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# Background Report on the Ontario Energy Sector

Mowat Centre

ONTARIO'S VOICE ON PUBLIC POLICY



School of Public Policy & Governance  
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# 1] Introduction

Mowat Energy, the energy hub of the Mowat Centre, is conducting research into the implications of the advent of significant distributed energy resources (DER) for the operation of the Ontario energy market. This phenomenon, which is happening all over the world, creates challenges and opportunities for market participants. There is an opportunity, and possibly a requirement, for regulators and lawmakers to re-consider aspects of the current approach to regulation and governance in the electricity sector.

Mowat Energy is specifically seeking input from international experts. It is hoped that the experience of other jurisdictions, with different regulatory architectures and histories, may provide insights into how best to accommodate DER in Ontario. Fresh perspectives from those who come unencumbered to the Ontario environment may provide unique and valuable analysis of the options for reform.

This Background Paper has been prepared to provide the sophisticated reader with an objective and reasonably comprehensive representation of the key elements of the Ontario electricity market. It describes the legal framework under which the energy market operates, the regulatory environment, the policy context and relevant history. It is hoped that this Background Paper will enable those reading it to move relatively quickly to the analysis we are seeking.

## 2] Developments in Ontario's energy sector

### 2.1 CURRENT PICTURE

#### 2.1.1 Quick overview of Ontario

Ontario is Canada's second largest province in area (after Québec). The population is the largest in Canada at approximately 13,750,000 (2015), with about 94 per cent concentrated in Southern Ontario relatively close to the St. Lawrence River and near the U.S. border. Most people, about 86 per cent, live in urban areas, such as Toronto, Ottawa, London or Windsor.

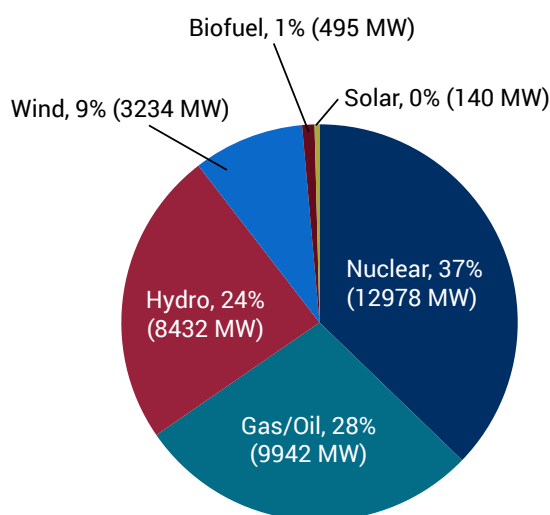
There are several climate zones in Ontario, with the north, which is sparsely populated, being considered to be sub-Arctic; the southwestern and southern areas around Toronto and the Niagara Peninsula are relatively temperate with hot, humid summers and cold but moist winters. Snow fall can be heavy in southwestern Ontario, and the area is referred to as the "Snow Belt." The central and eastern portions of Ontario also have warm summers (although traditionally with shorter periods of high temperatures than the southern and southwestern areas) and the winters tend to be longer and colder, also often with significant snow. Electricity consumption is highest in urban areas at the height of the summer, when air conditioning is in use.

#### 2.1.2 Electricity mix in Ontario

Ontario's electricity energy supply mix has evolved considerably since markets were opened in 2002, with renewable sources of energy playing an increasingly important role. A political decision was taken to eliminate the coal-fired generation fleet, and that has now been accomplished.

Indeed, over 12,400 megawatts (MW) of additional electricity supply has been added, much of it from renewables and natural gas. There has also been significant investment in infrastructure, especially in nuclear units. While the total amount of electricity generation available is contingent on several factors, including facility outages and planned or unplanned maintenance, the energy supply mix is shown in Figure 1.

FIGURE 1 Ontario electricity supply overview



Source: Independent Electricity System Operator, "Supply Overview." At <http://www.ieso.ca/Pages/Power-Data/Supply.aspx>.

## 2.2 HISTORIC MODEL

For over a century, energy in Ontario has been centrally planned and managed. Consumers were all treated as having the same needs, and were often ignored and seen only as “rate payers.” Successive governments maintained a “postage stamp” rate architecture, in that everyone pays the same rate regardless of location, so that there was no costs-driven locational component to rates setting. Low electricity rates formed part of a broader industrial policy, and at times rate freezes were imposed, regardless of cost drivers. The centrally managed model worked at this time as provincial consumers all had similar needs despite their specific location – they depended on the system to ensure reliable and relatively cheap access to energy. This model may need to change. It is conceivable that locational cost drivers may give rise to locational rates differentiation. Current developments in the energy sector in Ontario and throughout the world are forcing a reconsideration of how energy is supplied and consequent consumer engagement.

In Ontario, as elsewhere, the energy market, consumer needs and technological developments are pointing to a cleaner, less centralized and more flexible energy system. Ideally, such a system would be more responsive to customer interests and local needs.

It is integral to our research that we understand the implications of this shift and how best to facilitate an evolution to a new, more responsive paradigm.

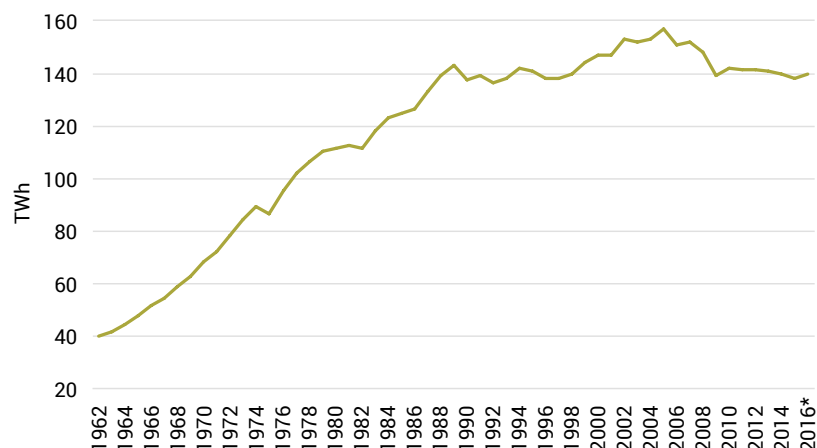
## 2.3 SIX DEVELOPMENTS DRIVING THIS SHIFT

### 2.3.1 Flat consumption demand

Electricity consumption is flat. As a result of economic and industrial changes, as well as increases in energy efficiency, Ontario electricity consumption has seen no significant growth since 2009, and this is not expected to change in the immediate future (Figure 2).

With flat demand and new generation resources expected to come online in the coming years, Ontario is expected to be able to meet electricity demand up to at least 2024.<sup>1</sup>

**FIGURE 2** Ontario electricity consumption between 1962 and 2014, and projections to 2016



\* Forecasts

Source: Independent Electricity System Operator, *18 Month Outlook: An Assessment of the Reliability and Operability of the Ontario Electricity System from July 2015 to December 2016*, June 22, 2015. At [http://www.ieso.ca/Documents/marketReports/18MonthOutlook\\_2015jun.pdf](http://www.ieso.ca/Documents/marketReports/18MonthOutlook_2015jun.pdf); Independent Electricity System Operator, “Demand: Total Annual Ontario Energy Demand.” At <http://www.ieso.ca/Pages/Power-Data/Demand.aspx>; 1962 to 1996 figures from various Ontario Hydro statistical reports.

1 North American Electric Reliability Corporation, 2014 *Long-Term Reliability Assessment*, November 2014, pp. 63-67. At [http://www.nerc.com/pa/RAPA/ra/Reliability%20Assessments%20DL/2014LTRA\\_ERATTA.pdf](http://www.nerc.com/pa/RAPA/ra/Reliability%20Assessments%20DL/2014LTRA_ERATTA.pdf).

Natural gas demand has also been flat since 2000. Any expected increase in gas demand up to 2020 is almost entirely due to an anticipated increase in gas-fired electricity generation.<sup>2</sup> Yet given stagnant electricity consumption, growth in gas-fired electricity generation is uncertain.

### 2.3.2 Regional areas of high demand growth

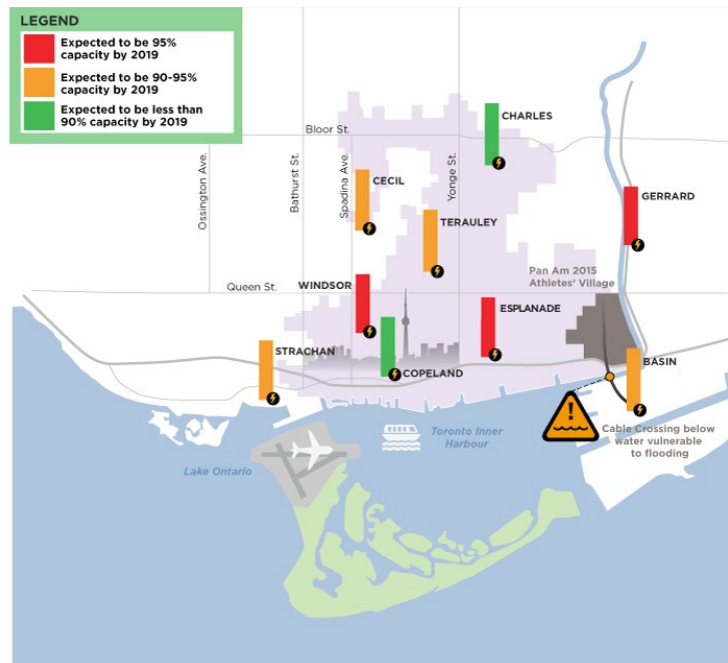
While province-wide electricity demand is flat, there are some high population growth regions where energy needs are growing. Ontario's urban growth is leading to denser development patterns, a trend found throughout North America.<sup>3</sup> In Ontario, the public's interest in urban living, as well as a densification policy,<sup>4</sup> means that population growth will primarily be in the Greater Toronto Area and around Ottawa.<sup>5</sup>

Thus, at the same time that provincial consumption will be flat, almost 80 per cent of downtown grid stations in Toronto will be at capacity by 2019 due to increased population growth and higher electricity demand (Figure 3). A similar pattern characterizes Ottawa.

While this demand is primarily an urban phenomenon, other regions, such as the northwest, could also see an increase in energy demand as a result of expected new mining and forestry operations.<sup>6</sup>

This growth in urban energy demand will also put additional pressure on the system during periods of peak demand – such as on hot summer days when air conditioning is turned up high. In Toronto, for example, demand for electricity during these peak periods is expected to grow by over one per cent a year.<sup>7</sup>

**FIGURE 3** Expected capacity of electricity substations in Toronto by 2019



Source: Toronto Hydro, "Grid Challenges." At <http://www.torontohydro.com/sites/electricsystem/GridInvestment/TorontosGrid/Pages/GridChallenges.aspx>

2 Ontario Energy Board, *Staff Report to the Board on the 2014 Natural Gas Market Review*, EB-2014-0289, March 31, 2015, pp. 9, 10 and 24. At [http://www.ontarioenergyboard.ca/oeb/\\_Documents/EB-2014-0289/Staff\\_Report\\_to\\_the\\_Board\\_2014\\_NGMR\\_EB-2014-0289.pdf](http://www.ontarioenergyboard.ca/oeb/_Documents/EB-2014-0289/Staff_Report_to_the_Board_2014_NGMR_EB-2014-0289.pdf).

3 M. Moos, R. Walter-Joseph, M. Williamson, T. Wilkin, W. Chen, and D. Stockmal, *Youthification: The New Kid on the Block*, 2015. At <http://generationcity.uwaterloo.ca/publications/>.

4 Ministry of Municipal Affairs and Housing, *Our Region, Our Community, Our Home: A Discussion Document for the 2015 Co-Ordinated Review*, 2015. At <http://www.mah.gov.on.ca/AssetFactory.aspx?did=10759>.

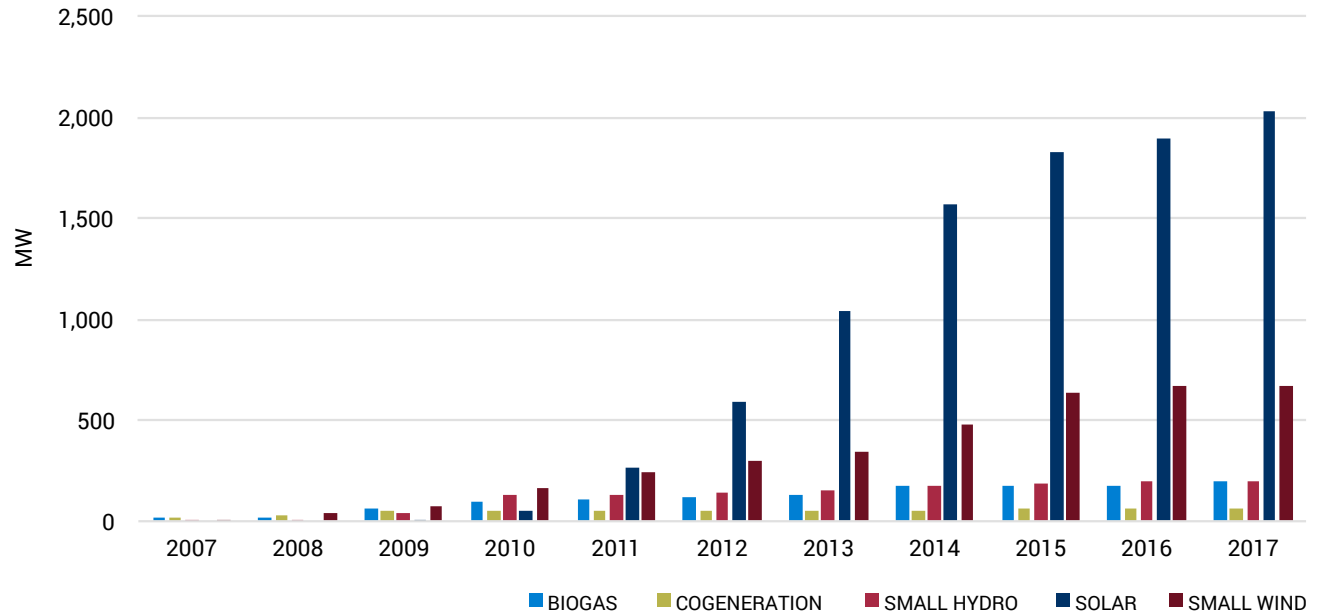
5 Ministry of Finance, *Ontario Population Projection, 2013-2041*. At <http://www.fin.gov.on.ca/en/economy/demographics/projections/>.

6 Independent Electricity Systems Operator, *Northwest Region Scoping Assessment: Outcome Report, January 28, 2015*. At [http://www.ieso.ca/Documents/Regional-Planning/Northwest\\_Ontario/Final\\_Northwest\\_Scoping\\_Process\\_Outcome\\_Report.pdf](http://www.ieso.ca/Documents/Regional-Planning/Northwest_Ontario/Final_Northwest_Scoping_Process_Outcome_Report.pdf).

7 Independent Electricity System Operator, *Central Toronto Area: Integrated Regional Resource Plan*, April 28, 2015, pp. 25-27. At <http://www.ieso.ca/Pages/Ontario's-Power-System/Regional-Planning/Metro-Toronto/default.aspx>.



**FIGURE 4** The growth in embedded generation in Ontario



Source: Independent Electricity System Operator, *Ontario Demand Forecast*, December 2015. At [http://www.ieso.ca/Documents/marketReports/18Month\\_ODF\\_2015dec.pdf](http://www.ieso.ca/Documents/marketReports/18Month_ODF_2015dec.pdf).

### 2.3.3 Consumers are investing in distributed energy resources

Distributed energy resources (DER) can encompass a number of different things, including renewable generation, such as wind and solar, combined heat and power plants, energy storage, demand response technologies, as well as conservation and demand management programs. The defining characteristic is that the DERs are much smaller than centralized energy systems, and in many cases are located on consumer premises.

Led by solar, small-scale distributed electricity generation in Ontario has more than doubled over the past five years (Figure 4).

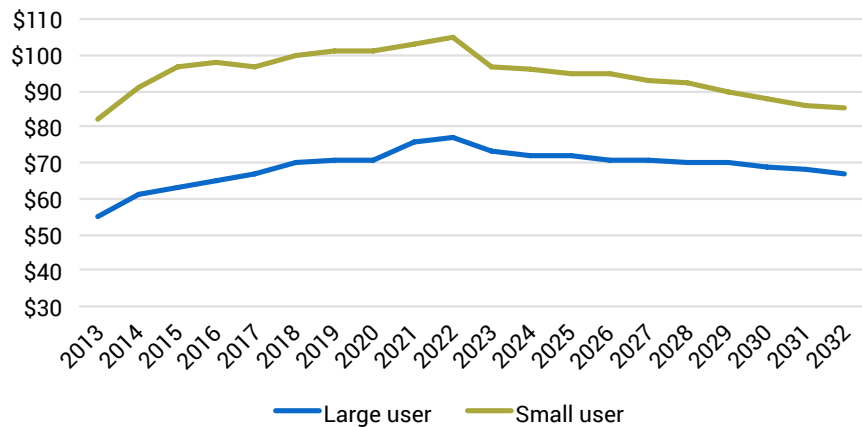
### 2.3.4 Prices

Since the start of the U.S. shale gas boom in 2008, prices for electricity and natural gas for Ontario consumers have diverged, with electricity prices continuing to increase, while natural gas prices have remained relatively flat, and well below pre-shale price projections.

Electricity prices in Ontario have been difficult to predict given the rapid evolution of our energy market, and its hybrid nature, including the role of long-term contracts for the vast majority of generation, and the anticipated nuclear refurbishments. The estimates, however, show a levelling off in real terms (Figure 5).

At the same time that electricity costs are increasing in the shorter term, natural gas prices are expected to continue to be relatively stable and low. Average Dawn Hub prices, the main natural gas trading hub for Ontario, are expected to rise from an estimated \$4.80/MMBtu in 2014 to \$5.68/MMBtu in 2020. Despite this increase, average natural gas prices in 2020 would still be lower than before the shale gas boom started in 2008-9.<sup>8</sup>

**FIGURE 5** Projected all-in electricity prices, in 2012\$/MWh



Source: All-in prices are the sum of the Hourly Ontario Electricity Price (HOEP) plus the Global Adjustment (GA) and exclude grid charges. The large user rate is an average rate for Class A customers, and the individual rate for each Class A customer would depend on its specific usage patterns. Ontario Power Authority, "GA Class A and Class B Unit Rates," *Cost of Electricity Service 2013 LTEP: Module 4, Excel Data File*, January 2014. At <http://powerauthority.on.ca/sites/default/files/planning/Data-Tables-Module-4-Cost.xlsx>.

Rising electricity costs are driving customers to take a more active role in managing their energy use, and indeed their relationship with the utility. According to a survey by Deloitte, 79 per cent of industrial and commercial customers in the U.S. say that reducing energy costs is a necessity, and they are investing substantial part of their capital budget to that task. While much of this investment is in traditional energy management systems, such as motion and time sensors and new HVAC equipment, businesses say that they are increasingly interested in more innovative solutions to managing their energy, and are experimenting with new ideas.<sup>9</sup> There is every reason to believe that this phenomenon is equally prevalent among Ontario customers.

### 2.3.5 Utilities need to invest in infrastructure

It is generally acknowledged that the energy infrastructure in Canada needs significant re-investment. Ontario is no exception. It has been estimated that, on average, \$15 billion a year will need to be invested over the next two decades just to maintain current service levels.<sup>10</sup> Aging assets are a problem in some regions. Hydro Ottawa, for example, estimates that 30 per cent of its assets are at the end of their operating life, and it is planning to devote a third of its capital budget over the next five years to replacing outdated equipment.<sup>11</sup> Toronto has shown a similar requirement.

8 Ontario Energy Board, *Staff Report to the Board on the 2014 Natural Gas Market Review*, EB-2014-0289, March 31, 2015, pp. 11 and 24. At [http://www.ontarioenergyboard.ca/oeb/\\_Documents/EB-2014-0289/Staff\\_Report\\_to\\_the\\_Board\\_2014\\_NGMR\\_EB-2014-0289.pdf](http://www.ontarioenergyboard.ca/oeb/_Documents/EB-2014-0289/Staff_Report_to_the_Board_2014_NGMR_EB-2014-0289.pdf).

9 Deloitte Centre for Energy Solutions, *Deloitte Resources Survey 2015: Energy Management Passes the Point of No Return*, June 2015, pp. 6, 10. At <http://www2.deloitte.com/content/dam/Deloitte/us/Documents/energy-resources/us-er-deloitte-resources-study-series.pdf>.

10 Canadian Electricity Association, *Vision 2050: The Future of Canada's Electricity System*, March 2014, p. 37. At <http://powerforthefuture.ca/wp-content/uploads/2014/04/Vision2050.pdf>.

11 Hydro Ottawa, *2016 Rate Application*. At <https://static.hydroottawa.com/documents/corporate/regulatory-affairs/2016-2020-Rate-Application/Hydro%20Ottawa%20-%202016%20Rate%20Application.pdf>.

