SCHOOL ENERGY COALITION

CROSS-EXAMINATION MATERIALS

HYDRO ONE/WOODSTOCK MAADS

EB-2014-0213

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city of
Woodstock

OFFICE OF THE CITY CLERK
City Hall
P.O. Box 1539
500 Dundas Street
Woodstock, ON
N4S 7W5
Telephone (519) 539-2382 ext 2501
Fax (519) 539-7705
ahumphries@cityofwoodstock.ca

November 27, 2014

Michael Harding
95 Vansittart Avenue
Woodstock, ON
N4S 6E3
c/o mharding@execulink.com

Re: Freedom of Information Request – Woodstock File Number 6-14 – IPC File Number MA14-0363

Please find enclosed additional disclosure of records further to the City's review of documents as part of the appeal process with the Information and Privacy Commissioner.

Sincerely,

Amy Humphries
Freedom of Information Officer

Woodstock Hydro
An ISO 9001:2008 Registered Company

Keeping Your Future Bright!

November 5, 2013

City of Woodstock
P.O. Box 1539, 500 Dundas Street
Woodstock, ON N4S 0A7

Dear Louise:

re: City of Woodstock / Hydro One Exclusive Negotiations

Please bring this correspondence to the attention of the Shareholder.

Please find attached a white paper prepared by the Woodstock Hydro Services Inc. Board of Directors and Woodstock Hydro Services Inc. senior management. The white paper has been prepared as a confidential information source in an aim to provide the Shareholder with an assortment of information pertinent to the exclusive negotiations currently underway with Hydro One with respect to Woodstock Hydro Holdings Inc. and Woodstock Hydro Services Inc.

Also attached as Appendix B, please find *A Report of the Consensus Accord – Electricity Distribution Sector Background Paper.* This document was created after thirty-eight (38) small- to medium-sized local distribution companies (representing approximately 600,000 customers) came together earlier in 2013 and analyzed the recommendations and findings of *The Report on the Ontario Sector Review Panel.* The consensus report challenges certain assumptions and offers tangible alternatives that focus on the best interests of the electricity customer. The Board believes that the consensus report contains insightful information that is pertinent to the exercise currently underway with Hydro One.

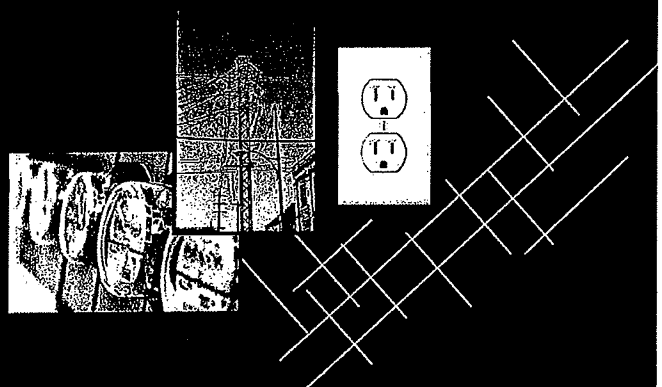
Sincerely,

Ross McMillan

Ross McMillan, B.A., C.C.P., C.M.A.
President & CEO
Woodstock Hydro Services Inc.

cc: David Creery, CAO, City of Woodstock
Woodstock Hydro Holdings Inc. and Woodstock Hydro Services Inc. Board of Directors

A Report of the
Consensus Accord



Taking the High Road –

To Improve Customer Service in the Electricity Distribution Sector

October 17, 2013

Background Paper – Rev 3

The Consensus Accord

September 12, 2013

Sometimes in the course of public events, it becomes clear that responsible people have two choices: They can either complain, shriek, and kick dirt on ideas put forth by their government or by others, or, they can take the "High Road" and instead offer suggestions and solutions they believe make more sense, thereby seeking to build bridges and "Consensus" to move things forward. The latter choice is what spawned this effort.

This document was created as a result of thirty-eight (38) small- to medium-sized Local Distribution Companies (representing approximately 600,000 customers) coming together to analyze and discuss the recommendations and findings of *The Report of the Ontario Sector Review Panel*, ***"Renewing Ontario's Electricity Distribution Sector: Putting the Customer First"***. The combined industry wisdom and experience of the group has led to a set of alternatives, insights and objectives with the goal of guiding the development and optimization of the Electricity Sector in Ontario – for the benefit of consumers.

We challenge many of the assumptions put forth in the Sector Panel Review Report, but more importantly, we offer tangible alternatives that could, and we believe would, move the industry forward along a customer-centric path.

We submit these ideas respectfully, hopefully, and certainly in the expectation that they will open the doors to a discussion which will lead to a better vision for tomorrow's Ontario Electrical Distribution System.

