REGULATOR RATIONALE FOR RATEPAYER-FUNDED ELECTRICITY AND NATURAL GAS INNOVATION

PREPARED FOR:

CANADIAN GAS ASSOCIATION and CANADIAN ELECTRICITY ASSOCIATION

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EXECUTIVE SUMMARY

The case for utility-led, ratepayer-funded innovation has strengthened over the past decade and is being driven by a series of interconnected energy realities. These include the need to employ technology to integrate significant quantities of customer-sited distributed energy resources, the emergence of new natural gas end-use technologies, and a recognition by governments that utilities can play a central role in the achievement of energy and environmental public policy goals that require innovative solutions. Regulators in Canada should take note that these factors have taken hold among global economic regulators and this report concludes that the trend is spreading beyond some of the early movers: The United Kingdom, California, New York and British Columbia. The responsibility for ensuring that innovation prepares the energy industry to realize the potential for reliable, affordable, and clean energy with greater customer choices among products and services is shared by the utilities, regulators and other policy makers.

It is becoming increasingly accepted that new business models need to be developed, enabled by energy and data system technologies that require development and testing before they can be deployed at scale. Network infrastructure (pipeline and wire) modernization is an explicit goal for utilities and regulators, for both gas and electric utilities. Future investments in the networks are being designed to support an unfolding market characterized by engagement of both customers and third parties in the utility business model and the implementation of new consumer products and services. Utilities can support this evolving market via rate-funded demonstration projects that test new technologies and business models. Generally, while innovation in energy technologies and less expensive ways of performing traditional utility activities continue to grow, there has been more focus in the past few years on integration of demand energy resources, new business models, and the security of "big data" that enables this transformation. These programs de-risk investments for both customers and shareholders and help establish the business case for full-scale technology development and market adoption. Utility-led technology deployment and demonstration activities will have important direct benefits for customers by improving the way their customers use energy, control their energy use and derive benefit from it. Further, we are seeing many national and subnational governments developing large technology and funding programs. Utility ratepayer funding offers an opportunity to leverage these funds.

Regulators have another important objective with innovation: to spur a transformation of utility cultures to become learning and innovative organizations. Electricity and natural gas "utilities of the future" will be required to leverage advancements in energy technology, big data, and the desire of consumers to be evermore involved in their energy use patterns. Regulators also cite a desire to increase the reliability and resiliency of utility service and improve environmental performance.

The United Kingdom regulator concluded that its earliest efforts at innovation, the Low Carbon Network Fund (LCNF), which aimed to achieve aggressively low carbon goals, demonstrated that regulation has a critical role in promoting utility innovation and removing existing barriers for utilities. California has long been a supporter of customer-funded demonstration projects and continues this effort. New York's policy makers have implemented longer-term research and development programs, and requested that the regulator adopt a longer-term perspective when evaluating ten-year business plans that can be reprioritized during the plan as experience is gained. Minnesota has engaged a stakeholder process to contribute to the design of demonstration projects before they are submitted for review by the regulatory commission, thereby improving the opportunities for learning by all parties. AVANGRID, for example, is developing a demonstration "Energy Smart Community" that will test new customer engagement and business models after it installs Advanced Metering capabilities for over 10,000 customers in Ithaca, New York. Australia has supported customer-funded innovation that aims to reduce peak demand as growth is threatening reliability and will require expensive infrastructure investments. Ontario currently funds innovation through a combination of customer, utility shareholder, and vendor funding. The Ministry of Energy recently published a 2017 Long Term Energy Plan that focuses more intently on the role of innovation, and the potential barriers presented by existing regulation. The Massachusetts Commission has recently signaled its willingness to fund demonstration projects, indicating a willingness to follow through with a policy that was established in 2014 by a prior Commission. In British Columbia, an ambitious provincial clean energy policy has provided flexibility for utilities to propose - and the regulator to approve - customer-funded innovation projects in areas such as renewable natural gas and natural gas for transportation. These projects are seen as precursors to kick-starting new technologies and new applications of those technologies that may ultimately lead to scaled-up competitive markets.

Table ES-1 identifies programs in each of these jurisdictions where regulators have made an explicit determination that they meet specific innovation or demonstration project requirements to merit customer funding.

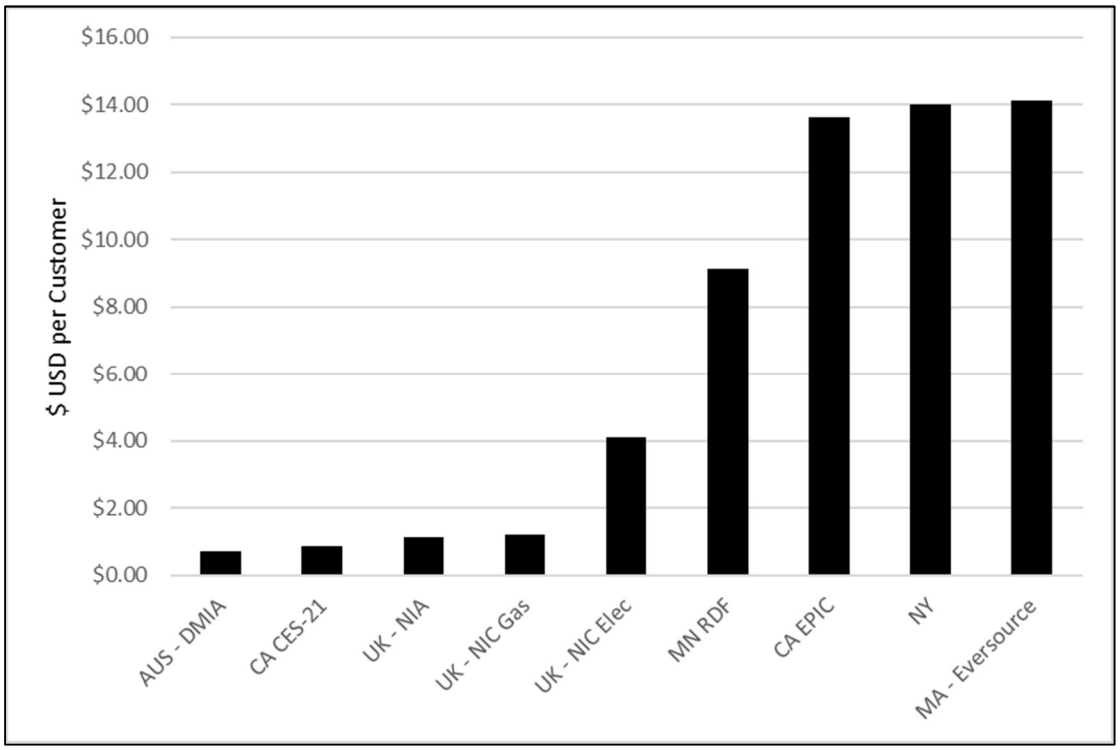
Table ES-1: Summary of Innovation Programs

Regulator/ Government	Program/ Directive	Link to Program	Start Date	Funding Level (annually per customer, $USD)
Ofgem	RIIO framework: Network Innovation Allowance (NIA) & Network Innovation Competition (NIC)	https://www.ofgem.gov.uk/network-regulation-riio-model https://www.ofgem.gov.uk/network-regulation-riio-model/current-network-price-controls-riio-1/network-innovation	2013-2015*	NIA: $1.13 NIC: $4.11 Electricity, $1.23 Gas
California PUC	California Energy Systems for the 21st Century (CES-21)	https://www.llnl.gov/sites/default/files/field/file/CES21.pdf	December 2012	$0.87
California PUC	Electric Program Investment Charge (EPIC)	http://www.energy.ca.gov/research/epic/	May 2012	$13.61
New York PSC and NYSERDA	Reforming the Energy Vision (REV)	https://rev.ny.gov/ http://www.dps.ny.gov/REV/	April 2014	NYSERDA funding: $4.69 ConEd REV project: $9.33
Minnesota PUC	Renewable Development Fund	https://www.xcelenergy.com/energy_portfolio/renewable_energy/renewable_development_fund	1994	$9.12
Australian Energy Regulator	Demand management incentive scheme and innovation allowance mechanism	https://www.aer.gov.au/networks-pipelines/guidelines-schemes-models-reviews/demand-management-incentive-scheme-and-innovation-allowance-mechanism	December 2017	DMIA: $0.72 *(hypothetical)*
Massachusetts DPU	Order requiring Grid Modernization Plan	http://www.raabassociates.org/Articles/MA%20DPU%2012-76-B.pdf	June 2014	Eversource demo projects: $14.12
IESO (Ontario)	Conservation Fund	http://www.ieso.ca/get-involved/funding-programs/conservation-fund/cf-overview	2005	*Insufficient data*

*Start dates vary by gas vs. electricity, and transmission vs. distribution.

