diverges from the precepts of innovation. Innovation most often occurs outside of the utility and amongst grid edge technology companies. As such, innovation is typically not afforded by the regulator. Oftentimes, adoption of innovation from third party providers on the grid edge also comes as a service, and therefore is treated as an expense, not a capital investment for the utility. Since no return is earned on non-capital expenses, there is little incentive to examine service-based grid modernization investments deeply. Electricity public policy is also politically charged as consumers are less forgiving when it comes to the use of ratepayer or taxpayer money to pursue ideas that may fail.

The overarching barriers of risk averse cultures and constraints outstripping support for innovation are further broken down in **Figure 2-1** and discussed below.

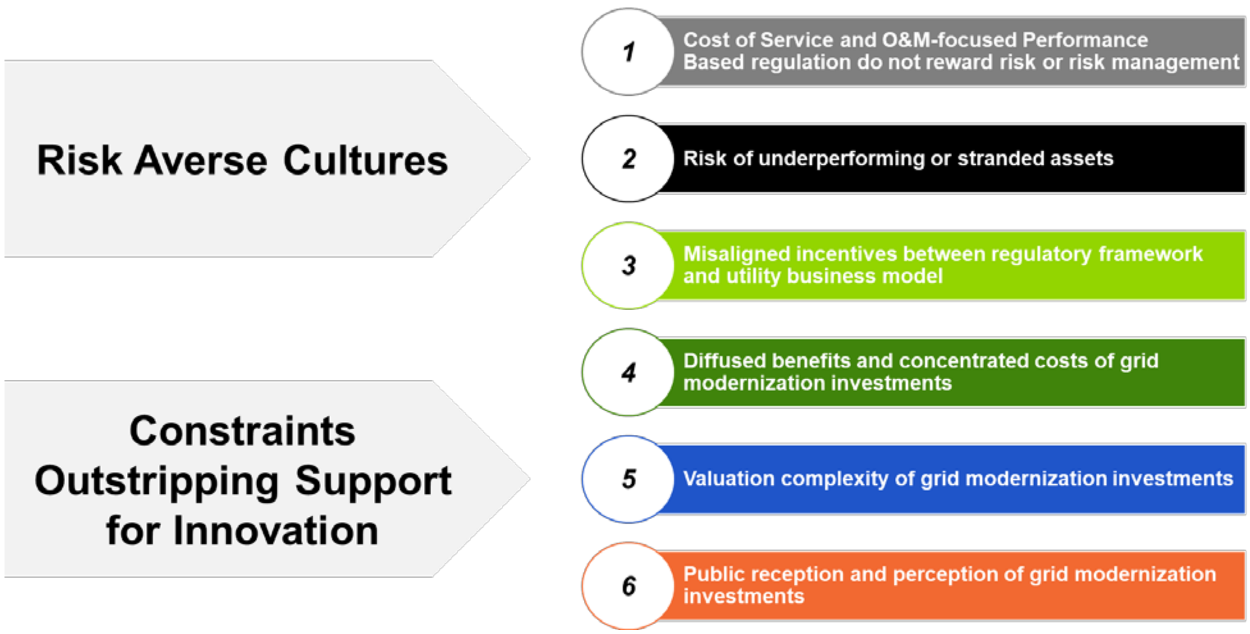

Figure 2-1 Utility Investment Barriers

1 Cost of service and O&M-focused performance-based regulation do not reward risk or risk management

Traditional cost of service regulation affords utilities the opportunity to earn a regulated rate of return in exchange for accepting the financial risk of continued capital investment and the obligation to serve all customers. As discussed earlier, the transforming energy landscape renders the traditional cost of service less effective as it does not reward utilities to be innovative in response to market changes, and does not incentivize investment in non-infrastructure and non-capital assets which become mostly O&M expenses. Most Canadian jurisdictions operate under a cost of service model. 1.4Appendix A provides a summary of regulatory structures across Canadian jurisdictions.

Elements of performance-based regulation (PBR) have been implemented across Alberta, Ontario and British Columbia. However, PBRs implemented thus far are focused on achieving operational and production cost efficiencies and do not reward utilities to manage uncertainty and risk.

2 Risk of underperforming or stranded assets

Due to inexperience with non-traditional distribution assets, there is risk and uncertainty of underperformance and potentially stranding grid modernization investments. With today's extremely high pace of change, oftentimes technology can become obsolete quickly. Cost of service and current forms of PBR regulation place a long-term view on depreciation of an asset and early obsolescence results in financial loss.

For utilities, existing and traditional assets also face stranding risk in a fast-moving transformative environment. Where modern grid investments enable further reduction in incumbent utility energy demand, incumbent assets continue to be underutilized and financially threatened. The treatment of stranded assets could also be a barrier depending upon the form. For example, due to a Supreme Court decision and multiple court cases, utilities in Alberta cannot recover the undepreciated capital costs of facilities that were prudently incurred to the service of customers, even where those assets are deemed to cease to be useful in public utility service due to an unanticipated event. The ability of regulators to establish alternative treatments for stranded assets vary across Canadian jurisdictions.

A key challenge for transitioning toward a clean, distributed and intelligent energy grid is balancing the pace of investments to position utilities' business for growth with ensuring rate stability and supporting customer needs.

Lessons can be taken from the domain of energy efficiency. For several decades utility incentive mechanisms have been tested and amended to drive adoption of and investment in demand side management programs and demand response, while at the same time addressing the barrier of reducing the fundamental means for utility revenues - electricity sold. However, with the right incentives and sharing mechanism, it has been found that utilities can invest in and benefit from energy efficiency alongside the customer. Energy efficiency has also been a mechanism leveraged to help stabilize rates and pace major capital investments through deferral, a function that energy efficiency may continue to serve in support of smoothing smart grid investments. Grid modernization can enable and support energy efficiency, and energy efficiency may be able to support grid modernization, as energy efficiency is typically thought of as a core criteria and metric of smart grid maturity.

3 Misaligned incentives between regulatory framework and utility business model

The most common rate designs link growth in electricity consumption and of grid infrastructure with utility business growth. Therefore, energy efficiency and DERs adversely impact utilities financially. There is inherent bias in the traditional regulatory framework as utilities can profit from capital expenditures, but not operating expenditures. Many non-traditional distribution investments reduce a utility's capital expenses and increase operating expenses, thus there is less utility profit should they opt for non-traditional distribution investments. For example, energy storage could be used as a non-wires alternative to defer distribution substation investment, provided it is more cost-effective than the traditional solution. Cloud-based computing offers advantages of scale and operational expertise of specialized technology companies while avoiding the cost of equipment, maintenance and software of on-premise IT systems. The bias for capital expenditure would need to be reduced or eliminated to encourage utilities to opt for the most cost-effective solutions regardless of the expenditure type.

There are mechanisms that have been implemented that address misaligned incentives between the traditional regulatory framework and utility business model, particularly in incentivizing energy efficiency. For example, a lost revenue adjustment mechanism and/or revenue decoupling can help ensure that utilities do not see revenue erosion for short-term losses in base rate revenues, often due to demand-side management programs. However, with the growth of DERs on the distribution grid, these mechanisms alone would be insufficient to mitigate rate impacts for consumers, while continuing to recover fixed costs associated with grid modernization investments. Further, unlike with energy efficiency where utilities have been instrumental in delivering programs, DERs and new customer-based technologies that impact revenues can be directly competitive with the utility and circumvent the regulated business altogether.

4 Diffused benefits and concentrated costs of grid modernization investments

Grid modernization investments generally deliver a range of benefits (e.g., reliability improvements, reduction in losses, reduced consumption, deferred traditional network reinforcement, etc.) across multiple segments of the industry including generation, transmission, end-user, and society (e.g. carbon emission reductions). Customer value is difficult to quantify, particularly when investments may be associated with a specific customer segment but bring benefits that are diffused unevenly across customers or may not be shared universally. However, the costs are disproportionately borne by the transmission and distribution segment and there are limited mechanisms for utilities to monetize the value of all benefits across all segments, and to leverage the benefits of behind-the-meter assets. As such, utilities may be less inclined to proceed with grid modernization investments.

5 Valuation complexity of grid modernization investments

It is challenging to quantify both the magnitude and timing of benefits and multiple value streams coming from grid modernization investments. The lack of data to draw from, particularly on more leading-edge technologies, makes it difficult to develop a compelling business case. Data gathering, tracking and analysis to assess costs and benefits are complex and resource intensive exercises, which may not be afforded by the current regulatory frameworks.

Valuation complexity is exacerbated by insufficient guidance on how utilities are expected to apply for and evaluate grid modernization investment projects and pilots. It is unclear which assets they can invest in and how cost-benefit analyses are to be carried out for grid modernization investments. Without guidance, there is uncertainty and a risk of wasting administrative and regulatory costs, having misaligned cost-benefit analysis methodologies across the sector, and undervaluation of grid modernization investments. For example, New

Brunswick Power is seeking approval of its application to invest $92 million in AMI for the second time. The New Brunswick Energy Utilities Board denied the initial application in 2018, citing that it was not in the public interest and that the utility failed to make a positive business case.[15] In the second filing, NB Power explored potential savings and costs that were not previously considered.

6 Public reception and perception of grid modernization investments

There is a general lack of public awareness and understanding of the smart grid, which increases the likelihood of confusion, misinformation and opposition to grid modernization investments. This makes it challenging to obtain public acceptance on the shared cost of grid modernization investments. Relatively low electricity rates in Canada also add to the challenge of convincing the public of the current and future benefits of grid modernization. Lack of understanding may also limit the extent to which customers can actively participate in the electricity system. Customers are price sensitive but would need to be engaged and made aware of the aging grid infrastructure requiring replacement and upgraded to take advantage of new technologies and the benefits they provide.

As discussed in Section 1.3, utilities may need to invest in new business models and revenue opportunities beyond their traditional service offering. The annual Pulse of Power survey published by Public Utilities Fortnightly confirms that one of the primary barriers preventing North American utilities from pursuing new business models is the rigidity of utility regulation and rate structure - a finding consistent with the previous years of surveys (see Figure 2-2). As the energy transition progresses, government bodies and regulators clearly have an important role to play in enabling grid modernization investment.

[15] New Brunswick Energy and Utilities Board. Decision Matter No. 375.

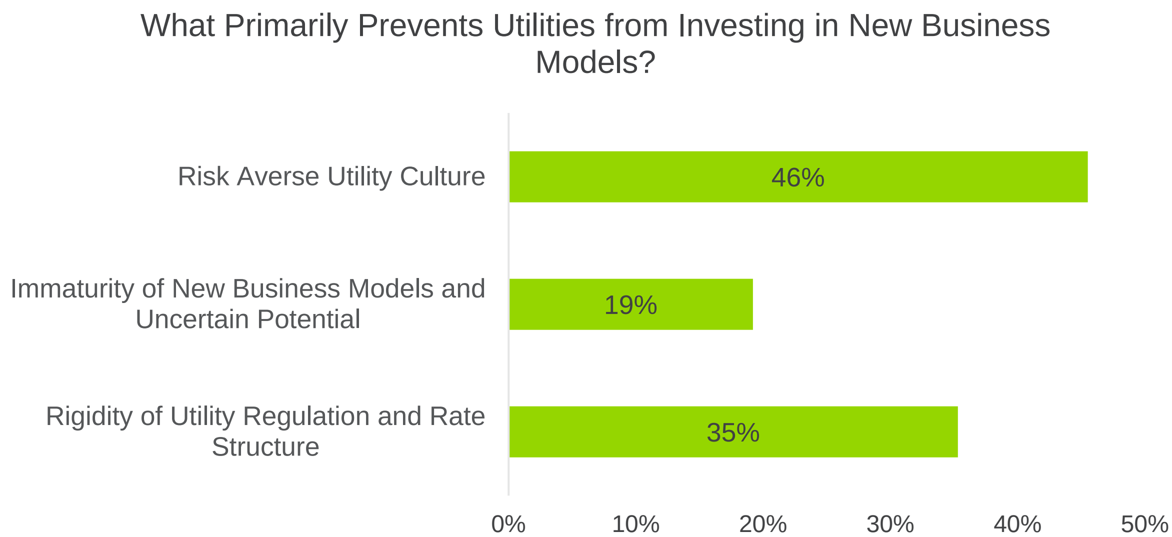

Figure 2-2 North American Utilities' Survey Response to Barriers[16]

While previous years' Pulse of Power surveys consistently identified the regulatory environment as a primary barrier preventing utilities from investing in new business models, the 2020 survey showed risk averse utility culture as the largest barrier. Change agents within utilities can be a helpful catalyst in altering their risk averseness. Although the immaturity and uncertainty of new business models is also a lesser concern, sentiment across the industry is still focused on more structural barriers to innovation like restrictive regulations and utility operating culture. This points to an opportunity for regulators and utilities to collaboratively create a more ambitious future vision for the electricity sector.