At the same time, extreme weather events, such as a serious ice storm in 2013, are further challenging the energy system. In 2015, 90 per cent of Canadian utilities said that they had already been affected by extreme weather, and extreme weather events are expected to increase.<sup>12</sup> Investments will be needed in new infrastructure to help improve reliability with extreme weather.

### 2.3.6 Societal expectations

Consumers are no longer passive and are making their preferences known. For example, they prefer renewable electricity<sup>13</sup> to traditional generation. In addition, engaging with the public on infrastructure projects and securing social license is becoming more necessary.<sup>14</sup>

12 QUEST, *Resilient Pipes*, June 23, 2015. At <http://www.questcanada.org/events-projects/research/rpw>.

13 Campaign Research, *Ontario and Energy, Presentation made to OEA Conference*, September 17, 2015. At [http://www.energyontario.ca/images/ENERGYCONFERENCE15/Remarks\\_and\\_Presentations/Ontario\\_\\_Energy\\_Polling\\_Presentation\\_-\\_Nick\\_Kouvalis\\_-\\_ENERGYCONFERENCE15\\_-\\_17.09.15.pdf](http://www.energyontario.ca/images/ENERGYCONFERENCE15/Remarks_and_Presentations/Ontario__Energy_Polling_Presentation_-_Nick_Kouvalis_-_ENERGYCONFERENCE15_-_17.09.15.pdf).

14 Richard Carlson and Eric Martin, *Re-energizing the Conversation: Engaging the Ontario Public on Energy Issues*, Mowat Centre, October 2014. At <http://mowatcentre.ca/re-energizing-the-conversation/>.

## 3] Ontario energy sector business models

### 3.1 INTRODUCTION

The Ontario energy sector is comprised of both private and public entities. The electricity market is overwhelmingly public, but the natural gas sector is privatized. The Ontario Energy Board (OEB) regulates provincial electrical and natural gas utilities. The OEB is responsible for setting rates and licensing all of Ontario's electricity sector participants, including transmission system operators, generators, distributors, transmitters and electricity wholesalers. The OEB also licenses all natural gas distributors, marketers, approves rates and examines the viability of natural gas pipelines.

There are three regulated natural gas utilities in Ontario, all privately owned. They have geographic monopolies and own the pipes and equipment for supplying gas. Two of these, Enbridge Gas Distribution and Union Gas Distribution, supply 99 per cent of the market, with the third, Natural Resource Gas, serving a much smaller territory. The municipalities of Kingston and Kitchener own their own respective gas distribution systems. Residential consumers have the option of purchasing their gas from either one of the gas utilities or a private energy retailer.

Ontario Power Generation (OPG) is owned by the government of Ontario and produces more than half the province's electricity. Hydro One Networks Incorporated (HONI) is the province's primary transmission systems operator, operating approximately 97 per cent of Ontario's high voltage transmission grid. The Independent Electricity System Operator (IESO) is a crown corporation<sup>15</sup> charged with operating the province's electricity market, as well as directing the operations of the bulk electrical system in Ontario. The IESO is tasked with governing the flow of electricity across the provincial transmission network owned by HONI. It is also responsible for the operation of management of Ontario's wholesale electricity market, which involves coordination with neighbouring jurisdictions as part of an integrated North American electricity market. The IESO also operates the data management system, which takes raw consumption information and organizes it for when local distribution companies bill customers. IESO also has a conservation and demand management (CDM) mandate.

The electricity distribution companies (also known as local distribution companies – or LDCs) are the product of the Ontario energy sector's history. The LDCs own and operate the distribution assets and supply electricity to customers. While there is much commonality among the companies, the form of electricity distributor company ownership delineates three distinct types of utilities: privately owned, municipally owned and provincially owned. Ownership differences translate into differences in governance priorities.

Most large municipalities, and many small ones, have their own municipally owned LDC, such as Toronto Hydro and Hydro Ottawa. Ontario has around 70 municipally owned LDCs of widely varying size, sophistication and capabilities. This large group of LDCs, many of them relatively small,

<sup>15</sup> A crown corporation is a corporation owned by the government.

presents unique problems. While the province has signalled strong support for consolidation of LDCs, progress in this area has been halting, after an initial round early on in the corporatization period. The small size of many of the utilities may present issues related to their ability to make investments in DER, and their level of sophistication. In areas not served by a municipal LDC, HONI is the local distributor. The historical role of HONI as both a distributor in the unorganized and rural areas of the province and its function as a transmitter is another distinguishing feature of Ontario's distribution system. The result is a patchwork of utilities, many small and "embedded" within HONI's sub-transmission voltage distribution network.

This section sets out the history of utility corporate structures, including the gas utilities, and examines the way these differences affect the capital planning of these LDCs.

## 3.2 GAS DISTRIBUTION COMPANIES

Ontario imports virtually all of its gas supply. The province has been well supplied with natural gas from the Western Canadian Sedimentary Basin and shale gas resources in the northeastern U.S. In recent years, American shale gas imports have displaced gas imports from Western Canada.

Ontario gas prices are generally set at the Dawn Hub, a large natural gas storage facility in southwest Ontario. Typically, Dawn Hub prices closely follow movements in Henry Hub (U.S.) prices, especially as American shale gas comprises a large percentage of supply. With the exception of a cold period in the winter of 2013/14, Ontario has not had gas supply concerns, and price volatility has dampened in comparison with the past. In the near- and medium-term, price volatility in Ontario is expected to remain low.<sup>16</sup> For Ontario gas customers the price of the commodity is a straight pass through, unless the customer elects to contract with a gas marketing retailer, in which case the price is the contract price.

While the Ministry of Energy does not play as large a role in the gas sector as it does for electricity, the government can issue directives to the OEB that impose conditions on the regulated gas utilities. As with electricity, the natural gas utilities are required by the OEB to prepare conservation plans, which are called demand side management (DSM) plans.

## 3.3 HISTORY OF THE LOCAL ELECTRICITY DISTRIBUTION COMPANIES

Prior to 1999, the electricity distribution sector was characterized by over 300 utilities varying in size from 600 to over a million customers. Ontario Hydro, the then vertically integrated generation, transmission and distribution company owned by the province, served the largest number of customers. Its distribution customers were largely in the non-organized areas of the province,<sup>17</sup> that is, in areas that were essentially rural. In addition to a small number of privately held utilities (fewer than five), there were over 300 distribution franchises structured as municipal (city) departments. Governance was via a municipal "hydro-electric" commission. The Power Corporation Act and the Municipal Act set out the legislative requirements for creating and governing these entities.

16 Ontario Energy Board, *Staff Report to the Board on the 2014 Natural Gas Market Review*, March 31, 2015. At [http://www.ontarioenergy-board.ca/oeb/\\_Documents/EB-2014-0289/Staff\\_Report\\_to\\_the\\_Board\\_2014\\_NGMR\\_EB-2014-0289.pdf](http://www.ontarioenergy-board.ca/oeb/_Documents/EB-2014-0289/Staff_Report_to_the_Board_2014_NGMR_EB-2014-0289.pdf).

17 Ontario Hydro's distribution operations were then known as "Ontario Hydro Retail."

At this time, Ontario Hydro rather than the OEB regulated these roughly 300 municipal utilities. Ontario Hydro itself was largely unregulated. Oversight, other than through government appointment of Ontario Hydro's board of directors, was limited to review of bulk power rates by the OEB, and even at that the OEB was limited to providing a report to government rather than any specific approval of rates.

In 1998, the government passed the *Energy Competition Act (ECA)* and included the *Electricity Act (EA)* as Schedule A. It also made changes to the *OEB Act* and the *Power Corporation Act*. In addition, changes were made to the *Municipal Act*, with the effect of consolidating a large number of municipalities and consequently reducing the number of municipal utilities.

As implied by its name, the purpose of the *Energy Competition Act* was to restructure the electricity sector and to introduce a competitive energy market. Ontario Hydro was divided into constituent parts: dispatch and planning (now IESO); generation (Ontario Power Generation, OPG); and distribution and transmission (HONI). The regulatory oversight of the municipal utilities was transferred to the OEB, as was regulation of high-voltage transmission rates (HONI transmission) and HONI distribution. All private utilities, except Cornwall Electric, became subject to OEB rate regulation. Initially, the bundled rates of the utilities were maintained while the utilities completed the exercise of unbundling rates according to the cost causality functions of commodity, transmission, distribution and market functions in accordance with instructions by the OEB.<sup>18</sup>

While the public focus of the *ECA* was largely on its impact on power generation and the creation of a retail power market, the associated changes to the electricity distribution sector were just as extensive. As discussed in more detail below, the legislation fundamentally altered the corporate model for municipally owned utilities. Instead of municipal departments, akin to water and sewage, they were established as stand-alone corporate entities. The process of "corporatization" was part of a policy that foresaw these utilities as profit-making entities like the privately owned distribution companies that already existed. Changes were also made to allow municipalities to create other energy-related companies.

Prior to restructuring, municipal electric utilities (then known as "MEUs") were prohibited from earning market returns on invested capital. The Ontario Hydro regulatory procedure would best have been characterized as "administered rate setting." MEUs provided costs, Ontario Hydro provided load projections, and these variables were input into an algorithmic rate model that output a set of rates.<sup>19</sup> There was no public process associated with rate approvals and final rates might be modified after discussions between Ontario Hydro regulatory staff and utility management. By design, this regulatory model made it difficult for MEUs to transfer income from distribution operations to other municipal departments. As a result, any dividends from electricity distribution would often take the form of shared assets (e.g., shared buildings and billing systems) or in non-cost derived rates. The latter took the form of "load retention rates" and other rate cross-subsidies designed by Ontario Hydro and MEUs to encourage local economic spin-off benefits.

18 The market function costs are referred to as "regulatory" costs, but this is a bit of a misnomer since they do not include the OEB's regulatory costs (which are recouped under the distribution charge), but rather the IESO's costs.

19 The model and its data were collectively known as "MUDBANK" and this asset was transferred to the OEB and used in the transition by the OEB for rate setting.

The result was that the first generation of OEB rate-making from 2001-2005, while notionally based on a price cap formula, was in fact characterized by a rate policy that sought to incorporate by annual increments market returns on invested capital. By the time the government froze electricity rates in 2002,<sup>20</sup> many LDCs (as the MEUs became known after restructuring) had yet to incorporate distribution costs into the full cost of their “market based regulated return,” or MBRR. This meant that in the initial years after lifting the rate freeze in 2005, many utilities would continue to be unaffected by the incentive rate policies of the OEB. The rate freeze also resulted in a halt to the OEB’s policy of doing an initial cost-of-service review of each of the approximately 130 utilities (post-municipal amalgamation) it had inherited from the previous regulator, Ontario Hydro. These reviews would eventually be restarted under the second generation incentive rate policy. A detailed history of electricity rate-making policies subsequent to unbundling is provided in Section 5 dealing with rate-setting in Ontario.

The OEB did not require the newly corporatized LDCs to include a return on capital in their rates. Initially, reflecting their “power at cost” heritage, a significant number of LDCs opted to run as “not for profit” or select a rate of return lower than that allowed by the OEB. At least one LDC, Thunder Bay Hydro Electricity Distribution, continues to seek rates that incorporate less than their allowed regulated return.

### 3.4 CONSOLIDATION

A large number of utility consolidations occurred immediately prior to the OEB’s acquisition of regulatory authority over the MEUs. The number of regulated utilities dropped from approximately 300 to around 130 by 2000,<sup>21</sup> then to approximately 90 by 2005, and then to about 70 in late 2015.

In the immediate period after the passing of the *ECA*, HONI acquired a large number of small service franchises for which its successor company, Ontario Hydro, had been the de facto operator. Between 2001 and 2008, HONI continued to acquire small utilities and incorporate these companies into their distribution operations.

Consolidation also occurred among municipally held utilities. PowerStream Inc. became the second largest municipally held utility through the consolidation of five former municipal utilities.<sup>22</sup> On the Niagara Peninsula, Horizon Utilities was formed from the amalgamation of two large urban utilities.<sup>23</sup> Entegrus Powerlines Inc. consolidated a number of utilities in southwestern Ontario<sup>24</sup> and Veridian Connections combined six utilities in the eastern part of the province.<sup>25</sup>

HONI also acquired one large urban utility, Brampton Hydro. HONI Brampton is operated as a separate affiliate but the government recently announced its intention to sell this utility to a

20 Following the opening of a competitive market in 2002, rates rose. In response to consumer complaints, the government enacted the *Electricity Pricing, Conservation and Supply Act* that capped retail prices until 2006.

21 The transfer left fewer utilities for the OEB to regulate; however, the MUDBANK data incorporated the larger number of utilities. The lack of consolidated data was one of the drivers for cost-of-service reviews for amalgamated utilities prior to incentive rates being applied.

22 Hydro Vaughan Distribution Inc., Markham Hydro Distribution Inc., Richmond Hill Hydro Inc., Aurora Hydro Connections Inc. and Barrie Hydro Distribution Inc.

23 Hamilton Hydro Inc. and St. Catharines Hydro Utility Services Inc.

24 Chatham-Kent Hydro, Middlesex Power Distribution Corporation, Dutton Hydro Limited and Newbury Power Inc.

25 Uxbridge Hydro, Port Hope Hydro, Brock Hydro, Belleville Utilities, Scugog Hydro Energy Corporation and Gravenhurst Hydro Electric Inc.

merged entity to be composed of PowerStream, Horizon Utilities and Enersource. In November 2015, the last of the relevant municipalities passed a motion approving the consolidation under which Brampton Hydro will be purchased for \$607 million. The OEB is expected to review the proposal in the spring of 2016.

Fortis Ontario acquired all privately-held utilities between 2000 and 2015. Fortis operates franchises in the towns of Gananoque and Fort Erie under

the CNPI banner, while operating Cornwall Electric and Algoma Power Inc. as separate corporate entities. There is common management of these utilities, with the costs reported through shared corporate service arrangements. Fortis also owns and operates a transmission corridor in the Niagara and Cornwall region, as well as a district heating operation in Cornwall.<sup>26</sup> Fortis is also a 10 per cent shareholder in three other municipally controlled utilities.<sup>27</sup>

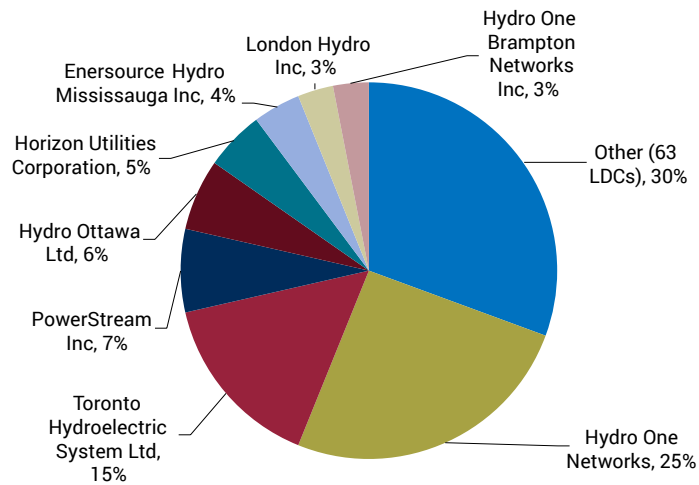
In 2014, the seven largest utilities served 70 per cent of the customers in Ontario (see Figure 6).

### 3.5 ROLE OF THE INDEPENDENT ELECTRICITY SYSTEM OPERATOR

The IESO is responsible for ensuring that there is enough power to meet Ontario's needs in real time, while also planning and securing energy for the future. It does this by:

- » balancing the supply of and demand for electricity in Ontario and directing its flow across the province's transmission lines
- » planning for the province's medium- and long-term energy needs (regional planning, input to LTEP, etc.)
- » procuring supply to meet those needs (standard offers, competitive procurements, capacity auction, contracts)
- » overseeing the electricity wholesale market
- » fostering the development of a conservation culture in the province (including demand response and oversight of LDC's CDM work).

**FIGURE 6** Percentage of customers by LDC in 2014



Source: Ontario Energy Board, *Yearbook of Electricity Distributors and Yearbook of Natural Gas Distributors*, 2014, July 31, 2015. At [http://www.ontarioenergyboard.ca/oeb/\\_Documents/RRR/2014\\_Yearbook\\_of\\_Electricity\\_Distributors.pdf](http://www.ontarioenergyboard.ca/oeb/_Documents/RRR/2014_Yearbook_of_Electricity_Distributors.pdf).

<sup>26</sup> Cornwall Electric is supplied by Hydro Quebec and is generally exempt from most LDC rate regulation in Ontario.

<sup>27</sup> Westario Power Inc., Rideau St. Lawrence Holdings Inc. and Grimsby Power Inc.



The *Electricity Act* established the IESO in 1998. It is governed by an independent board (the chair and directors are appointed by the government) and operates independently of all other participants in the electricity market. The government established the Ontario Power Authority (OPA) in 2004 to provide long-term planning to the electricity sector. The IESO and the OPA merged on January 1, 2015, bringing together real-time operations of the grid with long-term planning, procurement and conservation efforts. The IESO undertakes extensive stakeholder consultations in its work.

The OPA originally had a mandate to develop an integrated power system plan (IPSP) that was to be tested before the OEB through an open adjudicative process. The government halted the first IPSP proceeding in the very early stages, ostensibly to ensure the incorporation of an enhanced focus on conservation into the plan. No subsequent IPSP has been filed with the OEB. Instead, the government has been consulting directly and producing *Long Term Energy Plans (LTEPs)*, with input and support from the IESO.<sup>28</sup> The government recently proposed legislation that would formalize the current practice, and in the new framework, the IESO will develop a “technical document” that will address the “adequacy and reliability of electricity resources with respect to anticipated electricity supply, capacity, storage, reliability and demand and on any other matters the Minister may specify.” The technical document will be posted prior to the government consultation on the *LTEP*. The OEB’s current role, to conduct a public review of an IPSP, would be revoked.<sup>29</sup>

The IESO has a lead role in regional planning as well. The process is overseen by the OEB through a defined process, but the process is intended to be a collaboration between the IESO, transmitters, distributors and stakeholders. The results of regional planning are incorporated into the five-year distribution system plans, which are reviewed by the OEB during cost-of-service rebasing applications. The efficacy of the regional planning process as a driver of detailed capital investment plans for the LDCs or the transmitter is still an open question. The OEB filing guidelines for LDC rate setting applications mandate an engagement in the process, but capital plans are not necessarily consequential.

The IESO is also responsible for the management of the provincial smart meter data repository known as the MDM/R (Meter Data Management and Repository), which is operated by the Smart Metering Entity (SME). This function involves taking data from metering and transforming it into the driver for LDC billing purposes. The IESO started a stakeholder engagement process to investigate how to enhance the value of the data set, specifically to define the information required to be associated with electricity consumption information (such as geo-location) and the development of rules and protocols for data access by third parties. IESO has also embarked on an examination of market-based initiatives, a process described below.

28 Ministry of Energy, Achieving Balance, *Ontario's Long-Term Energy Plan*, December 2013, [http://www.energy.gov.on.ca/en/files/2014/10/LTEP\\_2013\\_English\\_WEB.pdf](http://www.energy.gov.on.ca/en/files/2014/10/LTEP_2013_English_WEB.pdf)

29 *Energy Statute Law Amendment Act* (Bill 135), [http://ontla.on.ca/web/bills/bills\\_detail.do?locale=en&BillID=3539&detailPage=bills\\_de-](http://ontla.on.ca/web/bills/bills_detail.do?locale=en&BillID=3539&detailPage=bills_detail_the_bill)

### 3.6 AFFILIATES OF THE LOCAL DISTRIBUTION COMPANY

As will be discussed in Section 4 on the legal framework of Ontario’s electricity sector, there are legislative restrictions on the activities that can be undertaken by a municipal distribution utility. For example, Ontario typically does not permit vertical integration of utilities. However, the current law allows energy-related companies to be established by the municipalities that own distribution utilities. These affiliates can engage in many of the activities that LDCs are not allowed to enter. Predominantly, four types of affiliates have been established by municipalities:

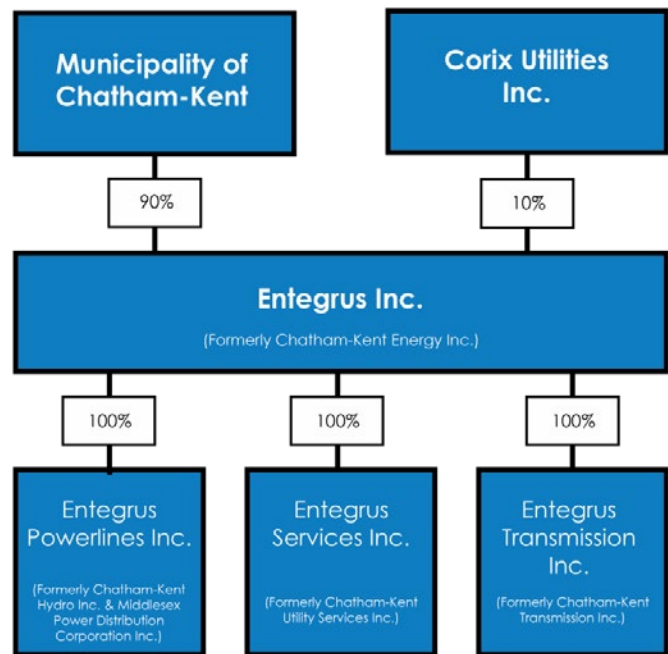
- » energy retail companies<sup>30</sup>
- » service companies
- » generation or transmission companies
- » communications/billing or other “shared asset” companies.

