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EPCOR UTILITIES INC.: MODERNIZING ALBERTA’S ELECTRICITY SYSTEM

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It was January 2014, and Rob Reimer, director of Metering and Wholesale Energy for EPCOR Distribution & Transmission Inc. (EDTI), was contemplating how to proceed with updating the current meter operations of EPCOR Utilities Inc. (EPCOR). In 2007, EPCOR’s senior leaders had asked Reimer to research smart grid technologies as a potential opportunity for EDTI. Smart grid technology had swept North America, enabled by advances in communication technology and support from U.S. government stimulus funding. Both of the primary smart grid technologies, automatic meter reading (AMR) and advanced metering infrastructure (AMI), represented significant improvements over manually reading meters. AMR, a meter-based technology, enabled meters to be read from the readers’ vehicles. With the additional installation of fixed networks, data from AMR meters could be remotely transmitted to central processing centres, eliminating the need for a fleet of vehicles. AMI, although a costlier technology, was a comprehensive system that enabled automated two-way communication between meters and a central network. Two-way communication provided benefits over AMR including immediate notification, resolution of operational failures (i.e., outages), and energy savings.

EPCOR had already begun to replace worn-out manually read meters with AMR, and continuing down this road would mean all meters would be transitioned to AMR in about 20 years. Although attractive in many regards, an immediate upgrade to either AMR or AMI represented a major capital expenditure. Additionally, EDTI’s application, in 2010, to implement AMI had been denied by the Alberta Utilities Commission (AUC) because the financial analysis did not demonstrate a clear benefit of upgrading. Since that time, however, several key changes had taken place that meant that a new application for AMI had a better chance of being accepted. These changes included more stringent and costly regulatory requirements for meter sampling and testing, which made the use of manual meters costlier. Additionally, Alberta’s Department of Energy (DOE) announced that, while utility providers would not be *required* to update their systems with smart technology, neither would they be barred from doing so. Lastly, the cost of smart meters had decreased significantly since 2010. With an opportunity in just four months to submit another application for smart grid technology, Reimer contemplated his main options: (1) continue with the status quo of replacing worn-out meters with AMR, (2) replace all meters with AMR, (3) replace all meters with AMR and install fixed networks to automatically collect batches of meter readings, or (4) reapply for AMI. If EDTI opted to reapply for AMI, which involved a far greater capital expenditure than AMR, acceptance of the application hinged upon the careful consideration of the interests of many different stakeholders. Thus, in deciding which alternative to pursue, Reimer knew that he needed to develop a thorough and thoughtful implementation plan and financial analysis, one that both was operationally viable for the business and considered the needs of major stakeholders.

The Industry

Overview

The utilities sector, according to the North American Industry Classification System (NAICS), encompassed public services including electric power, natural gas, steam supply, water supply, and sewage removal.[[1]](#endnote-1) Utility companies managed large-scale infrastructure and delivered essential services to both residential and commercial customers. In 2014, with the utility sector in a state of transformation, organizations faced massive environmental shifts including demands for environmental sustainability and decarbonization, challenges in adapting to new technologies, and significant business model changes such as the decentralization of data management.[[2]](#endnote-2) In order to succeed in the face of such large shifts, utility providers needed to respond with substantive or even disruptive innovations. With any changes, utility providers needed to carefully consider possible impacts to operations, assets, regulation requirements, and, last but not least, stakeholders.