Funding levels for innovation vary across the jurisdictions we have examined. The most recent data are summarized below in Table ES-2. These programs span a range from $0.72 to $14.12 per customer, or an average of $6.55. While virtually all policymakers and regulators express concern for costs, they also recognize the potential benefits. Ratepayer advocates have expressed concern that demonstration projects should be sufficiently defined with quantifiable benefits to support such investments.[1] The potential gains from adaptation of new technologies and business approaches to a "mature" industry are large, and studies indicate the potential consumer benefits from RD&D outweigh the costs by up to 5:1 multiples.[2]

Diagram ES-2: Examples of Utility Funding Levels, in Annual USD Per Customer[3]



Notes:
AUS – DMIA: Australia Demand Management Innovation Allowance
CA CES-21: California Energy Systems for the 21st Century
UK – NIA: Ofgem Network Innovation Allowance
UK – NIC Gas/Electric: Ofgem Gas/Electric Network Innovation Competition
MN RDF: Minnesota Renewable Development Fund
CA EPIC: California Electric Program Investment Charge
NY: New York State Energy Research & Development Authority and Con Edison
MA – Eversource: Eversource Grid Modernization Plan projects

In considering these funding levels, policymakers and regulators might ask: what is the optimal level of funding, which programs are most successful, and what factors determine whether funding should be increased or decreased? These are important questions without easy answers, but our research sheds light on them. Where energy policy dictates a shift in the status quo, funding levels would be expected to be higher to facilitate the transition, and targets comparable to the CA-NY-MA range may be appropriate. Given the relatively new nature of utility funded innovation, it is difficult to measure success, but Ofgem programs appear at the forefront, with benefits for certain programs estimated in the 4.5-6.5 times funding level range. Capital investment theory stipulates that any investment with a positive return should be undertaken with risk and capital costs factored in. This suggests that program funding up to a return ratio of 1:1 is warranted. Even with current budgets, California has estimated its RD&D funding gap is as much as $670 million per year. As long as estimated benefits continue to exceed funding levels, policymakers and regulators are serving the public interest.

Overall, this report documents the trend toward increased customer funding of innovation projects in both the natural gas and electricity industries and cites the rationale relied upon by policy makers and regulators. In some jurisdictions, the changes are implemented through a combination of legislation and regulation. The potential returns from innovation are significant. Whether avoiding costly investments in infrastructure, or helping customers save money on their bills by utilizing technology to manage their energy use, regulators are concluding that the short- and long-term benefits clearly justify the costs of demonstration projects.

INTRODUCTION

Concentric's 2014 report, "Stimulating Innovation on Behalf of Canada's Electricity and Natural Gas Consumers" described the significant benefits that energy innovation provides to customers and society with benefit-to-cost ratios in the 2 to 5:1 range across several programs. As noted in the Executive Summary:

> *An increased emphasis on innovation by utilities could yield a range of new technologies, applications, processes, and business models—e.g., more efficient end-use equipment, smart-grid technologies and services, advanced low-carbon energy sources, energy storage technology solutions, and community energy systems. Such innovations can provide cleaner, less expensive energy services to Canadian households and businesses while creating jobs, bolstering Canadian competitiveness, and promoting Canada's position among global energy leaders.*[4]

The 2014 report provided a framework for evaluation of alternative funding mechanisms, focusing primarily on government (taxpayer) and utility (customer) funding options. Government funding is most appropriate in the high-risk early research & development phase or where there are significant spillover benefits that discourage risk-taking. Utility customer funding is most appropriate where the benefits largely accrue to utility customers and where they are in a unique position to test new technologies and business models. The report identified potential obstacles to utility innovation and recommended a utility customer-funding model that maintains active regulatory oversight.

Two subsequent updates (2015 and 2016) provided updates on trends in utility-sponsored innovation along with examples of recent projects. This 2018 update focuses on customer-funded innovation programs with a deeper dive into the reasons why regulators in eight jurisdictions support customer-funded innovation. These include four leading United States jurisdictions (California, New York, Minnesota, and Massachusetts), two Canadian provinces (Ontario and British Columbia), and two international jurisdictions (Great Britain and Australia). We supplemented regulatory research with regulatory and policy interviews in these jurisdictions to obtain perspective on whether the programs were working, and indications of results achieved to date. The following sections describe the approaches taken in each jurisdiction and insights gained from evaluation of these programs.

CUSTOMER-FUNDED INNOVATION FROM AROUND THE GLOBE

1. UNITED KINGDOM

'The United Kingdom's energy regulator, the Office of Gas and Electricity Markets ("Ofgem"), has been an international leader in regulatory reform since its predecessor agencies were established when natural gas and electricity markets were privatized in the 1980s. Notably, it was an earlier adopter of performance-based regulation ("PBR"). The most recent version of this multi-year utility revenue model is "RIIO", representing the equation, "Revenue = Incentives + Innovation + Outputs", which was applied to natural gas and electricity distributors in 2013 and 2015, respectively. This new model was the result of a "RPI-X@20" review of PBR as applied in the UK. During this same era, Ofgem and the U.K. utilities gained experience with the Low Carbon Network Fund (LCNF).

The LCNF provided approximately £250m of funding for Distribution Network Operators ("DNOs") during the 2010-2015 period, a dramatic increase in innovation funding that was occurring under the PBR framework. LCNF was part of the electricity distribution price control. In the electricity distribution network, there are 14 DNOs which are owned by 6 groups. Focusing on achieving a low-carbon future while maintaining reliability and efficient services to customers, the LCNF was designed to integrate innovation as part of normal business operations and to share learning across the six DNOs. The estimated net benefit from this investment was £1.1 to £1.7 billion[5] or 4.5 to 6.5 times the funding level.[6]

The concept of compensating utilities for how well they perform as innovators grew from the recognition that the energy sector was about to experience significant change and that utilities needed to be able to innovate in order to respond to evolving customer demands and policy drivers.[7] Ofgem recognized that even within the new incentive-based ratemaking framework, "research, development, trials and demonstration projects - the earlier stages of the innovation cycle - are speculative in nature and yield uncertain commercial returns."[8] Ofgem recognized that even "failures" in terms of innovation attempts could provide useful information.[9]

Regulatory Rationale

Ofgem noted that the innovation stimulus is intended to "kick start" a cultural change at utilities.[10] Innovation funding is provided by customers since they will benefit from innovations.[11]

The initial decision noted that there was widespread support throughout the consultation for an incentive for innovation:

> *Given the scale of the challenge that network companies face and the uncertainty about how best to deliver, innovation is needed to ensure network companies deliver a sustainable energy sector and long-term*

> *value for money. The need for innovation has been widely recognized throughout RPI-X@20, including in responses to our consultations.*[12]

Ofgem concluded that networks will need to become a lot "smarter" to meet several challenges including:

- connecting more home-based microgeneration, i.e., solar panels and small scale renewable generation;
- connecting more small-scale renewables and CHP to the low voltage distribution network;
- balancing the electricity network to manage large amounts of renewable generation which by its nature is intermittent; and
- gas networks will face further growth in the use of Liquefied Natural Gas, as well as carbon capture and storage facilities at power stations.[13]

This rationale was restated in a March 2017 network innovation review:

> *As a consequence, network-related costs could increase significantly from connecting large volumes of generation, as well as managing the impacts of new sources of gas. We think it is in consumers' interests that the network companies respond creatively to the challenges posed by these changes. New approaches could deliver more efficient and timely services needed by network customers and lessen the cost impact on consumers. This might be achieved, for example, by developing and adopting new technology, different operational practices and novel commercial arrangements.*[14]

Ofgem noted the enormity of the investment that will be required to achieve its objectives, estimating that approximately £32 billion (approximately $53 billion Canadian dollars) of network investment will be required.[15] Ofgem recognized that in order to have an impact, the incentives for innovation must be significant:

> *The innovation stimulus package will include substantial prize funds to reward network companies and third parties that successfully implement new commercial and charging arrangements to help deliver a sustainable energy sector.*[16]

Ofgem established two distinct innovation funding programs to implement the innovation component of RIIO: the Network Innovation Allowance (NIA) and the Network Innovation Competition (NIC). These two programs fund research by the Distribution Network Operators (DNOs) that will facilitate the transition to a low carbon economy, while providing cost savings to customers. Customers will pay for these activities through their energy bills. The NIA is for funding smaller innovation projects and is a set annual allowance available to each network operator. For

electricity distribution, Ofgem required utilities to define innovation strategies based on NIA funding of between 0.5 and 1 percent of their base revenues. NIA projects do not require individual project approvals. While funding caps are company-specific, they have generally been between 0.5 and 0.7% for both electric and natural gas DNOs. £61 million is available for the NIA annually.[17]