Some of examples of the various municipal-LDC-affiliate corporate structures are shown below.

The most common affiliate is the service company. Historically, many municipalities established these companies to ensure the continuation of shared water/waste billing, street lighting maintenance and other traditionally overlapping municipal services. Some utilities operate almost as “virtual utilities,” in which only the utility rate base assets are held by the OEB-regulated LDC, with other business functions being done by the municipality or third-party companies.

The easing of the restrictions on LDC activities (especially with respect to street lighting), the availability of alternative service providers for billing and other in-common activity, and the evolution of ownership to one where a municipality is a minor shareholder in a consolidated utility have all contributed to the decline in the use of affiliates. While some “full service” service companies continue to exist, many now are limited to billing and street lighting services. A number of smaller utilities still have financial and other professional services provided through corporate service agreements with their associated municipality.

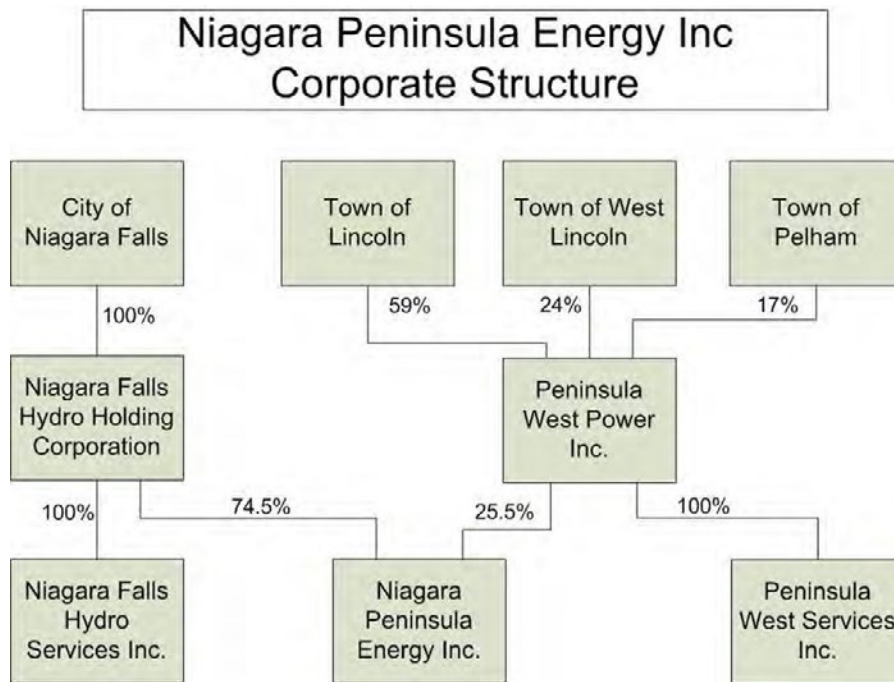
**FIGURE 7** Example of thirds party investment in LDC (Entegrus)



Source: Entegrus Powerlines, “Exhibit 8: Rate Design,” EB-2015-0061, p. 9. At [http://www.rds.ontarioenergyboard.ca/webdrawer/webdrawer.dll/webdrawer/search/rec&sm\\_udf10=EB-2015-0061](http://www.rds.ontarioenergyboard.ca/webdrawer/webdrawer.dll/webdrawer/search/rec&sm_udf10=EB-2015-0061).

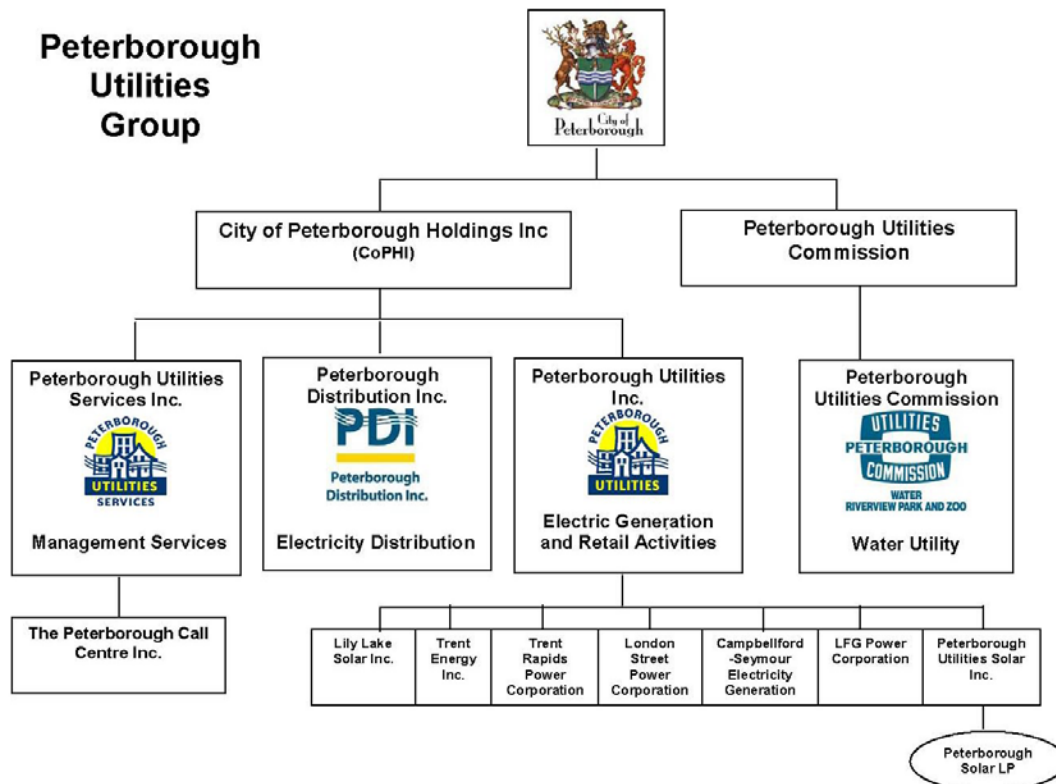
30 There are no active affiliated retail energy commodity companies active in Ontario.

FIGURE 8 Example of multiple municipal ownership of an LDC (NPEI)



Source: Niagara Peninsula Energy, "Exhibit 1, Tab 6, Schedule 19," 2015 COS Application, EB-2014-0096. At [http://www.rds.ontarioenergyboard.ca/webdrawer/webdrawer.dll/webdrawer/search/rec&sm\\_udf10=eb-2014-0096](http://www.rds.ontarioenergyboard.ca/webdrawer/webdrawer.dll/webdrawer/search/rec&sm_udf10=eb-2014-0096).

FIGURE 9 Example of an LDC with a generation affiliate (Peterborough Utilities Group)



Source: Peterborough Distribution, "Exhibit 1, Tab 1, Schedule 14," Administration Documents, EB-2012-0160. At [http://www.rds.ontarioenergyboard.ca/webdrawer/webdrawer.dll/webdrawer/search/rec&sm\\_udf10=EB-2012-0160](http://www.rds.ontarioenergyboard.ca/webdrawer/webdrawer.dll/webdrawer/search/rec&sm_udf10=EB-2012-0160).

The relationships between the distribution utility and any affiliates are governed by the OEB's Affiliate Relationship Code (ARC). The ARC sets out requirements between the affiliate and the distribution utility that:

- » require service agreements governing the relationship between affiliate and LDC
- » require confidentiality of customer data
- » set rules with respect to transfer pricing
- » restrict preferential sharing of utility system information.

The ARC seeks to enforce two general principles. The first is that the affiliate should be prohibited from extracting economic rents from the ratepayers of the monopoly. The second is that affiliates should not be provided a competitive advantage in a third-party business activity that relies on, or requires, utility assets, including customer and system data.

This latter principle would need to be examined in any model where both the utility and the third parties participate. The principle should apply that the monopoly distributor should not engage in favouritism to its affiliate engaged in a competitive market activity.

The passage of the *Strengthening Consumer Protection and Electricity System Oversight Act* (Bill 112) in 2015 means that the OEB may allow an LDC to directly do business that, in the past, would have to have been carried out by an affiliate. This may require revisiting the provisions of the ARC.

### 3.7 UTILITY CORPORATE GOVERNANCE

The ARC requires that one-third of the members of the board of directors of a regulated utility be independent of any affiliate (including the municipality). Typically, boards of utilities are populated by mayors and city councillors, senior executives of the utility or city, and qualified persons with standing in the community. The provincial government appoints HONI's board of directors. Selection of the boards of Ontario's privately held utilities is made by Fortis Ontario as shareholder.

Municipal shareholders and senior management at most utilities are generally motivated to maximize returns as opposed to keeping rates low. However, many utilities remain underleveraged as compared to the OEB's allowed 40/60 equity/debt structure. Conceptually, these utilities should be able to raise additional capital if desirable. However, many municipally held utilities, especially small ones, remain debt averse. While the larger utilities, such as Toronto Hydro and HONI, have the ability to raise debt in the market, smaller utilities are generally restricted to bank loans and monies lent from Infrastructure Ontario, a government agency. It should be noted that the municipal shareholder does have legislated restrictions on its ability to raise capital under the *Municipal Act*.

## 3.8 UTILITY MANAGEMENT

Historically, the management of the municipally held utilities might best be characterized as “operational.” Senior management of the utility would typically be an engineer or a person qualified in distribution engineering. Financial and human resource management were often sub-contracted to the municipality to be carried out by its employees. Since 2000, this model has evolved. Today all larger utilities and many small utilities operate on a “stand-alone” basis. The CEO, CFO and HR functions are carried out internally at the seven large utilities.

HONI operates an integrated distribution and transmission utility. Assets are allocated functionally and operations costs are allocated both functionally and through corporate shared service agreements. HONI distribution rates are set separately and are usually not concurrent with the setting of transmission rates. The utility is unionized, with the Power Worker Union (PWU) representing most operational staff and the Society of Energy Professionals (“the Society”) representing most engineers and other professionals in non-management positions.

The municipally held utilities are represented by the PWU, the Society or the International Brotherhood of Electrical Workers (IBEW). Generally speaking, the IBEW represents the same work group in municipal utilities as the PWU does at HONI. Pattern bargaining is prevalent. The PWU and the Society are frequent intervenors in OEB proceedings affecting its members. The IBEW is an infrequent intervenor.<sup>31</sup>

Labour rates within the distribution sector, even those of third-party qualified service operators (e.g., Black & MacDonald), are similar to those of the utilities, since many third party qualified providers are also organized.

## 3.9 UTILITY ASSOCIATIONS

The Electricity Distributors Association (EDA) is the industry body representing LDCs in Ontario. The utilities also self-insure through MEARIE, which is associated with the EDA. A number of smaller utilities are part of cooperative service groups to whom they pay membership fees. Cornerstone Hydro Electric Concepts (CHEC) is one such group. It provides regulatory, bulk buying and other services to 10-14 smaller utilities.

<sup>31</sup> See 4.2.4, below, about the role of intervenors in OEB processes.

## 4] Legal and regulatory framework for electricity in Ontario

### 4.1 REGULATORY AGENCIES IN ONTARIO

It may be useful to put the description of the Ontario legal framework into the context of a typical legal framework of a regulated sector in Canada. It would be comprised of the following:

1. Legislation that defines, generally in broad terms, what is to be regulated and the criteria by which it is to be regulated. Since the legislature does not have the capacity to implement what the legislation prescribes, the legislation would delegate the authority to implement the legislation to a regulator. Typically, there would be companion legislation that would create the regulator and grant it the powers required to carry out its delegated functions. A particular regulator may be responsible for the implementation of several regulatory statutes.
2. One or both of these acts might set out the objectives of the legislation and direct the regulator to pursue the achievement of those objectives in the exercise of its delegated authority. An important feature of one or both pieces of legislation would be the nature and extent of the discretion granted to the regulator in the exercise of its power. The legislation may authorize the government to issue directives that would have the effect of constraining, to greater or lesser degrees, the discretion granted to the regulator.
3. The legislation would typically authorize the Lieutenant-Governor-in-Council (LGIC)<sup>32</sup> to issue regulations that would prescribe, in detail, matters such as the standards or criteria to be applied by the regulator in the exercise of its powers.
4. The legislation creating the regulator would, either directly or by necessary implication, prescribe the manner in which the regulator must exercise its delegated authority. In some cases, decisions would have to be made after a hearing, a requirement which, in turn, would require the regulator to follow the rules of natural justice. Included in those rules is the requirement that a decision be made independently and based only on the evidence presented to the regulator.

A consideration of the legal framework must include a consideration of the role of government policies and, in particular, the obligation of the regulator to implement those policies. Chief Justice of the Supreme Court of Canada Beverley McLachlin, in the *Ocean Port Hotel Ltd. v. British Columbia* decision, described administrative tribunals in the following words:

They [administrative tribunals] are, in fact, created precisely for the purpose of implementing government policy.<sup>33</sup>

The Chief Justice's observation suggests that, in dealing with government policies, the function of administrative tribunals is, literally, a purely administrative one, that is one lacking any element

<sup>32</sup> In practice, this is the premier and cabinet. At the federal level, this entity would be the Governor-in-Council and be essentially the prime minister and cabinet.

<sup>33</sup> *Ocean Port Hotel Ltd. v. British Columbia* (General Manager from the Liquor Control and Licensing Branch), 2001 S.C.C. 52 at para 24.

of discretion. However, where regulators are required to exercise their discretion in a quasi-judicial way, there is often a tension between the obligation to implement policy and the obligation to exercise the decision-making authority in an independent, unbiased way.

Administrative tribunals tasked with important economic oversight functions, such as the OEB, report to the legislature *through* the minister. They do not report to the minister. This is an important distinction in terms of accountability and also practical management of the agency. Only a member of the legislature can lay information before the legislature; the chair of the agency does not have direct access to the legislature. Therefore, annual reports or special reports must be presented to the minister for them to be laid before the legislature. Annual reports, including budgets, are important for accountability. Generally, the minister is the one to respond to any questions about the agency, although the chair may be required to testify before a legislative committee on matters relating to the agency or the chair's responsibility.

Regulatory tribunals such as the OEB have expert and administrative staff, as well as a chair and members who are appointed for set terms by the government of the day. If the government changes, they are not required to resign. The degree to which a regulatory tribunal operates with some independence from the government (at both the political and bureaucratic levels) and when it may be subject to the government's policy demands is a matter of balance. All decisions and actions by an agency must be authorized by legislation; they have no real inherent jurisdiction without statutory authority. This is one important characteristic that distinguishes them from the courts. Many of the decisions and actions of a regulatory agency, however, must follow the rules of natural justice or fairness. Ministers, their staff and government officials are forbidden from interfering in a case before an agency or from trying to influence the outcome.

The accountability of Canadian regulatory agencies is not provided by direct decision-making by elected officials but is established mainly by several mechanisms:

- » The decision-making process is relatively transparent; hearings are public subject to certain confidentiality procedures, usually dealing with financial matters. Transcripts, with the confidentiality exception, are available and reasons for decision are written and public. In recent years, a great deal of effort has gone into providing reasons that clearly explain the rationale for decisions.
- » Agencies often issue guidelines, interpretations, compliance documents and other information about their process, approach to regulatory issues and policies.

Agencies are subject to judicial review, particularly of their decisions made after the public process of hearings. Generally, these reviews focus on process and fairness and do not directly deal with the merit of the regulatory decision itself, although the court's decision can clearly have a direct impact on the actual regulatory decision and the direction the agency may be required to take. Like any agency, the OEB is subject to judicial review.

In some cases, the decision of agencies may be appealed to the courts.

The implications of this architecture include an opportunity for affected persons to be fully engaged in the adjudicative processes. This means that government or agency fiat is not generally effective as a policy implementation tool. Where categories of customers feel themselves to be unduly prejudiced by the implementation of a given policy direction, they may find effective opportunities to challenge it. Hence, such issues as equity between customer classes may be justiciable.

## 4.2 REGULATORY STRUCTURE OF THE ELECTRICITY SECTOR

### 4.2.1 Introduction

The regulatory structure of the Ontario electricity sector is driven by three entities: the government, the OEB and the IESO. The government is active in setting policy, implementing policy and exercising its authority to influence others in the sector. The OEB is the independent economic regulator for the sector, and the IESO is the independent planner and system operator for the province. This section discusses each entity, setting out mandates, processes and priorities.

### 4.2.2 Role of the government in electricity

The Ontario government has long been directly involved in the electricity sector. This is understandable given the historical context: public ownership of major generation, transmission and distribution infrastructure; policies to drive province-wide electrification; and the alignment of electricity and economic policy. In contrast, the Ontario natural gas sector has been subject to limited government intervention. The gas commodity market is competitive, the transmission and distribution utilities are investor-owned, and the OEB has authority to set rates for the regulated portions of the sector. Therefore, the gas companies are accountable for the prudence of their gas supply decisions.

Key pieces of legislation include:<sup>34</sup>

- » *Ontario Energy Board Act*, 1998
- » *Electricity Act*, 1998
- » *Green Energy Act*, 2009
- » *Energy Consumers Protection Act*, 2010
- » *Strengthening Consumer Protection and Electricity System Oversight Act* (Bill 112) – received Royal Assent on December 1, 2015
- » *Energy Statute Law Amendment Act* (Bill 135) – ordered to Standing Committee after second reading on December 1, 2015

<sup>34</sup> See Appendix B.



### 4.2.3 Role of the Ontario Energy Board

The OEB is the independent economic regulator for Ontario's natural gas and electricity sectors. The Board is headed by a combined chair/CEO. A management committee comprised of the chair/CEO and two vice chairs provide governance. The OEB is composed of both full-time and part-time members and a supporting staff of about 175. The Lieutenant-Governor-in-Council appoints members by cabinet recommendation. The selection process is not overtly political and generally members are selected after a broadly advertised process.

In legislation, the OEB's objectives for the electricity sector are:

1. to protect the interests of consumers with respect to prices and the adequacy, reliability and quality of electricity service
2. to promote economic efficiency and cost effectiveness in the generation, transmission, distribution, sale and demand management of electricity and to facilitate the maintenance of a financially viable electricity industry
3. to promote electricity conservation and demand management in a manner consistent with the policies of the government of Ontario, including having regard to the consumer's economic circumstances
4. to facilitate the implementation of a smart grid in Ontario
5. to promote the use and generation of electricity from renewable energy sources in a manner consistent with the policies of the government of Ontario, including the timely expansion or reinforcement of transmission systems and distribution systems to accommodate the connection of renewable energy generation facilities.

The OEB's key roles are to:

1. license all market participants including the IESO, generators, transmitters, distributors, wholesalers and retailers
2. determines payment amounts for most of OPG's generation production, which represents about half the total installed capacity in the province
3. set the rate charged by distributors for the commodity (see Regulated Price Plan below) under standard service supply
4. set electricity transmission and distribution rates, and distribution rates for the natural gas utilities
5. determine whether the construction of electricity transmission lines will be permitted
6. determine whether proposed mergers, divestitures or acquisitions will be permitted

7. monitor the electricity market through the Market Surveillance Panel, and review IESO market rules and consider appeals of IESO orders
8. monitor transmitter and distributor performance through regular reporting
9. set performance requirements and standards through formal codes and rules.

The OEB does not regulate competitive services. Competitive services for electricity are all business activities other than distribution, transmission and providing standard supply service. Although the OEB licenses generators, this is almost exclusively an administrative function. The OEB does not regulate the rates of competitive natural gas marketers and electricity retailers, but there is strong consumer protection legislation in place, and there is an extensive set of formal performance requirements for these entities that the OEB sets and enforces.

#### 4.2.4 OEB PROCESSES AND PRIORITIES

The OEB uses both hearings and consultations to carry out its mandate.

Hearings are used to decide rate applications, transmission proposals and merger and acquisition proposals. The rate-setting process is discussed separately in this report. For transmission projects, the OEB only considers the impact of the project on price, quality and reliability of electricity, and whether the project is consistent with the government's renewable generation policies. The OEB has no authority over environmental considerations. Previously the OEB had the authority to determine whether a project was needed in the public interest. Under recent legislative amendments (Bill 112), the government will be able to issue an order specifying that a particular project is needed as a priority, and the OEB must accept that in its proceeding. For mergers and acquisitions, the OEB must approve any transaction that involves the acquisition of at least 10 per cent of the voting shares before the transaction can proceed (reduced from a threshold of 20 per cent following recent legislation). The OEB has adjudicated a number of mergers and acquisitions, and has a longstanding policy of using a "no harm" test to determine whether the transaction is in the public interest. No proposed transactions have been denied. (The recently initiated privatization of HONI is explicitly excluded from OEB oversight).