One primary area of innovation was a move towards more energy-efficient electricity service, which involved “solutions for measurement, such as metering and monitoring, as well as dynamic grid operations and consumer involvement.”[[3]](#endnote-3) Given the pressure of industry changes, it was paramount that utilities responded by adopting emerging technologies in operational areas including demand response, optimization of asset use, and the timely detection and mitigation of issues.[[4]](#endnote-4)

The Electricity Market in Alberta

Alberta’s electricity market was comprised of three primary areas—generation, transmission/distribution, and retail (see Exhibit 1). Alberta’s market was unique compared with other provincially owned and operated utility companies in Canada. In contrast to these, the Alberta market operated as a “power pool” market, or a wholesale system, through which the price for electricity was established on an hourly basis. This hourly price determined the revenue for generators as well as the cost to customers.[[5]](#endnote-5) Alberta’s hourly pricing model reflected short-term events like outages and extreme weather, which created volatility.[[6]](#endnote-6) Longer-term pricing was the norm for the industry and was more stable because it resulted from averaging hourly prices. With longer-term pricing, price changes were reflective of “big picture” events such as provincial demand growth, supply additions, and sustained changes in natural gas prices due to its use as a fuel for many electricity generators.[[7]](#endnote-7)

Regulatory Environment

After deregulation of the Alberta utilities industry in 2001, the market was governed by a large number of laws and government policies, which created a highly complex and nuanced regulatory environment. The overall direction of the deregulated energy and wholesale electricity market was determined by the DOE. Market governance and the roles of key agencies were defined by two main pieces of legislation: the *Electric Utilities Act* (2003)[[8]](#endnote-8) and the *Alberta Utilities Commission Act* (2007).[[9]](#endnote-9) The key agencies included the Alberta Electric System Operator (AESO), the AUC, and the Market Surveillance Administrator. Together, these agencies were responsible for the “development, operation and management of the markets and transmission infrastructure, as well as surveillance over behaviour.”[[10]](#endnote-10) Additionally, the Utilities Consumer Advocate (UCA) and other intervener groups represented the interests of electricity and natural gas consumers and intervened in regulatory applications submitted to the AUC and in utility rate hearings.[[11]](#endnote-11)

With the prices of electricity no longer regulated, electricity generators sold their power through the AESO. The AESO was responsible for operating the “power pool” in a manner that was fair, efficient, and openly competitive. It established and enforced many policies and procedures for market participants. It was responsible for overseeing the development of, and access to, the transmission system, providing the “safe, reliable and economic operation of the Alberta Interconnected Electric System (AIES) and promoting a fair, efficient and openly competitive market for electricity.”[[12]](#endnote-12)

The AUC was responsible for adjudication related to industry standards, including the approval or denial of transmission and distribution applications and the application of penalties for non-compliance of standards. In addition, the AUC approved the construction, connection, and operation of new transmission facilities and all of the costs incurred by transmission facility owners to provide their services. In addition to overseeing transmission facility owners, the AUC also oversaw operation costs and distribution rates for investor-owned and certain municipality-owned distributors, referred to as “wire owners.” Costs incurred to wire owners for “the design, maintenance, construction and financing of the electric system that deliver[ed] energy to a customer’s home” were recovered by customers through a tariff.[[13]](#endnote-13) However, the AUC had jurisdiction only over customer rates for electricity from wire owners. Customers were also able to purchase electricity from a variety of retailers through a competitive contract. If customers did not choose a retailer, they automatically received service from the regulated rate option provider in their area, over which the AUC had jurisdiction.[[14]](#endnote-14) In summary, the electricity regulatory environment was highly complex, and the AUC had to be rigorous in reviewing and adjudicating regulatory applications to ensure that costs and rates were reasonably justified.

Smart Grid Technology

In terms of smart grid innovation across Canada, by 2014, approximately CA$368 million[[15]](#endnote-15) had been invested in 37 smart grid technology projects across 24 companies, six of which were Canadian utilities. The nation’s utilities, in particular, were considered to be the test beds of innovation for achieving a clean, reliable, and sustainable electricity supply that was supported by smart grid systems.[[16]](#endnote-16) Companies and a few utilities in Quebec, Ontario, Saskatchewan, British Columbia, and Alberta either had already deployed or were in the process of deploying some form of AMI.[[17]](#endnote-17) Amidst industry changes, two meter-reading technologies were most prevalent: AMR and AMI.