The NIC is an annual competition to fund selected innovation projects, and is focused on larger, more complex projects that require approval.[18] In 2016, Ofgem provided £44.6 million in funding to six projects through the NIC. This funding is combined with the companies' contributions and external funding, creating a total of £53.9 million (approximately $75 and $90 billion Canadian dollars, respectively). These recently approved projects are shown in Table 1. The projects must meet certain criteria, such as generating new and shareable knowledge, being cost effective, and accelerating to move to a low carbon energy sector.[19] The total annual funding available for the electricity NIC was recently reduced to £70 million, down from £90 million, but the amount available annually for gas networks remained at £20 million.[20]

Table 1: NIC Projects Approved in 2016

	Project	DNO	Funding Sources	Length	Description
ELECTRIC	OpenLV	Western Power Distribution	4.9m – NIC, 0.5m – WPD, 0.5m – partners	3 years	Develop software platform to enhance visibility of residential substations
ELECTRIC	TDI 2.0	National Grid Electric Transmission	8m – NIC, 1.5m – NGET + UKPN	3 years	Test technical & commercial solutions to resolve constraints on the transmission network
ELECTRIC	PowerFul-CB	UK Power Networks	4.6m – NIC, 0.6m – UKPN, 0.9 – partners	4.5 years	Develop 2 types of circuit breakers on GB network
ELECTRIC	Phoenix	SP Transmission	15.6m – NIC, 1.8m – SPT, 2.3m – partners	4 years	Test new way of providing services (traditionally fossil-fueled power stations) to balance electricity network
GAS	HyDeploy	National Grid Gas Distribution	6.8m – NIC, 0.4m – NGGD, 0.4m – NGN	3 years	1st practical deployment of hydrogen onto live GB gas distribution network since the 1970s
GAS	Future Billing Methodology	National Grid Gas Distribution	4.8m – NIC, 0.5m – NGGD	3 years	Explore options for fair & equitable billing methodology, fit-for-purpose in lower carbon future

DNOs submit annual reports that provide a summary of all NIA projects. Customer-facing NIA projects are the subject of more detailed technical reports. DNOs have been providing individual reports on each NIC project that present spending updates along with learning to date and key challenges and risks that have been encountered. This is being transitioned to a single report for each company in 2018.

NIC projects were eligible for rewards based on successful delivery, but this has been subsequently eliminated now that the programs are up and running and the DNOs have been deemed to be managing the programs well.

Interview Insights[21]

The UK's focus on innovation is intended to produce a low-carbon future, while also driving down costs for network customers. Ofgem has significant authority and has not required legislation to implement its innovation agenda. The LCNF experience, supported by a survey from an independent evaluation report prepared by the consultancy Pöyry in October 2016, demonstrated that regulation has a critical role to serve in promoting utility innovation and removing existing barriers for DNOs.[22] The NIA and NIC programs continued the goal to foster a more innovative culture within network companies. Policy makers are hopeful that the innovative culture will be applied to resolving industry challenges as they arise and provide value to customers. Ofgem has made tweaks to governance over the past few years, providing more flexibility to DNOs based on satisfactory performance to date.

Funding Levels

In 2016, funding for the NIC was approximately £3.05 per electric customer and £0.91 per gas customer ($4.11 and $1.23 USD, respectively). With the reduction of £90 million to £70 million in electric NIC funding, future funding will be approximately £2.37 per electric customer ($3.20 USD).[23]

Insights: The UK government, through Ofgem, has made utility innovation a key objective of its regulatory framework. The regulator wants to drive cultural change at utilities in order to create a smarter, distributed, renewable, sustainable, efficient, and diversified electric and gas grid for the benefit of customers. Utility customer funding is utilized along with co-funding from third party vendors. The goals and scope of the UK program are among the most ambitious examined.

2. CALIFORNIA

California has two large programs that fund RD&D in the energy sector. The CES-21 program is a collaborative effort among the three large investor-owned utilities and Lawrence Livermore National Laboratories (LLNL) that funds investments in several specified areas, focusing most recently on cybersecurity and grid integration projects. The Electric Program Investment Charge (EPIC) Program funds investments that promote the adoption of clean technologies. Both programs are reviewed and approved by the California Public Utilities Commission (CPUC) and rely on customer funding.

In 2011, California's three large investor-owned utilities requested approval from the CPUC to enter into a five-year, $150 million research and development agreement with LLNL that was projected to produce over $550 million in savings. This program is referred to as the "21st Century Energy Systems Research Project" or "CES-21". The PUC approved this initial funding level in 2012 after determining that the proposal was consistent with a provision in the California Public Utility statute that authorized the CPUC to approve utility research, development and demonstration (RD&D) programs that considered the following guidelines:

1. Projects should offer a reasonable probability of providing benefits to ratepayers.
2. Expenditures on projects which have a low probability of success should be minimized.
3. Projects should be consistent with the corporation's resource plan.
4. Projects should not unnecessarily duplicate research currently, previously, or imminently undertaken by other electrical or gas corporations or research organizations.
5. Each project should also support one or more of the following objectives:
    a. Environmental improvement;
    b. Public and employee safety;
    c. Conservation by efficient resource use or by reducing or shifting system load;
    d. Development of new resources and processes, particularly renewable resources and processes which further supply technologies;
    e. Improve operating efficiency and reliability or otherwise reduce operating costs.

Regulatory Rationale

The statute provides the CPUC with the clear authority to approve RD&D funding by utilities and establishes a set of guidelines to consider. In the absence of clearly expressed legislative intent, the CPUC could have relied on more general "public interest" statutory provisions that are common in utility statutes. The Commission cited a Staff position suggesting that the California RD&D funding gap was as much as $670 million per year.[24]

Noting that the petition was consistent with the statutory guidance, the CPUC cited six benefits to utility customers:

1. The research findings are very likely to improve the safety of gas operations by reducing the gas pressure in transmission pipes needed to maintain distribution flows, by improving leak detection, and by predicting pipe breaks;
2. The project is very likely to provide benefits to ratepayers that exceed costs across both electric and gas operations by avoiding unnecessary purchases of power support services and by identifying with precision places where more grid investment is needed;
3. Research pertaining to the operations of electric and gas utilities is currently underfunded;
4. The research pertaining to cybersecurity will better protect both electric and gas operations and customer privacy;
5. Only the use of supercomputers, a core strength of LLNL, will enable utilities to process the three terabytes of data a day produced by smart meters and thereby improve grid operations and stability; and
6. The proposed research uses the special research strengths of LLNL in supercomputing, modeling, and cybersecurity.

It is evident from the fifth and sixth reasons that the CPUC was particularly focused on cybersecurity and potential threats to customer privacy and network security. In approving the initial funding levels of $30 million per year, the CPUC exercised care not to be overly prescriptive and require detailed project definitions, recognizing that the projects would be developed over time through collaboration among the utilities and LLNL. These decisions were delegated to CES-21's Board of Directors subject to the requirement that projects must fall within one of four areas: Gas Operations, Electric Operations, Electric Resource Planning, and Cybersecurity. The CPUC approved the agreement over the objections of two California ratepayer advocate organizations (TURN and DRA) whose objections focused on governance concerns, citing the reliance on estimates of benefits and the delegation of decision-making authority to CES-21's Board of Directors.

Subsequent legislation enacted in 2014 (Senate Bill 96) reduced the level of spending from approximately $150 million to $35 million over the five-year period. The Bill limited the areas of research to cyber security and grid integration and streamlined the governance process while adding more rigorous monitoring and reporting requirements that documented expenditures and described the beneficial outcomes from the research, as well as limiting administrative charges to 10% of program budgets. The limit was in response to concerns regarding administrative costs that were charged to the program and recovered from customers. The CPUC decision reaffirmed its support for RD&D by utilities.[25]

The program has been operating for a few years, and annual reports which detail progress to date have been released. Most recently, the 2016 Annual Report discussed updates to the cybersecurity and grid integration projects. The Simulation Engine has modeled security threats and malware attacks, and outreach sessions have focused on identifying synergies and checking for duplication. The project has also expanded simulations of the Western Interconnect, modeling every generation

unit and load zone across the region. This allows the researchers to examine power flows between regions to study the impact on the grid's need for operational flexibility.[26] The cybersecurity project will continue addressing next steps over the coming years, while the grid integration half of the program is set to produce the final deliverables by 2018.

The EPIC program was established by the CPUC in 2012, and consists of the three utilities administering an RD&D program that funds innovative technologies and approaches that promote reliability, lower costs, and increase safety. The investment decisions reflect the following principles:

1. Providing societal benefits;
2. Reducing greenhouse gas emissions in the electricity sector at the lowest possible cost;
3. Supporting California's loading order to meet energy needs first with energy efficiency and demand response, second with renewable energy (distributed generation and utility scale), and third with clean conventional electricity supply;
4. Supporting low-emission vehicles and transportation;
5. Providing economic development; and
6. Using ratepayer funds efficiently.

A broad range of programs has been implemented including research on net zero emissions buildings, testing of new demand response strategies, microgrid commercialization, adaption of the electric system to climate risk, and energy storage.