Respectfully submitted,

The Consensus Accord:

Bluewater Power Distribution Corporation Brant County Power Inc. Centre Wellington Hydro Ltd. Chapleau Public Utilities Corporation Cooperative Hydro Embrun Inc. Erie Thames Powerlines Corporation Essex Powerlines Corporation Fort Frances Power Corporation Greater Sudbury Hydro Inc. Haldimand County Hydro Inc. Grimsby Power Inc. Hearst Power Distribution Company Limited Hydro 2000 Inc.	Hydro Hawkesbury Inc. Innisfil Hydro Distribution Systems Limited Lakefront Utilities Inc. Lakeland Power Distribution Ltd. Midland Power Utility Corporation Milton Hydro Distribution Inc. Newmarket – Tay Power Distribution Ltd. Niagara-on-the-Lake Hydro Inc. North Bay Hydro Distribution Limited Northern Ontario Wires Inc. Orangeville Hydro Limited Orillia Power Distribution Corporation Ottawa River Power Corporation Parry Sound Power Corporation	PUC Distribution Inc. Rideau St. Lawrence Distribution Inc. Sioux Lookout Hydro Inc. St. Thomas Energy Inc. Tillsonburg Hydro Inc. Wasaga Distribution Inc. Welland Hydro-Electric System Corp. Wellington North Power Inc. Westario Power Inc. Woodstock Hydro Services Inc.

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Acknowledgements

The Accord would like to acknowledge the support and guidance of the Steering Committee formed for this report and in particular, the dedication and leadership of the Chair and Vice Chair of the committee.

In addition, the Accord thanks MNP LLP and the team of Craig Sabine, Daniel Bida and Sarah Keyes, who provided extensive consulting and technical advisory assistance in development of the report and its analysis. Responsibility for the final product and its conclusions is reserved to The Consensus Accord alone and should not be assigned to any reviewer or other external party.

EXECUTIVE SUMMARY

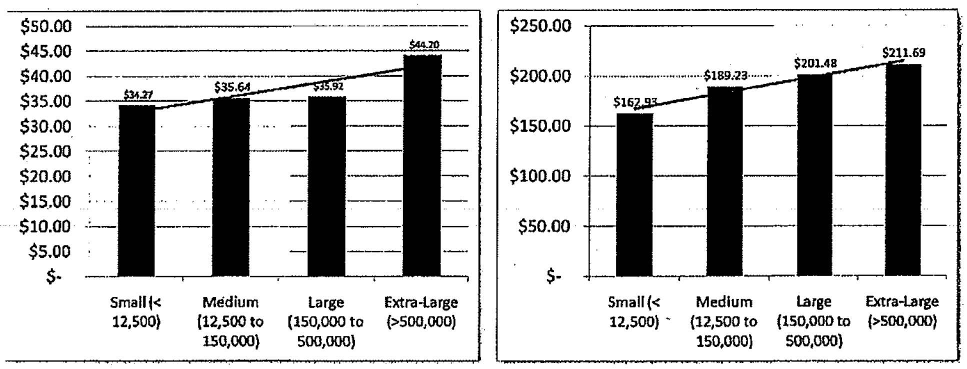
A collaboration of forty Ontario-based local distribution companies (LDCs) are collectively and cooperatively exploring alternative options to mandatory electricity distribution sector consolidation, as was recommended in the Report of the Ontario Distribution Sector Review Panel, *"Renewing Ontario's Electricity Distribution Sector: Putting the Customer First".* The combined industry wisdom and experience of the group has supported development of this report that analyzes the recommendations and findings of the Sector Review Panel and presents a set of alternative assumptions, insights and objectives with which to guide the development and optimization of the electricity sector in Ontario. The report and its authors support a number of key concepts, which are believed to provide a more pragmatic, actionable and customer-focused guide for enhancement of the distribution sector. The Group supports several recent announcements related to consolidation, including avoidance of mandatory policy measures and themes that rely on voluntary business practices to "*bend the cost curve*". The report also questions some of the fundamental assumptions of the Sector Review Panel Report and brings forward three key messages as follows:

- The Group strongly believes that municipally-owned and local LDCs are customer focused and consistently conduct business in the best interests of the customer. The advantages of the local LDC are discussed in this paper and demonstrate their core focus of *putting the customer first,* consistent with the primary objective of the sector panel's recommendations.
- The Group contends that the Sector Panel Review Report is flawed. The net efficiency gains in the distribution sector postulated through *mega-mergers* are unclear, distorted by real barriers (such as what to do with Hydro One's asset in contiguous utility regions) and inherently risky. The level of cost savings, as reported by the panel are not transparent and based on indefinite analysis. The Group supports the Minister of Energy's recent announcement that rejects the notion of mandatory consolidation of the sector within two years.
- The Group provides recommendations that are based on factual data and result in real cost savings for the customer. The recommendations of the Group can provide real benefits while avoiding the significant transaction and transition costs associated with mandatory consolidation.

As a key set of sector stakeholders, we question the value in mass consolidation and ask- *is it worth the risk?* Is it worth the risk to fundamentally shift the distribution sector and give up the clear benefits that local utilities offer their communities? Is it worth the risk for the chance at some percentage of unproven cost savings claimed by proponents of consolidation? Is it worth the risk of increases to customer bills, and is it worth the risk to draw focus away from where real savings for ratepayers can be harvested in the industry? We propose instead to maintain the principal objectives of consumer focus, enhanced efficiencies and preparation for the future, but also to look for alternative options, where consensus and cooperation can be garnered to nurture a new electricity distribution sector that all Ontarians can be proud of.