AMR technology used electric metering devices that enabled the remote collection of data on electricity usage, the status of meter and line functionality, and even diagnostics. Technicians were able to collect data from AMR units electronically by just driving by the units. AMR thus eliminated the need for meter readers to walk from property to property, manually reading meters and writing down the readings, which then had to be manually keyed into the system.[[18]](#endnote-18) Furthermore, with the additional expense and installation of fixed networks, data from AMR meters could be automatically transferred to a central database to be used for multiple purposes including billing and troubleshooting.[[19]](#endnote-19) Fixed networks thus eliminated the need for drive-by reading. Reasonably priced relative to other meter-reading technologies, AMR promised to increase efficiency, decrease safety concerns, and reduce labour costs. AMR did not, however, mean laying off employees because manual meter readers would be re-trained to support AMR. Because AMR technology was unit based rather than system based, an additional benefit of AMR was that the electronically read meters could replace manually read meters over time.

Unlike AMR, AMI encompassed not only meters but also communication networks that enabled two-way communication between customer sites and the AMI host system (i.e., the service provider).[[20]](#endnote-20) From the host system, data could be sent to the meter data management system for processing (i.e., billing), analysis, and storage.

Despite its greater up-front cost, AMI had the potential to deliver positive results for consumers, utilities, and the community. There were both short-term and long-term financial benefits associated with AMI including cost reduction in managing and maintaining equipment, improvements in inventory management, and the ability to minimize outages and restoration expenses. Utility providers were better able to manage outages because AMI technology could recognize, immediately, when and where outages occurred, enabling faster repairs. Another key benefit of AMI was the increased efficiency and quality in meter data collection—the ability to gather accurate and real-time feedback, provide remote connection and disconnection, better conduct utility asset management, and detect energy theft. Like AMR, AMI also effectively eliminated the need to collect meter readings as well as the associated vehicles and overhead of fleet management. As with AMR, EPCOR’s manual meter readers would be transitioned to support AMI. Not having to manually read meters meant much safer working conditions for these employees.

AMI also enabled higher-quality services for both customers and communities. For customers, AMI brought greater value through its ability to rapidly flag meter failures, improve billing accuracy, offer flexible billing cycles, and produce customer profiles for developing energy efficiency/demand response programs. These benefits translated to more pricing and service options for consumers. Communities also reaped the reward of AMI through more efficient energy distribution and utilization, resulting in a reduction of the overall environmental impact. A primary drawback of AMI was that it required an entire system change (e.g., all meters plus additional infrastructure) at once, which involved a significant capital expenditure.

The Company

History

EPCOR was founded in 1891 in Edmonton, Alberta, as Canada’s first municipally owned electric utility. It was established as a stand-alone company in 1996 and provided electricity and water products and services to customers. Throughout its history, EPCOR offered competitive power systems, transportation electrical systems, energy efficiency consulting, and utility support. EPCOR’s stated goals were to offer clean water and wastewater services and safe, reliable electricity.

EPCOR’s organizational structure was unique. The company operated as an incorporated business, but with a single shareholder—the City of Edmonton. As a component of its unique organizational structure, EPCOR was governed through an independent board of directors.

In 2014, EPCOR’s products and services included the following:

* Alberta-wide electricity services (rate-regulated and contract electricity services) to approximately 600,000 residential and small commercial customers
* distribution of 13.5 per cent of Alberta’s energy consumption to about 369,000 residential and commercial customers in Edmonton
* water, wastewater, and distribution services
* water operations in Arizona and New Mexico, serving 22 communities and seven counties

EPCOR hoped to achieve its vision of becoming a premier essential services company by focusing on the values of people, health, safety and environment; operational excellence; customers and stakeholders; and growth. Given the nature of EPCOR’s core business of providing essential services to the communities in which it operated, community investment and environmental stewardship were also key focuses for the business.