The initial 2012-2014 EPIC budget was $368.7 million, including a 10% cap on administrative costs. This increased modestly to $405.8 million for the 2015-2017 period. The California Energy Commission, as one of the administrators of EPIC, produces an annual report that documents investments.

Funding Levels

CES-21 funding in 2016 was $10.3 million, divided among the approximately 11.9 million customers of the three IOUs, results in a funding level of $0.87 per customer. EPIC's annual budget of $162 million translates to funding of approximately $13.61 per customer.

Insights: California is a leader in customer-funded innovation. The California CES-21 program demonstrates that enabling legislation can achieve two objectives: 1) clarifying the authority of a regulatory agency to approve RD&D expenditures by utilities and 2) establishing guidelines that a regulatory agency can apply in approving specific proposals. However, it also demonstrates that legislatures can subsequently modify their perspectives with respect to the amount and focus of RD&D. In this instance, the decision to reduce funding of the CES-21 program appears to have been caused by concerns about the proportion of the funding that was being used to fund administrative costs.

3. NEW YORK

New York supports customer-funded RD&D projects in both the natural gas and electric industries. There are several categories of funding. The seminal order establishing competition in New York's electric and natural gas industries (Order 96-12) established a non-bypassable systems benefits charge (SBC) from customers to fund research and development as well as energy efficiency investments, low-income programs, and environmental monitoring. The New York State Energy and Research Development Authority (NYSERDA) was designated in 1998 to administer the SBC funds. Prior to that time, utilities performed research and development activities that were approved by the New York Public Service Commission (NYPSC) and funded through customers' utility bills. New York's utilities continue to request and receive authorization to perform R&D activities that are approved in their rate cases.

In 2000, the NYPSC approved a surcharge intended to fund medium-to-long-term R&D by New York's investor-owned natural gas local distribution companies (LDCs) in response to a decision by the Federal Energy Regulatory Commission to phase out support for the Gas Research Institute through a surcharge on interstate pipeline deliveries.[27] New York's LDCs pledged to work collaboratively to address common needs and avoid duplication of research activities. The NYPSC relied on a Staff recommendation to have funds directed to distribution activities, and not to upstream activities (i.e., supply and storage) or to improving end-use appliances that were considered competitive activities. An appendix to the recommendation provides a list of qualifying distribution activities that includes pipe installation, pipe repair and maintenance, modeling of pipe flows, and improvements that would address environmental impacts related to the distribution function. This effort came to be known as the Millennium Fund. An industry trade group estimated that the benefit-to-cost ratio of gas R&D projects was approximately 3:1. The Millennium Fund remains in place today.

Millennium Fund programs are supplemented by utility-specific natural gas R&D programs that are approved in individual LDC rate cases. For example, Consolidated Edison proposed the deployment of trenchless technologies that allow the companies to repair gas distribution lines without digging a trench. Central Hudson has proposed to test a "non-pipes alternatives" concept as a way to meet growing peak demand on constrained parts of their system.

New York's support for innovation experienced a renaissance with its "Reforming the Energy Vision" (REV) proceeding that began in 2014. Customer-funded RD&D occurs through two mechanisms: (1) REV demonstration projects proposed pursuant to the Track 1 Order in the REV proceeding, and (2) RD&D efforts organized and managed by NYSERDA and funded by the SBC.

REV demonstration projects were filed pursuant to guidelines established in the REV Track 1 Order issued on February 26, 2015. The REV proceeding is New York's broad-based initiative to leverage technology and business model innovation in order to integrate substantial amounts of "Distributed Energy Resources" and thereby enhance reliability and resiliency while lowering carbon emissions.

Regulatory Rationale

The NYPSC expressed its support for innovation with its opening paragraph of the Track 1 Order:

The electric industry is in a period of momentous change. The innovative potential of the digital economy has not yet been accommodated within the electric distribution system. Information technology, electronic controls, distributed generation, and energy storage are advancing faster than the ability of utilities and regulators to adopt them, or to adapt to them. At the same time, electricity demands of the digital economy are increasingly expressed in terms of reliability, choice, value, and security.[28]

The Track 1 demonstration projects represent the NYPSC's commitment to supporting the realization of REV's ambitious objectives by inviting and subsequently approving customer-funded demonstration projects. Customer-funded demonstration projects were broadly supported by stakeholders, but the largest industrial customers expressed reservation about "significant" commitment of customer funds while REV concepts were still under development.[29] The NYPSC cited the following rationale for approving demonstration projects:

> *Demonstration projects will inform decisions with respect to developing DSP functionalities, measuring customer response to programs and prices associated with REV markets, and determining the most effective implementation of DER. Demonstration projects will test new technology approaches to assess value before going to scale. Data collected from these projects will inform regulatory changes, rate design, and the most effective means to integrate DER on a larger scale. Demonstration projects will also help to identify the kinds of price signal, tariff, data and consumer protection regulations necessary to bring products to scale.*[30]

As documented in our 2015 Update, the NYPSC established the following eight criteria for reviewing utility demonstration project proposals:

1. Demonstrating Innovation – Diversity of projects in the demonstration portfolio;
2. Value Distribution – Allocation of project benefits among customers, utilities and third parties;
3. Partnerships – Between utilities and third parties;
4. Customer Engagement – Response to DERs across the spectrum of customers;
5. Market Solutions – Enabling participants to propose solutions through competitive solicitations;
6. Developing Competitive Markets – Testing rules that will further the development of new markets;
7. Cyber Security – Developing data security standards and protocols; and
8. Scalability – The ability to accelerate development at scale.[31]

The five New York utilities submitted eleven demonstration projects in July 2015. These were approved on a staggered basis during the following 9-month period. Cost recovery is approved in utility rate cases, with a cap on demonstration project cost recovery at 0.5% of total revenue requirements or $10 million. The following table lists five of these projects.[32]

Table 2: Highlighted REV Demo Projects

Demo Project	IOU	Partners	Project Goals
Building Efficiency Marketplace	ConEd	Ecova Inc. and Honest Buildings	Build an online C&I marketplace to enable targeted building owners to leverage energy data and connect with qualified products/service vendors
CenHub Marketplace	Central Hudson	Simple Energy	Build an online mass market marketplace that connects customers and 3rd party DER providers with detailed home energy profiles and enhanced data analytics
Clean Virtual Power Plant	ConEd	SunPower and Sunverge	Bundle residential solar with storage offerings to aggregate and dispatch as a virtual power plant for local distribution system needs
Community Energy Coordination	NYSEG	Taitem Engineering	Aggregate and coordinate local demand for clean energy technologies through an online marketplace
Flexible Interconnect Capacity Solution	NYSEG	Smarter Grid Solutions	Provide cheaper/faster large scale DER interconnections with infrastructure-as-a-service model

These projects are supplemented by electric RD&D projects in rate cases. National Grid has requested approval for a number of demonstration projects that examined the value of data analytics, changes in workflow and business processes, and the use of mobile device applications by employees. They also proposed electric heat and electric transportation demonstration projects.

In a recent National Grid rate case, the Commission explained: "Although, to date, we have not adopted REV programs expressly targeted to our natural gas utilities, we support economically viable projects to the extent that they advance REV goals and benefit the gas system."[33] In this spirit, National Grid and Con Edison have both proposed natural gas demonstration projects in their rate case filings to align with the goals of REV. The Commission approved National Grid's three demonstration projects that aim to create a smarter and more resilient gas network while also encouraging customer engagement and helping to achieve the goals set out in REV. These projects consist of technology packages to test behaviors and response to energy efficiency options, assessing the effectiveness of generating units in load reduction, and a commercial demand response program to test market incentives. In Con Edison's most recent rate case (case 16-G-0061), the company emphasized how AMI deployment will help build the smart grid of the future as envisioned in REV. Con Edison has also recently proposed the Smart Solutions for Natural Gas Customers Program, which aims to decrease gas usage, procure alternative resources, and contribute to State environmental goals. The proposal also includes a Gas Innovation Program, aimed at testing new business models for clean heating technologies in order to determine if the technology could be scaled for a greater impact.[34]

A third category of RD&D projects in New York is either funded by NYSERDA or hosted on a recently launched REVConnect web-based platform. NYSERDA is interested in demonstration projects that test REV concepts, particularly those involving new business models that will provide revenue and

earnings opportunities for utilities and third parties. These projects will test the willingness of customers to engage with – and pay for – new products and services that are delivered in an innovative manner. Ideally, proposed projects are scalable if they prove to be promising.

The REVConnect platform (https://nyrevconnect.com) brings utilities, third parties, investors, and regulators together to develop innovative solutions, and the REVConnect team serves as a facilitator to promote collaboration.