[16] Public Utilities Fortnightly. [Annual Pulse of Power Survey, 2020.]

3. Potential Options to Address Barriers

Section 3.1 discusses the range of policy responses to electricity sector transformation and the broad alternative regulatory mechanisms. Section 3.2 provides a summary of potential options that may alleviate barriers outlined in Section 2.1.

3.1 Policy and Regulatory Response Continuum

Energy policy across jurisdictions generally reflects growing consumer preference for cleaner sources of energy and societal pressure to address climate change. These factors combined with technology innovation emphasize the need for utilities to improve performance, enhance security, resilience, reliability, flexibility, and to integrate DERs and renewables; all while ensuring affordability for consumers. Figure 2-3 is intended to illustrate how some jurisdictions approach the energy transition more incrementally, while others could make step changes through transformative initiatives. Typical actions listed are non-exhaustive, not necessarily sequential and may overlap. It is important to note that incremental actions do not automatically equate to low impact; incremental steps over a time period could be very substantive with robust planning, pace and implementation and perhaps be more prudent than more disruptive change.

	Incremental		Transformative
Core Themes	Market development/ commercialization, renewables policy and climate change, operational efficiency, asset by asset change	DER penetration and market growth, economic competitiveness and parity, system impacts grow, grid modernization awareness develops, stranded assets risk, ratepayer fairness, cost recovery, cross-subsidization	Grid modernization strategy and objective setting, innovation and customer focus, total efficiency and performance, DER system benefits, system wide platform for change, utility as a platform business model
Typical Actions	Net energy metering (NEMs) tariffs, tax incentives, renewable portfolio targets, pilots, AMI deployment mandates, procurement targets and mechanisms, multi-year rate plans	Multi-year rate plans with performance metrics and/or program-based incentives, regulatory sandboxes, discussion papers, innovation funds	Value-based ratemaking, locational value, system performance value, regulatory framework overhaul, comprehensive multi-stakeholder planning and coordination

Figure 2-3 Policy and Regulatory Response Continuum

Incremental efforts tend to center on themes of market development, renewables and climate change policy, regulating utilities for operational efficiency and introducing asset by asset change. For example, as the first step towards grid modernization, several Canadian jurisdictions have implemented AMI to varying degrees, from pilots, to selected areas or customer segments, to wide scale deployment.

The level of effort may also vary depending on local market trends. DER market growth, grid cost parity, and growing system impacts of DER tend to develop further awareness of grid modernization and bring topics of stranded asset risk, ratepayer fairness, and cost recovery to the forefront of utility policy discussions. To address some of these concerns, jurisdictions may develop discussion papers and/or adopt alternative regulatory mechanisms. Such mechanisms could include multi-year rate plans with performance metrics and objective-based scorecard approaches, or updating regulatory accounting to remove bias for capital expenditure.

To further understand system impacts and test innovative solutions, demonstrations made possible by innovation funds and/or regulatory sandboxes are initiated. For example, Canada continues to support projects under the 4-year, $100 million Smart Grid Program to fund next-generation smart grid technologies.[17] Section 3.1.1 further discusses alternative regulatory mechanisms and highlights adoption or proposal examples.

As highlighted in Examples 1 and 2 below, other jurisdictions, such as New York and California, have taken a more transformative approach in which a system wide platform for change is developed. The themes focus on grid modernization strategy and objectives setting, innovation and customer-centric initiatives, utility total efficiency and performance, DER system benefits and new utility business models. Typical actions may include comprehensive multi-stakeholder planning and coordination to examine a regulatory framework restructuring, value-based ratemaking that considers the total efficiency of capital, and developing guidance and methodologies for quantifying the temporal and locational value of DERs and other system assets.

Example 1: New York's Renewing the Energy Vision (REV) [18]

The New York State Public Service Commission (NYPSC) issued an order in 2016 to adopt a new regulatory model that incentivizes utilities to act according to REV objectives (system reliability, customer knowledge and capabilities, reduced carbon emissions, etc.) by better aligning utility shareholders' financial interests with customers' interests. This is done by adding a combination of market-based and outcome-based performance incentive mechanisms for utilities, which the NYPSC calls Earning Adjustment Mechanisms (EAMs).

Examples 2: California's DER Action Plan[19]

California's DER Action plan aligns a long-term vision with actions from multiple proceedings. The plan guides initiatives related to rates and tariffs, distribution grid infrastructure, planning, interconnection and procurement, wholesale DER market integration and interconnection.

California has undertaken a bottom-up policy approach with comprehensive multi-stakeholder engagement. Utilities were mandated to submit Distribution Resource Plans, which required identifying grid modernization investments to integrate the growing number of DERs and determining how DERs should be valued.

Adopting transformative approaches can be a major challenge that often entails complex proceedings, as highlighted in Example 3. Massachusetts initiated grid modernization efforts and utility reform in 2012 but lagged in advancing them. Progress tended to be stalled by gubernatorial election and changes in administrations in 2015. However, Massachusetts has demonstrated significant progress in energy efficiency and has been focused on the integration of clean energy and greenhouse gas reduction, which has led to high penetration of renewables in the state.

[17] Environment and Climate Change Canada. *Pan-Canadian Framework on Clean Growth and Climate Change, 2020.*

[18] New York Department of Public Service. *Reforming the Energy Vision.*

[19] California Public Utilities Commission. *DER Action Plan, 2017.*

Example 3: Massachusetts's Grid Modernization Plan and Clean Peak Energy Standard[20],[21]

The Massachusetts Department of Public Utilities (DPU), which is the Public Utilities Commission of the State of Massachusetts, issued an order in 2014 requiring utilities to develop and implement 10-year Grid Modernization Plans that reduce outages, optimize demand, integrate DERs, and improve workforce and asset management through a combination of "grid-facing" and "customer-facing" measures. However, it was not until May 2018 that the DPU approved utility proposals for a $220 million investment in grid-facing technologies only and not AMI. Authorized investments include distribution automation, advanced distribution management systems (ADMS), and volt/volt-ampere reactive (VAR) optimization. The delay in AMI investment demonstrates a more gradual approach towards DER integration and optimization in the state. DPU reiterated the goal of full deployment of AMI if and when it can be deployed cost effectively.

Massachusetts also recently established a Clean Peak Energy Standard to increase clean energy during periods of peak demand. The standard has supported clean resources and reduced infrastructure costs by allowing peak demand to be served more completely by local renewable energy sources, instead of relying on GHG-emitting generation resources under expensive reliability-must-run contracts. Peak energy standards are supported by intelligent grid systems. Starting in 2020, the Clean Peak Energy Standard will be 1.5% of retail electricity sales and will increase by at least 1.5% annually to ensure the minimum by 2030 is 16.5%.

There is no one size fit all response that can be prescribed for Canadian jurisdictions to direct, guide and establish grid modernization. Each province and territory, along with its unique stakeholders, would have to determine what approach or combination of options best suit their respective markets. However, broad concepts and focus areas can be useful for decision makers to examine. Section 3.1.1 below discusses alternative regulatory mechanisms for consideration and roles for policymakers as part of the pathway to alleviate barriers to utility investment in grid modernization.

3.1.1 Alternative Regulatory Mechanisms[22]

As discussed in Section 2, it is a challenge for utilities to invest in grid modernization infrastructure that would meet customer expectations while maintaining an affordable, resilient and reliable system under the traditional regulatory framework.

Alternative regulatory mechanisms have emerged that offer critical elements for change and a set of options that respond to evolving customer needs and expectations relative to changing technological, policy, and market conditions. Alternative regulatory mechanisms can be grouped into three categories, as shown in Figure 3-1. The electricity sector is diverse in market structures, generation profiles, natural resources, geography, customer size and segments. The examples included below are non-exhaustive and may not apply universally across jurisdictions.

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[20] Government of Massachusetts. *Press Release by the Department of Public Utilities.* Accessed September 2020.

[21] Massachusetts Department of Energy Resources. *Clean Peak Energy Portfolio Standard. Filed July 2020.* Accessed August 2020.

[22] Electricity Regulation for a Customer-Centric Future. *Survey of Alternative Regulatory Mechanisms*, Prepared for Edison Electric Institute, 2020, Guidehouse.

Figure 3-1 Alternative Regulatory Mechanisms

***Revenue Adjustment Mechanisms* (RAM)** refer to how a utility's target revenues are determined, collected, and/or adjusted over time. RAMs tend to focus away from historic costs and sales, like in a cost of service approach, and attempt a more prospective approach that incentivizes and rewards cost control, but also considers value, thus benefitting customers.

Multi-year rate plans (MRP) are common for utilities in Alberta, British Columbia, Ontario and Quebec, and have been highly successful in the natural gas utility space. Example 4 highlights a case where Quebec's Bill 34 froze distribution rates for five years, with annual inflation adjustments.

Example 4: Quebec's Bill 34 and Multi-year Rate Plan[23]

Adopted in late 2019, Bill 34 simplifies the rate making process for Hydro-Québec (HQ) by freezing distribution rates for five years, with annual inflation adjustments. HQ is no longer required to obtain Régie de l'énergie approval for infrastructure investments and changes to its distribution network annually. It remains to be seen how effective Bill 34 will be in encouraging HQ to reduce costs and whether its flexibility could make HQ more inclined to pursue innovative products or technologies in its distribution network at a faster pace.

Performance Mechanisms provide focused incentives for utilities to reach performance targets aligned with policy and customer priorities through public metrics or scorecards, or through financial rewards for achieving certain levels of performance. Reported metrics are used to enhance transparency and to encourage specific utility performance by tracking and reporting results. Scorecards compare reported metrics to a performance target, benchmark, or peer. As highlighted in Examples 5 and 6, Ontario and Illinois use performance metrics to measure utility performance against defined outcomes.

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[23] National Assembly of Québec. *Bill 34.* Enacted December 2019.

Example 5: Ontario's Renewed Regulatory Framework for Electricity (RRFE)[24]

The Ontario Energy Board implemented RRFE in 2014 to better align utility reliability and quality of service levels with customer expectations. RRFE uses a scorecard to measure utility performance against defined performance outcomes including customer focus, operational effectiveness, public policy responsiveness and financial performance.

Performance *incentive* mechanisms pair a metric with a performance target and a financial incentive to motivate utilities' performance towards achievement of operational, customer or public policy goals. For example, Hawaii's existing performance incentive mechanism includes service quality metrics and policy metrics related to the timely acquisition of cost-effective demand response resources from third-party aggregators and the successful procurement of grid-scale renewable energy. However, not all performance incentive mechanisms truly connect public policy or customer goals and tend to come short, focusing mostly on simple cost productivity and reliability.