The analysis performed in this report covers a qualitative and quantitative review of the strengths and weaknesses found in the Sector Review Panel report, as well as an examination of the provincial electricity sector. The Group's approach is grounded in the same principles of the Sector Panel Review Report to guide the findings and recommendations offered. Fig. 1 shows that small and medium utilities deliver distribution services at rates nearly 25% more competitive to Ontario consumers, in comparison with larger utilities.

Figure 1: 2011 Average Monthly Residential and Commercial Delivery Cost per Customer by LDC Size Range[1]



This report builds a case that dismisses forced or widespread consolidation as the only solutions that lead to optimization in the sector. Our recommendations incorporate flexibility, taking into consideration a variety of unique industry factors and providing a series of tools that will lead to enhanced efficiency and service through cooperative organizations between utilities, a streamlining of regulatory agencies and their activities and voluntary consolidations. There are numerous specific examples of successful actions that have occurred to date, where efficiencies and synergies have been obtained without formal consolidation or M&A activity.

Our overall recommendations include the following:

1. Development of Facilitative Policy - To incent strong business-based merger activity and remove simple barriers to increase the flexibility for innovative solutions to enhanced efficiency for all LDCs.
2. Localized Long-Term Energy Planning – Includes LDCs and their local communities.
3. Focus on Regulatory Efficiency – Promotes improvement of mechanisms to deliver sector-wide efficiencies and minimize the costs of regulation.
4. Voluntary Consolidation and Collaboration – Suitable in some instances where clear benefits and a strong business case exists, including amalgamation of Hydro One distribution assets.

Our conclusion is that a "one size fits all" approach to consolidate the existing 75 LDCs into 8 to 12 regional distributors simply does not make good business or socioeconomic sense in an electricity market as diversified as Ontario. Ultimately, we believe that mass consolidation into 8 to 12 regional distributors is not the answer. The recommendations provided in this report can achieve the same goals of cost efficiency, enhanced service, and focus on the customer, as those contained in the Sector Panel Review Report, without requiring formal consolidation.

[1] Your Electricity Utility, Ontario Energy Board. 2012.

INTRODUCTION

In December 2012, a blue-ribbon panel mandated by the Government of Ontario to investigate the electricity distribution sector released its highly anticipated report, *Renewing Ontario's Electricity Distribution Sector: Putting the Customer First*. The Distribution Sector Review Panel Report (DSRP) summarized a variety of analyses and set out a number of recommendations, much of which have been highly contentious across the Ontario economy and with its consumers. The finding that consolidation, or amalgamation, of the province's 75 local distribution companies (LDCs) being the only viable solution to reduce costs and stabilize rates, does not hold strong from all perspectives. The argument that bigger-scale utilities set a better path to enter the future of the electricity industry is flawed (or that bigger is always better in the first place). Of course, all parties have their own biases. Each particular lens that is applied can change analytical findings considerably in an industry as complex and dynamic as the electricity production and delivery industry. Therefore, these issues should be discussed more broadly and policy should guide the desired results through the creation of positive environments for sector participants to clearly see the optimal paths forward and make business decisions without prescriptive intervention.

We believe the intentions and spirit of the DSRP to be genuine, but there is simply no comprehensive evidence suggesting that consolidating the sector is best for the consumer. Since the DSRP's release, discussions have not led to consensus on the strategic or tactical directions the sector should take. History has shown us it is therefore likely that prescriptive sector policy will inevitably fail.

This report endeavours to change the conversation. Developed by a group of 40 LDCs, the Consensus Accord has leveraged the combined knowledge and wisdom of distribution sector leaders from across the province. Appendix A to this report summarizes a survey conducted to set the context for our analysis and identifies the key issues that the Accord believes pertinent. Our report offers a comprehensive set of analyses that counter those found in the DSRP, while recognizing the merits of the Electricity Distributors Association's *Six Point Plan*, published in August of 2012. The analyses included here, apply transparent data and methodology. Our findings support further exploration of best practices and look towards alternative solutions that can be effective in producing cost efficiency without losing robust customer service and local economic activity, while encouraging mergers where appropriate.

Our report references the following customer size ranges based on the number of customers serviced by an LDC:

Small Utilities	Less than 12,500 customers
Medium Utilities	12,500 to 150,000 customers
Large Utilities	150,000 to 500,000 customers
Extra-Large Utilities	Greater than 500,000 customers

The customer size ranges above are intended to be akin to the ranges used by the sector panel in the DSRP for comparability purposes. However, we have elected to extend the upper limit of the Medium Utilities group from 100,000 customers to 150,000 customers for the purposes of this report. Data will demonstrate that utilities with a customer base around 100,000 customers tend to exhibit the characteristics of more medium sized LDCs, of which there are a large number of in Ontario. It is believed that many of these characteristics are positive and beneficial for the customer. More often, the medium sized group (including those LDCs up to 150,000 customers) performs more effectively for the consumer in operations and cost management than larger LDCs. We believe the adjusted categorization gives a clearer picture of the various customer bases and their corresponding metrics. All references to LDC sizes throughout this report are based on the above thresholds to maintain a level of consistency and comparability across the analyses.