Metering Operations

EDTI was considered a wire owner and was the operating company responsible for building and maintaining the electricity distribution and transmission infrastructure in Alberta. EDTI owned and operated approximately 30 substations and thousands of circuit kilometres of transmission cables and distribution lines.

One of EDTI’s primary functions was to manage and collect data on electricity usage data through meter reading. To maintain meter operations, EDTI employed a large number of meter installers, meter readers, and other meter operations staff. EDTI’s meter installers entered customer premises to install or replace meters, connect or disconnect electricity services, and perform meter inspections. Meter readers were required to physically visit residential or commercial sites to manually read and record cumulative data from the meters on a monthly basis. As a quality control measure, EDTI was also required to periodically review and compare meter reads.[[21]](#endnote-21) The safety of meter installers and meter readers was a key concern for EDTI because there were very real risks and hazards involved in entering customer properties and premises on a day-to-day basis. This was significant for EDTI, particularly because of EPCOR being “fully committed to the protection of the environment and the health and safety of its employees, customers, and stakeholders.”[[22]](#endnote-22)

Competitors

Alberta customers had a choice of receiving electricity either through a regulated rate option or by signing a competitive contract for electricity provided through retail services. Customers who did not sign a competitive contract would automatically receive retail services from EPCOR Energy Alberta GP Inc., a subsidiary of EPCOR. Thus, EPCOR’s main competitors were other retailers who provided competitive contracts for customers. However, the AUC regulated the amount of infrastructure that could exist in any given area. Therefore, these competitive retailers worked with EPCOR to use its existing infrastructure to provide customers with service.

Since EPCOR was the default service provider of electricity in Edmonton, much due diligence was in place to ensure that customers were informed of their ability to choose among multiple utility providers. Through Alberta’s *Code of Conduct Regulation*, EPCOR informed all customers or potential customers that they were free to choose any retailer for their utilities through the “Fair Competition Statement.”[[23]](#endnote-23)

The Issue

Stakeholders and Their Concerns

A number of stakeholders were involved in the utilities industry. In making his business case for smart grid technology, Reimer had to ensure a proper balance of stakeholder engagement, defined as “the process by an organization to engage relevant stakeholders for a clear purpose to achieve accepted outcomes.”[[24]](#endnote-24) A number of stakeholders were involved, and their concerns and the relationships among stakeholders were complex (see Exhibit 2).

Alberta Policy Maker—Department of Energy

Alberta’s DOE was the governmental policy maker for Alberta’s energy matters. Since smart grid technologies heavily affected Alberta’s energy focus, the DOE undertook numerous initiatives that impacted smart grid technologies in Alberta. In May 2008, the DOE submitted a discussion paper that presented the benefits of an AMI system. In December 2008, the DOE announced the “Provincial Energy Strategy: Launching Alberta’s Energy Future,” which promoted smart metering and the “migration of electrical meters to advanced metering infrastructure.”[[25]](#endnote-25) The DOE’s main concern was the impact that a smart grid transition would have on customers.

Alberta Regulator—Alberta Utilities Commission

Since a policy regarding smart grid or AMI was not yet in place, the AUC had examined tariff applications, which presented the benefits of AMI to customers. The AUC’s focus was on the costs and benefits to customers, as well as on how or when costs for a smart grid transition would be recovered.

Customers

Ultimately, it was the customers who would pay for, and benefit from, smart grid technologies like AMR or AMI. Either of the two technologies meant greater energy reliability, more cost-effective energy delivery, and more timely information on energy usage, which would encourage and enable customers to reduce energy consumption. The cost of capital investments in infrastructure would be included in the delivery charge on customers’ bills. To date, there had been little direct communication with consumers regarding smart grid technology.