The OEB uses a number of process steps in a public hearing, including written interrogatories, expert witnesses, technical conferences, settlement negotiations and oral hearings with cross-examination. A panel of two or three members is assigned to the hearing, and they make the final decision. There are generally a number of active participants (known as intervenors) during a hearing, including representatives from various customer groups (including industrial, residential and low income), environmental advocates, service providers, unions, etc. The OEB has broad powers to grant cost awards to various intervenors. Many rate proceedings are settled through the use of alternate dispute resolution.

The OEB uses consultations to set regulatory policy. Regulatory policy establishes a standard approach to issues that affect the entire sector, thereby enhancing consistency and predictability.

Public consultations involve many stakeholders, including distributors, transmitters, generators, customers, environmental advocates, service providers, unions, etc. Policy consultations involve a number of process steps including stakeholder conferences and written submissions. Policy consultations are less formal than hearings.

Regulatory policy is then implemented through individual hearings. For example, the OEB recently completed a consultation on residential distribution charges and set a regulatory policy that distribution costs should be recovered through a fixed charge. The specific charge and specific steps in the four-year transition will be decided through individual applications and individual public hearings (as part of a larger rate application).

The OEB has been increasing its efforts to involve stakeholders, especially residential customers. This is part of its adoption of a more “consumer centric” approach to regulation generally. The OEB is increasing the accessibility of its processes and is actively engaging consumers through focus groups, surveys and online tools, as well as more outreach into communities. The OEB is also reviewing how best to ensure consumer interests are represented in public hearings. Bill 112 requires that the OEB “establish one or more processes by which the interests of consumers may be represented in proceedings before the Board, through advocacy and through any other modes of representation provided for by the Board.” The government also may make regulations to govern the process or processes.

The OEB’s *2015–2018 Business Plan* contains several initiatives designed to ensure that regulation keeps pace with “the fundamental changes occurring within the energy sector enabled by new technologies, changing customer demands, and evolving public policy.”<sup>35</sup> These initiatives include:

**Distribution rate design**

Implementation of fixed charge for residential customers, assessment of options for non-residential customers

**Regulated Price Plan**

Revise methodology, including options for more efficient allocation of the Global Adjustment to encourage conservation through price signals

**Natural gas demand side management (DSM)**

Promote further evolution of the framework through additional studies including examination of achievable potential

**Underserved communities**

Formulate policy options to bring gas and electricity service to these areas

**Cap-and-trade**

Develop regulatory framework for province’s cap-and-trade program

**Venergy services market**

Review evolution of the market, assess implications for regulated businesses, and address barriers that limit the ability of “valued energy services” (including storage) to compete in Ontario.

35 Ontario Energy Board, *Enabling Ontario’s Energy Future: Ontario Energy Board 2015-2018 Business Plan*, October 27, 2015, p. 7. At [http://www.ontarioenergyboard.ca/oeb/\\_Documents/Corporate/OEB\\_Business\\_Plan\\_2015-2018.pdf](http://www.ontarioenergyboard.ca/oeb/_Documents/Corporate/OEB_Business_Plan_2015-2018.pdf).

## 4.2.5 The regulation of management: Supply, capacity, demand and reliability

The authority to regulate the management of electricity supply, capacity and demand is found in the *Electricity Act*. That authority has been delegated to the IESO. The IESO's discretion in exercising that authority is subject to the constraints contained in directives, and directions, issued by the minister. Directions and directives are discussed further in section 11.

The objectives of the IESO include the following:

1. to engage in activities related to contracting for the procurement of electricity supply, electricity capacity and conservation resources
2. to conduct independent planning for electricity generation, demand management, conservation and transmission
3. to engage in activities to facilitate the diversification of sources of electricity supply by promoting the use of cleaner energy sources and technologies, including alternative energy sources and renewable energy sources
4. to engage in activities in support of system-wide goals for the amount of electricity to be produced from different energy sources
5. to engage in activities<sup>36</sup> that facilitate load management.

The wording of the objectives is sufficiently broad to permit the IESO to plan for, though not necessarily to implement, the integration of DER into the distribution system.

The IESO has the power to:

1. develop procurement processes for managing electricity supply, capacity and demand
2. enter into contracts in accordance with approved procurement processes
3. make adjustments to ensure that amounts paid by the IESO to generators and those with whom the IESO has a procurement contract are recovered in the rates charged by distributors.

In addition, the IESO may provide "services" that would assist the government in achieving its goals in electricity conservation, including services<sup>37</sup> related to electricity load management.

<sup>36</sup> What constitutes "activities" is not defined in the EA.

<sup>37</sup> What constitutes "services" is not defined.

## 4.3 LOCAL DISTRIBUTION COMPANIES

The basic structure of the local distribution sector was created by the 1998 amendments to the *EA* and the *OEB Act*. The *EA* required the distribution assets owned by municipalities to be transferred to corporations governed by the *Ontario Business Corporations Act (OBCA)*. The operations of those corporations were to be subject to regulation by the OEB. While in the intervening period there have been numerous changes to the *EA* and the *OEB Act*, the basic legal framework remains as it was in 1998.

The legislated obligations of distribution utilities include the following:

1. obtain a licence from the OEB, and comply with its terms
2. comply with codes issued by the OEB
3. only charge rates that have been approved by the OEB
4. obtain the approval of the OEB for an acquisition, sale or merger
5. connect anyone who wants electricity service
6. sell electricity to anyone who wants to purchase it
7. connect with a renewable energy source.

OEB has the following powers over the distribution sector:

1. to issue licences to electricity distributors, a power that includes the authority to prescribe conditions to be included in the licence
2. to issue codes
3. to approve rates
4. to approve special rates for both rural and remote customers
5. to approve rates for investments connecting to generation facilities
6. to approve rate assistance for certain classes of consumers
7. to approve changes in ownership
8. to approve the construction of distribution and transmission lines.

Section 71 of the *OEB Act* limited the types of activities that a distributor may undertake directly instead of through an affiliate. The OEB can authorize a distributor to carry on a business activity other than distributing electricity directly if, in the opinion of the OEB, the special circumstances of a particular case require it. What such “special circumstances” would consist of is, apparently, left entirely in the discretion of the OEB to decide, within the context of its quasi-judicial processes. That means that the decision to expand the role of the utility, as a utility, would be subject to comment and potential opposition from rate payer advocates. It is foreseeable that some rate payer advocates would support, while others might oppose, the extension of new areas of activity for utilities. It is also true that the risk profile of utilities may change depending on the nature of the activities undertaken in a new mandate. That risk profile informs the regulated rate of return for utilities.

## 5] Regulatory functions

### 5.1 RATE-SETTING IN ONTARIO

Rate-setting in Ontario, which is grounded in a cost-of-service approach, has changed over time to include a variety of incentive regulation mechanisms, and is evolving to a performance-based system. Current electricity distribution rate-setting is focused on outcomes (rather than inputs) and includes three options for multi-year incentive rates, along with planning and performance requirements.

This section sets out the history of rate-setting in Ontario, focusing on the role of the OEB and the evolution of electricity distribution rates. The OEB's work in natural gas rate-setting and electricity rate setting provides an important context for future options as the energy sector evolves.

### 5.2 HISTORY OF ONTARIO ENERGY BOARD'S RATE-SETTING AUTHORITY

The OEB has had rate-setting authority for over 50 years, but for most of that history the authority was limited to natural gas and natural gas utilities.

In the 1980s, when natural gas was deregulated in Canada, the OEB changed its approach to rate-setting for natural gas utilities in order to promote the development of a competitive market for the commodity. Each component of the service was unbundled, and separate rates were developed for delivery, storage, and the commodity.

Commodity costs were tracked using balancing accounts, and customers purchasing the commodity from their distribution utility purchased the commodity at cost, with no margin added for the utility. Commodity costs are adjusted quarterly.

For delivery, gas utilities submit a cost of service application approximately every five years, providing estimates of expected demand and expected capital and operating costs. Using these figures, the OEB sets a base rate, which includes a set rate of return. The rates are adjusted annually using a formula that considers inflation minus a productivity factor.

The OEB also has the authority to stop or forebear from regulating rates where it finds that competition is sufficient to protect the public interest. Natural gas storage services, for example, have been partially deregulated.<sup>38</sup> The OEB has also had experience with value-based and market-based rates when there is evidence of competitive pressure from alternative services or through direct connection to the interprovincial transmission system. "Bypass competitive" rates have been available to distributors for many years to discourage large customers from connecting directly to the TransCanada PipeLine, while at the same time ensuring some contribution to fixed costs on the system.

<sup>38</sup> Storage services were partially deregulated in 2006, in the OEB's Natural Gas Electricity Interface Review proceeding. See the OEB's decision in EB-2005-0551, issued November 6, 2006.

The OEB has had the authority to set rates for electricity service since 1999, after the government restructured the sector to introduce competition. Before restructuring, the OEB had conducted an annual review of Ontario Hydro (the provincially-owned vertically integrated utility) and provided recommendations to the government about pricing and other issues. However, the recommendations were not binding. The government set rates, and in turn, Ontario Hydro determined the rates that the municipal distributors could charge. Under the restructuring, as noted above, Ontario Hydro was broken up into HONI (distribution and transmission), OPG, the IESO and the Electrical Safety Authority (ESA). Municipal electricity distributors were converted to business corporations, and a framework was established to allow competitive retail service. The OEB was granted authority to set rates for most of OPG's generation, and all of transmission and distribution.

The OEB sets electricity transmission rates for five transmitters using a cost-of-service approach.<sup>39</sup> Their individual revenue requirements are pooled, and uniform transmission rates are set for the Province. The OEB sets payment amounts for OPG's generation from specific assets, including the Pickering and Darlington nuclear stations and most of the hydroelectric generating stations.<sup>40</sup> The OEB also sets the retail electricity commodity price based on a forecast and a true-up for past variances.<sup>41</sup> Electricity distribution rate-setting is the area that has seen the greatest evolution in OEB policy and practice over the last 15 years and it is the focus of the remainder of this section.

## 5.2.1 EVOLUTION OF THE OEB'S ELECTRICITY DISTRIBUTION RATE SETTING

With the advent of the *EA*, the OEB was tasked with setting rates for over 90 distribution companies that had had no experience with formal rate regulation. The OEB began with a fairly simple and largely prescriptive approach to incentive regulation (IR). Over time the framework has evolved to become more complex, with more options for distributors. There have been four frameworks since the market was restructured, and each is described briefly below.

### 1<sup>st</sup> Generation IR (2001–2005)

The focus was on unbundling rates, incorporating a market-based rate-of-return on equity, and setting a simple annual adjustment formula. Rates were set by unbundling the then existing rates. The price cap formula included inflation and a fixed productivity factor of 1.5 per cent. This framework was intended to last three years, but shortly after the 2002 market opening, the government imposed a rate freeze which lasted until 2006.

### 2<sup>nd</sup> Generation IR (2006–2009)

Distributor rates for 2006 were set using 2004 as an historical test year, with some adjustments. Rates for the following years were set using a price cap adjustment (inflation and a 1 per cent productivity factor), for a maximum of three additional years. This framework was a transition from the initial 1<sup>st</sup> Generation IR to a more comprehensive approach. 2<sup>nd</sup> Generation IR provided time

<sup>39</sup> There are many other transmitters that only deliver power from generation facilities to the main grid that are not rate-regulated.

<sup>40</sup> Some of OPG's generating capacity is not rate-regulated and is under contract with the province (through the IESO).

<sup>41</sup> More information on retail pricing can be found in section 6.

for the OEB to conduct the analytical and consultation work needed to support the new approach. The OEB developed a handbook to establish a standardized approach for most issues and provide model templates for distributors.

### **3<sup>rd</sup> Generation IR (2009 – 2013)**

Building on 2<sup>nd</sup> Generation IR, the OEB moved to a forward test year, extended the term to four years, and introduced a productivity stretch factor to the annual adjustment mechanism. The stretch factor was based on the results of benchmarking work. Each distributor was placed in one of three cohorts to recognize the differing levels of productivity potential, and the stretch factor varied depending upon the cohort (0.2 per cent, 0.4 per cent or 0.6 per cent). The benchmarking analysis was done annually, which provided distributors with the ability to improve their performance and thereby move to a lower stretch factor for the subsequent year.<sup>42</sup> The OEB also introduced the Incremental Capital Module (ICM). Under this mechanism, a distributor could apply to have otherwise unaccounted for incremental capital costs recovered through rate riders added to the price cap formula rates.

### **Renewed Regulatory Framework (RRFE) (2014 – present)**

The RRFE introduced a broad set of reforms and a suite of policies covering planning, rate-setting and performance measurement.<sup>43</sup> Overall the focus is on outcomes: customer focus, operational effectiveness, public policy responsiveness and financial performance. The planning policy covers distribution system planning and integrates regional planning, conservation and smart grid policies. The performance measurement policy introduces a transparent and uniform scorecard approach. The rate-setting policy provides distributors with three options:<sup>44</sup>

- » **Price Cap IR** (formerly known as 4<sup>th</sup> Generation IR) is similar to 3<sup>rd</sup> Generation IR (cost-of-service rebasing followed by multiple years of price cap formula adjustment), but the term is extended to five years. The annual adjustment formula has been revised to include an industry-specific inflation factor. There are still two factors for productivity: the industry-wide factor (set at 0 per cent) and the individual stretch factor. The stretch factor is based on how far a distributor's efficiency differs from its predicted level based on benchmarking. There are five efficiency groups, and the stretch factor varies from 0.0 per cent to 0.6 per cent. The Incremental Capital Module and Advanced Capital Mechanism are available (discussed further below). Most distributors have chosen the Price Cap IR option.
- » **Custom IR** is designed to address the needs of distributors with large or highly variable capital requirements. Again, the term is five years, but rates are set based on a five-year forecast of the distributor's costs and sales volumes. It is not intended to be a five-year cost of service exercise.

42 There was limited movement between cohorts. For example, in 2013, eight distributors moved: six moved up one cohort, and two moved down one cohort. Of the more than 70 LDCs, only about half a dozen moved each year – and generally about half moved up a cohort and half moved down a cohort.

43 Ontario Energy Board, *Report of the Board on the Cost of Capital for Ontario's Regulated Utilities*, EB-2009-0084, December 11, 2009. At [http://www.ontarioenergyboard.ca/oeb/\\_Documents/EB-2009-0084/CostofCapital\\_Report\\_20091211.pdf](http://www.ontarioenergyboard.ca/oeb/_Documents/EB-2009-0084/CostofCapital_Report_20091211.pdf).

44 In 2015, there were four Custom IR applications, approximately ten Cost of Service rebasing applications (leading to Price Cap IR), approximately 53 distributors on Price Cap IR, and about five distributors on Annual IR.



Custom IR is intended to be customized to fit the specific distributor's circumstances, but expected inflation and productivity gains are to be built into the rate adjustment over the term. (The Incremental Capital Module is not available under Custom IR). Several large distributors have adopted the Custom IR option.

- » **Annual IR** is designed for distributors with limited incremental capital requirements. Under Annual IR no rebasing application is required. Rates are adjusted annually using the price cap formula and the highest stretch factor, thereby ensuring the lowest level of rate increase over time. Several distributors have adopted this approach.

## 5.2.2 Key issues in rate-setting

The OEB's rate-setting has evolved against a backdrop of key issues that continue to be the focus of ongoing analysis and consideration:

### **Return on equity (ROE)**

Setting the return on equity was historically a time and resource-intensive activity for the OEB, involving extensive expert analysis. That approach was replaced with a formula approach to setting the ROE. The formula was most recently reviewed in 2009, and changes were made to the methodology. The ROE for utilities that rebase in 2016 is 9.19 per cent.

### **Capital additions**

Throughout the evolution of incentive ratemaking in Ontario, utilities have advocated for a closer alignment between capital spending and rate changes, and the regulator has been concerned with the tendency to cluster capital expenditures in the rebasing year. The Incremental Capital Module (ICM) is a mechanism to allow the recovery of incremental capital through rate riders above the price cap adjustment. Initial applications were unsuccessful, but through subsequent applications the OEB developed a consistent set of criteria that increased the level of predictability for these applications. The OEB has now added the Advanced Capital Mechanism (ACM) that also allows for incremental rate increases to recover the costs of discrete capital projects.<sup>45</sup> Applications under the ICM are made during the IR term, whereas the ACM involves a review of forward expenditures during the cost of service rebasing proceeding and the incremental funding is then built into the forward rate-setting. There are also incentive mechanisms available for certain types of capital expenditures, but there have been no applications made for these.<sup>46</sup>

45 Ontario Energy Board, *New Policy Options for the Funding of Capital Investments: The Advanced Capital Module*, EB-2014-0219, September 18, 2014. At [http://www.ontarioenergyboard.ca/oeb/\\_Documents/EB-2014-0219/Board\\_ACM\\_ICM\\_Report\\_20140918.pdf](http://www.ontarioenergyboard.ca/oeb/_Documents/EB-2014-0219/Board_ACM_ICM_Report_20140918.pdf).

46 Ontario Energy Board, *The Regulatory Treatment of Infrastructure Investment in connection with the Rate-regulated Activities of Distributors and Transmitters in Ontario*, EB-2009-0152, January 15, 2010. At [http://www.ontarioenergyboard.ca/oeb/\\_Documents/EB-2009-0152/Board\\_Report\\_Infrastructure\\_Investment\\_20100115.pdf](http://www.ontarioenergyboard.ca/oeb/_Documents/EB-2009-0152/Board_Report_Infrastructure_Investment_20100115.pdf).

## **Distributor consolidation**

Two recent government-sponsored reviews of the sector have recommended greater consolidation in the electricity distribution sector.<sup>47</sup> The OEB established a policy in 2007 that permitted distributors to defer cost of service rebasing for up to five years to facilitate the recovery of transaction costs through merger savings and synergies, after which those benefits were expected to flow through to customers.<sup>48</sup> The OEB recently revised this policy to permit a deferral of up to 10 years (if justified), but during years five to ten the policy calls for the 50/50 sharing of earnings in excess of 300 basis points over the allowed return. The new policy also permits distributors to apply for recovery of capital costs using the Incremental Capital Module during the deferral period.<sup>49</sup> Some consolidation has taken place, but around 70 distributors remain.

## **Planning**

With the RRFE comes a greater focus on planning – and greater transparency of that planning and greater alignment between the plans and the rate applications. Distributors are required to develop five-year distribution system plans that integrate regional planning and conservation considerations, as well as reflect the input from customer engagement.

## **Customer engagement**

With the introduction of the RRFE, the OEB has emphasized the importance of greater customer engagement directly by distributors. The input received through customer engagement is to be incorporated into distributor plans and rate applications. The OEB is also working to make its rate-setting process more accessible to consumers, and to gather input directly from consumers.

## **Performance benchmarking**

Early analysis commissioned by the OEB was burdened by poor data quality and industry resistance. Over time, data has improved and general acceptance has grown. Recent developments have focused on developing total cost benchmarking, and this approach is used to set the stretch factors for the price cap formula. The OEB also expects utilities to present benchmarking evidence to support Custom IR applications, but there has been mixed success with this and not all applications have included this evidence. Under RRFE, distributors must report their performance across a range of measures using a template scorecard. This has increased the transparency of distributor performance, but there are no direct incentives or penalties that would link performance directly with the return earned by distributors.

47 Ontario Distribution Sector Review Panel, *Renewing Ontario's Electricity Distribution Sector: Putting the Consumer First*, December 2012. At [http://www.energy.gov.on.ca/en/files/2012/05/LDC\\_en.pdf](http://www.energy.gov.on.ca/en/files/2012/05/LDC_en.pdf). Premier's Advisory Council on Government Assets, *Retain & Gain: Making Ontario's Assets Work Better for Taxpayers and Consumers*, November 2014. At <https://www.powerstream.ca/ContentMgr/attachments/2014-11-11-draft-report-premiers-advisory.pdf>; Premier's Advisory Council on Government Asset, *Striking the Right Balance: Improving Performance and Unlocking Value in the Electricity Sector in Ontario*, April 2015. At <https://www.ontario.ca/page/improving-performance-and-unlocking-value-electricity-sector>.

48 Ontario Energy Board, *Rate-making Associated with Distributor Consolidation*, EB-2007-0028, July 2007. At [http://www.ontarioenergyboard.ca/documents/cases/EB-2007-0028/report\\_ratemaking\\_20070723.pdf](http://www.ontarioenergyboard.ca/documents/cases/EB-2007-0028/report_ratemaking_20070723.pdf).

49 Ontario Energy Board, *Rate-Making Associated with Distributor Consolidation*, EB-2014-0138, March 2015. At [http://ontarioenergyboard.ca/oeb/\\_Documents/EB-2014-0138/Board\\_Report\\_MAADs\\_Ratemaking\\_20150326.pdf](http://ontarioenergyboard.ca/oeb/_Documents/EB-2014-0138/Board_Report_MAADs_Ratemaking_20150326.pdf).