THE DISTRIBUTION SECTOR PANEL REPORT

Prior to the release of the DSRP, a comprehensive six-month sector-consultation process was conducted. The report aims to represent, broadly, the input and outlook of various market participants, although at times, it seems to overlook balanced comment from LDCs of all sizes and operational models. The DSRP describes the criticality of the electricity sector as a building block of a strong economy and proposes that aggressive consolidation of Ontario's distribution utilities will lead to substantial cost efficiencies, enhancing our competitiveness as an economy. The following section discusses some of the findings and recommendations of the DSRP in detail and presents alternative analyses that suggest differing and/or conflicting conclusions. Our analysis demonstrates that the DSRP interpreted data to over-simplify operating assumptions and exaggerate the cost savings of consolidation. Transparent application of publicly available sector data results in very different conclusions to those found in the DSRP. These conclusions have been demonstrated by numerous analysts, academics and market participants over time and we are again demonstrating the dynamic nature of the distribution sector in the sections that follow. We believe that Medium-sized utilities, and in many cases, Small utilities, can be as competitive and efficient in their operations as Extra-Large ones. Furthermore, Small utilities can often have lower costs and provide the highest levels of customer service and responsiveness. This report explores a number of DSRP inconsistencies and elements of speculation that are unclear or questionable, including interpretation of cost efficiencies (OM&A), customer pricing, performance and reliability, labour costs and historical merger results. This section also presents some key findings from the DSRP that are important for consideration and those that will allow all LDCs, regardless of size, to improve service and enhance the customer experience.

DSRP Critical Review

In reviewing the DSRP, there are a number of inconsistencies identified in the document that warrant further discussion and analysis in order to garner a complete picture of the distribution sector. The discussions that follow have been developed based on the principal objectives of *consumer focus*, *enhanced efficiencies* and *preparation for the future*. It is believed that further analysis of DSRP conclusions reveals a tremendous amount of systematic uncertainty, which will inhibit the effectiveness of holistic and prescriptive policy action as the Panel has recommended.

The DSRP has recommended the consolidation of Ontario LDCs into 8 to 12 regional distributors that are large enough to deliver improved efficiency and enhanced customer focus, while at the same time maintaining connections with local communities. The fundamental recommendations suggests that there should be 2 regional distributors to serve the north (one in northeast and one in northwest), leaving 6 to 10 regional distributors in southern Ontario. Per the DSRP, any new regional distributor in southern Ontario should have a minimum of 400,000 customers. Toronto Hydro, with an existing customer base in excess of 700,000, is recommended to be one of the 8 to 12 regional distributors, as it has already consolidated with a number of smaller local LDCs in the past.

A "one size fits all" mindset is counterintuitive when considering the goal of putting the customer first. In such a diversified market as Ontario, carte blanche approaches can often lead to adverse effects for many. The analysis performed below serves to identify the inconsistencies within the DSRP and shed light on some of the core issues that exist, if an unsophisticated consolidation of Ontario's LDCs were to be carried out. A particular emphasis has been placed on the number of customers and the relevant costs incurred per customer. Cost comparisons identify problems in the interpretation of data analyzed by the DSRP and the final recommendations of the Panel.

Cost of Delivery Comparison

The fundamental objective of the DSRP is to put the customer first when considering the future of the Ontario electricity distribution sector. This includes ensuring that the customers are not shouldering the burden of inefficiencies in the marketplace, over which they have no control. A key component in the cost to the customer is the delivery charges, which include a customer-service charge (monthly flat fee varying by LDC) and variable distribution/ transmission charges based on kWh consumed (adjusted for the LDC loss factor). Delivery cost per customer is a key metric and subject to regulation by the OEB (i.e. fixed rates for electricity charges) – this is the only significant component of the monthly electricity bill that varies by LDC. Other elements of the bill are by and large uniform from one customer to the next within the same class.

In Figs. 2 and 3, an analysis of the delivery charges has been performed to allow for comparability of a cross-section of representative LDCs by size, using the OEB website for standard monthly usage levels. In the Extra-Large category, only Toronto Hydro has been used in the analysis (i.e. excluded Hydro One for the same reasons noted above and consistent with the DSRP). For residential customers in Fig. 2, the analysis has been performed assuming a customer who uses 800 kWh per month and whose pattern of electricity use is 64% off-peak, 18% mid-peak and 18% on-peak. For commercial customers in Fig. 3, the analysis has been performed assuming a customer who uses 6,500 kWh per month with the same pattern of electricity use.[2]

In Figs. 2 and 3 below, it is apparent that both the average residential delivery cost per customer and average commercial delivery cost per customer are highest in the Extra-Large Utilities category. In fact, there is a linear correlation between the size of the utility (in terms of number of customers) and the average delivery cost per customer on monthly electricity bills.

Therefore, it is entirely unclear why any customer should support consolidation of Ontario LDCs into utilities with 400,000 customers or more. The data suggest that this will be highly unlikely to reduce the controllable delivery costs to the customer. It appears the opposite is true – the larger the LDC, the higher the monthly costs per customer. In particular, Toronto Hydro has the highest monthly residential and commercial delivery costs per customer, which indicates that if the DSRP recommendations were to be implemented, a number of customers may actually see an increase in their monthly electricity bills as a result.