The most common transformative application of performance incentive mechanisms is in energy efficiency. Utilities could be permitted to share net benefits and earn a percentage of savings from energy efficiency programs. Earnings may also be tied to meeting one or a set of multiple pre-established savings-based goals. Lastly, utilities could also be allowed to earn a return on energy efficiency program spending.

REV transformed New York's regulatory model by adding a combination of market based and outcome-based performance incentive mechanisms for utilities, called Earning Adjustment Mechanisms (EAMs). Each utility proposes the performance areas, metrics and targets, and the level of incentive it would earn individually with the regulator. Targeted areas include system efficiency and peak reduction, energy efficiency, the distributed generation interconnection process, customer engagement in innovative programs, and GHG reduction through increased renewable sources and electrification of transportation and building heating and cooling.

Reported metrics and scorecards can be used as building blocks towards a performance incentive mechanism, as they build capabilities for metric tracking and gathering historic and peer-compared performance trends.

Other Regulatory Mechanisms include shared savings mechanism and others that remove long institutional bias for capital expenditure, providing utilities the opportunity to earn revenue from the procurement of cost-effective, third-party solutions to deliver products and services that support grid modernization, such as cloud-based computing or aggregated DER. This is a critical concept in the modern economy. As more and more value shifts downstream in a vertically integrated supply chain, value shifts towards digital service-based solutions and away from capital intensive investments upon which utility profits typically depend. As highlighted in Example 6, Illinois considered allowing utilities to earn a return on cloud-based computing.

[24] Ontario Energy Board. *Utility Performance and Monitoring.* Accessed September 2020.

Example 6: Illinois' Energy Infrastructure Modernization Act (EIMA) and Cost Recovery Ruling[25,26]
EIMA allows a formula rate model and requires utilities to file multi-year performance metrics and goals over a 10-year period. These metrics included a variety of categories such as reliability indices, peak demand reductions, renewable energy adoption, GHG reductions, reductions in estimated bills and the adoption of new smart grid technologies. In 2018, the Illinois Commerce Commission (ICC) proposed a ruling to allow utilities to treat 80% of cloud hosting capacity and software subscription fees as regulatory assets, with the balance treated as operating expenses. The proposed rule goes further and would permit some earnings on a pay-as-you-go service, though not on an equal level with prepaid cloud computing services. However, the ICC rejected the proposed rule in July 2020, due to concerns around the lack of a necessary consumer protection mechanism.

A shared savings mechanism allows utilities to retain a portion of savings as profit while sharing the rest with customers, often via lower rates. This allows utilities to pursue cost-effective solutions without compromising customer and shareholder interests. Shared savings mechanisms may apply to capital expenditures (CAPEX), operating expenditures (OPEX), total expenditures (TOTEX) or some subgroup such as non-wires solution or alternative or demand management programs.

Since utilities earn a rate of return on CAPEX, and not OPEX, there is an inherent bias for utilities to prefer capital investments over other solutions under the traditional regulatory framework. However, capital solutions are not always the best or most cost-effective for customers. Service-based solutions such as cloud-based computing or third-party DER services emphasize the need for a regulatory framework that rewards utilities for pursuing the least cost and highest value solutions for customers, regardless if it is under CAPEX or OPEX. This is possible by allowing utilities to earn a rate of return on service-based solutions. DER incentive adders allow utilities to earn a return on the total cost of payments to a third party for a DER-derived service solution. For example, California's Competitive Solicitation Framework Pilot[27] allowed an incentive equal to 4% for annual DER payments that displace or defer CAPEX on traditional distribution project investments.

Allowing some earnings on pay-as-you go services would also permit utilities to leverage the flexibility and scalability of service solutions by decreasing the investment risk, and could potentially reduce costs, if it uses less of a service than anticipated.

Performance-Based Regulation (PBR)

PBR uses a combination or a set of alternative regulatory mechanisms and processes to align utility performance with outcomes desired by customers, utility and shareholders, and regulators today. Under PBR, a utility is provided an opportunity to earn a higher return if it can deliver on the identified performance outcomes.

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[25] Illinois General Assembly. *Public Act 097-0616, Sec. 16-108.5. Infrastructure investment and Modernization. Enacted October 2011.*

[26] Illinois Register. *Notice of Proposed Rules, Title 83 Part 289. July 2018.*

[27] California Public Utilities Commission. *Integrated Distributed Energy Resources. December 2016.*

PBR can be applied in different combinations and sometimes components of it are applied in regulatory frameworks that are largely traditional. PBR generally includes a revenue decoupling mechanism, multi-year rate plan, and performance mechanisms, including performance incentive mechanisms. As customer expectations continue to evolve and emerging technologies enable grid modernization, a modern PBR framework can be designed to allow utilities to succeed while achieving provincial and territorial policy goals, customer-centric objectives and delivering value-added services. Example 7 highlights Great Britain's RIIO, which includes performance incentive mechanisms and a TOTEX approach that combines a portion of CAPEX and OPEX into a regulatory asset that allows a rate of return on both. As highlighted in Example 8, Hawaii also signed PBR into law, creating a new business model not reliant on investment, but on market performance metrics.

Example 7: Great Britain's RIIO[28]

The UK's RIIO - "Revenue = Incentives + Innovation + Outputs" is regarded as the most comprehensive example of PBR in practice today. It is composed of several alternative regulatory mechanisms, including eight-year "price control" periods, benchmarking, earnings sharing mechanisms, and performance incentive mechanisms. Its TOTEX approach combines a portion of CAPEX and OPEX into one regulatory asset that allows a rate of return on both. This removes utilities' bias towards capital investments.

Most utilities outperformed their TOTEX allowances, although critics have pointed to flaws in the benchmarking and revenue setting process. The first phase of RIIO was perceived as overly complex and burdensome, however the second phase is intended to include several improvements. While RIIO is not perfect, it is a step in the right direction.

Example 8: Hawaii PBR Law[29,30]

In 2018, Hawaii signed PBR into law, directing the regulator to implement PBR that completely breaks the link between utility revenues and capital investment levels, creating a new business model not reliant on investment, but on market performance metrics. The following guiding principles were established to inform the development of the commission's PBR framework:

1. A customer-centric approach, including immediate "day 1" savings when the new regulations takes effect;
2. Administrative efficiency to reduce regulatory burdens to the utility and stakeholders; and
3. Utility financial integrity to maintain the utility's financial health, including access to low-cost capital.

The Hawaii Public Utilities Commission also established priority outcomes to guide the development of the PBR mechanisms in the second phase of the proceeding. Some of the emerging priority outcomes include interconnection experience, customer engagement, DER asset effectiveness, grid investment efficiency, GHG reduction, electrification of transportation and system resilience.

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[28] Ofgem. *RIIO.* Accessed September 2020.

[29] Hawaii State Legislature. *The Ratepayer Protection Act.*

[30] Hawaii Public Utilities Commission. Summary of Phase 1 Decision & Order Establishing a PBR Framework. 2019.

Elements of PBR have been implemented across Alberta, Ontario and British Columbia. Alberta's PBR uses five-year rate plans with reopener provisions and efficiency carryover mechanisms.[31] There are minimal innovation incentives, particularly for cases where the innovation does not yield material efficiencies or cost savings during the same PBR term. Funding for innovation is also often the first casualty when finding efficiencies under PBR. Ontario's Renewed Regulatory Framework for Electricity (RRFE)[32] monitors and uses a scorecard [33] to measure utility performance against defined performance outcomes including service quality, customer satisfaction, safety, system reliability, asset management and cost control, public policy responsiveness and financial performance. British Columbia uses a combination of cost of service and PBR to encourage its utilities to operate efficiently by permitting its shareholders and customers to share in cost savings if specified targets are met.[34] None of the PBRs implemented in Canada currently include performance incentive mechanisms tied to metrics beyond O&M efficiency. However, reported metrics and scorecards can be used as building blocks towards a performance incentive mechanism as it builds capabilities for metric tracking.

Regulatory Sandboxes

The regulatory sandbox concept emerged to create flexibility and a safe space for utilities and partners to pursue new and innovative ventures in an environment free from the normal regulations and cost prudence requirements of cost-based regulation. It is intended to expedite the traditional process in order to test new ideas and business models and introduce new customer products and solutions to market in a timely manner, unencumbered by regulatory procedure. Regulatory sandboxes are less about R&D or technical feasibility and are more focused on solution integration to the energy system to benefit all (societal benefit streams).

One such regulatory sandbox is the Ontario Energy Board's Innovation Sandbox, launched in 2019, for both the electricity and natural gas sectors. It was designed to assist proponents interested in *"innovative energy-related projects that show clear potential for benefit to consumers – whether in the form of long-term economic efficiencies, cost performance improvement, service enhancements or other ways".* The process is primarily focused on information exchange and knowledge sharing between proponents and regulatory staff.[35] Information exchange can help innovators overcome perceived regulatory or procedural barriers and inform policy makers to better understand how to make systemic changes to facilitate innovation in the long-term.

The design and scope of regulatory sandboxes will vary depending upon the desired objectives of jurisdictions. In the case of the UK's sandbox, the objective evolved over time. The initial objective was to promote new business models as new market entrants emerged to provide customers with more choice. Following the UK's net-zero by 2050 commitment, Ofgem developed a Decarbonization Action Plan wherein they recognize that "*decarbonising at the lowest cost to consumers goes hand-in-hand with protecting consumers and enabling competition and innovation*." [36]

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[31] Alberta Utilities Commission (AUC). *Distribution Rates.* Accessed September 2020.
[32] Ontario Energy Board (OEB). *Renewed Regulatory Framework for Electricity, 2010.*
[33] Ontario Energy Board (OEB). Scorecard Performance Metrics. Accessed September 2020.
[34] Fortis BC. *Regulatory Affairs.* Accessed September 2020.
[35] OEB Innovation Sandbox. Accessed September 2020.
[36] Ofgem. *Decarbonisation Programme Action Plan, 2020.*

In the Netherlands, the Electricity Act Experiments scheme, also known as a regulatory sandbox, is administered by the Ministry of Economic Affairs and Climate Policy with an advisory role offered by the regulator. The objective of Netherland's sandbox is to identify whether legislation needs to adjust for future solutions for the energy transition.[37] The first iteration of the sandbox, from 2015 to 2018, focused on flexibility services and DERs, and resulted in the approval of 17 projects.[38] Projects approved were not funded via rate base, only exemptions within the legislation were provided. With the second iteration of Netherland's sandbox, the regulator is planning to extend the sandbox to the natural gas sector.[39]

In Italy, the Regulatory Authority for Energy, Networks and the Environment regulates experiments to promote innovation in their power system. To address regulatory and financial barriers, the innovation goals of Italy's sandbox include enabling new functionalities for networks, new incentive regulation for fostering innovation roll-out, and new actors in electricity markets.[37] Between 2010 and 2019, there have been five competitive calls for pilot projects including regulatory experiments on smart functionalities for medium voltage networks, different business models for EV charging, utility-scale energy storage to alleviate high voltage congestions due to excess wind generation, and flexibility services. Most of the funding for these projects is rate-based and outcomes of the projects have been made public, to enable external evaluation and circulate best practices. However, third-party market players make their own investments and are partially remunerated for select projects.

3.2 Summary of Potential Options

The diversity of Canadian jurisdictions will require tailor-made pathways for mitigating the barriers and challenges that exist for deep utility investment in grid modernization. Regulatory and policy frameworks will need to adapt quickly to allow utilities to pursue innovative and non-traditional solutions, while ensuring that consumers are protected and benefit from grid modernization. Utilities would need to be agents of change as well to pursue innovative solutions and ensure benefits of grid modernization are tangible for customers.

Otherwise, as new market entrants overwhelm utilities with competition, utility financial viability may be called into question, a situation unattractive for all stakeholders – utility shareholders, regulators, customers and government. Aligning these needs is not an easy mission. Managing risks and balancing the pace of grid modernization requires close collaboration and partnership amongst stakeholders. Change can be ignited incrementally through investment decision making and guidance or can be ignited fundamentally with disruptive reimagination of the regulatory framework or deeper deregulation.