Some customers had varying concerns surrounding the use of smart meters. They were particularly concerned with the health and safety impacts of the new meters. They were also concerned with the security and privacy of personal information, as well as cost considerations. A significant public challenge to smart grid technology deployment was the concern that radio frequency radiation emitted by wireless smart meters would result in negative health effects.[[26]](#endnote-26) Another safety concern regarded the numerous AMI smart meter fires that had been reported in Canada and the United States.[[27]](#endnote-27)

EPCOR Employees and IBEW Local 1007

Employees of EPCOR who would be affected by changes to meter reading included EDTI meter readers and installers—members of the International Brotherhood of Electrical Workers (IBEW) Local 1007. The increasing safety concerns for EDTI meter readers, who were required to enter customer premises, would continue until all meters could be read remotely. Safety concerns also existed for EDTI meter installers, who were required to enter customer premises to disconnect customers’ electrical services because of non-payment. However, implementing smart meters meant that these types of employees would no longer be required. This change was thus a major concern for EPCOR employees in IBEW Local 1007, whose positions would become obsolete, likely resulting in major layoffs.

Shareholder—City of Edmonton

As EPCOR’s sole shareholder, the City of Edmonton was primarily concerned with receiving a return on its investment. And the city wanted, of course, to ensure that any new project would benefit the residents of Edmonton.

Utilities Consumer Advocate

The UCA represented the interests of Alberta’s electricity and natural gas consumers. The UCA ensured that consumers were provided with the information, representation, and protection they needed to make knowledgeable decisions in Alberta’s deregulated electricity markets. For example, the UCA mediation team helped to resolve consumer complaints with utility companies that consumers were unsuccessful in resolving on their own.[[28]](#endnote-28)

In summary, EDTI needed to understand the effects that smart grid technologies would have on each of these important and varied stakeholders. To gain this understanding, EDTI had to anticipate and consider each stakeholder’s needs and interests.

Previous Regulatory Decisions

In December 2009, Reimer worked with several other EPCOR departments on an application to the AUC that included a business case for introducing AMI to EPCOR’s portion of the Alberta energy grid. In the application, EDTI provided evidence of several cost, efficiency, staff safety, and environmental benefits. Specifically, EDTI focused on AMI’s reduced cost of meter operations (a savings of around $2 million per year), the reduction of safety concerns for meter installers and readers required to enter customer premises, and the financial and service benefits to customers. These benefits, however, had to be weighed against the up-front capital expenditure of implementing AMI—a cost of over $70 million.

After submission of the application and business case, the DOE directed the AUC to hold an inquiry on how smart grid technology could be used in Alberta. On April 20, 2010, the AUC launched its Notice of Inquiry with a report due to the Minister of Energy by December 25, 2010. At the rate hearings for EDTI’s tariff application, Reimer was questioned for two and a half days on why EDTI should be permitted to move forward with AMI installation. At these hearings, interveners argued that EDTI’s AMI project would not align with the recommendations that had been made in the forthcoming Smart Grid Inquiry report. In addition, Alberta’s Rural Electrification Associations lobbied government representatives against the smart grid initiative due to its high costs.

On October 28, 2010, the AUC rendered its decision on EDTI’s AMI project, officially denying the application. However, on June 1, 2011, the Smart Grid Inquiry report was made public, presenting a significant turn of events for EDTI. The cover letter to the report by the Minister of Energy stated that, while the Department of Energy would not put in place mandatory requirements for smart meters, neither would utilities be precluded from implementing smart grid initiatives on their own accord.

Measurement Canada Changes

Measurement Canada regulated every measurement device sold in Canada, including the meters used by EPCOR. It determined what types of meters were legal for use, the lifespan of such use, and the rules by which measurement devices were to be statistically sampled in order to determine their accuracy.[[29]](#endnote-29)

In 2010, Measurement Canada announced new regulations for compliance testing and meter replacements.[[30]](#endnote-30) Under the new regulations, organizations that performed meter testing (i.e., EDTI) were required to conform to new testing rules by January 1, 2014.[[31]](#endnote-31) The new specifications increased the sampling number of meters that were required to be pulled from service sites to be tested. The new specifications also reduced the time that meters could remain in service and introduced financial penalties for failed meter tests. This was a significant change from past specifications, which had allowed for re-verification and for meters to be left in service until a group sample test failure occurred. Furthermore, previous specifications had not carried any financial penalties.[[32]](#endnote-32) The regulation changes posed significantly increased costs to EDTI for additional compliance sampling and meter replacement costs. These costs, however, could be avoided with the implementation of smart meters.