Interview Insights[35]

Policy makers were particularly interested in demonstrating that the industry could transition to a new business model without having an adverse impact on reliability. NYSERDA recognizes that utility participation in RD&D is critical to the ultimate goal of new technologies and business models being deployed for the benefit of customers who are funding the research through the SBC. There is a tension between the uncertainty and risk associated with RD&D and the cost-benefit analysis that regulators typically apply to more traditional utility investments. The longer timeframe associated with returns to RD&D also present a challenge as regulators are generally looking for some measurable customer or environmental benefit (e.g., a specified carbon reduction quantity) within the first five years. Although NYSERDA is a state agency, its budget and activities are subject to review and approval by the NYPSC. As part of the Clean Energy Fund review, NYSERDA has received approval to apply a ten-year business planning horizon to its portfolio of programs. NYSERDA will file annual, rolling updates to its portfolio, adjusting priorities in response to technology and market developments, and defunding programs that no longer appear promising. This longer horizon is more aligned with the risk associated with RD&D, and also provides greater certainty and continuity as the NYSPC grows more comfortable with NYSERDA's portfolio approach.

The New York approach to innovation requires that the NYPSC apply a different perspective to its review and oversight of RD&D than it takes to its more traditional approval actions. The Commission is being asked to adopt a higher risk tolerance on behalf of customers based on the belief that customers will benefit in the long run from innovation and that, absent customer-funding, a suboptimal level of RD&D will occur in the regulated utility segment.

Funding Levels

Cap on REV demonstration project cost recovery of 0.5% of total revenue requirements, or $10 million per year.

Insights: New York has promoted utility innovation through multiple programs targeting both the gas and electric industries. While New York policy makers are pressuring the utilities to be innovative, they are also keeping utilities firmly within a cost-of-service regulatory environment. The introduction of potentially disruptive market and regulatory models is a concern among utilities as DERs continue to be integrated throughout the state. The issue may be brought to a head with NYSERDA taking a more active policy role in an effort to sustain the momentum toward increasing innovation.

4. MINNESOTA

Minnesota has two initiatives that provide customer-funded RD&D projects: a Renewable Development Fund established in 1994, and a more recent effort to develop demonstration projects through extensive stakeholder participation as part of Minnesota's e21 initiative. This initiative is addressing the future of energy market more comprehensively by examining changes to business models and regulatory frameworks necessary to leverage new technologies to promote a sustainable future with greater reliance on customer-sited and other renewable energy supplies.

a. Renewable Development Fund

The Minnesota Legislature established the Renewable Development Fund in 1994 as part of a condition that allowed Xcel Energy, Minnesota's largest electric utility, to store spent nuclear fuel in dry casks at the Prairie Island nuclear generating plant site. The legislation required the utility that operates the Prairie Island nuclear generating plant (Xcel Energy) to transfer $500,000 per year for each cask being used to store spent nuclear fuel into a fund that could only be used to develop renewable energy sources. This same legislation required Xcel Energy to spend 2 percent of its annual revenue requirements on energy conservation improvements. Funding requirements have been amended by legislation as on-site storage needs continued to grow, increasing to $25.6 million by 2016. Xcel Energy must file an annual report to the legislature listing each project and its projected financial benefit for customers. RDF is funded by a surcharge to Xcel Energy's Minnesota and Wisconsin customers. A typical Minnesota customer pays 0.1034 cents per kWh or $0.76 per month for the program.[36]

Regulatory Rationale

The RDF's objective is to remove barriers to entry for renewable energy technologies, including economic barriers from competing against conventional energy sources.[37]

Specifically, the RDF is allowed to fund:

- Increasing market penetration of renewables;
- Promoting start-up, expansion, and attraction of renewable projects in Minnesota;
- Stimulating in-state R&D into renewable electric energy technologies; and
- Developing near-commercial and demonstration scale renewable or infrastructure products.

The funds are allocated either as designated by the legislature or to energy production projects (biomass, hydro, solar, and wind) or research programs that are recommended by a stakeholder group to Xcel Energy and the Minnesota Public Utilities Commission (MPUC). Up to $10.9 million annually must be allocated to support renewable energy production incentives through Jan 2021 with over 85% of this targeted for wind energy facilities.

As reported in Xcel Energy's 2017 annual report to the legislature, the RDF program has funded over $276 million in renewable energy projects since its inception. The majority of this spending provides direct support to projects that produce renewable energy or to customers that are securing solar power. However, the RDF has also supported $52.5 million to 181 R&D projects that have produced research papers, funded workshops, and supported patent applications. Examples of ongoing or recent R&D projects are provided in Table 3.

Table 3: Highlighted RDF-Funded Projects

	Project Name	Funding	Resource	Description
1	University of Minnesota (Dairy)	$982,408	Solar/Wind	Model a "net zero" energy dairy parlor at the West Central Research and Outreach Center by integrating 20 kW wind and 54 kW solar with storage.
2	University of Minnesota (Biomass)	$819,159	Biomass	Evaluated economic and technical issues related to biomass fuel and integrated gasification combined cycle technology.
3	University of Minnesota (Torrefaction)	$1,899,449	Biomass	Demonstrate a prototypic torrefaction bioconversion process and distributed electric generation.
4	West Central Telephone Association	$137,000	Wind/Solar	Designed and tested configurations and specifications of a hybrid wind/solar power system for distributed generation in remote locations.
5	University of Florida	$999,995	Biomass	Demonstrated two-stage anaerobic digester at American Crystal Sugar in Moorhead, MN to generate methane for conversion to electricity.
6	Xcel Energy	$1,000,000	Wind	Installed a 1.0 MW sodium sulfur battery adjacent a wind farm to validate the value of energy storage for greater wind energy penetration.
7	University of Minnesota (Noise)	$625,102	Wind	Research the sources and quality of wind turbine sound and the thresholds of potential health impacts on humans.
8	University of St. Thomas	$2,157,215	Solar/Wind	Install a 0.25 MW peak, multi-purpose microgrid in Chicago City to establish an Engineering Senior Design Clinic for microgrid research and testing.
9	SarTee Corporation	$350,000	Biofuel	Researched the growth of algae fed on CO2 from flue gas and extracted the algae oils for conversion into a marketable biodiesel product.
10	Windlogics	$997,000	Wind	Defined, designed, built and demonstrated a complete wind power forecasting system.

The largest of these projects is the microgrid project at the University of St. Thomas, including 50kW each of solar capacity, wind, biodiesel generators and energy storage.

b. e21 Stakeholder Initiative

The e21 initiative is funded by the Minnesota-based McKnight Foundation that brings together energy industry stakeholders in an effort to develop a future business model and regulatory framework that better align utility financial objectives with public policy goals. The e21 initiative has produced Phase I (2015) and II (2016) reports and is currently engaged in a third and final phase that focuses on demonstration projects. As part of the third and final e21 phase, Xcel Energy has consulted with stakeholders to develop a pilot program for time-of-use rates. The initial filing for this pilot was completed in November of this year, and estimates the total pilot cost to be $8 million in capital and $2.9 million in O&M. If the project is approved, Xcel will seek to recover the majority of these costs through the annual Transmission Cost Recovery (TCR) Rider. The pilot provides participants with increased information and support, and seeks to shift load away from peak times in order to reduce or avoid the need for system investments in fossil fuel plants. The filing cites the Minnesota Legislature's Grid Modernization Statute, which directs utilities to identify investments

that modernize the grid and authorizes the Commission to certify these projects. The utility may then seek cost recovery for these projects under the TCR rider.[38]

A second project, developed as a partnership between Seventhwave and Lawrence Berkeley National Laboratory (LBNL), would evaluate alternative performance-based regulatory frameworks. Finally, the MPUC has directed Xcel to develop a 400 MW demand response pilot program.[39]

Interview Insights[40]

The e21 approach to innovation tests the value of including stakeholders in the design and development of demonstration projects, particularly when the objective is to test a new business model or a new way for utilities to work with third-parties, or when the demonstration project is testing the engagement and responsiveness of customers to new products and services. Although specific demonstration projects still need to be reviewed and approved by the MPUC, the stakeholder experience improves the design of the projects and increases their eventual likelihood of success. Stakeholders engage directly with the utility throughout this facilitated process and are in a position to support regulatory approval, including ratepayer support. The benefits of improved stakeholder relationships can carry over to more controversial utility regulatory matters that employ stakeholder engagement, including integrated resource planning efforts. This type of engagement has the potential to reduce regulatory risk and regulatory lag that is exacerbated by lengthy litigation.

One byproduct of the e21 Initiative is legislation that codifies the authority of MPUC to approve multi-year rate plans, extending the maximum from 3 to 5 years, and requires any such plan to include a distribution system plan.[41] This legislation, the 2015 Jobs and Energy Bill, also provides the MPUC with the authority to develop performance metrics for utilities.[42] The identification of measures, specific metric definitions, and targets all benefit from stakeholder engagement outside of a more rigid litigation process. Thus, the e21 Initiative has effectively created a role for itself that complements rather than competes with the more traditional relationship among the regulator, utilities, and stakeholder intervenors. The issues faced by utilities and their regulators are expected to become increasingly complex as energy business models continue to evolve in response to technology and market developments.