This section discusses high-level potential options, listed in Table 3-1, for consideration in developing long-term policy and regulation for grid modernization. A comparative analysis of stakeholder motivators and issues is also included to provide context on how the options may help alleviate the barriers identified in Figure 3-2.

[37] IEA. *International Smart Grid Action Network, 2019.*

[38] Netherlands Enterprise Agency. *Decisions on Exemptions from Electricity Act Experiments.* Accessed August 2020.

[39] Netherlands Enterprise Agency. *Electricity Law and Gas Law experiments.* Accessed August 2020.

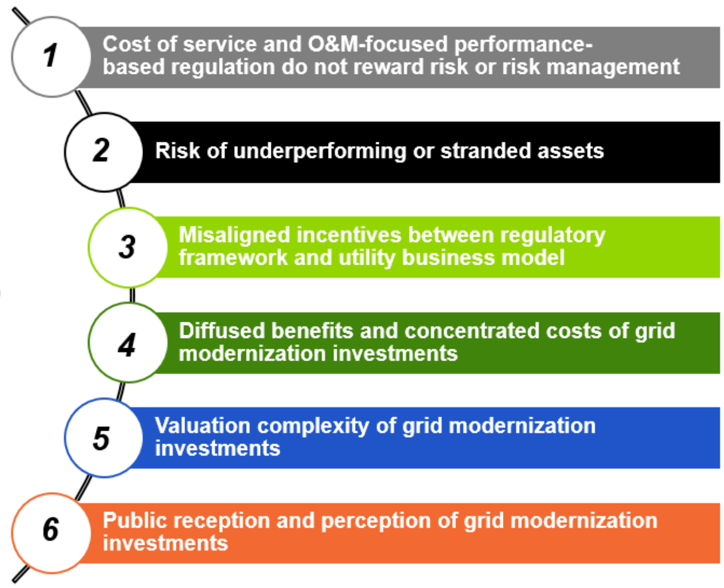

Figure 3-2 Utility Investment Barriers

Table 3-1 Potential Options to Alleviate Utility Investment Barriers

Barriers Addressed	Potential Options
1 2 3 4 5 6	a) Align regulatory frameworks to encourage a shift in utility cost of service remuneration models that would help achieve desired public policy goals and grid modernization objectives.
1 2 6	b) Encourage utility and private sector partnerships to shift risk away from ratepayers and maximize value to customers, while fostering innovation and potential returns for investors.
5 6	c) Develop more strategic and fulsome guidance on the process for the development, review, approval and monitoring of grid modernization investments.
2 4 6	d) Develop standardized data and methodologies to address locational benefits and costs of grid modernization investments within the system, to help minimize risks and ensure the right investments are made.
6	e) Promote customer engagement and education on the benefits of a modern grid and enhanced participation.

a) **Align regulatory frameworks to encourage a shift in utility remuneration models that would help achieve desired public policy goals and grid modernization objectives.**

The transforming energy landscape requires evolution in regulatory frameworks to enable utilities to achieve grid modernization outcomes and objectives. Public policy focused on GHG emissions reduction, clean electricity, low-carbon economic growth, and climate change adaption requires integration of renewables and DERs, as well as strategic adaptation and hardening the grid to become more resilient. All of this requires a modernized intelligent system but comes at a cost and risk. Grid modernization generally delivers a range of benefits, but the costs are disproportionally borne by distribution utilities and not by other elements of the value chain.

Since utilities earn a rate of return on CAPEX, and not OPEX, there is an inherent bias for utilities to prefer capital investments over other solutions under the traditional regulatory framework. Shifts in utility remuneration models could help utilities select cost-effective solutions that would allow them to both adapt to the evolving market but also maintain focus on providing a safe, secure, resilient, reliable and affordable grid for consumers, regardless of expenditure type. Mechanisms to monetize the value of and benefits from grid modernization may be required to encourage utilities to manage the risk that comes with grid modernization investments. At the same time, a customer-centric approach will be important to provide value to consumers while protecting and minimizing risks.

A combination or set of alternative regulatory mechanisms can help reconcile stakeholders' primary motivators and grid modernization objectives. New York, California, Hawaii, Illinois, and the UK provide examples of regulatory reforms that are strongly tied to public policy goals and/or grid modernization objectives, as highlighted in Section 3. New York recognizes the need for utilities to expand their roles and function as integrated system planners, grid operators, and market operators. As such, NYPSC has added a combination of market-based and outcome-based performance incentive mechanisms as another way of achieving utility earnings.

Ontario's Renewed Regulatory Framework for Electricity is a step in the right direction, as it better aligns utility performance against defined performance outcomes, including public policy responsiveness. Further, the use of reported metrics and/or scorecards can be used as building blocks towards performance incentive mechanisms as it builds capabilities for metric tracking and gathering historic performance trends.

Figure 3-4 below demonstrates the tensions that exist on various smart grid adoption motivators. Within the service customer chain, relationships between these motivators provide clues as to the readiness of stakeholders to accept and effect a change. In many cases there is clear misalignment and tension exists. These are the areas that require focus and inclusive engagement from policymakers to develop and nurture alignment. In other areas, alignment may already exist in the motivators, suggesting solutions can be based on common objectives and consensus.

Figure 3-4 Change Motivator Tension Matrix

Change Motivators	Regulator	Utilities & Shareholders	Customers	Government
Affordability	Affordability is the critical economic metric used to approve utility investments and rates. Financial stability and affordable rates are a constant tension			Governments must support an affordable essential service and are often shareholders in its provision at the same time
Maintain focus on safety, security, reliability, and serve all customers				
Build adaptable and resilient infrastructure				
Understanding the magnitude and timing of grid modernization benefits to justify risks associated with investments	Regulators need the tools and insight to evaluate new investments			Government support helps but the function of the regulator will remain
Protect and minimize risk for consumers, and reduce administrative and regulatory costs				
Maintain business growth and earnings	Utilities must remain financially viable to deliver the utility model		Customers balance affordability with financial stability, but lack fair information access	Governments are often utility shareholders and require returns
Meet GHG emissions reduction targets and lead investment in non-emitting and renewable energy sources	Climate change is important to all, but economic regulators are not always enabled or empowered to consider it directly in cost and rate decisions through legislation			Climate change and GHGs are critical issues for current governments. Actively or by implication, electricity sector response is critical to achieve climate change goals
Shift towards low-carbon economic growth				

Strength of Smart Grid Adoption Motivators			
Weak Motivator	Moderate Motivator	Significant Motivator	Critical Adoption Motivator

← TENSION →

b) Encourage utility and private sector partnerships to shift risk away from ratepayers and maximize value to customers, while fostering innovation and potential returns for investors.

Utility and private sector partnerships can be used to shift some of the financial risk of investing in non-traditional assets away from ratepayers, without the utility shareholder directly shouldering the burden. Private companies tend to have greater risk tolerance, especially for identifying new technologies with the potential to become ubiquitous, and they do not typically spend ratepayer money. Innovation also most often occurs with suppliers and grid edge technology companies, but few transform the grid platform itself through aggregation and centralized control.

Private sector partnership will attract investment with a different return expectation and risk profile, thereby allowing innovation to flourish under the management of appropriate investors. Utility fixed income investors can remain and continue to have the appropriate long-run security. Utility and private sector partnerships would not only mitigate some of the financial risk, but also leverage utilities' existing customer relationships, expertise and knowledge of their local distribution networks to bring innovative solutions to market. Fostering this type of partnership can potentially contribute to the goal of leveraging Canadian clean technology and innovation to seize export and trade opportunities to expanding global markets.

Although utility-led, some projects that were beneficiaries of the smart grid component of Natural Resources Canada's (NRCan) Green Infrastructure Phase II Program[40] are in partnership with grid edge technology companies. For example, Hydro Ottawa's MiGen Transactive Grid project is in collaboration with numerous others in academia and industry. MiGen is simulating an energy marketplace for energy, wherein customers will generate more of their own electricity, store electricity as necessary and send any excess back to the grid. MiGen started with partial funding from the Ontario Smart Grid Fund and the LDC Tomorrow Fund and is also a recipient of NRCan's Green Infrastructure fund.[41]

Another example where third-party innovation fund helps to align and forge partnerships within the industry is Alectra's Grid Exchange project, in collaboration with Sunverge, IBM and Interac.[42] Its goal is to leverage Alectra's existing POWER.HOUSE customers to demonstrate the ability of blockchain software technology to provide real-time visibility of DERs and enable grid services transactions between customers and a utility. This project is also a recipient of NRCan's Green Infrastructure fund.[40]

Ontario's Smart Grid Fund facilitated opportunities for partnerships between utilities, governments, communities and solution providers through 45 projects to date with a total investment of $200 million. [43] The LDC Tomorrow Fund was administered by the MEARIE Group to fund research projects and finance energy innovation and opportunities for the benefit of utilities in the competitive marketplace of Ontario.[44]

New York's REV Connect platform matches utilities and private sector companies to accelerate innovation, develop new business models, and deliver value to consumers. Companies can submit ideas through the REV Connect platform, after which they will receive streamlined evaluation, expert feedback, and if successful, be matched with one of New York utilities and other potential market partners.[45]

c) Develop more strategic and fulsome guidance on the process for the development, review, approval and monitoring of grid modernization investments.

Guidance around which technologies and/or business models utilities can pursue and for which purpose can help lessen some uncertainty and risk related to administrative and regulatory costs. This guidance or framework must be developed collaboratively by both utilities and regulators as they both have a need for understanding the magnitude and timing of grid modernization benefits to justify risks associated with investments. It may also help ensure that the requirements or criteria developed are feasible and that duplicative efforts are minimized. For example, in a Massachusetts rate case, National Grid proposed a mechanism for a request for proposal system for non-wires alternatives (NWA). Three criteria that must be met are: the cost of traditional infrastructure to meet the need is greater than $1 million; the load being

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[40] Natural Resources Canada. *Current Investments*. Accessed August 2020.

[41] Hydro Ottawa. *MiGen Transactive Grid.* Accessed September 2020.

[42] Alectra Green Energy & Technology Centre. *Grid Exchange.* Accessed September 2020.

[43] Ontario Government. *Projects funded by the Smart Grid Fund.* Accessed September 2020.Program ended in 2018.

[44] The MEARIE Group. *LDC Tomorrow Fund.* Accessed September 2020.

[45] NY REV Connect. Accessed September 2020.

addressed is less than 20% compared to total area load; and the need is at least three years out.[46] National Grid is going to be required to evaluate NWA options side-by-side with utility-owned infrastructure. Rules and decision-making mechanisms like these simplify the task of evaluating traditional infrastructure against non-traditional solutions by narrowing the scope to situations in which NWAs are most likely to be attractive.

Prompted by Southern California Edison's controversial $1.9 billion grid modernization proposal in 2017, California Public Utilities Commission (CPUC) provided guidance to establish a process for the development, review and approval of grid modernization plans within general rate cases. Multi-stakeholder workshops were held as part of the Distribution Resource Plan (DRP) proceedings.[47] These informed the development of a framework to evaluate grid-modernization investments that are primarily aimed at increasing DER penetration, integration and value maximization. The framework identified distribution grid technologies and/or functions that are needed to enable greater penetration, integration, and value maximization of DERs[48]. CPUC also stated that grid modernization investments need to be evaluated within the context of the overall cost-effectiveness of the DERs and must result in net benefits for ratepayers.