Technological Advancements

Changes in the smart grid technology market had taken place since the AUC denied EDTI’s application for AMI in 2010. By 2014, the cost of smart meters had decreased from $150–$200 per meter to around $100 per meter. Additionally, service disconnect switches were now standard for smart meters, so an additional $30–$50 fee was no longer incurred. These changes significantly reduced EDTI’s costs to deploy AMI meters.

Need for Change

After weighing the many possible benefits of moving to smart grid technology, Reimer struggled with how to proceed. As 49 per cent of meters across Canada were already AMI meters, Reimer could not help but feel that EDTI was behind the times. EDTI could continue its current practice of installing AMR meters for new installations and when old meters needed to be replaced; this approach would result in the gradual replacement of all non-AMR meters over 20 years. Reimer also estimated that within 12–15 years, EDTI could begin to implement the limited use of drive-by technology where high concentrations of AMR meters could supplant the need for meter readers. Thus, by the end of the 20-year replacement strategy, EDTI would be able to utilize a full drive-by solution.

Another alternative was for EDTI to undertake a project to replace all non-AMR meters for its customers over three years, allowing a full drive-by solution to be implemented much sooner. Vehicles outfitted with collection devices could drive through neighbourhoods on a monthly basis to remotely collect meter readings. Alternatively, EDTI could also implement an AMR solution with a fixed network, meaning that remote collector devices could be affixed in strategic locations, transmitting meter readings to the central system. This would eliminate the need for vehicles to drive by homes, but it would require that EDTI undertake a major project to select a vendor and implement an AMR network system over a period of two years.

Lastly, Reimer considered whether a fully integrated AMI solution was the way to go, even though it had been rejected by the AUC in 2010. The AMI project still carried the largest capital investment of all the alternatives. However, Reimer believed that AMI was still the most future focused and sustainable option, given the prevalence of AMI across North America and its numerous benefits to the business, consumers, and communities.

To aid his decision-making process, Reimer performed a complex financial analysis for both the cash flow and the costs of each option (see Exhibit 3). In the previous application, Reimer had only analyzed cash flow and had not accounted for net present value, which factored in estimated inflation rates. The new financial analysis also considered the long-term financial implications of each option, estimating both cash flow and costs through to the year 2023. Costs were particularly important for Reimer to analyze because they were directly passed on to customers. Most importantly, the new financial analysis demonstrated the negative impact that the status quo alternative would have on both cash flow and costs, which was apparent in two main factors. The first was the increased costs for compliance sampling and meter replacements to keep EDTI compliant with Measurement Canada’s requirements beginning in 2014. The second was that customers would not benefit from the lower costs that automation would provide.

There were clear benefits and drawbacks for each alternative, but Reimer had to decide into which of the options he should invest time and effort for building a business case. Which of the alternatives would be most beneficial for the business and its stakeholders in the long run? What was most likely to be accepted by the stakeholders, and how could EDTI facilitate this? What kind of business case would need to be presented to the AUC for a project to be approved?

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EXHIBIT 1: ELECTRICITY SUPPLY CHAIN IN ALBERTA

|  |  |  |  |  |
| --- | --- | --- | --- | --- |
|  | Generation | Transmission | Distribution | Retail |
| Industry Structure | Deregulated | Regulated | Regulated | Regulated and Deregulated |
| Regulating and Intervening Bodies | Alberta Electric Systems Operator  Alberta Utilities Commission  Market Surveillance Agency  Department of Energy | | Utilities Consumer Advocate  Consumers’ Coalition of Alberta  City of Edmonton | |

Source: Created by the authors using data from company documents.