Funding Levels

For the RDF, there is a $25.6 million annual contribution to the fund. In 2017 the RDF charge for a typical customer was $0.76 per month, equaling $9.12 per year.

Insights: Minnesota, with the e21 initiative, is increasing the likelihood that regulators will be willing to approve customer-funded innovation by increasing the degree of collaboration between the utilities and stakeholders, and by beginning the collaboration while the demonstration projects are still in the design phase.

5. AUSTRALIA

The Australian Energy Regulator (AER) is beginning to respond to changes in the energy industry and the role of behind-the-meter resources as it faces rising peak demands. The AER proposed a demand management incentive scheme (DMIS) and demand management innovation allowance (DMIA) to encourage utilities to manage demand more proactively. The AER released a draft decision on the DMIS and DMIA in August of 2017 and finalized the decision that December.[43]

The DMIS is ongoing and will give electric companies a stronger incentive to undertake expenditures on demand management options. It benefits the grid and gives consumers more opportunities to earn money from managing their demand by making it more financially attractive for network businesses to use demand management. For example, customers may rely on their solar panels and batteries to trade electricity on a local energy exchange.

The DMIA supplements Australia's existing incentive based regulatory framework. The program is dedicated to specific projects and will provide funding for R&D on demand management projects that have potential to reduce long-term costs. The innovation allowance continues to reduce the risk that utilities currently face when investing in R&D activities. Customers contribute to the fund through an increment in each distributor's revenue requirement according to the formula: $200,000 plus 0.075% of the applicable maximum allowed revenue requirement.[44] Projects must satisfy at least one of three criteria to be funded:

1. Based on new or original concepts,
2. Involves technology or a technique not previously implemented in the National Electricity Market (NEM), or
3. Focused on customers in a market segment that has not been exposed to the technology.

Distributors must file an annual report that identifies the funding for all projects. Subsequent project-specific reports will describe the methodology and outcomes.

In describing the background for the mechanism, the AER cites a July 2017 report prepared by Energy Networks Australia (ENA),[45] an industry association, with support from the Energy Consumers Association.[46] The AER highlights the unique role that distributors play in addressing the challenges to distribution operations from integration of intermittent generation and distributed energy resources. The DMIA rationale addresses regulatory barriers directly, noting that regulated utilities have a lower incentive to conduct R&D than competitive businesses because they:

- Face lower 'up-side risk.' Competitive businesses may be more likely to profit from R&D than monopolies as R&D can provide them with a 'competitive advantage.' Moreover, to the extent that R&D results in future cost reductions, distributors will pass a material portion of these gains onto electricity consumers under [the] regulatory regime.
- Still face 'down-side risk.' If R&D costs occur significantly before the benefits, distributors risk being financially penalized from making these decisions under the regulatory regime.[47]

The ENA report, "Network Innovation: Discussion Paper" describes the barriers to innovation at great length. It observes that the proposed DMIA applies only to the electricity industry and not to

the natural gas distributors. It cites two industry reports that address the immediate challenges and future role of technology in both the electricity and natural gas industries.[48] The report identifies several regulatory barriers including the fact that RD&D projects cannot satisfy traditional pre-approval investment tests and the mismatch between the relatively high risk of innovation and low regulated returns. The report notes that the benefits of innovation typically accrue over a longer-term than traditional investments, reinforcing these risks and financial barriers.[49]

The ENA report also points to the potential role for innovation in the gas sector. "Similarly, innovation will play a key role in realizing opportunities for further decarbonizing Australia's gas sector. There is a strong potential to use three transformational technologies - biogas, hydrogen and carbon capture and storage – to create clean, dispatchable energy resulting in zero emissions that can use existing gas networks' infrastructure."[50] Pointing to the gap it sees in the scale of investment required to achieve this potential, the ENA cites industry-led initiatives, including Energy Networks Australia's Gas Committee innovation fund established in 2016 for targeted R&D and technical activities in industry-identified priority areas.[51]

The AER has also addressed the issue of which services should be provided by regulated distributors (DNSPs), and which should be open to competition through a "ring-fencing" set of guidelines. The objectives of these guidelines, as illustrated by those established for electric distributors, are designed to prevent:

- Cross-subsidizing an affiliate's services in contestable markets with revenue derived from its regulated services
- Discrimination in favor of a DNSP's related electricity service provider operating in a contestable market
- Providing related electricity service providers with access to commercially sensitive information acquired through provision of regulated services
- Restricting access of other participants in contestable markets to infrastructure services provided by the DNSP, or providing access on less favorable terms than to its related electricity service providers.

According to the AER: "The Guideline sets out the obligations a DNSP must meet to separate its regulated monopoly services from any services it may seek to offer to contestable markets. We expect the Guideline will aid development of competitive markets where competition is feasible and support efficient, incentive-based regulation of monopoly networks where competition is not feasible."[52]

Interview Results[53]

The driving forces impacting utility regulatory policy in Australia are consumer concerns regarding energy prices, reliability concerns, pending retirements of coal-fired plants and the growing penetration of renewables. The existing regulatory model is a multi-year incentive program. Companies come in every five years with forecasts for the next five years. The regulator, with technical advisors, determines if the forecast reflects "efficient costs," and then sets revenue for five years. The underlying rationale is if the utility can improve on costs, they retain the difference, and if there is a non-network alternative that's more cost-effective, the utility has the incentive to look at that alternative.

Regulatory Rationale

Despite these incentives, the AER has found it challenging to move utilities beyond a perceived focus on capital investments, and prior incentives have not been sufficient to overcome that hurdle. There is a cultural resistance. The AER is attempting to promote innovation through the DMIA and also wants to distinguish between services that should remain under regulation, and those that should be competitive, as described in its ring-fencing guidelines.

The AER is seeing more partnering between the networks and different innovators, and the networks are becoming more open to innovation. The AER sees its role as setting up a framework, and the industry is responding. The AER is also emphasizing a movement away from an adversarial relationship to a more collaborative model. Pilot projects are beginning to illustrate scalability. Tesla, for example, is building a 129-MWh battery with French energy company Neoen in South Australia, characterized as the world's largest battery.

Australia also funds RD&D projects as a result of the ARENA Act 2011, which targeted $2 billion (Australian dollars, equal to approximately $1.97 billion Canadian dollars) to invest in renewable energy and the Australian renewable technology sector. Funding has been modified by the Clean Energy Legislation (Carbon Tax Repeal) Bill 2013 and Budget Savings (Omnibus) Bill 2016.

Funding Levels

DMIA funding is AU$200,000 plus 0.75% of annual revenue requirements (ARR). DMIS funding is up to 1% of ARR.

Insights: Australia is poised to implement customer-funded innovation mechanism at a meaningful level. This proposal is broadly supported by stakeholders who recognize that utility innovation is part of the solution to adapt to a changing environment. This includes targeting a combination of energy costs, reliability, and the integration of renewable energy resources. A combination of government-funded, customer-funded and industry-led mechanisms are being utilized.

6. ONTARIO

Ontario currently funds innovation through a combination of ratepayer, utility investor, and third-party vendor resources. Ratepayer-funded projects are financed through the IESO's Conservation Fund and are included as a component of the Global Adjustment charge that appears as a separate line item on electric bills for all customers.

More recently, the provincial government of Ontario and its energy regulator have increased their attention on the role that innovation needs to serve in the energy sector. The Ministry of Energy's 2017 Long Term Energy Plan (2017 LTEP), released in October 2017, devotes an entire chapter to innovation.

Regulatory Rationale

Ontario is focused on maintaining affordable energy for residential and business customers. Innovation in the delivery of electricity and natural gas, greater customer choice, and expanded access to natural gas, are viewed as major contributors to realizing this goal. The emphasis on innovation responds to stakeholder input that "electricity costs are too high," the Ministry should "consider new technologies and methods to manage energy use," and there is a need to "expand access to natural gas."[54] The Ontario Energy Board's (OEB) 2017-2020 Business Plan identifies "technological innovation that presents new choices for consumers and challenges traditional business and regulatory models" as one of four key trends that define the current environment.[55]

The 2017 LTEP projects that innovation in the natural gas sector will increase Ontario's reliance on renewable natural gas, leveraging the Waste-Free Ontario Act 2016 and the Organic Waste Action Plan that promote the use of organic waste to produce natural gas. The Government of Ontario intends to work with the Independent Electricity System Operator (IESO) on a pilot program to transform electricity into hydrogen gas that can be used for traditional and new transportation end-uses.

Technology innovation in the electricity sector will focus on three areas:

1. Employing technologies to modernize the electricity network, increasing automation, addressing cybersecurity issues, and enabling transactive energy markets;
2. Integrating distributed energy resources (DER) including energy storage to help customers manage their energy end-use (frequently referred to as "Smart Home" initiatives); and
3. Electrification of the transportation sector.