Monitoring and tracking actual costs and benefits to compare against projects is also critical in determining actual benefits realized. Doing so can help inform future grid modernization evaluations and eventually hold stakeholders accountable on the outcomes. Grid modernization plans are a major undertaking and mistakes are inevitable as better understanding of the value of grid modernization come from undertaking it and deploying necessary infrastructure. Guidance around the development, review, approval, and monitoring of grid modernization investments can help minimize costs, understand benefits realized, and set up utilities for success.

d) Develop standardized data and methodologies to address locational benefits and costs of grid modernization investments within the system, to help minimize risks and ensure the right investments are made.

A process for valuing less-tangible benefits of grid modernization, such as integrating renewables and DERs, customer choice and satisfaction, and reduced environmental impacts, could help spur grid modernization. The benefits of each grid modernization investment are very difficult and complex to isolate from the benefits provided by other grid investments and solutions it can enable. Grid modernization investments need to be evaluated within the context of the overall cost-effectiveness of DERs or other solutions made possible by a modernized and intelligent grid.

In California, utilities were mandated to identify grid modernization investments to integrate the growing number of DERs and determine how DERs should be valued through DRP proceedings. A multi-stakeholder collaborative process resulted in the development of standardized data, methodologies and tools. These include DER growth scenarios and load forecasts; DER hosting capacity analyses; DER avoided cost calculator developed by Energy + Environmental Economics and adopted for demand-side cost effectiveness proceedings[49]; and

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[46] National Grid. *Massachusetts Electric Company and Nantucket Electric Company. Initial Filing.* Accessed August 2020.

[47] California Public Utilities Commission (CPUC). *DRP Workshops.* Accessed September 2020.

[48] CPUC. *Rulemaking 14-08-013. Decision 18-03-023.* Accessed August 2020.

[49] Energy + Environmental Economics. *Avoided Cost Calculator for DERs.* Accessed August 2020.

a locational net benefits analysis tool.[50],[51] Data collection activities such as these are crucial for minimizing risks and ensuring the right investments are made to support DERs in the system.

In California's case, distribution utilities were mandated to undertake distributed resource planning and CAISO's use of locational market mechanisms supported development of proxies for valuing the benefits of DERs. As some Canadian jurisdictions are centrally planned, an alternative mechanism would likely have to be developed to determine the value of a grid asset or DER investment such that the costs are fairly allocated to those customers they benefit. Some jurisdictions could also shift towards a more regional or zonal resource planning approach as an incremental step towards valuing resources at the distribution level.

Standardizing data and methodologies would require a collaborative multi-stakeholder process, which may be cumbersome and would require utilities' resources. Such efforts and associated costs may not be afforded by current regulatory frameworks and must be considered. Understanding the magnitude and timing of grid modernization benefits is a common challenge that both regulators and utilities are facing. Therefore, there is a partnership opportunity to develop solutions and achieve their respective mandates. Utilities need financial motivation to justify risks associated with investments while regulators need to protect and minimize risks for consumers.

e) Promote customer engagement and education on the benefits of a modern grid.

Customers play a critical role in the industry transformation as their preferences evolve, requiring new and different services from energy companies. With all the technological advancements, utilities have an opportunity to engage customers, enhance relationships and produce solutions that meet customer needs. Grid modernization investments that facilitate integration of DERs can help customers sell electricity back to the grid and/or enable utilities to engage customers through new pricing options, service plans and/or tools that can help them understand and manage their electricity use. Having the choice of self-generating with DERs and/or empowering customers via engagement tools are how benefits of grid modernization can be made more tangible for customers. For example, Ontario's Regulated Price Plan (RPP) pilot explored pricing and non-pricing mechanisms (i.e. providing real-time information on energy use, energy saving tips etc.) to test ways to help customers better manage their electricity costs while also helping make the system more efficient.[52]

A positive customer experience before and throughout deployment of grid modernization infrastructure is crucial to gaining customer support and participation. Understanding customer needs by conducting voice of customer research and communication through their preferred channel can help improve awareness and understand customer concerns. To further demonstrate the benefits of a smarter grid, utilities can offer products and services that provide tangible value to customers.

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[50] CPUC. *Distribution Resources Plan.* Rulemaking 14-08-013. Accessed August 2020.

[51] Analysis Group. *The Value of "DER" to "D": The Role of DER in Supporting Local Electric Distribution System Reliability. 2016.* Accessed August 2020.

[52] OEB. *RPP Roadmap*. Accessed September 2020.

4. Conclusions

The electricity sector is aware of the need for grid modernization to respond to changing policy, regulation and market trends. Embracing a culture of agile innovation and flexibility is necessary for all stakeholders in order to achieve grid modernization objectives. Prioritization and pathways to achieving these objectives will vary across jurisdictions, but generally converge around themes of high-asset utilization, security, reliability, resilience, flexibility, sustainability, renewables and DER integration, and affordability.

Advances in technologies offer opportunities and benefits for utilities, service providers and consumers. Revenue growth opportunities are anticipated to grow downstream, closer to the customer or behind-the-meter, as DER costs continue to decline and smart consumer-enabling technologies are adopted. This further drives the need for an even greater deployment of technology and infrastructure at the edge of the grid. Utility organizations, regulators and consumers will be forced to share in the risks and rewards of modernization.

Barriers to grid modernization manifest via two fundamental pivots, which are reinforced by an entrenched cost of service – rate of return-based model. Figure 4-1-1 below breaks down these barrier themes further.

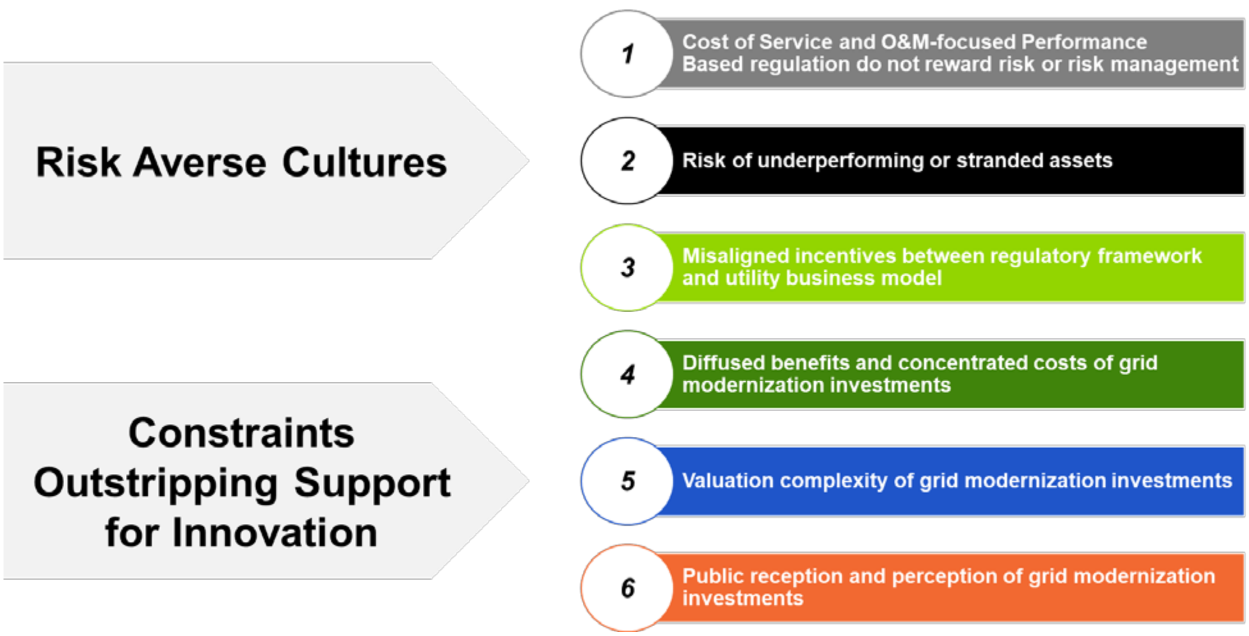

Figure 4-1 Summary of Utility Investment Barriers

The diversity of Canadian jurisdictions will require tailor-made pathways for mitigating the existing barriers for utility investment in grid modernization. Regulatory and policy frameworks will need to adapt to allow utilities to pursue innovative and non-traditional solutions and business models, while ensuring that consumers are protected and benefit from grid modernization. Collaboration and partnerships will be crucial in effectively managing risks and balancing the pace of grid modernization.

Table 4-1 Potential Options to Alleviate Utility Investment Barriers

Barriers Addressed	Potential Options
1 2 3 4 5 6	a) Align regulatory framework to encourage shifts in utility cost of service remuneration models to help achieve desired public policy goals and grid modernization objectives.
1 2 6	b) Encourage utility and private sector partnerships to alleviate risk away from ratepayers and maximize value to customers, while fostering innovation.
5 6	c) Develop guidance on the process for the development, review, approval and monitoring of grid modernization investments.
2 4 6	d) Develop standardized data and methodologies to address locational benefits and costs of grid modernization investments, to help minimize risks and ensure the right investments are made.
6	e) Promote customer engagement and education on the benefits of a modern grid.

Appendix A. Federal, Provincial, and Territorial Scan

The federal, provincial, and territorial scan in Table A-1 through Table A-41 highlights:

i. Grid modernization initiatives

ii. Policies and initiatives that are enabled by and/or are supportive of grid modernization outcomes

iii. Key regulatory structure relevant for smart grid investment (for provinces and territories)

Federal

The federal summary below highlights smart grid technology and infrastructure initiatives and funding programs, as well as key programs adjacent to and enhanced by smart grid.

Table A-1 Federal Grid Modernization Initiatives

Area	Description
Grid Modernization Initiatives	• The federal government has ongoing funding programs that support smart grid technologies and grid modernization, either directly or indirectly, at various technology maturity levels including: o Energy Innovation Program - $53 million per year for clean energy technology research and development (R&D).[53] o Program of Energy Research and Development - $35 million per year for R&D focused on building a sustainable energy future for Canada's economy and environment.[54] o Clean Growth Program - $155 million for clean technology R&D in energy, mining, and forestry.[55] o Green Infrastructure Phase II – A collection of programs aiming to accelerate the deployment and market entry of next-generation clean energy infrastructure.[56] o Smart Grid Program - $100 million for utility-led projects to reduce GHG emissions, better utilize existing electricity assets, and foster innovation and clean jobs.[57] o EV Infrastructure Demonstration Program - $30 million for next-generation and innovative EV charging infrastructure projects.[58] o EV and Alternative Fuel Infrastructure Deployment Initiative Program - $80 million to support EV fast chargers (level-3) as well as natural gas and hydrogen fueling stations.[59] o Emerging Renewable Power Program - $200 million for the deployment of emerging renewable energy technologies.[60] o Energy Efficient Buildings Research, Development and Demonstration Program - $182 million for building code development and new net-zero energy-ready building initiatives.[61]

[53] NRCan. *Energy Innovation Program.* Accessed September 2020.
[54] NRCan. *Program of Energy Research and Development.* Accessed September 2020.
[55] NRCan. *Clean Growth Program.* Accessed September 2020.
[56] NRCan. *Green Infrastructure Programs.* Accessed September 2020.
[57] NRCan. *Smart Grid Program.* Accessed September 2020.
[58] NRCan. *EV Infrastructure Demonstration Program.* Accessed September 2020.
[59] NRCan. *EV and Alternative Fuel Infrastructure Deployment Initiative Program.* Accessed September 2020.
[60] NRCan. *Emerging Renewable Power Program.* Accessed September 2020.
[61] NRCan. *Energy Efficient Buildings Research, Development and Demonstration Program.* Accessed September 2020.