## 5.2.3 The electricity bill

Although rates are determined separately for generation, transmission, distribution and other components, some are re-bundled for purposes of presentation on the customer's bill. Residential bills display the following categories of charges:

### **Electricity**

The cost of the electricity generation and Ontario's Global Adjustment (which includes additional contract payments, the costs of conservation programs, etc.). These costs are passed through to customers with no margin for the distributor.

### **Delivery**

This charge recovers the costs of transmission and distribution. It is a combination of fixed and variable charges, and includes the cost of losses on the system. Residential distribution charges are transitioning to a fully fixed charge over the next four years.

### **Regulatory**

This charge recovers the costs of the IESO to plan and administer the wholesale electricity system and maintain the reliability of the provincial grid. It also recovers the subsidy provided to rural and remote customers and some of the costs of connecting renewable generation to the distribution grid.

### **Debt Retirement Charge**

The revenues from this charge pay down the debt of the former Ontario Hydro. The charge is fixed at 0.7 cents/kWh. Residential and small general service customers have been exempt from this charge since January 1, 2016.

## 5.3 CONSERVATION AND DEMAND MANAGEMENT

### 5.3.1 Introduction

Government policy has placed a heavy emphasis on conservation. Conservation is seen as a tool to avoid the costs of more expensive generation and transmission and as a way to enable consumers to reduce their bills.

The government has also committed to promoting a coordinated approach that involves natural gas and electricity and that involves distribution planning as well as grid planning. This section describes the history of conservation in Ontario and the current framework.

### 5.3.2 History of conservation in the Ontario energy sector

There is a long history of conservation activity by Ontario's two main gas distributors, Union Gas Limited and Enbridge Gas Distribution Inc. The OEB has always overseen this activity, with the first regulatory framework established in 1993 under EBO 169-III. Beginning with that first policy, and throughout the evolution of gas demand side management (DSM), the term for conservation in the gas sector, the OEB has set the principles, budgets, revenue protection and incentive mechanisms and process requirements. Union and Enbridge then develop multi-year plans. A key feature of

these plans has been the extensive involvement of stakeholders in the ongoing planning by the distributors, as well as in the monitoring and verification processes.<sup>50</sup>

Conservation in the electricity sector has also gone through a long evolution. Early conservation programs undertaken by Ontario Hydro beginning in the mid-1980s were abandoned in the early 1990s as priorities shifted to cost containment. Conservation came to the fore again as part of market restructuring. As part of restructuring, municipal distribution companies were corporatized and there was a gradual introduction of market rates of return into distribution rates. In order to include the third (and final) part of that market return into rates beginning in 2005, distributors were required to commit to spending an equivalent amount on conservation programs by the end of 2007. These were known as “third tranche” programs. Between 2007 and 2010, the government committed \$400 million for conservation programs. The funding was provided to develop province-wide programs that were delivered by distributors. Distributors could also propose custom programs directly to the OEB, but few were approved.

Beginning in 2011, the approach changed again. The *Green Energy and Green Economy Act* set the stage for mandatory conservation and demand (CDM) targets for LDCs and a more focused approach for province-wide CDM programs developed by the OPA and delivered by distributors. The OEB retained oversight for targets and results, but the funding was provided through the Global Adjustment, and was therefore recovered through the cost of electricity, not distribution rates. The targets for the four-year program (2011-2014) were a reduction in peak demand across all distributors by the end of the period of 1,330 MW and a cumulative reduction in demand by the end of the period of 6,000 GWh. Overall, distributors achieved the cumulative energy reduction target, but only about 60 per cent of the peak demand reduction target.

### 5.3.3 The “Conservation First” framework 2015–2020

The government’s “Conservation First” framework, which runs from 2015 through 2020, is targeting reductions of 1.7 TWh for transmission-connected customers and 7.0 TWh for distribution-connected customers, with a total budget of \$2.4 billion. The IESO is the lead agency. Transmission-connected customers have access to incentives and support through the IESO’s Industrial Accelerator Program. Distributors will develop their own programs, which will be approved and funded by the IESO.

LDC’s CDM plans must address the needs identified in the associated regional plans, distributor system plans and community energy plans. Distributors are encouraged to work cooperatively with each other (and natural gas distributors) and have flexibility to allocate their budgets to meet local conditions. The IESO will recover the funding through the Global Adjustment. Almost all distributors have had their CDM plans approved.

<sup>50</sup> Information on Union’s and Enbridge’s DSM plans can be found on the OEB website at [http://ontarioenergyboard.ca/oeb/Industry/Regulatory%20Proceedings/Policy%20Initiatives%20and%20Consultations/Conservation%20and%20Demand%20Management%20\(CDM\)/Natural%20Gas%20DSM](http://ontarioenergyboard.ca/oeb/Industry/Regulatory%20Proceedings/Policy%20Initiatives%20and%20Consultations/Conservation%20and%20Demand%20Management%20(CDM)/Natural%20Gas%20DSM).

The IESO also administers a Conservation Fund to promote innovation in the sector. Since 2005, the IESO has funded projects that build marketplace capacity, test new or unique conservation program elements, verify the energy savings potential and cost-effectiveness of novel demand-side technologies and processes, or that can be scaled-up to achieve significant energy savings.

The main areas of concern amongst stakeholders are target achievement and the cost effective delivery of programs. The IESO will conduct a mid-term review in 2017. There is also ongoing verification and reporting of achieved results. Distributors are concerned with protection from revenue erosion, and this has been provided for through the Lost Revenue Adjustment Mechanism, which tracks the amounts for recovery by the distributor. This mechanism will likely be removed over time with the introduction of fully fixed distribution charges for residential customers.

### 5.3.4 Other conservation-related activities

In 2014, the OEB established a new framework to govern gas DSM plans for 2015-2020.<sup>51</sup> This framework is consistent with the “Conservation First” policy and was developed in accordance with the requirements imposed by the minister’s directive. Enbridge and Union developed their DSM plans and submitted them to the OEB in early 2015. Unlike many DSM plans in the past, the distributors were not able to reach a negotiated settlement with their stakeholders. The OEB recently concluded its hearing on the gas DSM proposals, although no decision has been issued yet.

The IESO has been active in the area of demand response (DR), which is expected to play an increasing role in Ontario’s electricity system. The IESO recently completed a competitive procurement for 80 MW of DR from five companies representing 20 projects ranging from 1 MW to 35 MW. These pilot projects will be used to assess their ability to follow changes in electricity consumption and help balance supply and demand.<sup>52</sup> The IESO is also working to more fully integrate demand response into the market. The IESO held an auction at the beginning of December 2015 to acquire demand response resources for summer 2016 and winter 2016/2017. This represents a shift from contract-based DR programs to a market-based approach that provides more competitive pricing and more flexibility. Three aggregators and four direct providers were successful; 391.4 MW were acquired for the summer at a clearing price of \$378.21/MW-day, and 403.7 MW were acquired for the winter at a clearing price of \$359.87/MW-day.

51 Ontario Energy Board, *Demand Side Management Framework for Natural Gas Distributors (2015-2020)*, EB-2014-0134, December 22, 2014. At [http://ontarioenergyboard.ca/oeb/\\_Documents/EB-2014-0134/Report\\_Demand\\_Side\\_Management\\_Framework\\_20141222.pdf](http://ontarioenergyboard.ca/oeb/_Documents/EB-2014-0134/Report_Demand_Side_Management_Framework_20141222.pdf).

52 See IESO website for more details on specific projects: <http://www.ieso.ca/Pages/Participate/Demand-Response-Pilot/default.aspx>.

## 6] Electricity commodity price in Ontario

### 6.1 INTRODUCTION

As outlined above, the *Electricity Act* unbundled the vertically integrated Ontario Hydro into five successor organizations and established a framework for the competitive procurement and pricing of electric power in Ontario's wholesale and retail electricity markets. Effective April 1, 1999, the structure of Ontario's electricity industry has been as follows.

An hourly spot market was started and there was to be competition in generation, support for bilateral contracts, and default supply by local distribution companies (LDCs) to customers who do not choose a retail energy supplier. Wholesale prices were to be uniform across the province initially.<sup>53</sup>

Successive legislative amendments to the *Electricity Act*, including the *Electricity Pricing, Conservation and Supply Act, 2002* and the *Electricity Restructuring Act, 2004*, altered the market structure, moving it from a framework where consumers of all sizes effectively paid a single market clearing price for electricity to a hybrid market comprised of market-based, regulated and contract-based supply.

Among other things, the *Electricity Restructuring Act* mandated the OEB to develop a regulated price plan (RPP) that would ensure that residential and small business consumers pay the true cost of electricity over time, but within a stable and predictable price framework. The minister also stated that this RPP should support conservation, "smart metering" and load shifting initiatives through "time of use" pricing.<sup>54</sup>

### 6.2 COMMODITY PRICE FOR ELECTRICITY IN ONTARIO

The average effective commodity price of electricity in Ontario is the sum of the following components:<sup>55</sup> average weighted Hourly Ontario Energy Price (HOEP), the average Global Adjustment (GA) and the average uplift. The effective commodity price varies by consumer class, as set out below.

53 Dan Dewees, *Electricity Restructuring and Regulation in the Provinces: Ontario and Beyond*, University of Toronto. September 2005, p. 4.

54 Ontario Energy Board, *Board Proposal: Regulated Price Plan for Electricity Consumers*, RP-2004-0205, December 7, 2004, p. 3.

55 Market Surveillance Panel, *Monitoring Report on the IESO-Administered Electricity Markets for the period from November 2013 to April 2014*. April 2015, p. 8. At [http://www.ontarioenergyboard.ca/oeb/\\_Documents/MSP/MSP\\_Report\\_Nov2013-Apr2014\\_20150420.pdf](http://www.ontarioenergyboard.ca/oeb/_Documents/MSP/MSP_Report_Nov2013-Apr2014_20150420.pdf).

## 6.2.1 Average weighted Hourly Ontario Energy Price

The average weighted Hourly Ontario Energy Price (HOEP) is determined by using the average of the five-minute Ontario energy prices and includes:<sup>56</sup>

1. Market Clearing Price (MCP): The real-time market in Ontario is administered by the IESO, which continually balances electricity supply and demand. The result of this balancing process is the market clearing price for energy. The MCP reflects the bids and offers into the real-time market from dispatchable facilities and boundary entities, and the supply and demand from non-dispatchable facilities. The market clearing price for energy reflects an ideal system, one with no physical constraints or limitations.
2. MCP for energy at each of the intertie zones with neighbouring markets.
3. MCP for each of the three operating reserve classes across Ontario.
4. MCP for 10 minute non-synchronized and 30-minute operating reserve at each of the intertie zones with neighbouring markets.

## 6.2.2 Average uplift<sup>57</sup>

Uplift is essentially made up of overhead charges to cover costs relating to various market programs and design features, and is separated into hourly uplift and non-hourly uplift.

Hourly uplift is comprised of congestion management settlement credit payments, intertie offer guarantee payments, operating reserve payments, hourly voltage support payments and line losses. Hourly uplift charges are allocated to consumers based on their share of total hourly demand in order to recover the costs associated with various market programs and design features.

Non-hourly uplift is comprised of three categories of costs:

1. payments for ancillary services, such as regulation service, black start capability and monthly voltage support
2. guaranteed payments to generators, including Day-Ahead Production Cost Guarantee payments and Real-time Generator Cost Guarantee payments
3. other, which is an aggregation of other charges and rebates, such as the administrative price charge and Local Market Power rebate.

Non-hourly uplift is charged to consumers based on their share of total demand during the relevant billing period, usually daily or monthly.

<sup>56</sup> Independent Electricity System Operator, *Overview of the IESO-Administered Markets*. January 2014, p. 21. At <http://www.ieso.ca/imoweb/pubs/training/MarketsOverview.pdf>.

<sup>57</sup> Market Surveillance Panel, *Monitoring Report on the IESO-Administered Electricity Markets for the period from November 2013 to April 2014*. April 2015, pp. 28-29. At [http://www.ontarioenergyboard.ca/oeb/\\_Documents/MSP/MSP\\_Report\\_Nov2013-Apr2014\\_20150420.pdf](http://www.ontarioenergyboard.ca/oeb/_Documents/MSP/MSP_Report_Nov2013-Apr2014_20150420.pdf).

## 6.2.3 Global Adjustment

The Global Adjustment (GA) represents the cost of providing both the contracted electricity supply and conservation programs in Ontario. Almost all generation, apart from OPG's regulated hydroelectric and nuclear assets, have long-term contracts. The GA is calculated as the difference between the average weighted Hourly Ontario Electricity Price and the sum of the following six resource sources that are captured in GA-related settlement mechanisms:<sup>58</sup>

- » contracts with nuclear facilities (Bruce Nuclear and OPG nuclear assets)
- » payments to holders of Clean Energy Supply contracts (including early-mover and accelerated gas-fired generation contracts), as well as Combined Heat and Power generation contracts
- » payments to holders of Ontario Electricity Financial Corporation non-utility generator contracts
- » payments to regulated or contracted hydroelectric generation
- » payments to holders of contracts for renewable power (Feed-in Tariff (FIT), microFIT, Renewable Energy Supply)
- » payments to others demand response programs, conservation programs and the contract with OPG's Lennox generating station.

In general, the value of the Global Adjustment varies and is inversely related to the average weighted Hourly Ontario Electricity Price. The higher the average weighted Hourly Ontario Electricity Price, the lower the Global Adjustment, and vice versa.

## 6.2.4 Allocation of Global Adjustment costs

All consumers who directly or indirectly pay the average weighted Hourly Ontario Electricity Price also pay the Global Adjustment.<sup>59</sup> The Global Adjustment is not charged to consumers who produce and consume power behind the meter or who export power from Ontario. However, how much of the Global Adjustment a consumer pays is dependent upon how much power the consumer uses.

The majority of Ontario's 5 million residential and small business consumers purchase electricity from their LDC and pay OEB-regulated time-of-use rates and are designed to include the recovery of Global Adjustment costs. Alternatively, these consumers may purchase electricity from an energy retailer; however, Global Adjustment costs are then included.

Large consumers are those uses more than 250,000 kWh of electricity per year. Large consumers pay both the Hourly Ontario Electricity Price and the Global Adjustment. The Hourly Ontario

58 Market Surveillance Panel, *Monitoring Report on the IESO-Administered Electricity Markets for the period from November 2013 to April 2014*. April 2015, p. 25. At [http://www.ontarioenergyboard.ca/oeb/\\_Documents/MSP/MSP\\_Report\\_Nov2013-Apr2014\\_20150420.pdf](http://www.ontarioenergyboard.ca/oeb/_Documents/MSP/MSP_Report_Nov2013-Apr2014_20150420.pdf).

59 For more information about the Global Adjustment, see the Independent Electricity System Operator, "Ontario Electricity Prices and the Wholesale Market." At <http://www.ieso.ca/Pages/Ontario%27s-Power-System/Electricity-Pricing-in-Ontario/default.aspx>.



Electricity Price for large consumer is determined using one of three possible options:

1. If a business has an interval meter, which measures consumption in real-time, it pays the average weighted Hourly Ontario Electricity Price based on the time of their consumption.
2. If it does not have an interval meter, it pays a weighted Hourly Ontario Electricity Price and the Global Adjustment based on its consumption pattern.
3. The business may choose to enter into a fixed-price contract offered by an energy retailer.

The manner in which large consumers are charged for the Global Adjustment depends upon their size.

Class A consumers are businesses which have an average hourly peak demand of 5 MW or higher, or have an hourly peak demand greater than 3 MW and meet certain industry classifications. All other consumers are designated Class B consumers. Class B customers pay the Global Adjustment based on their total electricity consumption.

Class A consumers are charged Global Adjustment costs based on their percentage contribution to the top five peak demand hours each year. The top five hours of peak demand in a year are those occurring on different days in which the greatest number of MW of electricity was withdrawn from Ontario's electricity system. This allocation methodology is known as the "High-5" allocation. The "High-5" allocation has a number of implications, which include the following.

First, Class A consumers have an incentive to reduce their usage during hours that are anticipated to be included in the "High-5" calculation by shifting their usage to other time periods or by self-generating using behind-the-meter capacity. This reduction in usage mitigates or even eliminates the Global Adjustment obligation of Class A consumers.

Second, Class B consumers pay the majority of the Global Adjustment costs, more than they would have based on a prior allocation methodology where all consumers were charged Global Adjustment costs based on their share of total consumption. In 2014, Class B consumers paid approximately 90.2 per cent of Global Adjustment costs that totalled approximately \$7 billion. Between September and December 2015, Class B consumers have paid approximately 89.5 per cent of Global Adjustment costs totalling approximately \$7.1 billion.<sup>60</sup>

<sup>60</sup> Independent Electricity System Operator, "Ontario Electricity Prices and the Wholesale Market." <http://www.ieso.ca/Pages/Ontario%27s-Power-System/Electricity-Pricing-in-Ontario/default.aspx>.

## 6.2.5 Average effective commodity price of electricity by consumer class

The average effective commodity price expressed in dollars per MWh is set out below in Figure 10. As previously discussed, the average effective commodity price of electricity in Ontario is the sum of these components: average weighted Hourly Ontario Energy Price, the average Global Adjustment and average uplift. The average effective price per MWh reflects the allocation methodologies used for each type of cost and consumer class. The average effective price per MWh for all consumers is a theoretical calculation, where Global Adjustment costs are allocated across all consumer classes, regardless of type, based on their share of total consumption during the period.

**FIGURE 10** Average effective commodity price of electricity by consumer class

Consumer class		Average weighted HOEP (\$/MWh)	Average Global Adjustment (\$/MWh)	Average uplift (\$/MWh)	Average effective price (\$/MWh)
Class A	2013/2014	36.03	21.39	3.29	60.71
	2012/2013	25.54	23.58	2.41	51.53
Class B	2013/2014	39.20	46.49	3.49	89.19
	2012/2013	27.18	47.86	2.47	77.50
All consumers	2013/2014	38.85	43.55	3.47	85.87
	2012/2013	27.00	45.14	2.46	74.60

Source: Market Surveillance Panel, *Monitoring Report on the IESO-Administered Electricity Markets for the period from November 2013–April 2014*, April 2015, p. 8. [http://www.ontarioenergyboard.ca/oeb/\\_Documents/MSP/MSP\\_Report\\_Nov2013-Apr2014\\_20150420.pdf](http://www.ontarioenergyboard.ca/oeb/_Documents/MSP/MSP_Report_Nov2013-Apr2014_20150420.pdf).

# 7] Regulated price plan and time-of-use rates

## 7.1 INTRODUCTION

Section 79.16 of the *Ontario Energy Board Act* requires the OEB to determine a regulated price plan (RPP) for certain eligible consumers. The *OEB Act* also requires that the OEB adjust RPP prices to clear any commodity-related balances in IESO variance accounts over a 12-month period.

The objectives of RPP prices have not substantially changed since April 2005, when the OEB first introduced its RPP pricing plan. The objectives are to:

- » set prices to recover the full cost of RPP supply; that is, the price structure must, on a forecast basis, recover all of the RPP supply costs from the consumers who pay the prices
- » set the price structure to reflect RPP supply costs; that is, the prices should reflect the differences in cost of supply at different times of the day and year
- » set tiered and time-of-use RPP prices and the price structure to give consumers incentives and opportunities to reduce their electricity bills by shifting their time of electricity use
- » create a price structure that is easily understood by consumers.<sup>61</sup>

## 7.2 TIME-OF-USE PRICES

Since 2012, the default RPP option for all small consumers is time-of-use (TOU) pricing. Three separate prices apply – off-peak, mid-peak and on-peak – and the times when these prices apply vary by time of day and season. The load-weighted time-of-use RPP prices must be equal to the average RPP price.

The initial time-of-use RPP prices set by the OEB reflected the allocation of generation supply costs across each time-of-use period, such that off-peak, mid-peak and on-peak RPP prices reflected a ratio of approximately 1:2:3. That is, the forecast price at mid-peak times was roughly twice the off-peak price, and the forecast price at on-peak times was approximately three times the off-peak price.

However, over time, changes in the nature of Ontario's generation supply portfolio and the costs per time-of-use period resulted in a convergence of the three prices. Thus, the OEB has made adjustments to the RPP price-setting methodology:<sup>62</sup>

- » Initially, the costs associated with the Global Adjustment were allocated uniformly on a per kWh basis across all time-of-use supply. However, the reduction in volatility in market prices that resulted from improved demand-supply balances in the Hourly Ontario Electricity Market and

61 Ontario Energy Board, "Regulated Price Plan." At <http://www.ontarioenergyboard.ca/oeb/industry/regulatory+proceedings/policy+initiatives+and+consultations/regulated+price+plan>.

62 Ontario Energy Board, *Regulated Price Plan Roadmap*, EB-2014-0319, November 16, 2015. At [http://www.ontarioenergyboard.ca/oeb/\\_Documents/EB-2004-0205/RPP\\_Roadmap\\_Report\\_of\\_the\\_Board\\_20151116.pdf](http://www.ontarioenergyboard.ca/oeb/_Documents/EB-2004-0205/RPP_Roadmap_Report_of_the_Board_20151116.pdf).