[2] Your Electricity Utility, Ontario Energy Board. 2012.

Figure 2: 2011 Average Monthly Residential Delivery Cost per Customer by LDC Size Range[3]

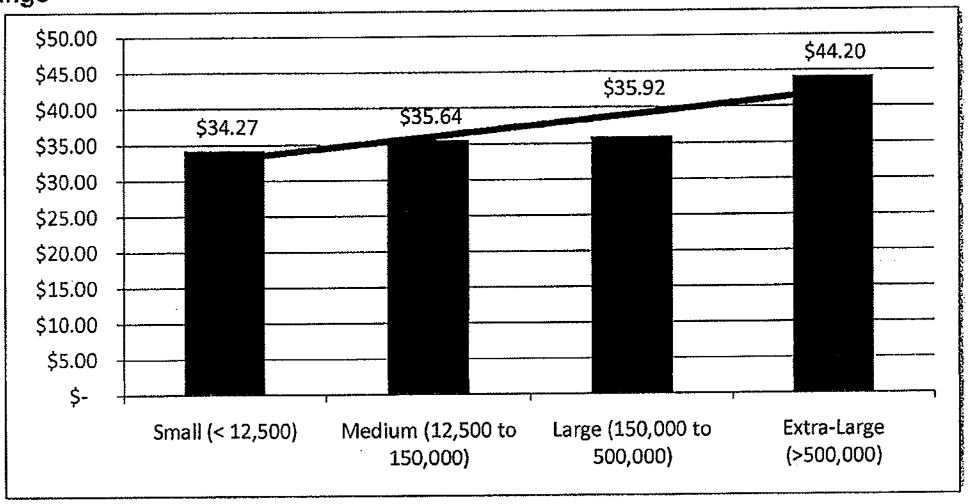
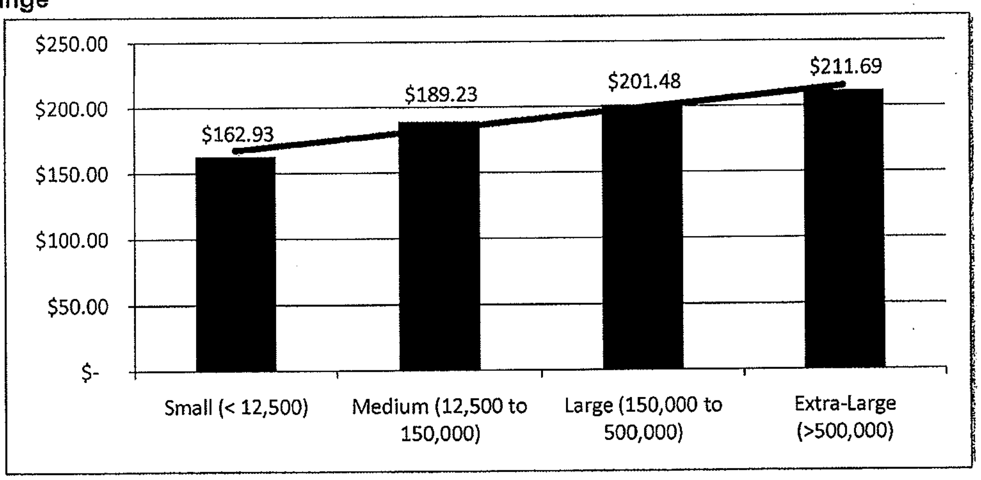


Figure 3: 2011 Average Monthly Commercial Delivery Cost per Customer by LDC Size Range[4]



OM&A Costs

The DSRP identified Operational, Maintenance and Administration (OM&A) costs as a key metric to consider. OM&A costs are a substantial component of operating a utility company and these costs are passed onto the customers through delivery costs charged on monthly electricity bills. Using OM&A cost per customer as a proxy, the DSRP hypothesizes that customers of smaller LDCs pay more for their service than customers of "optimally" sized LDCs, defined as a utility with a minimum of 400,000 customers in the DSRP. However, the analysis in Figures 2 and 3 above shows this to be a flawed

[3] Ibid.
[4] Ibid.

conclusion. While it is important to acknowledge OM&A cost as a key element of the industry, we also caution against the generic notion that OM&A costs are optimized as utility sizes increase.

In determining the OM&A costs per customer in Fig. 5, the 75 existing Ontario LDCs have been categorized into size ranges based on the total number of customers, consistent with the ranges described in the introduction. Hydro One has been excluded from the Extra-Large Utilities category in this case, due to its unique set of circumstances, with higher costs being driven by the low overall customer density of its service territories and customers spread out over a wider and more diverse geographic area. This is consistent with the exclusion of Hydro One from the OM&A cost per customer analysis in Figure 6 of the DSRP report[5].