Area	Description
Grid Modernization Initiatives	o Clean Energy for Rural and Remote Communities Program - $220 million to reduce reliance on diesel fuel in Canada's rural and remote communities and industrial sites.[62] o Sustainable Development Technology Fund - $400 million to develop and demonstrate new environmental technologies.[63] o Strategic Innovation Fund - $1.3 billion for various innovation projects in the industrial and technology sectors.[64] • Export Development Canada helps Canadian cleantech and smart grid companies expand internationally.[65] • Generation Energy is a federal initiative to exchange ideas on what a low-carbon energy future looks like for the next generation of Canadians.[66] • The Canada Smart Grid Action Network, organized by the Federal government, brings together smart grid enablers including F/P/T governments, academic networks and industry associations.[67] Collectively they contribute to the Smart Grid in Canada report and facilitate Canada's engagement in the International Smart Grid Action Network under the International Energy Agency. • The Regional Electricity Cooperation and Strategic Infrastructure Initiative (RECSI) funds studies and dialogues to identify critical electricity infrastructure projects with the potential to significantly reduce GHG emissions.[68] • The federal government also tracks and supports the deployment of different smart grid applications across Canada including AMI, DR, distributed energy storage, and microgrids.[69] • The federal government's Clean Growth Hub provides resources to support companies and projects, coordinating programs and tracking results in the cleantech sector. Interested parties can contact them for further information about all programs and initiatives listed above, and for current information on grid modernization support.[70]

[62] NRCan. *Clean Energy for Rural and Remote Communities Program.* Accessed September 2020.
[63] NRCan. *Sustainable Development Technology Fund.* Accessed September 2020.
[64] NRCan. *Strategic Innovation Fund.* Accessed September 2020.
[65] Export Development Canada. *Cleantech at EDC.* Accessed September 2020.
[66] NRCan. *Generation Energy.* Accessed September 2020.
[67] SmartGrid Canada. *The Canadian Smart Grid Action Network.* Accessed September 2020.
[68] NRCan. *RECSI Western Region Summary for Policy Makers, 2018.*
[69] NRCan. *Smart Grid in Canada, 2018.*
[70] NRCan. *Clean Growth Hub.* Accessed September 2020.

Table A-2 Federal Policies and Initiatives Enabled by and/or Supportive of Grid Modernization Outcomes

Area	Description
GHG Emissions Reduction	The federal government has set a target to reduce GHG emissions to 30% below 2005 levels by 2030 and is developing a plan for net-zero by 2050.[71] This includes regulations to phase out traditional coal-fired electricity by 2030 as well as greenhouse gas regulations for natural gas-fired electricity[72].
Renewables	The federal government has set a target to increase the share of zero-emitting electricity generation sources from 82% in 2017 to 90% by 2030.[73]
Energy Efficiency (EE)	Canada is setting a 3% annual EE target, including an initial $27.3B investment in building retrofits.[74]
Energy Storage	The federal government is supporting various energy storage projects through innovation funds and support programs.[75]

[71] Government of Canada. *Progress towards Canada's greenhouse gas emissions reduction target, 2020.*

[72] Government of Canada. *Coal phase-out: the Powering Past Coal Alliance, 2020*.

[73] NRCan. *Energy and Greenhouse Gas Emissions (GHGs), 2020.*

[74] Generation Energy Council Report. *Canada's Energy Transition. Page 26: Efficiency Milestones, 2018*

[75] NRCan. *Current Investments, Technology Area: Smart Grid and Energy Storage, 2020.*

British Columbia

Table A-3 Grid Modernization Initiatives in British Columbia

Area	Description
Grid Modernization Initiatives	• $930M was dedicated by BC Hydro to a smart meter program which deployed 1.93 million AMI by 2016. The program was completed more than 100 million CAD below budget and had more than 99% of customers installed with AMI by end of 2016.[76] • In 2016, BC's EV Smart Infrastructure Project demonstrated various technology pathways for controlling EV loads on the grid through demonstration projects that validated either business-to-business (B2B) or direct utility pathways for smart charging with residential customers.[77] • Through NRCan's innovation fund, BC Hydro has a 1MW battery project to enable demand response and improved reliability for a near-capacity and prone to outages substation in Golden and Field, BC.[78]

Table A-4 Policies and Initiatives Enabled by and/or Supportive of Grid Modernization Outcomes in British Columbia

Area	Description
GHG Emissions Reduction	Through its CleanBC Plan the government has set a target to reduce GHG emissions to 40% by 2030, 60% by 2040, 80% by 2050 below 2007 levels.[79]
Renewables	The government has set a target that 93% of energy generated in BC must be from clean or renewable sources (Clean Energy Act).[80]
Energy Efficiency	Average annual 1.4% electric savings target between 2019 and 2030, reduce BC Hydro's expected increase in demand by 66% through demand-side measures by 2020.[81]
Energy Storage	The rich hydro resources found in B.C. have enabled hydroelectric facilities to provide many of the touted benefits of energy storage (capacity, time shifting, and demand response).[82]

[76] Government of British Columbia. *Review of BC Hydro Report. Page 14. 2011.*
[77] NRCan. *BC EV Smart Infrastructure Project, 2018*.
[78] NRCan. *Energy Storage and Demand Response for improved reliability in an outage-prone community, 2018.*
[79] Government of British Columbia. *Climate Planning & Action, 2019.*
[80] Government of British Columbia. *Clean Energy Act. Part 1- 2(c). 2010*
[81] Government of British Columbia. *Energy Efficiency Policy & Regulations.* Accessed August 2020.
[82] Energy Regulation Quarterly. *Electricity Storage in North America, 2019.*

Table A-5 Regulatory Structure in British Columbia

Area	Description
Regulatory Structure	• The electricity network in British Columbia includes BC Hydro, a vertically integrated crown corporation, and Fortis BC, an investor owned company with generation, transmission, and distribution assets. The regulatory oversight is provided by the British Columbia Utilities Commission (BCUC). • FortisBC 2020-2024 rate plan proposes targeted incentives including customer engagement, FortisBC Energy targeted incentives included GHG emissions reductions and growth in renewable gas, with revenue decoupling and earning sharing mechanisms[83] • BCUC has an ongoing proceeding to analyze COSR vs PBR for BC Hydro.[84]

[83] Fortis BC. *2020-2024 Multi-Year Rate Plan*

[84] BC Hydro. *Fiscal 2020 to Fiscal 2021 Revenue Requirements Application*

Alberta

Table A-6 Grid Modernization Initiatives in Alberta

Area	Description
Grid Modernization Initiatives	• Through its Distribution System Inquiry (DSI), the Alberta Utilities Commission (AUC) is mapping out key issues related to the future of Alberta's electric and natural gas distribution system.[85] • Market rule mandated smart meter installation for sites with peak demand >2MW. • EPCOR, Fortis AB, City of Lethbridge, Medicine Hat had large scale deployment of AMI. • The Alberta Smart Grid Consortium established in 2017 aims to accelerate smart grid demonstration and deployment initiatives in Alberta.[86] • EPCOR Smart Grid System deployed a 12MW solar PV with Distributed Energy Resource Management System (DERMS).[87] • In 2018, the City of Lethbridge implemented grid optimization technologies to lower the operating voltage of the electricity distribution system and improve the overall energy efficiency of the grid.[88]

Table A-7 Policies and Initiatives Enabled by and/or Supportive of Grid Modernization Outcomes in Alberta

Area	Description
GHG Emissions Reduction	The government has set a target to reduce methane gas emissions from oil and gas operations by 45% by 2025.[89]
Renewables	The government has set a target to achieve 30% renewable energy by 2030.[90] Elimination of coal power generation by 2030
Energy Efficiency	$806M lifetime savings and 6.8MT of avoided GHGs through Energy Efficiency AB, which was recently dissolved, with some programs integrated into Emissions Reduction Alberta.[91]

[85] AUC. *Distribution System Inquiry.* Accessed August 2020.
[86] NRCan. *Smart Grid in Canada, 2018.*
[87] EPCOR. *Smart Grid System (ESGS).* Accessed August 2020.
[88] Lethbridge News Now. Press Release, 2018. Accessed August 2020.
[89] CAPP. *Methane Emissions.* Accessed August 2020.
[90] Government of Alberta. *Renewable energy legislation and reporting.* Accessed August 2020.
[91] Energy Efficiency Alberta. Accessed September 2020.

Area	Description
Energy Storage	The AESO Energy Storage Roadmap sets out a plan to facilitate the integration of energy storage. In March 2019, 7 market participants received funding from Emissions Reduction Alberta (ERA) for their proposed energy storage facility projects.[92]

Table A-8 Regulatory Structure in Alberta

Area	Description
Regulatory Structure	• The electricity network in Alberta includes unbundled investor and municipal owned corporations, regulated by the Alberta Utilities Commission (AUC). • Multi-year rate plan with reopener provisions and efficiency carryover mechanisms. • Metrics tracked (not tied to incentives) include service quality and reliability.

[92] AESO. *Energy Storage Roadmap.* Accessed August 2020.

Saskatchewan

Table A-9 Grid Modernization Initiatives in Saskatchewan

Area	Description
Grid Modernization Initiatives	• Initial 2014 AMI rollout safety issues resulted in reversing of initiative. • C&I AMI pilot programs launched by SaskPower since 2015 have deployed 7,500 AMI to date and plan to deploy 20,000 between 2019-2020.[93] • SaskPower implemented OMS and SCADA as part of their advanced distribution management system. SaskPower Distribution Modernization Program will upgrade existing substation and feeder sensors, deploy telecommunication devices, and integrate information from their AMI system. It will support voltage reduction and power flow optimization which will reduce system losses and enable integration of renewable power generation.[94] • Power Generation Partner Program supports the development of new small renewables ranging from 100 kW to 1 MW and new carbon neutral non-RE projects. An existing net metering program also allows for up to 100 kW installations to offset customer consumption.[95]

Table A-10 Policies and Initiatives Enabled by and/or Supportive of Grid Modernization Outcomes in Saskatchewan

Area	Description
GHG Emissions Reduction	The government has set a target to reduce GHG emissions to 40% below 2005 levels by 2030.[96]
Renewables	The government has set a target to achieve 50% renewable electricity generation by 2030 from 25% in 2017.[97]
Energy Efficiency	The government has set a target to save 87 GWh in 2030 from energy efficiency and conservation programs.[98]

[93] SaskPower. Building a Modern Power Grid. Accessed September 2020.
[94] NRCan. SaskPower Distribution Modernization Program. Accessed September 2020.
[95] SaskPower. *Power Generation Program*. Accessed August 2020.
[96] SaskPower. *Emissions.* Accessed August 2020.
[97] SaskPower. *The Path to 2030, 2017.*
[98] American Council for Energy-Efficient Economy. *Energy Efficiency Scorecard*. Accessed August 2020.

Area	Description
Energy Storage	The Cowessess Renewable Energy Storage Facility has 800 kW wind, 400 kwh solar and 740 kWh storage. This resulted from a joint venture between Cowessess First Nation and Saskatchewan Research Council.[99]

Table A-11 Regulatory Structure in Saskatchewan

Area	Description
Regulatory Structure	• Vertically integrated crown corporation advised by the Rate Review Panel • Cost of service rate plan

[99] Saskatchewan Research Council. Press Release, 2018. Accessed August 2020.