The 2017 LTEP calls for pricing innovation that would test alternative time-varying pricing approaches, leveraging smart technologies and communications as well as consideration of net energy metering policies.

There are innovative uses for natural gas as well in Ontario, as discussed in the 2017 LTEP. Renewable natural gas (RNG) is seen as innovative in that it is a low-carbon fuel that can use the existing distribution system to replace conventional natural gas. Along this same vein and in

connection with Ontario's Climate Change Action Plan, the government is developing a pilot program that will allow agricultural sectors to produce RNG and will support businesses in using RNG for vehicles. Power-to-gas, transforming electricity to hydrogen gas, is seen as another potential innovative link between Ontario's electricity and natural gas systems. Recognizing the versatility of this fuel, and the fact that it is a way to decarbonize the natural gas supply, Ontario is undertaking a feasibility study of fueling passenger trains with hydrogen. The government will also work with the IESO to explore the energy system benefits and GHG emission reductions that could result from using electricity to create hydrogen.[56]

The LTEP acknowledges that there are currently several barriers to innovation, and stakeholders are indicating a need for government funding support for R&D, including enhanced funding of the existing Smart Grid Fund. Ontario's $50 million Smart Grid Fund was launched in 2011 to assist local distribution and smart grid companies test and build the technologies needed for grid modernization. Nonetheless, the report notes that there has been uneven investment in grid modernization, citing an Electricity Distributors Association finding that "half of Ontario LDCs still approach innovation in a gradual or incremental way," before concluding:

> *It is clear that barriers to innovation remain. With the rapid development of new technology and the increase in customer expectations, the time to address these barriers is now. To encourage change in the energy sector, the government will work with utilities and other partners to build a culture of innovation, and will look to the OEB to explore, where cost-appropriate.*

The report identifies specific barriers, including three regulatory framework barriers:

1. The regulatory treatment of LDC capital and operational expenditures, which can inhibit the uptake of these non-wires solutions;
2. A cost-benefit framework that provides clarity on the treatment of investments, such as those with localized costs that provide benefits to other electricity system participants (also known as the diffuse benefits issue); and
3. The ability of utilities to make non-traditional distribution system investments and participate in market opportunities that would ultimately reduce ratepayers' costs associated with capital or other investments.

As noted by the Ministry, the OEB will play a key role in addressing these and other barriers to utility innovation. The OEB's business plan cites many of the same industry drivers, trends, and objectives as the 2017 LTEP. These include the need for utilities to integrate increasing numbers of DER, including electric vehicles and microgrids. The OEB is working on a 2018 roadmap for regulatory reforms needed to take advantage of technology innovation and new rate designs that will support efficient use of distribution networks.

Interview Results[57]

Ontario funds innovation through a combination of ratepayer, utility investor, and third-party vendor resources. Ratepayer-funded projects are financed through the IESO's Conservation Fund and are included as a component of the Global Adjustment charge that appears as a separate line item on electric bills for all customers. Recent demonstration projects that have been funded through this

mechanism include several pilot programs that test TOU and other pricing mechanisms (often combined with energy management system technologies). They also include testing new energy technologies such as energy storage and the potential for solar power to defer infrastructure investments.

Stakeholders involved generally understand the goals: be cost effective, make the customer's voice heard, and meet environmental policy goals. An outcomes approach to regulation is compatible with these objectives. The OEB perceives a hangover of existing habits and approaches to distribution planning, and some prior regulatory features that do not provide adequate incentives for least cost systems. Incentives that align customer and utility objectives will drive down system costs. The OEB has also relied on moving more distribution charges to the fixed customer charge to remove barriers to innovation.

Governance for pilot projects includes the OEB establishing guidelines, followed by interim reports showing results based on the sample (e.g., how effective is it at demand response and consumer elasticity), followed by a mandatory final report. Monthly monitoring reports are sometimes utilized in the first period, followed by bimonthly reports.

Insights: Ontario is supporting customer-funded innovation through a broad-based customer-funded mechanism collected through the ISO. The strong positioning of the role of innovation in addressing energy costs in Ontario by the Ministry is important in reaching alignment with the OEB to provide support for innovation. The 2017 LTEP and OEB business plan recognize that regulatory barriers need to be addressed. The regulator is seeking to better align utility and customer interests and the regulatory model through demonstration projects and incentives that will ultimately deliver lower energy costs.

7. MASSACHUSETTS

In 2014, the Massachusetts Department of Public Utilities (DPU) issued an order on electric grid modernization, requiring each utility to file a Grid Modernization Plan (GMP). The order supports utility innovation and directs each of the Commonwealth's three investor-owned utilities (National Grid, Eversource, and Fitchburg Gas & Electric) to propose a list of projects that focus on testing, piloting, and deploying RD&D projects that modernize the grid and employ new technologies. The DPU invited the utilities to propose funding mechanisms as part of their GMP filings, clearly inviting customer-funded proposals. However, the DPU also directs utilities to leverage outside funding and pursue collaboration to the extent possible.[58]

Regulatory Rationale

Notably, the DPU indicated that it would not deny cost recovery "merely because of lack of success," responding directly to one of the major barriers to utility innovation, noting further that the DPU had not been supportive of RD&D projects in the past, and signaling an intent to reverse existing precedent. Grid modernization would result in lower energy costs by contributing to a less expensive electric system (investments, operations and maintenance expenses), reducing peak demands, and by providing customers with tools that they could employ to reduce their electricity usage, particularly during price spikes.

The DPU cited increasing reliability, lower energy bills, and clean energy as grid modernization goals. Increases in reliability and resiliency would be supported by "a range of grid modernization technologies and policies." [59] The DPU's order expressed a clear preference for advanced metering functionality (AMF) which would enable time-varying pricing mechanisms.[60] Clean energy is another factor cited by the Department in support of its grid modernization initiative:

> *The modern electric system that we envision will be cleaner, more efficient and reliable, and will empower customers to manage and reduce their energy costs. The modern electric system will build on the Patrick Administration's progress towards our clean energy goals by maximizing the integration of solar, wind, and other local and renewable sources of power.*[61]

The utilities filed their GMPs in August 2015, in compliance with the DPU policy directives. For example, National Grid proposed to fund its grid modernization RD&D efforts through an RD&D provision in a new tariff, identifying $29.3 million that it proposes to pursue through the grid modernization RD&D program over the next decade. National Grid pledges to continue to leverage RD&D investments by joining with other utilities (through industry organizations or other means) to seek to fund work that, by itself, would be too expensive for a single utility and to seek outside funding.

The DPU review of the grid modernization filings was put on hold after the election of a new Governor in November 2015, and subsequent appointment of a new Chair. This is not uncommon when there is a change in administration, particularly when there is also a change in party, as in this case. The

entire Commission has now turned over. Hearings were held this past summer, and the parties have filed initial and reply briefs.

Eversource filed a five-year performance-based regulation proposal earlier in the year, proposing to roll-in its grid modernization investments as part of its rate plan. In an order dated November 30, 2017, the Department declined to address grid modernization and indicated that it preferred to consider the three plans together in the grid modernization dockets to allow time for a more thorough examination and enable the DPU to establish consistent policy across the utilities with respect to cost recovery and other issues. The DPU noted the level of uncertainty associated with both costs and anticipated benefits, and its intention to ensure that grid modernization investments will produce an optimized level of net benefits.[62] The DPU did signal its intent to apply the standards established by the prior Commission in the grid modernization policy proceeding.

The DPU, however, made two exceptions that it deemed to be consistent with existing precedent. First, it approved funding of $55 million for Eversource's two energy storage demonstration projects, finding that they will facilitate the market for energy storage in Massachusetts and provide data that will be critical in evaluating future energy storage deployments as part of Massachusetts' clean energy future. The Department found that the proposed energy storage demonstration program is consistent with the grid modernization objectives of integrating distributed resources and improving asset management.

Second, the DPU approved $45 million to fund EV charging stations and customer education and outreach, noting that these investments will help accelerate electric vehicle charging infrastructure development in Massachusetts, encourage electric vehicle purchases, and contribute to greenhouse gas emissions reductions in the Commonwealth.

Funding Levels

As an example, the recent approval of Eversource's storage and EV projects includes approved capital investments of $100 million. The annual revenue requirements associated with these investments will be recovered from Eversource's 1.4 million electric customers in Massachusetts. The Department considered bill impacts, net of customer benefits, when approving these spending levels.

Insights: Although the DPU has not yet issued orders in the grid modernization cases filed over two years ago, the Eversource order signals its intention to apply the policies from the prior Commission and its willingness to fund demonstration projects that advance the public interest. Most importantly, this qualifies as customer-funded innovation. It will be a few years before these recently approved projects will produce results that can be evaluated. The funding for Eversource's storage and EV projects coincided with approval of its PBR plan, indicating innovation and PBR can be pursued simultaneously.