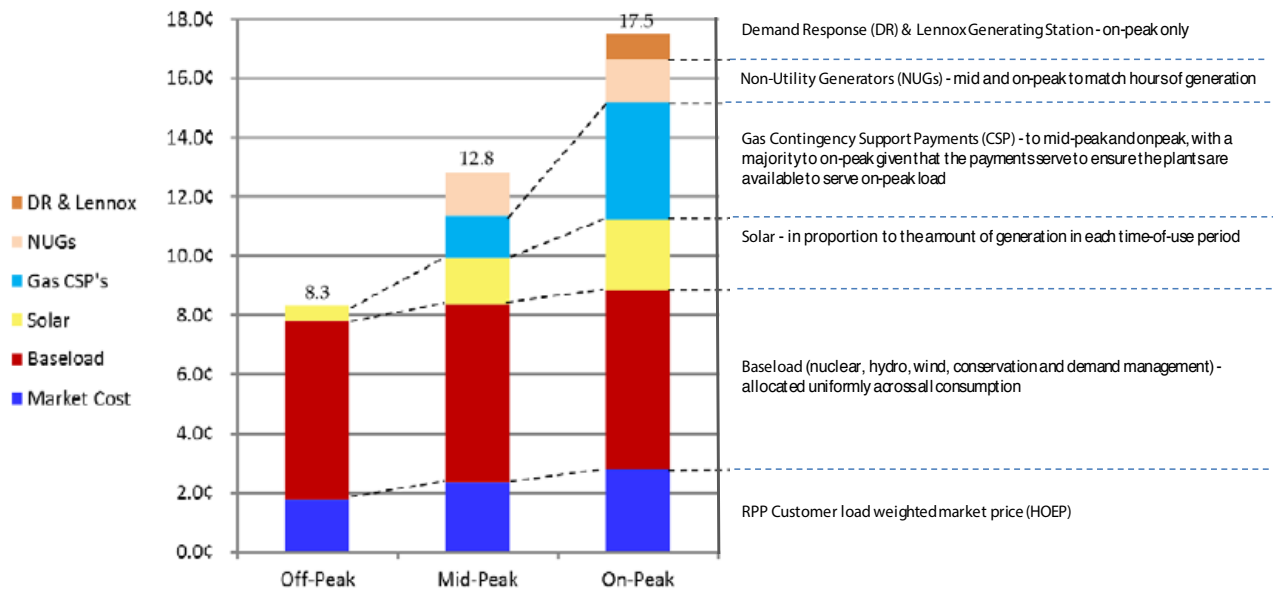
greater reliance on long-term supply contracts reduced the spread between time-of-use prices. For example, the ratio of on-peak to off-peak prices declined from approximately 3.2:1 to 2:1. As a result, in 2009 the OEB revised the allocation of Global Adjustment costs to attribute these costs to the time-of-use consumption periods reflecting the system purpose for which many of the generating facilities were initially contracted. The intention was to preserve load shifting incentives inherent in time-of-use RPP pricing while ensuring supply cost recovery.

- » In 2011, the time at which the off-peak period began on weekdays was changed to 7:00 p.m. throughout the year and also during weekends and statutory holidays, and conservation and demand management programs undertaken by local distribution companies and approved by the OEB were included in the Global Adjustment costs.
- » In 2015, the OEB made changes in the allocation of the costs of natural gas generators into the mid-peak and one-peak periods, reflecting the system purpose for which many of the facilities were initially contracted to ensure reliability of supply as intermittent renewable energy continued to be added to the Ontario electricity supply-mix and to be a dispatchable source of power at times of higher demand. This change again increased the ratio between on and off peak time-of-use prices, once again preserving load shifting incentives while ensuring supply cost recovery.

For the small number of customers that are technically not on TOU pricing, tiered pricing is available. The tiered price is an average of the TOU price.

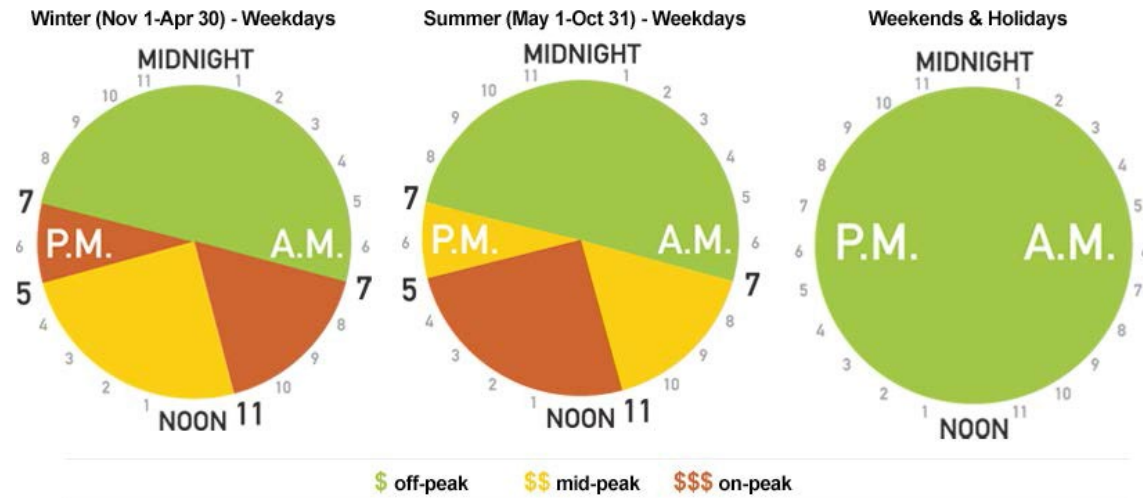
The allocation of supply costs to time-of-use periods as of November 2015 is as set out in Figure 11.

**FIGURE 11** Allocation of supply costs to time-of-use periods (cents per kWh)



Source: Ontario Energy Board, *Regulated Price Plan Roadmap*, EB-2014-0319, November 16, 2015, p. 16. At [http://www.ontarioenergyboard.ca/oeb/\\_Documents/EB-2004-0205/RPP\\_Roadmap\\_Report\\_of\\_the\\_Board\\_20151116.pdf](http://www.ontarioenergyboard.ca/oeb/_Documents/EB-2004-0205/RPP_Roadmap_Report_of_the_Board_20151116.pdf).

FIGURE 12 Summer and winter time-of-use periods

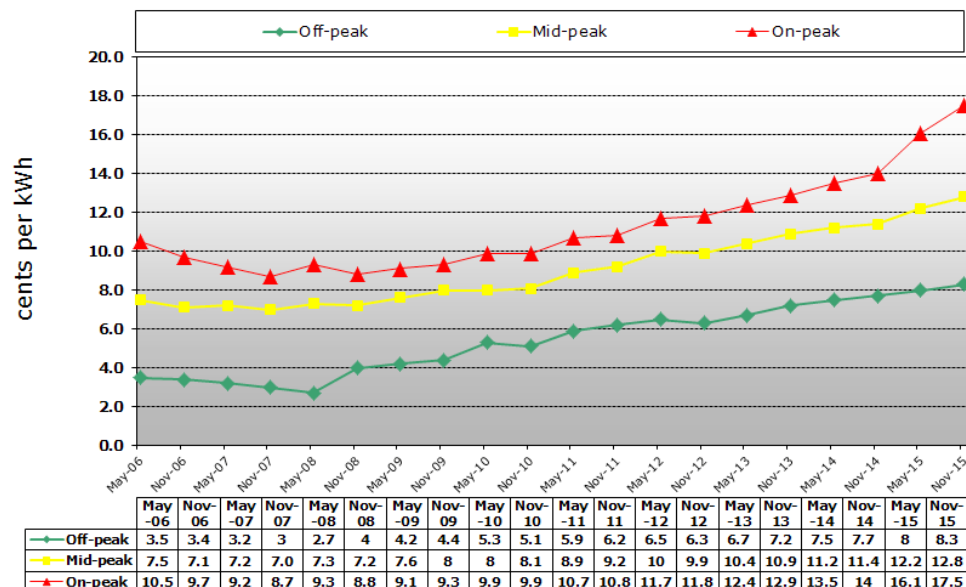


Source: Ontario Energy Board, *Backgrounder: November 1st electricity price change*, October 15, 2015, p. 2. At [http://www.ontarioenergyboard.ca/oeb/\\_Documents/Press%20Releases/bg\\_RPP\\_20151015.pdf](http://www.ontarioenergyboard.ca/oeb/_Documents/Press%20Releases/bg_RPP_20151015.pdf).

The time-of-use periods change every May 1 and November 1, the same day time-of-use prices are adjusted. The time-of-use periods differ between the summer and winter periods and reflect differences in consumer habits. In the summer, electricity consumption typically peaks in the afternoon, when temperatures are at their highest and air conditioning load is maximized. In the winter, electricity utilization has two peaks – the morning and early evening – as illustrated in Figure 12.

Historical time-of-use RPP prices are set out in Figure 13.

FIGURE 13 Historical time-of-use RPP prices



Source: Ontario Energy Board, "Historical Electricity Prices." At <http://www.ontarioenergyboard.ca/OEB/Consumers/Electricity/Electricity+Prices/Historical+Electricity+Prices>.

On November 16, 2015, the OEB released a report entitled Regulated Price Plan Roadmap.<sup>63</sup> In that report, the OEB indicated that it would be undertaking a comprehensive process to redesign the RPP. The roadmap sets out a number of regulatory barriers that are to be addressed in the RPP redesign:

### **Regulated off-peak period**

The present weekday, off-peak period is mandated by government in Ontario Regulation 95/05. However, the time-of-use time periods do not match well with the existing system load shape and further divergences are expected in the future, particularly as the amount of embedded solar generation increases.

### **Misalignment of the Global Adjustment recovery**

Global Adjustment costs are recovered differently between Class B RPP consumers and Class B Non-RPP consumers, and actions by Class B RPP consumers to shift consumption and reduce consumption may adversely affect non-RPP Class B consumers.

### **Long-run marginal cost**

There is a need to ensure that RPP costs reflect long run marginal cost, rather than short run costs, in order to provide an incentive to reduce demand at peak times and mitigate additional investments in generation capacity.

## **7.3 TIERED PRICES**

For those customers who, generally for technical reasons, are not able to use time-of-use pricing, the OEB has retained its earlier tiered pricing structure. The tier prices are the same for all RPP customers who make use of this price structure; however, the tier thresholds are not the same at all times. The tier prices must be calculated so that the expected average price, calculated on a tiered load weighted basis, equals the average RPP time-of-use price.

The tier thresholds for residential RPP consumers are 600 kWh per month for the period May 1 to October 31 annually, and 1,000 kWh per month for the period November 1 to April 30 annually. The tiers reflect the OEB's view that electricity for space heating during the colder months is a necessity, whereas space cooling during the warmer months is more discretionary. The tier thresholds for residential RPP consumers have remained consistent since November 1, 2005. The tier threshold for all non-residential RPP consumers is 750 kWh per month and has been at this level since inception.<sup>64</sup> The tiered RPP prices since November 1, 2005 are set out below in Figure 14.

63 Ontario Energy Board, *Regulated Price Plan Roadmap*, EB-2014-0319, November 16, 2015. [http://www.ontarioenergyboard.ca/oeb/\\_Documents/EB-2004-0205/RPP\\_Roadmap\\_Report\\_of\\_the\\_Board\\_20151116.pdf](http://www.ontarioenergyboard.ca/oeb/_Documents/EB-2004-0205/RPP_Roadmap_Report_of_the_Board_20151116.pdf).

64 Ontario Energy Board, *Regulated Price Plan Manual*, November 13, 2013, p. 22. At [http://www.ontarioenergyboard.ca/oeb/\\_Documents/EB-2004-0205/RPP\\_Manual.pdf](http://www.ontarioenergyboard.ca/oeb/_Documents/EB-2004-0205/RPP_Manual.pdf).

**FIGURE 14** Historical tiered electricity prices for RRP consumers

	For six months beginning May 1		For six months beginning November 1	
	600 kWh or Less/ month	More than 600 kWh/month	1,000 kWh or Less/ month	More than 1,000 kWh/month
2015	9.4	11.0	9.9	11.6
2014	8.6	10.1	8.8	10.3
2013	7.8	9.1	8.3	9.7
2012	7.5	8.8	7.4	8.7
2011	6.8	7.9	7.1	8.3
2010	6.5	7.5	6.4	7.4
2009	5.7	6.6	5.8	6.7
2008	5.0	5.9	5.6	6.5
2007	5.3	6.2	5.0	5.9
2006	5.8	6.7	5.5	6.4

Source: Ontario Energy Board, "Historical Electricity Prices." At <http://www.ontarioenergyboard.ca/OEB/Consumers/Electricity/Electricity+Prices/Historical+Electricity+Prices>.

## 7.4 CONSUMER ELIGIBILITY

The following consumers are prescribed by the RPP regulation as being eligible to pay RPP prices:<sup>65</sup>

- » low-volume consumers
- » a consumer who has a demand of 50 kW or less
- » a consumer who has an account with a local distribution company and the account relates to a dwelling, a condo, a rental property or a co-operative dwelling, as each defined
- » a consumer who annually uses at least 150,000 kWh but not more than 250,000 kWh of electricity
- » a farmer who has an account with a local distribution company.

Ineligible Class B consumers are known as non-RPP Class B consumers, and the Global Adjustment costs allocated to non-RPP Class B consumers are "recovered from non-RPP Class B consumers through a uniform flat rate determined by the IESO."<sup>66</sup>

<sup>65</sup> Ontario Regulation 95/05: *Classes of Consumers and Determination of Rates*, January 1, 2011. At <https://www.ontario.ca/laws/regulation/050095>.

<sup>66</sup> Ontario Energy Board, *Regulated Price Plan Roadmap*, EB-2014-0319, November 16, 2015, p. 18. [http://www.ontarioenergyboard.ca/oeb/\\_Documents/EB-2004-0205/RPP\\_Roadmap\\_Report\\_of\\_the\\_Board\\_20151116.pdf](http://www.ontarioenergyboard.ca/oeb/_Documents/EB-2004-0205/RPP_Roadmap_Report_of_the_Board_20151116.pdf).

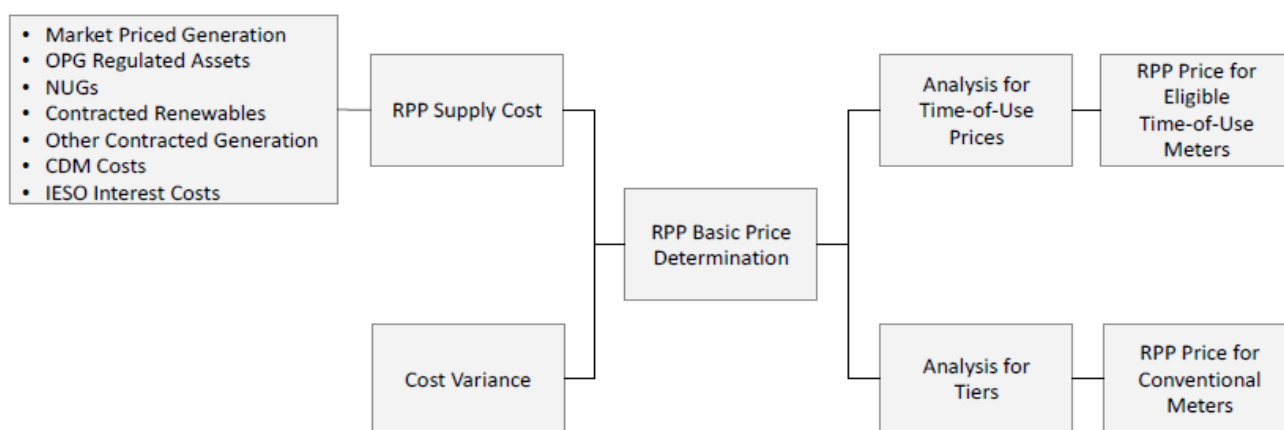
## 7.5 SETTING RPP PRICES

In general, the methodology to determine RPP prices has two steps:

1. forecasting the total RPP supply cost for 12 months
2. establishing the prices to recover the forecast RPP supply cost from RPP consumers over a 12-month period.

The process for determining the RPP price for customers with conventional and smart meters is set out below in Figure 15.

**FIGURE 15** Process flow for determining the RPP price



Source: Ontario Energy Board, *Regulated Price Plan Manual*, November 13, 2013, p. 5. At [http://www.ontarioenergyboard.ca/oeb/\\_Documents/EB-2004-0205/RPP\\_Manual.pdf](http://www.ontarioenergyboard.ca/oeb/_Documents/EB-2004-0205/RPP_Manual.pdf).

## 7.6 FORECASTING RPP PRICES

Two types of costs are used to forecast RPP supply costs:

1. the forecast RPP supply cost
2. the accumulated variance account balance that is carried by the IESO.

These two costs comprise the basic RPP price determination, which must be set to recover the full cost of electricity supply.

Figure 16 illustrates total electricity supply and cost by generation type, and Figure 17 illustrates the average RPP supply cost summary for the period November 1, 2015 to October 31, 2016.



**FIGURE 16** Total electricity supply and cost

	Percentage of total Supply	Percentage of total GA	Total unit cost (cents/kWh)
Nuclear	60%	45%	6.9
Hydro	22%	13%	6.0
Gas	8%	17%	1.3
Wind	7%	13%	13.3
Solar	2%	12%	47.5
Bioenergy	0%	0%	13.0

Source: Ontario Energy Board, *Regulated Price Plan Price Report*, November 1, 2015 to October 31, 2016, October 15, 2015, p. 19. At [http://www.ontarioenergyboard.ca/oeb/\\_Documents/EB-2004-0205/RPP\\_Price\\_Report\\_Nov2015.pdf](http://www.ontarioenergyboard.ca/oeb/_Documents/EB-2004-0205/RPP_Price_Report_Nov2015.pdf).

**FIGURE 17** Average RPP supply cost summary for the period from November 1, 2015 through October 31, 2016

Forecast wholesale prices		\$18.82
Load-weighted price for RPP consumers (\$/MWh)		\$20.57
Impact of the Global Adjustment (\$/MWh)+		\$87.92
Adjustment to address bias towards unfavourable variances (\$/MWh)	+	\$1.00
Adjustment to clear existing variances (\$\$/MWh)	+	(\$2.22)
Average supply cost for RPP consumers (\$/MWh)	=	\$107.28

Source: Ontario Energy Board, *Regulated Price Plan Price Report*, November 1, 2015 to October 31, 2016, October 15, 2015, p. 19. At [http://www.ontarioenergyboard.ca/oeb/\\_Documents/EB-2004-0205/RPP\\_Price\\_Report\\_Nov2015.pdf](http://www.ontarioenergyboard.ca/oeb/_Documents/EB-2004-0205/RPP_Price_Report_Nov2015.pdf).

## 8] Incentives in Ontario's electricity industry

This section describes a number of the key incentives in Ontario's electricity industry. It is not intended to be exhaustive; rather, it highlights the most significant incentives that drive the allocation of capital by the private and public participants in Ontario's electricity industry, as currently structured. Incentives are, generally speaking, features that have been expressly designed to meet certain policy or legal requirements. However, incentives often have unintended consequences that are difficult to address without fundamentally changing energy policy or long-standing regulatory practice.

### 8.1 COST-OF-SERVICE REGULATION

As previously discussed, in section 4, the OEB is required by statute to allow entities subject to its jurisdiction an opportunity to recover their reasonably incurred costs of providing service. In general, the following characteristics of the current cost-based regulatory approach produce a number of behaviours that may be considered to be undesirable.

#### **Forward test year approach**

The rate-setting approach in Ontario makes use of a forward test year, where estimated future costs are subject to discovery and litigation. Although continuity schedules are generally provided for previous fiscal periods and the last approved-costs, applicants have a tendency to increase estimated costs in the test year and cluster capital expenditure increases in the year immediately preceding the test year and the test-year itself. Costs and capital expenditures are then "managed" during the following rate-setting years, to the benefit of shareholders. A number of regulatory tools have been implemented to combat these behaviours, including capping the maximum return on equity a utility shareholder can earn during a fiscal period and asymmetric sharing of lower OM&A and costs in rates relating to the quantum and timing of capital expenditures.

#### **Flow through of OM&A costs**

Although the onus is on the rate-regulated applicant to demonstrate that costs are reasonable and that the resulting rates would be just and reasonable, significant information asymmetry exists between the applicant and the OEB (as well as any intervenors). While the OEB is able to make use of any method or device it chooses to establish rates, can direct the filing of substantial information, and is able to exercise considerable discretion, the utility's incentive to control OM&A costs is muted. Incentive regulatory approaches attempt to reduce the rate of growth in OM&A costs and index OM&A costs with inflation for the years between cost-of-service rate applications. However, applied-for OM&A increases at the time of rebasing are typically higher than the rate of inflation, as incentive structures may not result in permanent changes in cost structures and/or attitudes regarding costs.

#### **Ratebase as a driver of net income**

Rate-regulated entities have considerable incentive to grow the ratebase and to capitalize indirect overheads; as investment increases, so do earnings. Overinvestment and "gold-plating" utility assets is a commonly discussed drawback of cost-of-service regulation. The capitalization of

indirect overheads has been partially addressed by the OEB via the adoption of the Modified International Financial Reporting Standard (MIFRS), where the capitalization of indirect overhead is not permitted.