Manitoba

Table A-12 Grid Modernization Initiatives in Manitoba

Area	Description
Grid Modernization Initiatives	• The Grid Modernization Program established by Manitoba Hydro focuses on installing smart devices to improve distribution infrastructure utilization.[100] • In 2007, Manitoba Hydro deployed 5000 AMI to selected areas in the city of Winnipeg as part of a smart-grid pilot project. The project concluded in 2009, with the final report stating the need for study of anticipated benefits and project risks.[101] • Util-Assist and Manitoba Hydro are evaluating the benefits and savings that AMI technology could bring to the utility and its customers.[102]

Table A-13 Policies and Initiatives Enabled by and/or Supportive of Grid Modernization Outcomes in Manitoba

Area	Description
GHG Emissions Reduction	The government has set a target to reduce GHG emissions by 1 Mt during 2018 to 2022 relative to 2018 to 2022 base case forecast . Actions to reduce GHG emissions have been identified in the Made-in-Manitoba Climate and Green Plan and in The Climate and Green Plan Act. On June 11, 2019, based on the recommendations of the Expert Advisory Council, the Government of Manitoba established a cumulative GHG emissions reduction goal of 1 megatonne (Mt) for the 2018 to 2022 carbon savings account (CSA) period.[103]
Renewables	Manitoba generates 99.7% of electricity from renewables.[104] When completed, an additional 695 MW renewable capacity is expected from the Keeyask Generating Station. In June 2020, construction of the Manitoba-Minnesota Transmission line to export renewable electricity was completed. In July 2020, construction of the Manitoba-Saskatchewan transmission line to export renewable electricity started.[105]

100 NRCan. Smart Grid in Canada, 2018
101 T&D World. *Manitoba Hydro to Deploy Advanced Metering Technology.* Accessed August 2020.
102 Util-Assist. *Util-Assist Awarded Manitoba Hydro Consulting Contract.* Accessed August 2020.
103 Expert Advisory Council to the Minister of Sustainable Development. *Carbon Savings Report, 2019.*
104 Manitoba Measuring Progress. *Quality of Life.* Accessed August 2020.
105 Manitoba Hydro. *Manitoba–Minnesota Transmission Project.* Accessed August 2020.

Area	Description
Energy Efficiency	The government has set a target to achieve cumulative annual 22.5% electricity savings over 15 years, as per the Efficiency Manitoba Act enacted in 2019.[106]
Energy Storage	Manitoba HVDC Research Centre successfully developed and tested a utility-size prototype microgrid with a battery system in their laboratory facilities using 5 second-life automotive Li-ion batteries. It validated methods that optimize diesel fuel consumption and reduce emissions of islanded grids.[107]

Table A-14 Regulatory Structure in Manitoba

Area	Description
Regulatory Structure	• Vertically integrated crown corporation regulated by the Manitoba Public Utilities Board • Cost of service rate plan

[106] Government of Manitoba. *Efficiency Manitoba Act. 2019.*

[107] NRCan. *Utility Scale Electricity Storage Demonstration Using New and Re-purposes Lithium Ion Automotive Batteries.* Accessed September 2020.

Yukon

Table A-15 Grid Modernization Initiatives in Yukon

Area	Description
Grid Modernization Initiatives	• The Kluane First Nation will install, own, operate and maintain three 100 kW wind turbines in Destruction Bay. The utility will install, own, operate and maintain a 250kWh battery and energy management system.[108] • YEC has a demand response demonstration involving ~400 customers fitted with DR devices, controllable from YEC's system control centre.[109]

Table A-16 Policies and Initiatives Enabled by and/or Supportive of Grid Modernization Outcomes in Yukon

Area	Description
GHG Emissions Reduction	The government set a target to reduce GHG emissions to 30% below 2010 levels by 2030.[110]
Renewables	The government set a target to maintain 93% of electricity generating from renewables on the main grid, and reduce diesel use by 30% by 2030, compared to 2010, for communities not connected to main grid.[110]
Energy Efficiency	The government has set no specific targets, however, plans to invest $30 million dollars on average each year for energy efficiency improvements to homes and buildings.[110]
Energy Storage	2016 Resource Plan by Yukon Energy identified storage as the most promising solution for their isolated grid which struggles to meet peak demand during winter. Fed. funded $16.8M for an 8 MW battery.[111]

Table A-17 Regulatory Structure in Yukon

Area	Description
Regulatory Structure	• Unbundled investor owned and crown corporations regulated by the Yukon Utilities Board • Cost of service rate plan

[108] NRCan. *Destruction Bay Renewable Hybrid-Diesel Project.* Accessed September 2020.
[109] NRCan. *Residential Demand Response Program (RDRP).* Accessed September 2020.
[110] Government of Yukon. *Our Clean Future Draft, 2019.*
[111] Yukon Energy. *2016 Resource Plan.* Accessed September 2020.

Northwest Territories

Table A-18 Grid Modernization Initiatives in Northwest Territories

Area	Description
Grid Modernization Initiatives	• Smart meter pilot has been deployed in four communities. • The Government of Northwest Territories has allocated to spend approximately $33 million from 2019 to 2022 on actions and initiatives to increase the share of renewable energy used for community heat and increase building energy efficiency.[112]

Table A-19 Policies and Initiatives Enabled by and/or Supportive of Grid Modernization Outcomes in Northwest Territories

Area	Description
GHG Emissions Reduction	The government has set a target to reduce GHG emissions to 30% below 2005 levels by 2030.[113]
Renewables	The government has set a target to double the share of heating met by renewable energy (to 40%) by 2030 over 2016 levels.[114]
Energy Efficiency	The government has set a target to increase commercial, residential and institutional building energy efficiency by 15% over 2016 levels by 2030.[114]
Energy Storage	The 2030 Energy Strategy plan highlights energy storage as a suitable option for moving towards a clean energy future.[114]

Table A-20 Regulatory Structure in Northwest Territories

Area	Description
Regulatory Structure	• Unbundled investor owned and crown corporations regulated by the Northwest Territories Public Utilities Board • Cost of service rate plan

[112] Government of Northwest Territories. *2030 Energy Strategy Energy Action Plan Report, 2019.*
[113] Environment and Natural Resource. *NWT GHG Emissions.* Accessed August 2020.
[114] Government of Northwest Territories. *2030 Energy Strategy.* Accessed September 2020.

Nunavut

Table A-21 Grid Modernization Initiatives in Nunavut

Area	Description
Grid Modernization Initiatives	• Quliq Energy Corporation's Iqaluit Smart Grid Program launched in 2016 installed over 4,000 smart meters and QEC also installed a specialized smart meter transformer, data server, and software, which allows for the transmission of smart meter data between the smart meter database and QEC's billing system. This program is targeting 1-2% demand reduction and 1% energy savings .[115] • QEC launched a net metering program in 2018 to allow customers to install up to 10 kW of generating capacity.

Table A-22 Policies and Initiatives Enabled by and/or Supportive of Grid Modernization Outcomes in Nunavut

Area	Description
GHG Emissions Reduction	The government has set no specific GHG emissions reduction targets.
Renewables	The government has set no specific targets.
Energy Efficiency	Established the Nunavut Energy Management Program, composed of: the Nunavut Energy Retrofit Program, Energy Awareness and Training, and the Building Energy Efficiency Review Program for New Construction.[116]
Energy Storage	Energy storage is part of hybrid renewable system project in Kugluktuk.[117]

Table A-23 Regulatory Structure in Nunavut

Area	Description
Regulatory Structure	• Vertically integrated crown corporation advised by the Utility Rates Review Council • Cost of service rate plan

[115] NRCan. *Iqaluit Smart Grid.* Accessed August 2020.

[116] Government of Nunavut. *Energy Management Program Policy, 2020.*

[117] Infrastructure Canada. *Projects Since 2002 – Nunavut.* Accessed August 2020.

Ontario

Table A-24 Grid Modernization Initiatives in Ontario

Area	Description
Grid Modernization Initiatives	• In 2013, the OEB released the RRFE which mandated addressing connection of renewable generation & smart grid development in their five-year capital plans.[118] • Ontario mandated widescale AMI deployment through its Smart Meter Initiative since 2004. This enabled TOU price plans, pricing pilots, Green Button initiative etc.[119] • The legacy Smart Grid Fund supported projects in the area of behind the meter services, data analytics, EV integration, energy storage, grid automation and microgrids; government, academic institutions, utilities, and the private sector jointly invested over $200M for 45 projects.[120] • IESO manages the Grid Innovation Fund has provided support for more than 200 grid modernization projects.[121] • Ontario released a Made-in-Ontario Environment Plan in 2018 highlighting Integrating smart grid technologies and DERs.[122] • To develop a more comprehensive regulatory framework that facilitates the investment and operation of DERs on the basis of value to customers, to identify how to remunerate utilities in ways that make them indifferent to traditional or innovative solutions, and to identify barriers to the connection of DERs, the OEB is holding three consultations: Responding to DERs,[123] Utility Remuneration,[124] and the DER connections review.[125]

Table A-25 Policies and Initiatives Enabled by and/or Supportive of Grid Modernization Outcomes in Ontario

Area	Description
GHG Emissions Reduction	The government has set a target to reduce GHG emissions to 30% below 2005 levels by 2030.[126]

[118] OEB. *Renewed Regulatory Framework for Electricity Distributors: A Performance-Based Approach, 2012.*
[119] OEB. *Smart Metering Initiative, 2004.*
[120] Government of Ontario. *Smart Grid Fund.* Accessed August 2020.
[121] IESO. *Grid Innovation Fund.* Accessed August 2020.
[122] Government of Ontario. *A Made-in-Ontario Environment Plan, 2018.*
[123] OEB. *Responding to DERs EB-2018-0288, 2019.*
[124] OEB. *Utility Remuneration EB-2018-0287, 2019.*
[125] OEB. *DER Connections Review EB-2019-0207, 2019.*
[126] Government of Ontario. *A Made-in-Ontario Environment Plan, 2018.*

Area	Description
Renewables	The government has set no specific targets.
Energy Efficiency	Currently renewing Ontario's post-2020 electricity demand management framework. The 2019-2020 Interim Framework has target of 1.4 TWh in energy savings and 189 MW in demand savings.[127]
Energy Storage	IESO administered two phases of energy storage procurement in 2014-15 - 28.8 MW for either regulation service or reactive support and voltage control and 11.75 MW for capacity service.[128] The IESO is now working on its Energy Storage Design Project to provide a vision for how storage resources will participate in the IESO-Administered Markets on an enduring basis.[129]

Table A-26 Regulatory Structure in Ontario

Area	Description
Regulatory Structure	The electricity network in Ontario includes unbundled crown, investor owned, and municipal owned corporations, regulated by the OEB. Ontario's current regulatory framework (RRFE) employs a multi-year incentive regulation mechanism rate plan, which allows utilities to choose from a menu of incentive options, uses a scorecard to monitor outcomes, and deploys benchmarking to drive efficiencies.[130] The scorecard metrics[131] include: • Customer focus (service quality, customer satisfaction) • Operational effectiveness (safety, system reliability, asset management, cost control) • Public policy responsiveness (conservation and demand management, connection of renewable generation) • Financial performance (financial ratios including liquidity, leverage, profitability)

[127] Efficiency Canada. *Canadian Provincial Energy Efficiency Scorecard, 2019.*
[128] IESO. *Energy Storage Procurement.* Accessed August 2020.
[129] IESO. *Launch of Energy Storage Design Project Engagement.* Accessed August 2020.
[130] OEB. *Approaches to Utility Remuneration and Incentives, 2019.*
[131] OEB. *Scorecard Performance Measures.* Accessed August 2020.

Québec

Table A-27 Grid Modernization Initiatives in Québec

Area	Description
Grid Modernization Initiatives	• Over 3.9 million AMI have been deployed to date, which is 98% of the total to be replaced.[132] • Hydro- Québec conducted the 'CATVAR' project between 2007-2016 to install and demonstrate equipment to manage distribution grid voltage and reactive power. The project was cancelled in 2016 due to planned energy surpluses and less than expected energy savings.[133] • Hydro- Québec is significantly advanced in distribution automation and control of the grid.[134] • Adopted ZEV standard[135] • Aiming to roll out 1,600 new fast EV charge stations by 2030.[136] • IREQ pilot testing smart charging, V2G and V2H.[137] • Lac Mégantic Microgrid is Québec's first microgrid slated to be commissioned in 2020.[138] • Hilo is a Hydro-Québec subsidiary whose mission is to develop innovative, value-added products and services designed to position Hydro-Québec as a major provider of new energy services and especially for smart home offerings. Hilo will soon launch services to help companies reduce their carbon footprint and energy costs. Other products and services will gradually be deployed, including electric mobility offerings, smart energy storage and solar self-generation. On August 19 2020, HILO unveiled a first commercial offer for its residential customers.[139]

[132] Hydro-Québec. *Meters and Meter-Reading.* Accessed August 2020.
[133] Hydro-Québec. *CATVAR.* Accessed August 2020.
[134] Hydro-Québec. *Distribution Automation Vision and Road Map, 2006.*
[135] Government of Québec. *ZEV, 2017.*
[136] Hydro-Québec. *Press Release, 2019.*
[137] Hydro-Québec. *Press Release, 2012.*
[138] Hydro-Québec. *Lac Mégantic Microgrid.* Accessed August 2020.
[139] Hydro-Québec. *Hilo.* Accessed August 2020.