8. BRITISH COLUMBA

Legislative Rationale

British Columbia, through a series of legislative actions, has established aggressive goals for its energy sector that depend on investments in clean energy production and infrastructure as well as technologies that support energy management activities. Many of these programs are funded through surcharges on energy usage.

The 2007 Greenhouse Gas Reduction Targets Act set initial targets for reductions in greenhouse gas ("GHG") emissions at a 33% reduction by 2020 and 80% by 2050, and established a carbon tax. The 2010 Clean Energy Act (CEA) set goals with respect to electricity self-sufficiency, including reducing the expected increase in electricity demand by at least 66% by 2020, generating at least 93% of electricity from clean or renewable resources, supporting the development of innovative technologies that support the conservation and clean energy goals, and reducing GHG emissions dramatically by 2050.

The CEA directs the British Columbia Utilities Commission to set rates as necessary to allow utilities, including British Columbia's largest electric utility, provincial-owned BC Hydro, to recover the costs they incur to achieve these goals. The Greenhouse Gas Reduction Regulation ("GGRR"), authorized under the CEA, allows for utilities' prescribed undertakings that work towards GHG reductions, while still allowing them to recover their costs through utility rates. The GGRR allows utilities to implement prescribed undertakings without seeking the prior approval of the BC Utilities Commission, although the Commission still has the ability to rule on the prudency of expenditures. British Columbia's utilities have provided incentive funding to customers to support development of CNG and LNG fueling stations, vehicle and marine vessel conversions, and the use of renewable natural gas.

One fund that is instrumental in achieving British Columbia's goals is the Innovative Clean Energy (ICE) Fund administered by the Province's Ministry of Energy, Mines and Petroleum Resources. The ICE Fund is a legislated Special Account designed to support the Province's energy, economic, environmental and greenhouse gas reduction priorities, and to advance B.C.'s clean energy sector. The ICE Fund was initially funded by a 0.4% levy on the final sales of electricity, natural gas, fuel oil and grid-delivered propane. The electricity levy has since been removed with the reinstatement of the Provincial Sales Tax on April 1, 2013.

British Columbia is interested in demonstrating the commercial viability of new technologies as an economic development program, with successful capabilities potentially being exported to other markets. In March 2017, the Province announced a $40 million partnership with Sustainable Development Technology Canada to support the development of pre-commercial clean energy projects and technologies. The parties will conduct a joint call over a three-year continuous intake period to seek out clean energy projects and technologies that will mitigate or avoid provincial greenhouse gas emissions, including prototype deployment, field testing and commercial-scale demonstration projects. Projects must take place in British Columbia and must demonstrate how the proposed project will result in GHG reductions, commercialization, and economic growth in British Columbia and Canada.

FortisBC has a Smart Learning Thermostat Pilot Program for both natural gas and electricity customers that is designed to test customer engagement and energy savings. FortisBC offers a

renewable natural gas service that has attracted 9,000 customers. BC Hydro has invested in a $12.5 million project to test the ability of grid storage to support reliability in remote areas of its distribution network. British Columbia's clean electric vehicle (CEV) program provides additional funding to meet growing demand for rebates on vehicles and specialty-use vehicles, and supports the expansion of charging stations, hydrogen fueling stations, and the development of new research and training programs. Both BC Hydro and FortisBC are building EV charging infrastructure to support growing demand in this sector.

Interview Insights[63]

A series of legislative and policy initiatives led to the establishment of the Clean Energy Act in 2010, and the subsequent GGRR in 2012. Under this legislation, utilities have the option to implement prescribed undertakings without seeking the prior approval of the BC Utilities Commission, although the Commission still has the ability to rule on the prudency of expenditures. The Province does not contribute any funding. The programs are fully funded by natural gas utilities and paid for by natural gas customers.

The GGRR has been amended over time to allow utilities to implement specific undertakings. In November 2013, amendments were made to allow utilities to expand their incentives to include trains and mine-haul trucks, and to provide tanker-truck delivery services to trucking, mining and marine-transportation customers. In May 2015, the Government further amended the GGRR to allow for shifts in the allocation of incentives and investments within the previously-approved total spending cap in order to better respond to changes in the marine market place. Amendments made in early 2017 enabled utilities to increase natural gas distribution to the marine transportation sector. Amendments also increased incentives for using RNG in transportation and established a Renewable Portfolio Allowance to increase the supply of RNG.

Concerns in BC have been expressed that these services might be offered by unregulated industry in a competitive market (e.g., LNG and CNG), and should not be supported by innovation funding because this would provide the utility with an "unfair advantage." Amendments to the legislation have been justified on the basis that utilities are serving a market that would likely not be served by competitive service providers. Utilities may also ask for incentives to execute innovative programs, particularly where a competitive procurement process is employed and overseen by an independent third-party "fairness advisor."

Utilities provide comprehensive reports on these initiatives to the provincial government and the commission.

Insights: In British Columbia, an ambitious clean energy policy has provided flexibility for utilities to propose - and the regulator to allow - cost recovery for customer-funded innovation investments. These projects are seen as precursors to kick-starting new technologies and new applications of those technologies that may ultimately lead to scaled-up competitive markets.

CONCLUSIONS

REGULATORY RATIONALE

Several policymakers, including utility regulators, have recognized the need for utilities to actively contribute to innovation in the electricity and natural gas sectors of the economy and the value this provides to customers. This report focuses on jurisdictions that provide customer funding for innovation and the reasons that regulators have cited in approving this funding. They have approved funding for demonstration projects that explore new business models, pilot technologies that result in delivery efficiencies, test new products and services, and support scalable investments. All of these investments help accelerate the pace of change in the sector.

Goals for these programs vary by jurisdiction, but common themes include: greenhouse gas reductions, lower energy prices, demand reduction or load shifting, accelerated deployment of renewable and distributed resources, improved system reliability, and the introduction of new utility technologies. Rationales also vary according to specific circumstances and preferences of regulators and policymakers. Ofgem sees innovation funding as a vehicle for driving cultural change at utilities, and necessary to achieve these objectives. California and BC see innovation as a mechanism for economic development. BC and Australia see innovation as a path for stimulating competitive service offerings. Ontario and Massachusetts emphasize new choices for consumers.

There is a growing recognition that customers are long-term beneficiaries from innovation in the utility business model, so investments on their behalf are justified and in the public interest. Customer funding for innovation-related projects is often applied in conjunction with funds that are contributed by government and third-party vendors.

MEASURING THE BENEFITS

The history of utility customer-funded innovation funding is relatively recent, so data on the benefits of these programs can be difficult to quantify. Successful deployment requires regulatory flexibility and appropriate governance to ensure the trade-offs between costs and impacts on rates are justified. Given the global nature of these policy objectives, the opportunity exists for lessons learned to be shared among regulators and industry stakeholders.

While not all demonstration projects successfully prove out a new technology or business model, these investments frequently prove to be gateways to new utility models, short-term accelerators to competitive service offerings, or some combination of quantitative and qualitative benefits. The potential gains from adaptation of new technologies and business approaches to a “mature” industry are large, and studies indicate the potential consumer benefits from RD&D outweigh the costs by up to 5:1 multiples. Whether avoiding costly investments in infrastructure, or helping customers save money on their bills by utilizing technology to manage their energy use, regulators are concluding that the short- and long-term benefits of customer-funded innovation justify the costs.

APPENDIX: Interview Subjects and Outline of Questions

INTERVIEWEES

UK | Jonathan Morris and Neil Copeland, both of Ofgem

New York | Bryan Berry, of NYSERDA

Minnesota | Rolf Nordstrom, of Great Plains Institute

Australia | Paula Conboy, of the Australian Energy Regulator

Ontario | Ceiran Bishop, of the Ontario Energy Board

British Columbia | Paul Wieringa and Jennifer Davison, both of British Columbia Government

QUESTION OUTLINE

A Q&A with Key Regulators & Policymakers on the process from conception to reality on their innovation levy, discussing:

1. The history and how it came to be
    - Was this led by the utility industry, political class or the economic regulator or some combination thereof?
    - What was the gap that needed to be filled?
2. What challenges the regulators faced;
    - Challenges from interveners
    - Information challenges
    - Political challenges
3. What was the rationale/justification (e.g., legal, market, financial or economic) for approving the program? Or, was there a gap in the market that was viewed to be filled effectively by the regulated utility?
4. How the regulator is kept informed/engaged in how the money is spent and the overall governance structure established;
    - What are the KPIs?
    - Is there an annual or semi-annual review?
    - How are the approved funds set aside (deferral account or other?)
5. How they think the program is working;
    - What, if anything, would be considered an improvement to the current design?
6. Results achieved – have they been measured?
    - Who measures them – third party, the utility or other?
    - What if there is an underperformance?

END NOTES

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