The focus on the ratebase also tends to cause transmitters and distributors to want to include assets as well as the capital-related costs in OM&A in the ratebase, despite these assets being attributable to non-network monopoly functions and would not be regulated assets. Owners and management of network monopolies have an incentive to favour monopoly solutions over those that could be provided by un-regulated third-parties using market-based technologies at market-based prices. Finally, rate-regulated entities have considerable incentives to use ratepayer funded capacity to compete in other businesses that are closely related, but are essentially competitive services.

## 8.2 CENTRALIZED PROCUREMENT OF GENERATION BY THE IESO

The IESO has, at the government's direction, been "inviting investment in generation technologies and facilities to supply new generation capacity over the last decade. The Ministry of Energy determines the procurement levels of each fuel type based on its Long-Term Energy Plan."<sup>67</sup> The IESO estimates that approximately 50 per cent of Ontario's installed capacity is subject to a contract with the IESO. Based on this estimate, the approximate total installed generating capacity in Ontario is about 46,432 MW, versus an estimated winter 2015/16 extreme weather peak demand of 23,181 MW<sup>68</sup> and an estimated extreme weather peak in summer 2016 of 24,569 MW.<sup>69</sup>

The presence of significant intermittent generation capacity (wind and solar totalling some 8,257 MW) in the estimate means that the notional capacity margin is overstated. The IESO regularly publishes its assessment of the reliability and operability of the electricity system in Ontario and its reserve margin requirements, with the latter meeting the requirements of the NPCC resource adequacy criteria over a five-year period.

The IESO's published supply mix data available on its website includes only the generation that is connected to the transmission grid or is an embedded generator (i.e., distribution connected) that participates in the IESO-administered market. The generation capacity that is the subject of the *Progress Report on Contracted Electricity Supply* reflects all transmission and distribution connected generation, but excludes generation that is subject to contracts with other Ontario agencies or subject to other administrative mechanisms, including price regulation by the OEB. In particular, the *Progress Report* excludes: OPG-regulated assets, heritage assets, non-utility generation operating under contracts with the Ontario Electricity Finance Corporation and market participants that sell energy on the open market and receive the hourly market price of electricity.

67 Independent Electricity System Operator, *Progress Report on Contracted Electricity Supply: Q2-2015*, September 21, 2015, p. 8. At <http://www.ieso.ca/Documents/Supply/Progress-Report-Contracted-Supply-Q12015.pdf>.

68 Independent Electricity System Operator, *18-Month Outlook: An Assessment of the Reliability and Operability of the Ontario Electricity System from October 2015 to March 2017*, September 21, 2015, p. 4. At [http://www.ieso.ca/Documents/marketReports/18MonthOutlook\\_2015sep.pdf](http://www.ieso.ca/Documents/marketReports/18MonthOutlook_2015sep.pdf).

69 Ibid.

In general, it is important to note that virtually all of the installed generating capacity in Ontario is subject to some form of contractual or administrative arrangement, in which variable and fixed costs of production, including a return of and on capital, are recovered from Ontario electricity consumers through the Global Adjustment. All procured generation costs must be paid by customers because of a statutory requirement in the *Electricity Act* that all costs flow through to customers, without exception.

It is also important to note that, unlike the situation in the United States or Australia, there is no special status for property rights under the Canadian Constitution. There is, however, protection provided by statute, treaty (e.g., the Universal Declaration of Human Rights), convention and political constraint. In general, the Ontario government has been unwilling to make the legislative changes necessary to abrogate the contracts for electricity supply procurement with private sector developers without paying a penalty or compensation. It is unclear whether this de facto protection will continue.

### 8.3 Implications of the procurement approach

Ontario's preference for administrative or contractual arrangements for generation and the statutory recovery of all costs from consumers has a number of implications.

First, contract terms and conditions are not subject to review by the OEB and reflect political policy considerations that put a priority on items other than cost. The result of the priority placed on policy considerations is the previously noted increases in the RPP prices.

Second, not all contracting processes are competitive and the resulting pricing and terms of service are not subject to any form of market discipline. Of all the generation solicitations undertaken by the IESO at the direction of the Ministry of Energy, the FIT and microFIT initiatives are the most vulnerable to this observation.

Third, the rates of return associated with the prices ultimately awarded or associated with each of these procurements are such that generator interest was well in excess of the MW for which contracts were ultimately awarded. In the case of the FIT and microFIT programs, contract up-take was significantly higher than expected so that contract terms and prices have been revised more frequently and more aggressively downward (in the case of price) than initially planned.

Fourth, the centralized procurement of generation by the IESO continues, even though the government is pursuing the potential policy role of distributed energy resources on a separate track. As the so-described "system cost" for electricity increases, largely as the result of the consequences of centralized procurement that are recovered via the Global Adjustment and the continued asset investment in other energy infrastructure, and distributed energy resources become competitive with the system cost (or achieve grid-parity), the incentive to by-pass the integrated electricity system increases. At issue is whether by-pass is "economic bypass" or "uneconomic by-pass," based on a false signal of system costs arising from centralized procurement activities that have resulted in excessive investment in some types of generation.

Finally, assuming that those who are able will adopt distributed energy resources to either completely or partially by-pass system costs, then those costs will simply be reallocated to remaining customers, unless various tools, regulatory or otherwise, are used to attribute costs to departing or semi-departing customers in recognition that existing investments in energy infrastructure were made to meet these customers' requirements for capacity, energy, and reliability and that these costs have not yet been recovered. There are significant fairness and social benefit issues arising from this potential reallocation of system costs.

## 8.4 SELF-GENERATION BEHIND THE METER

### 8.4.1 "Conservation First" framework

In March 2014, the Ontario Minister of Energy issued a directive to the IESO regarding the 2015 to 2020 "Conservation First" framework. As a result the IESO established eligibility rules for behind-the-meter generation projects that may be accepted into conservation programs. There are two types of behind-the-meter generation projects that may be eligible: waste energy recovery (WER) and conservation combined heat and power (CCHP) projects. A proposed behind-the-meter facility must:<sup>70</sup>

1. have a gross nameplate capacity of less than 10 MW
2. not be used for the sole purpose of reducing electricity demand during the five critical system-peak hours
3. in the case of a waste energy recovery project, demonstrate that natural gas or propane purchased from or otherwise supplied by a third party to the proponent does not exceed 10 per cent of the fuel energy input
4. in the case of a conservation combined heat and power project, meet the following criteria:
  - a. use natural gas or propane as its sole fuel, unless otherwise approved in writing by the IESO
  - b. be designed and operated in a manner that the conservation combined heat and power project achieves a minimum annual total system efficiency of 65 per cent
  - c. not use the thermal output from the conservation combined heat and power project to generate electricity
5. not be the subject of, or have been the subject of, a physical or financial power or capacity purchase contract relating to the generation of electricity by such proposed facility (in whole or in part), or other form of contract relating to electricity relating to such proposed facility with the IESO, the Ontario Electricity Financial Corporation or the government of Ontario or any other agency
6. not be split across multiple applications for the purpose of circumventing the 10 MW limit on gross nameplate capacity.

<sup>70</sup> Independent Electricity System Operator, "Behind-the-Meter Generation Project Rules," *Conservation First Framework LDC Tool Kit*, March 18, 2015, p. 2. At <http://www.powerauthority.on.ca/sites/default/files/conservation/Behind-the-Meter-Generation-Project-Rules-v1.pdf>.

In addition to the eligibility requirements, the IESO agreement with the proponent will include the following terms and conditions:<sup>71</sup>

1. the proponent shall not directly or indirectly assign, transfer, sell or supply electricity it generates from a behind-the-meter generation project into the IESO-controlled grid
2. the proponent shall not use a behind-the-meter project at any time during the term of the agreement for the primary purpose of reducing electricity demand during the five critical system-peak hours
3. the proponent shall be a distribution consumer at all times during the term of the agreement.
4. the proponent's facility shall be connected to the distribution system at all times during the term of the agreement
5. the agreement will include any other provision required to give effect to the behind-the-meter generation project rules

Certain incentives are available to proponents of behind-the-meter generation, consistent with the overall program rules. For conservation combined heat and power project, the incentive is equal to the lower of 40 per cent of the eligible costs of the behind-the-meter generation project or the amount of the incentive set out in the program rules.

## 8.4.2 microFIT to net-metering/self-consumption

On April 7, 2015, the Ontario Minister of Energy issued a directive to the IESO regarding the FIT and microFIT programs. The minister directed certain changes to the FIT program and reaffirmed the government's commitment to previously announced initiatives, including its commitment in the 2013 Long-Term Energy Plan to explore the potential evolution of the microFIT program to a net-metering initiative.<sup>72</sup>

The IESO has defined the microFIT program and net-metering/self-consumption initiative as follows:<sup>73</sup>

### **microFIT**

a generating purchasing program for homeowners and other eligible participants for renewable electricity generation projects 10 kW or less in size

### **net metering**

a billing mechanism that credits renewable energy system owners for the electricity they output to the electricity grid

### **self-consumption**

electricity that is consumed onsite first at a customer site before any excess is exported to the electricity grid.

71 Independent Electricity System Operator, "Behind-the-Meter Generation Project Rules," *Conservation First Framework LDC Tool Kit*, March 18, 2015, p. 3. At <http://www.powerauthority.on.ca/sites/default/files/conservation/Behind-the-Meter-Generation-Project-Rules-v1.pdf>.

72 Minister of Energy, Directive: *Feed-in Tariff (FIT) and microFIT programs*, April 7, 2015. At [http://www.ieso.ca/Documents/Ministerial-Directives/MC-2015-742\\_FIT.pdf](http://www.ieso.ca/Documents/Ministerial-Directives/MC-2015-742_FIT.pdf).

73 Ministry of Energy, *Net Metering/Self-Consumption In-Person Engagement Sessions*, September 14, 2015, p. 4. At [http://www.cansia.ca/sites/default/files/2015-09-11\\_nmssc\\_in-person\\_engagement\\_session\\_ministry\\_deck\\_sept14toronto.pdf](http://www.cansia.ca/sites/default/files/2015-09-11_nmssc_in-person_engagement_session_ministry_deck_sept14toronto.pdf).

The ministry is targeting a transition to a net-metering initiative in late 2017 or early 2018. The objectives of the program are:<sup>74</sup>

1. reduce ratepayer costs associated with small-scale renewable generation, relative to the current microFIT program, with the ultimate goal of achieving a self-sustaining program
2. support the “Conservation First” policy by ensuring systems are right-sized and sited close to load
3. reflect the costs and benefits of integrating net metered generation into the electricity system, and recover the costs efficiently and equitably
4. continue to offer consumers choice to offset their load using renewable energy, subject to system need and cost considerations.

The net metering/self-consumption proposal reflects the concept that the program will offer a long-term framework for the development of small-scale renewable energy systems in Ontario that aligns with value to the electricity system, and fairly allocates costs and benefits among all ratepayers.<sup>75</sup>

The key guiding principles include:

- » Local distribution companies would connect and compensate generators at a value that reflects system costs and benefits.
- » Conservation would be considered first by the appropriate sizing of systems to customer needs.
- » Compensation would be set transparently and predictably.
- » The program would be flexible and responsive to changing system needs.
- » The process for eligible customers to participate in the program would be streamlined.
- » The program would allow for the integration of new metered renewable energy systems with innovative technologies, such as energy storage.
- » The program would incorporate best practices.

The customer would receive compensation for excess energy production (i.e., production greater than consumption) as a credit against the customer’s bill. The customer would also receive funding in relation to benefits

### 8.4.3 IESO market-based initiatives

Since 2011, the IESO has consulted with Ontario electricity industry stakeholders to assist in developing a future direction for the electricity market. As a result of these consultations, the

<sup>74</sup> Ministry of Energy, *Net Metering/Self-Consumption In-Person Engagement Sessions*, September 14, 2015, p. 17. At [http://www.cansia.ca/sites/default/files/2015-09-11\\_nmssc\\_in-person\\_engagement\\_session\\_ministry\\_deck\\_sept14toronto.pdf](http://www.cansia.ca/sites/default/files/2015-09-11_nmssc_in-person_engagement_session_ministry_deck_sept14toronto.pdf).

<sup>75</sup> Ministry of Energy, *Net Metering/Self-Consumption In-Person Engagement Sessions*, September 14, 2015, p. 18. At [http://www.cansia.ca/sites/default/files/2015-09-11\\_nmssc\\_in-person\\_engagement\\_session\\_ministry\\_deck\\_sept14toronto.pdf](http://www.cansia.ca/sites/default/files/2015-09-11_nmssc_in-person_engagement_session_ministry_deck_sept14toronto.pdf).

IESO is working to develop efficient market-based mechanisms to help meet future needs in a cost-effective manner, improve price signals, reduce barriers to participation in the market and better align conservation and demand management with system needs. These efforts include the initiatives set out below. It is important to note that these initiatives continue the tradition of centralized procurement of resources in Ontario and that all costs associated with these initiatives are recovered from customers via the Global Adjustment.

### **Non-utility generators framework assessment**

On September 1, 2015 the IESO issued a report to the minister of energy in which it assessed the framework for non-utility generating recontracting. The IESO recommended continuing the current pause in the recontracting of non-utility generation; actively monitoring evolving sector conditions and impacts on system need; and continuing the development of the capacity auction and capacity export markets with consideration given to facilitating broad participation, including that of non-utility generation.

### **Capacity auctions**

The IESO's capacity auction would establish an open process to meet future energy needs, lower costs, increase transparency around these costs and would result in greater innovation in the electricity market. The first capacity auction is slated for 2017 to secure supply by the end of the decade.

### **Demand response pilot**

Following a competitive procurement, the IESO has secured up to 80 MW of demand response from five companies representing 20 projects ranging from 1 MW to 35 MW, each with unique technical characteristics, requirements and constraints. The pilot is to see how demand response can provide the following services: five-minute load following, hourly load following and unit commitment. Selected resources will be required to vary their consumption in response to IESO dispatch instructions for at least 100 hours per contract year.

### **Energy storage procurement – Phase II**

On November 23, 2015, the IESO announced that it has selected five energy storage proponents for contract offers, representing nine projects totalling 16.75 MW. The IESO is seeking to better understand how energy storage projects can be integrated and operated in the Ontario market.

### **Foundation Project**

On November 4, 2015, the IESO issued its recommendations resulting from the Foundation Project, which focused on developing recommendations to: ensure that the consumption data sent to the centralized Meter Data Management Repository includes geo-location, customer identifier or other relevant information to capture the analysis value of the data set; and to develop a framework or protocol to govern access to data from the Meter Data Management Repository and the associated "data mart," and build in "privacy by design."<sup>76</sup>

<sup>76</sup> See, for example, [https://www.ipc.on.ca/site\\_documents/pbd-resolution.pdf](https://www.ipc.on.ca/site_documents/pbd-resolution.pdf).



## 9] Utility system planning

### 9.1 CDM AND THE SMART GRID INITIATIVES 2004-2013

LDCs are generally treated as demand entities and have had little interaction with provincial resource planning. The exception has been conservation and demand management (CDM). The IESO develops province-wide programs, while the LDCs can provide similar programs under the ambit of OEB demand side management policies. Prior to 2009, there was little interaction between the provincial CDM programs and the LDC-led local CDM programs.

The passage of the *Green Energy Act* in 2009 introduced feed-in tariffs for renewables and CDM targets for most LDCs. The OEB subsequently incorporated these targets into the distribution licences of the utilities. The Board also established the Conservation and Demand Management Code for electricity distributors. The code requires coordination between provincial and LDC CDM programs.<sup>77</sup> In addition, the OEB established so-called “Lost Revenue Adjustment Mechanisms” (LRAM) in order to compensate utilities for revenue decline associated with CDM programs.<sup>78</sup> The LRAM protection is in place for one rate period (usually a period of three to five years). Subsequently upon a cost-of-service rebasing, the reduction in load becomes built into the utility’s load forecast.

### 9.2 THE SMART GRID

The other impact of the *Green Energy Act* on utility distribution planning has been the FIT program; both FIT and microFIT generation present challenges to LDCs. The larger FIT-related generation proposals quickly revealed the bottlenecks within the transmission and sub-transmission networks. MicroFIT projects demonstrated a need for new switching, isolation, power quality and SCADA technologies in order to accommodate new multiple points of supply. While the installation of smart meters was anticipated to start building of a “smart grid,” in fact, it has been the interoperability requirements associated with micro generation that have largely led the way in terms of LDC “smart-grid” capital investments.<sup>79</sup>

The OEB established a consultative forum on the smart grid in 2013. The initiative seems largely moribund with the associated Smart Grid Advisory Committee having yet to release any significant recommendations. Currently, it appears focused on energy storage technologies.

### 9.3 LDC CAPITAL PLANNING

Prior to 2005, long-term planning was not done by most LDCs other than the largest urban companies and HONI. Utilities generally operated assets on a run-to-failure basis. Most distributors did not operate SCADA or remote switching systems.

<sup>77</sup> *The Conservation and Demand Management Code* also sets reporting requirements, CDM program objectives, accounting requirements and a number of other related requirements.

<sup>78</sup> Details of the LRAM mechanism, its evolution to LRAMVA and further CDM requirements are set out in Ontario Energy Board, *Conservation and Demand Management Requirement Guidelines for Electricity Distributors*, EB-2014-0278. At [http://www.ontarioenergyboard.ca/oeb/\\_Documents/Regulatory/CDM\\_Guidelines\\_Elec\\_Distributors\\_20141219.pdf](http://www.ontarioenergyboard.ca/oeb/_Documents/Regulatory/CDM_Guidelines_Elec_Distributors_20141219.pdf).

<sup>79</sup> The establishment of a central billing data repository – the Smart Meter Entity – is being projected as one of the potential foundations for a “data revolution.”

The initial cost of service reviews, which began in 2006, revealed the lack of rigorous systematic capital planning and made it difficult for the OEB to responsibly approve the cost consequences of capital programs. However, between 2006 and 2010 a large part of both the OEB's and LDC's focus would be on the mandated requirement to install smart meters for all residential customers in Ontario.

The *Green Energy Act's* anticipation of renewable generation and smart grids resulted in the Board issuing guidelines in 2009 that focused on investments in "renewable enabling improvements" and smart grid demonstration projects.<sup>80</sup> The guidelines also anticipated the future requirement of LDCs to file comprehensive distribution system plans as part of cost-of-service rate applications. These requirements would later be codified in filing requirements.<sup>81</sup> The requirements include provisions for a *Green Energy Act Plan (GEA Plan)* related to investments made for renewable projects that have provincial-wide benefit and whose costs may in part be recovered from the body of provincial ratepayers. To date, such investments have been marginal. The OEB also instituted a requirement for LDCs to submit their capital investments plans related to FIT and microFIT programs for review.

In 2013, the OEB consolidated the *GEA Plan* requirements and added new comprehensive requirements related to distribution system planning under Chapter 5 of its electricity distribution filing requirements.<sup>82</sup> In addition to certain mandatory reporting, including standardized reporting categories for capital expenditures, the filing requirements call for a forward looking five-year distribution system capital plan to be submitted at the time of an application for rebased cost-of-service rates.

In support of the capital program, the utility is required to submit both an asset management plan, which examines the condition of utility assets and a distribution system plan. The distribution system plan follows from the asset assessment plan and explains how utility assets are to be maintained over the period of the investment horizon. Other requirements relate to performance and reliability metrics as part of both need (scorecards) and an assessment of the plan's implementation (outcome targets).

The filing guidelines also contemplate a number of smart grid type investments, including DER investments calling for the consideration a distributor has given to the investments necessary to facilitate the integration of distributed generation and more complex loads (e.g., customers with self-generation and/or storage capability).<sup>83</sup>

80 Ontario Energy Board, *Guidelines: Deemed Conditions of Licence: Distribution System Planning*, OEB G-2009-0087, June 16, 2009. At [http://www.ontarioenergyboard.ca/oeb/\\_Documents/EB-2009-0087/Dx\\_System\\_Planning\\_Guidelines\\_20090616.pdf](http://www.ontarioenergyboard.ca/oeb/_Documents/EB-2009-0087/Dx_System_Planning_Guidelines_20090616.pdf).

81 Ontario Energy Board, *Filing Requirements: Distribution System Plans under the Green Energy Act*, OEB EB-2009-0397, December 18, 2009. At [http://www.ontarioenergyboard.ca/oeb/\\_Documents/EB-2009-0397/draft\\_filing\\_requirements\\_DSP\\_20091218.pdf](http://www.ontarioenergyboard.ca/oeb/_Documents/EB-2009-0397/draft_filing_requirements_DSP_20091218.pdf).

82 Ontario Energy Board, *Filing Requirements for Electricity Transmission and Distribution Applications*, Chapter 5 – Consolidated Distribution System Plan Filing Requirements, March 28, 2013. At [http://www.ontarioenergyboard.ca/oeb/\\_Documents/Regulatory/Filing\\_Requirements\\_Tx\\_Dx\\_Applications\\_Ch5.pdf](http://www.ontarioenergyboard.ca/oeb/_Documents/Regulatory/Filing_Requirements_Tx_Dx_Applications_Ch5.pdf).