Table A-28 Policies and Initiatives Enabled by and/or Supportive of Grid Modernization Outcomes in Québec

Area	Description
GHG Emissions Reduction	The government has set a target to reduce GHG emissions to 20% by 2020, 37.5% below by 2030 below 1990 levels.[140]
Renewables	The government's 2030 Energy Policy has set a target to increase share of renewable energy production in total energy production by 25% from 2016 levels by 2030.[141]
Energy Efficiency	The 2030 Energy Policy calls for a 2030 objective to improve energy efficiency by 15% from 2013.[141]
Energy Storage	A Memorandum of Understanding (MOU) has been signed by Hydro-Québec and the U.S. Department of Energy Berkeley Lab which allows for collaboration towards R&D and scaling of on energy storage and transportation electrification.[142]

Table A-29 Regulatory Structure in Québec

Area	Description
Regulatory Structure	• The electricity network in Québec includes vertically integrated crown corporation, Hydro Québec, historically regulated by Régie de l'energie. • Bill 34 passed into Québec law in late 2019. It repealed the mandate for transmission and distributor PBR and replaced the Régie's approved MRP with an alternative MRP. The new MRP features a revenue cap index that allows rates to grow by the inflation in Québec's Consumer Price Index. The new MRP has a 5-year term.[143]

[140] Government of Québec. *GHG Emissions Reduction Targets.* Accessed August 2020.

[141] Government of Québec. *The 2030 Energy Policy, 2016.*

[142] Berkeley Lab. *Berkeley Lab and Hydro-Québec Announce Partnership for Transportation Electrification and Energy Storage, 2017.*

[143] National Assembly of Québec. *Bill 34.* Accessed August 2020.

New Brunswick

Table A-30 Grid Modernization Initiatives in New Brunswick

Area	Description
Grid Modernization Initiatives	• The Energy Smart NB initiative (a core component of NP Power's 10-year plan) specifies grid modernization efforts to save 600 MW and 2TWh by 2038.[144] • It includes "smart grid" (technology and software), "smart habits" (energy efficiency and demand response), "smart solutions" (new products and services that engage consumers and leverage demand side management and smart grid technology) elements. • NB Power has filed a second time for a $92 million capital project to install approximately 360,000 AMIs.[145]

Table A-31 Policies and Initiatives Enabled by and/or Supportive of Grid Modernization Outcomes in New Brunswick

Area	Description
GHG Emissions Reduction	The government has legislated the following emissions targets for provincial emissions: 14.8Mt in 2020, 10.7Mt in 2030, and 5 Mt in 2050. The 2020 National GHG Inventory Report shows that New Brunswick's GHG emissions from Public Electricity and Heat production are 54% below 2005 levels.[146]
Renewables	Renewable Portfolio Standard of 40% of in-province sales from renewable energy sources by 2020. In 2019/20 NB Power served 44% of in-province sales from renewable sources. Including nuclear, 80% of in-province sales were served from clean sources. A further 78MW of new community owned renewable generation projects are currently at various stages of development, delivering 32% growth from contracted in-province wind resources over the last 4 years.[147]
Energy Efficiency	Since 2015, NB Power with the support of the Low-Carbon Economy Fund,[148] has invested in energy efficiency initiatives saving electricity customers 585 million KWh and other fuel customers 265,000 gigajoules of energy savings for a combined total of 2.4 million gigajoules and 300,000 tonnes of GHG emissions savings.

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[144] NB Power. *10-Year Plan, 2019.*

[145] NB Power. *Advanced Metering Infrastructure Capital Project, 2019.*

[146] Government of New Brunswick. *Update on New Brunswick Climate Change Actions, 2017.*

[147] Government of New Brunswick. *Renewable Portfolio Standard.* Accessed August 2020.

[148] Government of New Brunswick. *Press Release, 2017.*

Area	Description
Energy Storage	Smart Energy Community Project in Shediac, NB selected 500 homes to test different technologies including in-home battery storage. Funding of \$5.7M was received from NRCan Smart Grid Program.[149]

Table A-32 Regulatory Structure in New Brunswick

Area	Description
Regulatory Structure	• Vertically integrated crown corporation regulated by the New Brunswick Energy and Utilities Board • Cost of service rate plan

[149] NB Power. *Press Release, 2019.*

Nova Scotia

Table A-33 Grid Modernization Initiatives in Nova Scotia

Area	Description
Grid Modernization Initiatives	• Nova Scotia released its Electricity Plan 2015–2040 detailing transformation of the power grid for short and long-term.[150] • NS Power launched an AMI initiative and was approved for a capital of $133M to replace about 495,000 conventional meters with smart meters over the period 2018–2020.[151] • EfficiencyOne and NS Power were ordered by regulator in 2016, to begin investigating non-wires alternatives and locational demand side management (DSM) (geotargeting) techniques, as applicable to Nova Scotia. In Q3 of 2019, EfficiencyOne started a Locational DSM pilot in the Kentville, NS area. This pilot will use both energy efficiency and demand reduction techniques to alleviate distribution loading and is planned to operate until the end of 2020.[152] • NS Power is currently testing both distribution-scale and behind-the-meter battery storage as part of the Intelligent Feeder Project, as well as certain other smart grid technologies

Table A-34 Policies and Initiatives Enabled by and/or Supportive of Grid Modernization Outcomes in Nova Scotia

Area	Description
GHG Emissions Reduction	The government has set a target to reduce GHG emissions to 45 to 50% below 2005 levels by 2030.[153]
Renewables	The government has set a target to achieve 40% renewable energy by 2020.[153]
Energy Efficiency	Average annual 1.1% electric savings target between 2019 and 2030,[154] investing up to $56 million of the federal Low Carbon Economy Fund over 2020-2023 in expanding Efficiency Nova Scotia programs and projects that focus on non-electric building efficiency.[153]

[150] Government of Nova Scotia. *Electricity Plan 2015-2040.*
[151] Nova Scotia Utility and Review Board. *Press Release, 2018.*
[152] Efficiency Canada. *Nova Scotia.* Accessed August 2020.
[153] Government of Nova Scotia. *Climate Change Progress Report, 2019.*
[154] Efficiency Canada. *Canadian Provincial Energy Efficiency Scorecard, 2019.*

Area	Description
Energy Storage	Intelligent Feeder Project launched by NS Power tests behind-the-meter storage. Technical specifications include: 10 Tesla Powerwall 2 residential batteries and 1 grid-sized Tesla Powerpack.[155]

Table A-35 Regulatory Structure in Nova Scotia

Area	Description
Regulatory Structure	• Vertically integrated investor owned corporation regulated by the Nova Scotia Utility and Review Board • Cost of service rate plan

[155] NS Power. *Intelligent Feeder Project.* Accessed August 2020.

Prince Edward Island

Table A-36 Grid Modernization Initiatives in Prince Edward Island

Area	Description
Grid Modernization Initiatives	• The first Demand Side Management Plan was approved in 2018 and prioritizes efficiency and conservation as a preliminary stage before using advanced metering infrastructure for programs like DR.[156] • There have been some AMI pilot programs in PEI. However, no widespread AMI deployment has occurred yet. • Wind Energy Institute of Canada R&D Park uses a 1 MW battery to integrate electricity from the 10 MW wind park.[157]

Table A-37 Policies and Initiatives Enabled by and/or Supportive of Grid Modernization Outcomes in Prince Edward Island

Area	Description
GHG Emissions Reduction	The government has set a target to reduce GHG emissions to 40% below 2005 levels by 2030.[158]
Renewables	New 30 MW wind project in 2019 and 40 MW wind project in 2025, in 2017 about 25% of electrical needs from wind.[159]
Energy Efficiency	Achieve electricity savings of 2% of electricity consumption each year through energy efficiency measures by 2020, 0.4% in 2017.[160]
Energy Storage	PowerShift Atlantic project demonstrated a fully integrated VPP with 17.3 MW load. All end uses had energy storage capability.[161]

[156] Island Regulatory Appeals Commission. *Order UE19-03, 2019.*
[157] NRCan. *Wind Energy R&D Park and Storage System for Innovation in Grid Integration.* Accessed August 2020.
[158] Government of Prince Edward Island. *Greenhouse Gas Emissions.* Accessed August 2020.
[159] Government of Canada. *Pan-Canadian Framework on Clean Growth and Climate Change, 2019.*
[160] Government of Prince Edward Island. Provincial Energy Strategy 2016/2017.
[161] NRCan. *Electricity Load Control Demonstration.* Accessed August 2020.

Table A-38 Regulatory Structure in Prince Edward Island

Area	Description
Regulatory Structure	• Unbundled investor owned and crown corporations regulated by the Island Regulatory Appeals Commission • Cost of service rate plan • Commission directs utilities to create multi-year EE and DSM programs, subject to approval

Newfoundland and Labrador

Table A-39 Grid Modernization Initiatives in Newfoundland and Labrador

Area	Description
Grid Modernization Initiatives	• The province's utilities have offered net metering program since July 2017. The net metering program allows RE projects up to a maximum of 100 kW and sized no greater than a customer's load to be connected to the grid.[162]

Table A-40 Policies and Initiatives Enabled by and/or Supportive of Grid Modernization Outcomes in Newfoundland and Labrador

Area	Description
GHG Emissions Reduction	The government has set a target to reduce GHG emissions to 30% below 2005 levels by 2030. Further, on June 5, 2020, the Government of Newfoundland and Labrador committed to net-zero emissions by 2050.[163]
Renewables	Achieve 98% renewable energy generation with completion of Muskrat Falls hydroelectric project and closure of Holyrood GS.[164] The province's Biogas Electricity Generation Pilot Program also encourages the development of biogas power generation and generates electricity for the system.[165]
Energy Efficiency	Average annual 0.3% electric savings target between 2019 and 2030, plans to use Low Carbon Economy Leadership Fund to help industry improve energy efficiency.[166]
Energy Storage	The Government of Newfoundland and Labrador is supporting the Nunatsiavut Government's pursuit of renewable energy solutions for its five communities through the Nunatsiavut Energy Security Working Group, including pursuit of a 1.6 megawatt wind micro-grid project in Nain with 15-60 minutes of battery storage.[167]

[162] Government of Newfoundland and Labrador. Net Metering. Accessed August 2020.

[163] Government of Newfoundland and Labrador. The Way Forward on Climate Change in Newfoundland and Labrador, 2019.

[164] NEIA. A New Climate Change Strategy for Newfoundland and Labrador, 2016.

[165] Government of Newfoundland and Labrador. Biogas Electricity Generation Pilot Program. Accessed August 2020.

[166] Efficiency Canada. Canadian Provincial Energy Efficiency Scorecard, 2019.

[167] Government of Nunatsiavut. Energy Security Plan, 2016.

Table A-41 Regulatory Structure in Newfoundland and Labrador

Area	Description
Regulatory Structure	• Unbundled investor owned and crown corporations regulated by NL Board of Commissioners of Public Utilities • Generally, a cost of service rate plan, with the exception of rural and diesel customers who are subsidized by customers on the interconnected system.