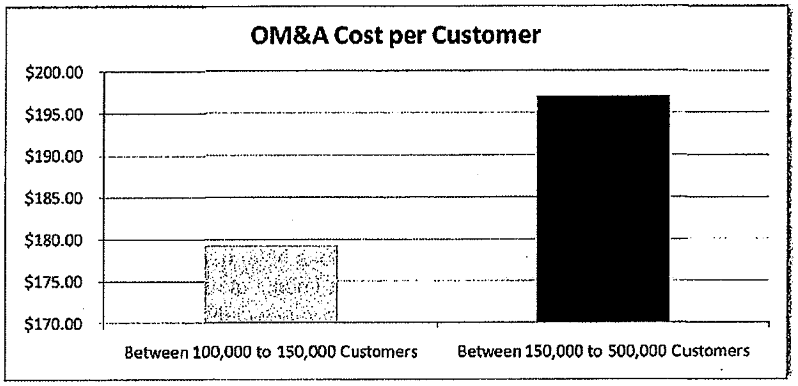
Conversely, it is worth questioning why the DSRP also excluded Toronto Hydro from its OM&A costs per customer analysis, whereby it concluded that a linear relationship exists between LDC size and OM&A costs (ie, the larger the LDC, the lower the OM&A costs per customer). Given that part of the overall recommendation in the DSRP is that Toronto Hydro remains unchanged as one of the 8 to 12 consolidated regional distributors, it brings into question the legitimacy of the OM&A of the analysis. Toronto Hydro is one of the higher cost utilities in the province (as demonstrated by a simple OM&A analysis). To "put the customer first", it is critical to make evaluations including Toronto Hydro in the Extra-Large Utilities category and assess whether the recommendation put forth in the DSRP will truly reduce costs to the customer in the long-term. Toronto Hydro is after all, a Large-sized utility within the recommended size range of the DSRP and has evolved from past amalgamations, which should make an interesting case study.

Fig. 5 shows that the current annual OM&A costs per customer do not follow the general rule identified in the DSRP. The industry average for OM&A cost per customer was approximately $292 in 2011; however, Toronto Hydro's actual OM&A costs per customer exceeds the industry average by $36 (or 12%) annually. While it is fair to state that Small utilities generally have a higher average OM&A cost per customer than the industry average, the OM&A cost per customer is only $2 (or less than 1%) higher than Toronto Hydro's, which has over 700,000 customers. Therefore, we conclude that there is no decisive evidence of a linear relationship between LDC size and OM&A costs.

The Medium and Large LDCs have far lower annual OM&A costs than the industry average and this is where the majority of Ontario LDCs can be categorized. Our analysis also finds that within a grouping of some of the largest Ontario LDCs besides Toronto Hydro, the OM&A costs of the 4 largest, are on average higher than the next 3 largest, which serve about 100,000 customers. Fig. 4 below demonstrates that the optimal size does not align with the DSRP recommendation and that a critical mass falls somewhere closer to the size of a much more diverse set of LDCs near 100,000 customers.

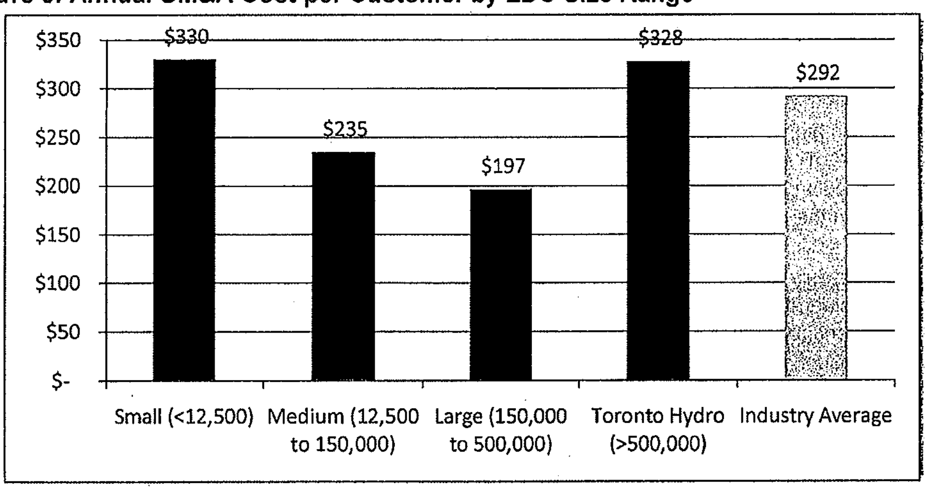
[5] *Renewing Ontario's Electricity Distribution Sector: Putting the Customer First*, Report of the Ontario Distribution Sector Review Panel. 2012.

Figure 4: 2011 Average Monthly Commercial Delivery Cost per Customer by LDC Size[6]



The DSRP recommendation for mandatory consolidation of Ontario LDCs to 8 to 12 regional distributors is not supported by an analysis of reduced OM&A costs. It is therefore questionable to assume that consolidation of smaller and mid-sized utilities, with any other larger Ontario utility, will have an immediate net OM&A cost benefit that consistently applies to customers.