83 Ontario Energy Board, *Filing Requirements for Electricity Transmission and Distribution Applications, Chapter 5 – Consolidated Distribution System Plan Filing Requirements*, March 28, 2013, p. 4. At [http://www.ontarioenergyboard.ca/oeb/\\_Documents/Regulatory/Filing\\_Requirements\\_Tx\\_Dx\\_Applications\\_Ch5.pdf](http://www.ontarioenergyboard.ca/oeb/_Documents/Regulatory/Filing_Requirements_Tx_Dx_Applications_Ch5.pdf).

Regional planning and consultation are also required, including the consideration of potential renewable generation connections and any planned network investments to accommodate the connection and the results of projects or activities involving the study or demonstration of innovative processes, services, business models or technologies.<sup>84</sup>

The most current distribution system planning regulatory policies are to be found in Chapter 2 of the filing requirements. These filing guidelines reiterate the regional planning requirement to file evidence that demonstrates that regional issues have been appropriately considered. This includes the requirement that the LDSC should consider municipal planning.<sup>85</sup>

## 9.4 FILED LDC DISTRIBUTION PLANS

The overarching policy of the OEB with respect to rate regulation is articulated in the RRFE. This policy contemplates exceptional capital investments under the ICM/ACM regulatory processes.

Since 2012, most utilities have included an asset management plan and a distribution plan or a plan that is a hybrid of the two. Many utilities employ a third party for the asset management document. Some utilities also employ a third party to develop the distribution system plan. Since 2014, distributors have sought approval of their five-year distribution plan, though at this juncture there is little guidance from the OEB as to the consequence of failing to substantively implement an approved plan.

The establishment of a clear regulatory requirement to produce comprehensive distribution plans has been accompanied, perhaps not unsurprisingly, by a significant increase in proposed capital expenditures by many utilities. Primarily, this is driven by an aging infrastructure, but also by management decisions to move from run-to-failure to pre-emptive asset management. Asset investment is largely focused around dressed poles, transformers and remedial underground cable investments. However, a noticeable amount of investment in switching, SCADA and control room investments and other “smart related” expenditures are occurring more frequently than in the past. The need to allow generation onto the distribution grid is well established in most utilities.

While many large utilities have introduced analytic tools (primarily in the form of asset data analytic software), there is little reflection in plans on alternatives to wire capital investments or integrated resource planning. Much the same could be said about the role of conservation and demand management to impact distribution system planning.

Beginning in late 2015, the first inclusion of integrated regional resource plans from the IESO began appearing in distribution plans filed by LDCs.<sup>86</sup>

84 Ontario Energy Board, *Filing Requirements for Electricity Transmission and Distribution Applications, Chapter 5 – Consolidated Distribution System Plan Filing Requirements*, March 28, 2013, p. 11. At [http://www.ontarioenergyboard.ca/oeb/\\_Documents/Regulatory/Filing\\_Requirements\\_Tx\\_Dx\\_Applications\\_Ch5.pdf](http://www.ontarioenergyboard.ca/oeb/_Documents/Regulatory/Filing_Requirements_Tx_Dx_Applications_Ch5.pdf).

85 Ontario Energy Board, Chapter 2, *Filing Requirements for Electricity Distribution Companies' Cost of Service Rate Applications Based on a Forward Test Year*, 2014 Edition for 2015, July 18, 2014. At [http://www.ontarioenergyboard.ca/oeb/\\_Documents/Regulatory/Filing\\_Reqs\\_Dx\\_Applications\\_ch\\_2.pdf](http://www.ontarioenergyboard.ca/oeb/_Documents/Regulatory/Filing_Reqs_Dx_Applications_ch_2.pdf).

86 See, for example, Entegrus Powerlines Inc., case EB-2015-0061, 2016 Rate Application, Appendix IVC, at [http://www.rds.ontarioenergy-board.ca/webdrawer/webdrawer.dll/webdrawer/search/rec?sm\\_udf10=EB-2015-0061](http://www.rds.ontarioenergy-board.ca/webdrawer/webdrawer.dll/webdrawer/search/rec?sm_udf10=EB-2015-0061).

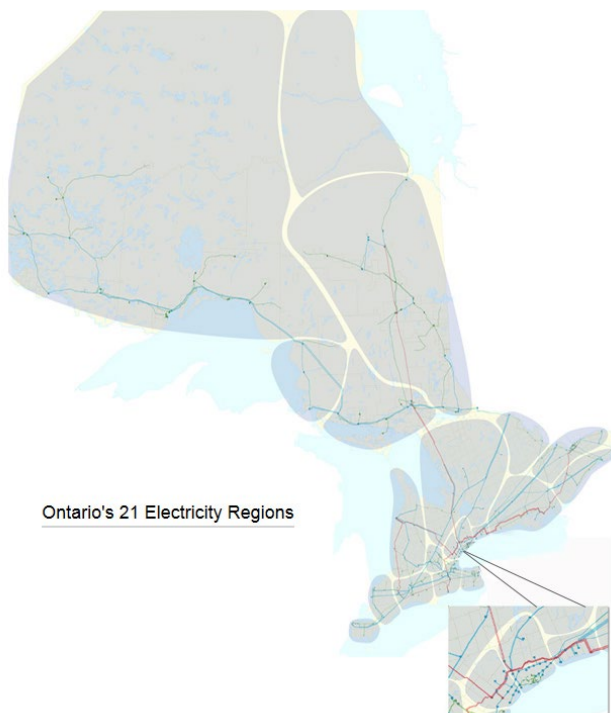
## 10] Regional electricity planning

There has been a recent turn toward regional electricity planning in Ontario. Currently, gas LDCs plan their own service areas. The OEB started to look at regional planning in 2011, and made it a requirement for some LDCs. In the 2013 LTEP, the province embraced regional planning as a way to reach local communities and improve the links between local and provincial planning.<sup>87</sup>

Regional planning is based on the 21 transmission regions in the provinces, as determined by the IESO (see Figure 18), with some sub-regions examined separately if needed. The IESO published the first seven integrated regional power plans on April 28, 2015.

The IESO, HONI and the LDCs prepare the regional plans. The first step is a needs screening, which is led by the LDC or the transmitter on regular basis. The IESO then has a scoping assessment that decides the next steps. If the needs of the region can be met through transmission, a Regional Infrastructure Plan (RIP), or wires-only plan, is prepared. If the needs of the region are greater than what can be provided from a wires-only solution, an Integrated Regional Resource Plan (IRRP) is prepared.

**FIGURE 18** Ontario's 21 electricity planning regions



IRRPs are prepared by the LDC, HONI (in its capacity as the transmitter) and the IESO. The IRRPs include transmission options, as well as generation and DER options, which includes CDM. Regional planning is still, however, relatively new in Ontario, and it is not clear how these regional planning initiatives will affect provincial planning.

For local input, the IESO is creating local advisory committees, which are expected to include representatives from municipalities, First Nation communities, consumers, businesses and environmental and conservation groups.<sup>88</sup> The IESO prepares the final plan and, as such, any implementation is governed at the provincial level. The 21 regions were divided into two groups, based on their needs, so that those regions with greater needs are studied first. Eight IRRPs were completed in 2015. Two of the IRRPs are for regions where sub-regional IRRPs are still under development.

87 Ministry of Energy, *Achieving Balance Ontario's Long-Term Energy Plan*, December 2013, pp. 58-63. [http://www.energy.gov.on.ca/en/files/2014/10/LTEP\\_2013\\_English\\_WEB.pdf](http://www.energy.gov.on.ca/en/files/2014/10/LTEP_2013_English_WEB.pdf)

88 Independent Electricity System Operator, "Local Advisory Committees." <http://www.ieso.ca/Pages/Participate/Regional-Planning/Local-Advisory-Committees.aspx>

# 11] Policy levers: Mechanisms to introduce change

The government has a number of tools that allow it to directly control the evolution of the electricity sector, including:

## **Legislation**

Since the late 1990s, major legislation has been introduced every few years in the electricity sector. Reforms have included market restructuring, promotion of renewable generation and integrated planning, consumer protection related to retailing, privatization of HONI, and others.

## **Directives**

Under current legislation, the minister has broad discretion to direct the agencies to take specific action. These directives may leave the agency with discretion around implementation, or they may be quite prescriptive. The minister has issued many directives related to such policy areas as the procurement of renewable electricity and conservation programs.

## **Long-term Energy Plan**

Originally, the OPA, now merged with IESO, was intended to be the planner, and the plan was to be subject to a public hearing by the OEB. The plan is now developed directly by the government, with input from the IESO and stakeholders, and there is no public hearing, although the government does hold public consultations. This *Long-Term Energy Plan (LTEP)* then guides subsequent activities and decision-making in the sector.

## **Shareholder**

The government exercises power indirectly through its ownership of key companies in the sector.

## **11.1 LEGISLATION**

Legislation allows for the most extensive and explicit introduction of policy change. As noted above, the electricity sector has been subject to frequent legislative change in recent years. The relationships among the players have been changed, as has the role of the OEB. New legislation can have advantages that are both political and practical: it can send signals of government priorities and values and it can provide certainty for the exercise of new powers or the limitations on old ones. There are also legislative disadvantages including the use of political capital and the limited resource of legislative time and attention. New legislation can be time consuming to prepare and the process can be lengthy. In the area of economic regulation, regulations or other policy instruments, such as directions, may still be required to provide the policy detail for a complex field or quickly evolving technology.

## **11.2 REGULATIONS**

Regulations or subordinate legislation must be authorized by statute. In most cases, they are passed by the Lieutenant-Governor-in-Council. Generally, they elaborate, provide detail, set out technical specifications or deal with matters that are too specific or evolving for inclusion in the

enabling statute. The balance of detail between a statute and its related regulations is a matter of drafting style, subject matter and political preferences. The process for enacting regulations is generally faster than statutory enactments and is within the control of the government, although broader political matters may have to be considered.

### 11.3 POLICY DIRECTION

The exercise of the authority granted to the OEB in the *OEB Act* is subject to directives issued by the minister of energy. The minister may also issue directions, which do not require such approval, to the IESO. For example, the minister may issue a request for a proposal to procure supply or capacity for renewable energy sources and specify the pricing or economic factors to be used by the IESO in doing so.

The *OEB Act* authorizes the minister to do the following:

1. to issue policy directives concerning general policy and objectives
2. to issue directives that require the OEB to take steps to promote energy conservation, energy efficiency, load management or the use of cleaner energy sources, including alternative and renewable energy sources
3. to issue directives that require the OEB to take steps specified in the directive to establish conservation and demand management targets to be met by distributors and other licensees
4. to issue directives that require the OEB to take such steps as specified in the directive relating to the establishment, implementation or promotion of a smart grid for Ontario
5. to issue directives that require the OEB to take such steps as specified in the directive relating to the connection of renewable energy generation facilities to a distributor's distribution system.

The OEB is required to implement the directives. It has some limited discretion in determining how they are to be implemented. Since implementing the directives entails costs, those costs must be recovered in rates. Requiring that these costs be recovered in rates thus limits to some degree the OEB's otherwise broad discretion to determine just and reasonable rates for the distribution of electricity.

The minister to date has issued some 94 directives and directions to the IESO. Like the OEB, the IESO must comply. While the IESO manages the operation of the electricity system, ensuring the adequacy and reliability of supply, and ensuring compliance with international obligations, much of the actual decision-making authority of the IESO is limited as a result of the directives and directions.

In the context of the issues canvassed by this paper, two powers to issue directions may be of particular significance. Subsection 25.32(4.6) of the *EA* gives the minister the authority to direct the IESO to establish measures to facilitate the development of renewable energy generation

facilities and distribution systems. Subsection 25.32(4.7) authorizes the minister to direct the IESO to develop programs that are designed to reimburse the direct costs incurred by a municipality in order to facilitate the development of renewable energy generation facilities and distribution systems.

The IESO had the power to develop system supply plans. Bill 135,<sup>89</sup> which is in committee as early as 2016, would vest that power in the minister to develop a long-term energy plan. Bill 135 would also authorize the minister to issue directives to the IESO and to the OEB, setting out the government's requirements with respect to the implementation of that long-term energy plan.

## 11.4 SHAREHOLDER INFLUENCE

The government's status as the owner of HONI, the OPG and the IESO provides influence and leverage. Even more specifically, municipalities that retain ownership of "corporatized" utilities have powers as shareholders under the *Business Corporations Act*. Aside from appointing directors and influencing the hiring of senior management, the municipalities are in a position to provide political direction.

## 11.5 INTEGRATING DER INTO THE DISTRIBUTION SECTOR

This section considers the legal framework within which DER could be integrated in Ontario. There are several basic assumptions. The first is that the primary focus for the integration of DER will be the electricity distribution sector. Thus, the integration of DER will have an impact on planning, supply and reliability. Accordingly, the legal framework governing those matters will also be considered.

The second assumption is that while the nature and extent of DER and its integration into the distribution system are to be determined, the range of issues to be addressed can be identified. Some of those issues could be described as foundational. They would include, for example, the issue of whether LDCs should function as platform service providers, as currently being discussed in the Reforming the Energy Vision process in New York State.<sup>90</sup> Other issues are of a continuing, operational nature; for example, how to determine the rates to be charged for maintaining the default distribution network, and how to allocate stranded costs. This section does not assume how those issues will be resolved. It does however consider whether, and if so, how the existing legal framework would allow those issues to be resolved.

The third assumption is that DER will be introduced on the basis of a number of principles, included, but not limited to, the following:

- » universal access to an essential service
- » the operation of a safe and reliable distribution system, meeting local, regional and international obligations

<sup>89</sup> *Energy Statute Law Amendment Act, 2015*, [http://www.ontla.on.ca/web/bills/bills\\_detail.do?locale=en&BillID=3539](http://www.ontla.on.ca/web/bills/bills_detail.do?locale=en&BillID=3539)

<sup>90</sup> New York Public Service Commission, "Reforming the Energy Vision." At <http://www3.dps.ny.gov/W/PSCWeb.nsf/All/CC4F2EFA3A23551585257DEA007DCFE2?OpenDocument>.

- » the promotion of a low-carbon, environmentally-sustainable economy
- » the use of competitive forces to enhance customer choice, fairly allocate risk, and ensure economic efficiency
- » the equitable treatment of rate classes and the equitable sharing of the burden of the costs of integration, and, in particular, the burden of stranded costs.

Against that general background, the key points to be kept in mind in analyzing the legal framework of the distribution sector are the following:

1. Does the legislation creating the legal framework permit the integration of DER into the distribution sector? If the answer to that question is no, then what changes are required in that legislation?
2. Is the discretion granted to the regulator sufficient to allow it to integrate DER into the distribution system? If the answer is no, how should that discretion be changed?
3. Regardless of whether the regulator has the discretion to integrate DER into the distribution system, should that discretion be constrained and, if so, in what ways?

The two principal statutes for this analysis are the *OEB Act* and the *EA*. Under those statutes, power is delegated to the OEB and to the Independent IESO.

The next question would be if the existing legal framework could permit the integration of DER. Subject to what is included in DER, the short answer is yes.

The power granted to the IESO, and the power of the minister to issue directives, both powers to be enlarged by Bill 135, are sufficient to permit the IESO to design, and in combination with the OEB, implement a supply and distribution system with integrated DER. The OEB could use its power to license the LDCs to expand the range of activities in which they could engage. In addition, as a result of Bill 112, the OEB could authorize LDCs to engage in a broad array of DER-related activities, or could police, through its affiliate relations code, the relationship between a municipally owned LDC and its affiliate carrying on a broad array of DER-related activities. Through its authority to approve rates, the OEB could try to manage the impact of the integration of DER on LDCs and consumers through, for example, the use of stand-by rates, changes in the proportion of fixed and variable costs, and the allocation of the burden of stranded costs.

Whether the OEB, alone or in combination with the IESO, has the jurisdiction to integrate DER into the distribution system depends on the interpretation of the extent of the OEB's jurisdiction. What the OEB has the authority to do is to approve the rates that are charged by distribution utilities. Courts have repeatedly said that the OEB's authority is broad. For example, the court in *Graywood Investments Ltd. v. Toronto Hydro-Electric System* described the OEB as a "specialized expert tribunal



with broad authority to regulate the energy sector in Ontario.”<sup>91</sup> However, whether that power, which rests on the authority to approve rates, is sufficiently broad to embark on a wholesale restructuring of the electricity sector in order to integrate DER into that sector is an open question, one that may be the subject of judicial review.

While judicial review of decisions of regulatory agencies is an important protection of the public interest, the decisions of courts are not an ideal way to design a distribution system. Given that, it would seem preferable for there to be a clear description of what DER is to consist of, of the principles and objectives to be pursued in integrating DER into the distribution system, and of the powers of the OEB and the IESO to effect that integration.

91 *Graywood Investments Ltd. v. Toronto Hydro-Electric System*, [2006] O.J. No 2030 at para. 24

# Appendix A: Acronyms

ACM: Advanced Capital Mechanism  
ARC: Affiliate Relationship Code  
CCHP: Conservation Combined Heat and Power  
CDM: Conservation and Demand Management  
DER: Distributed energy resources  
DR: Demand Response  
DSM: Demand Side Management  
EA: Electricity Act  
GA: Global Adjustment  
HOEP: Hourly Ontario Energy Price  
HONI: HONI Networks Inc.  
ICM: Incremental Capital Module  
IESO: Independent Electricity System Operator  
IMO: Independent Market Operator (subsequently the IESO)  
IPSP: Integrated Power System Plan  
IR: Incentive Regulation  
LDC: Local Distribution Company  
LGIC: Lieutenant Governor in Council  
LTEP: Long-Term Energy Plan  
LRAM: Lost Revenue Adjustment Mechanisms  
MBRR: Market-Based Regulated Return  
MCP: Market Clearing Price  
MDM/R: Smart Meter Data Management and Repository  
MIFRS: Modified International Financial Reporting Standard  
NPCC: Northeast Power Coordinating Council  
OEB: Ontario Energy Board  
OM&A: Operating, maintenance and administration  
OPA: Ontario Power Authority  
OPG: Ontario Power Generation  
REV: Reforming the Energy Vision (New York State)  
ROE: Return on equity  
RPP: Regulated price plan  
RRFE: Renewed Regulatory Framework  
SME: Smart Metering Entity  
TOU: Time of use  
WER: Waste Energy Recovery

## Appendix B: List of statutes and regulations

*Business Corporations Act*, R.S.O. 1990, Chapt. B-16, as amended

<https://www.ontario.ca/laws/statute/90b16/v28?search=business+corporations+act>

*Electricity Act, 1998*, S.O. 1998, Chapt. 15, Sched. A

<https://www.ontario.ca/laws/statute/98e15?search=electricity+act>

*Electricity Pricing, Conservation and Supply Act, 2002* (Bill 210)

<https://www.ontario.ca/laws/statute/s02023>

*Electricity Restructuring Act, 2004*, c. 23 (Bill 100)

<https://www.ontario.ca/laws/statute/S04023>

*Energy Competition Act, 1998*

[http://www.ontla.on.ca/web/bills/bills\\_detail.do?locale=en&BillID=1836&ParlSessionID=36:2&isCurrent=false](http://www.ontla.on.ca/web/bills/bills_detail.do?locale=en&BillID=1836&ParlSessionID=36:2&isCurrent=false)

*Energy Consumers Protection Act, 2010*, S.O. 2010, Chapt. 8

<https://www.ontario.ca/laws/statute/10e08?search=energy+consumers+protection+act>

*Green Energy Act, 2009*, S.O. 2009, Chapt. 12, Sched. A

<https://www.ontario.ca/laws/statute/09g12?search=energy+act>

Ontario Reg. 397/11: Energy Conservation and Demand Management Plans, August 23, 2011

<https://www.ontario.ca/laws/regulation/r11397>

*Municipal Act, 2001*, S.O. 2001, Chapt. 25

<https://www.ontario.ca/laws/statute/01m25>

*Ontario Energy Board Act, S.O. 1998*, Chapt. 15, Sched. B

<https://www.ontario.ca/laws/statute/98o15>

*Ontario Regulation 95/05: Classes of Consumers and Determination of Rates, January 1, 2011*. At

<https://www.ontario.ca/laws/regulation/050095>.

*Power Corporation Act*, R.S.O. 1990, Chapt., P-18

<https://www.ontario.ca/laws/statute/90p18>

*Strengthening Consumer Protection and Electricity System Oversight Act, 2015*

[http://www.ontla.on.ca/web/bills/bills\\_detail.do?locale=en&BillID=3415](http://www.ontla.on.ca/web/bills/bills_detail.do?locale=en&BillID=3415)

*Energy Statute Law Amendment Act* (Bill 135)

[http://ontla.on.ca/web/bills/bills\\_detail.do?locale=en&BillID=3539&detailPage=bills\\_detail\\_the\\_bill](http://ontla.on.ca/web/bills/bills_detail.do?locale=en&BillID=3539&detailPage=bills_detail_the_bill)

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