EXHIBIT 2: KEY STAKEHOLDERS

|  |  |  |
| --- | --- | --- |
| **Stakeholders** | **Impact on Electricity Operations** | **Concerns with Smart Grid** |
| Alberta Policy Maker (Department of Energy) | * The governmental policy maker for Alberta’s energy matters: smart grid technologies heavily affect Alberta's energy focus. | * Effects on customers from the transition |
| Alberta Regulator (Alberta Utilities Commission) | * Alberta’s independent utility regulator controls the utilities sector, natural gas, and energy markets in order to protect social, economic, and environmental concerns. | * Is this program of benefit to customers? * What is the net present value of a new smart grid project? * How/when will these costs be recovered? |
| Customers | * The cost of capital investments in infrastructure will be included in the delivery charge on customers’ bills. | * Health and safety concerns related to AMI * Radio frequency radiation * Meter fires * Security & privacy of personal information |
| EPCOR Utilities Inc. Employees | * EPCOR Utilities Inc.’s employees who would be affected by changes to meter reading are members of IBEW Local 1007—meter readers. | * Current state: safety concerns for meter readers who have to enter customer premises * With AMR or AMI implementation: do meter reader positions become obsolete? |
| Independent System Operator (the Alberta Electric System Operator) | * The Alberta Electric System Operator is focused on promoting a fair, efficient, and openly competitive market for electricity. | * A predictable and sustainable electricity market |
| Market Surveillance Administrator | * The Market Surveillance Administrator monitors Alberta’s electricity and retail natural gas markets to ensure proper, fair, and efficient operations. | * Efficient operations |
| Shareholder (City of Edmonton) | * The City of Edmonton is EPCOR Utilities Inc.’s sole shareholder. | * Return on investment * What benefits will residents of Edmonton see? |
| Utilities Consumer Advocate | * The Utilities Consumer Advocate represents the interests of Alberta’s electricity and natural gas consumers. | * Ensuring consumers benefit from the project * Ensuring customer concerns are addressed * Ensuring that any costs added are fair |

Note: IBEW = International Brotherhood of Electrical Workers; AMI = advanced metering infrastructure; AMR = automatic meter reading. Source: Created by the authors with data from company documents.

EXHIBIT 3: analysis summary of long-term cash flow and Costs for each alternative

|  |  |  |  |  |
| --- | --- | --- | --- | --- |
| **Alternative** | **Benefits** | **Drawbacks** | **Net Cash Flow**  **($CA millions)** | **Costs**  **($CA millions)** |
| Alternative 1: Status Quo | * No capital investment is required. | * Manual meter reading is required until all meters replaced with AMR (approximately 20 years). | −26.36 | 21.85 |
| Alternative 2: AMR (Drive-By Reading) | * Drive-by reading replaces manual reading. | * Capital investment is required. * Vehicle fleet is still required. | 30.01 | −26.88 |
| Alternative 3: AMR (Fixed Network: Automated Reading) | * Meter reading is automated. * Allows meter and line status and diagnostics. | * Capital investment is required. | 32.50 | −28.50 |
| Alternative 4: AMI | * Provides two-way communication. * Allows for remote repair of system malfunctions (i.e., outages). * Allows for more accurate and flexible billing. * Allows for more efficient energy usage. | * Large capital investment is required. | 36.11 | −33.67 |

Note: AMI = advanced metering infrastructure; AMR = automatic meter reading.

Source: Created by the authors using data from EPCOR Distribution & Transmission Inc., *Capital Business Case and Engineering Study, Distribution Capital Tracker: Advanced Metering Infrastructure, Appendix A-19*, February 28, 2014, 41.

EndNotes

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