Figure 5: Annual OM&A Cost per Customer by LDC Size Range[7]



As a measure of the actual costs paid by the customer, OM&A costs should also be considered carefully for artificial adjustment or veiled application. In comparing Figs. 2, 3 and 5, an inconsistency is identified in the data. If OM&A costs are truly passed on to the customer in the delivery charges on their monthly electricity bills, Fig. 5 would correlate directly to Figs. 2 and 3. The primary reason this alignment does not exist is due to the fact that OM&A is a function of the utility's capitalization policy, which is strictly an accounting policy choice without any cash consideration. Larger utilities have more aggressive capitalization policies than smaller utilities. For example, Toronto Hydro has a capitalization policy for all borrowing costs on construction-in-progress assets (called "Allowance for Funds Used During construction" or "AFUDC"). In 2012, approximately $2.3 million was removed from interest expenses and

[6] 2011 Yearbook of Electricity Distributors, Ontario Energy Board. 2012.
[7] 2011 Yearbook of Electricity Distributors, Ontario Energy Board. 2012.

capitalized into intangible and construction-in-progress assets[8]. Smaller utilities do not have this flexibility as they do not have the customer base to justify such massive capital expenditures on construction-in-progress assets, which is a key requirement of capitalization under the reporting requirements set out by the OEB. This accounts for the discrepancy between Figs. 2, 3 and 5.

The OEB has recognized the need to review whether OM&A in its current form is appropriate and is considering changing the OM&A metric within the Renewed Regulatory Framework for Electricity Distributors (RRFE). A key component of the RRFE is the Modified International Financial Reporting Standards (MIFRS), which dictates how the financial statements are prepared for the Ontario utilities. The OEB is currently in the process of revising how recoverable depreciation rates are determined in order to make costs in the industry more comparable. Until these revisions have been achieved, the comparison of costs across utilities in the province is inadequate due to the impact of capitalization and depreciation policies on the financial reporting by the utilities. These policies vary widely and will often distort comparisons as some LDCs may capitalize less of their administrative expenses, thereby driving up OM&A indices.

Another consideration affecting OM&A costs as an adequate measure is due to the fact that many of the Small utilities in Ontario are located in Canadian Shield regions or other difficult terrain. Similar to Hydro One, these utilities have a unique set of operating circumstances: low overall customer density of service territories, customers spread out over a wider and more diverse geographic area, and volatile environmental conditions. In Shield regions, construction and maintenance is more difficult and requires more specialized distribution equipment and materials. Therefore, in excluding Hydro One from the OM&A analysis, it further supports that these Small utilities share these exceptional circumstances, which makes it difficult to normalize and compare their OM&A costs to their counterparties located throughout the rest of the province. In a 2013 benchmarking study prepared for the OEB, it was acknowledged that utilities operating in the Canadian Shield are subject to a unique set of geographical circumstances that inevitably results in higher OM&A costs than utilities in any other region of the province[9]. This further supports that the OEB recognizes this as a key contributor to the higher OM&A costs and as a result, it is difficult and misleading to compare OM&A costs per customer for utilities located in northern Ontario to the other utilities in the province.

Reliability & Responsiveness

An important consideration for customers is the reliability and responsiveness metrics of the utilities that serve them – essentially how often outages occur and how long they last. The DSRP notes that smaller utilities are less responsive. Figs. 6 and 7 show these important performance indicators by LDC size. With careful evaluation, the data disputes the DSRP findings and recommendations.

All Ontario LDCs have been included in our analysis; specifically, Hydro One is included in the Extra-Large category. In considering reliability and responsiveness, one must understand the potential reality that faces 8 to 12 regional Ontario LDCs under a consolidated scenario. Some of these hypothetical utilities would face the same unique and understandably difficult set of circumstances faced by Hydro One – a low overall customer density spread out over a wide service area with difficult geographic and environmental conditions.

Achieving 8 to 12 shoulder-to-shoulder utilities in Ontario would mean that the current operational challenges of Hydro One and other larger widespread utilities will be transferred to most of the consolidated utilities that would exist. More customers will be immediately impacted by the higher cost-

[8] 2012 Annual Report, Toronto Hydro. Accessed in 2013.
[9] *Third Generation Incentive Regulation Stretch Factor Updates for 2013*, Report for the Ontario Energy Board. Power System Engineering, Inc. November 27, 2012.

delivery models, unavoidable because of expanded service territory and a greater diversity of customer type. As an example, Hydro Ottawa has attempted for years to purchase the assets and territory of approximate 47,000 Hydro One customers embedded in their service territory. The case is clear; Hydro Ottawa provides less costly service with higher reliability[10]. However, the service areas have not been transferred or sold and those customers continue to pay higher rates than their neighbours.

We believe it is important to assess the existing metrics and determine whether, and how much, consolidation will benefit the customer in terms of reliability and responsiveness. Is consolidation and sector disruption worth the expected changes to reliability and responsiveness?

Fig. 6 represents the average total hours of system interruption for all of Ontario's LDCs during 2011 based on their size. The figure clearly shows that the highest system interruption hours are incurred by Extra-Large Utilities, which calls into question the potential reliability of utilities in Ontario of the DSRP's proposed size. The ability of larger consolidated LDCs to be as responsive as the local LDCs that currently serve Ontario's communities is questionable. Larger utilities spread across rural areas will face the same challenges in maintaining the system as today's currently geographically diverse Extra Large utilities. Fig. 6 also shows a narrow margin in performance between Small, Medium and Large LDCs. It therefore seems egregious to consider fundamental and disruptive changes to the sector for the upside of less than one hour of saved interruption time. All of the other benefits that local utilities provide their customers likely outweigh the potential for small and unproven improvements in reliability indices.

In a more likely scenario, if the DSRP recommendation were to be implemented, the industry average of total hours of system interruption is just as likely to increase due to reduced local control over distribution assets resulting from the elimination of local LDCs. The data below is inconclusive given that the largest utilities have the highest outage ratings.

Figure 6: System Average Interruption Duration Index (SAIDI) by LDC Size Range[11,12]

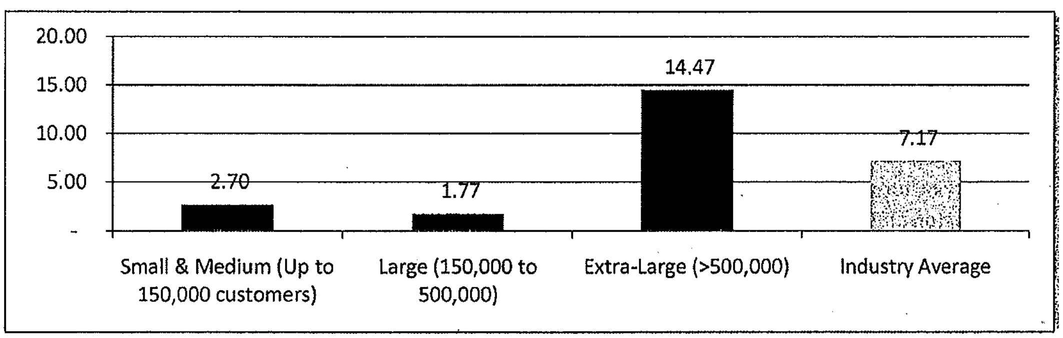


Fig. 7 represents the average frequency of system service interruption for all of Ontario's LDCs during 2011 based on their size. Similar to the above, Fig. 7 demonstrates that the highest average frequency of service interruption is incurred at the Extra-Large Utilities, which again calls into question the impact of consolidation on the reliability to customers on the whole. If the DSRP recommendation were to be implemented, the industry average of total frequency of system interruption will likely increase due to reduced local control over distribution assets resulting from the elimination of local LDCs. In the case of

[10] Ottawa Citizen, Rural Hydro Customers Stuck with Hydro One Indefinitely, Hydro Ottawa Says, June 26, 2013
[11] 2011 Yearbook of Electricity Distributors, Ontario Energy Board. 2012.
[12] Within the Large category, there are no LDCs with a customer base in excess of 400,000.

SAIFI, there is even less variability in the data and therefore, less room for improvement. Industry restructuring over a difference of 30 minutes in a total of 8,760 total hours of highly reliable services seems illogical.

It is worthwhile to note that many of the large utilities and consequently those that have undergone prior merger activity are located in some of Ontario's fastest growing regions. These are generally the cities and communities with the most recently developed and newest infrastructure, such as Markham, Mississauga, Durham Region and the Grand River Area. Correspondingly, it is logical to assume that these utilities would experience fewer and shorter-duration system interruptions due to the newer and more technologically advanced infrastructure in place. Fig. 8 presents several of the upper and single tier growth municipalities as identified in the government's Places to Grow growth plan strategy[13] and their corresponding utilities services. The diversity within regional systems, as evidenced by these SAIDI and SAIFI indices, often makes comparison of Small and Medium LDCs to some of Ontario's larger LDCs, just as poor a comparison as using older and/or rural service utilities such as Toronto Hydro and Hydro One. However, once again we see the Small & Medium and Large-sized utilities outperforming.

Figure 7: System Average Interruption Frequency Index (SAIFI) by LDC Size Range[14,15]

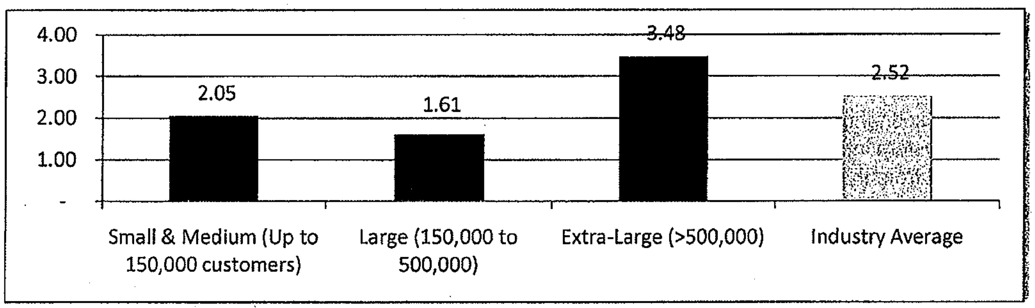


Figure 8: High Growth Regions and Reliability Performance 2011[14]

Places to Grow Ontario	Principal Utility	Size Category	SAIFI (2011)
Region of Durham	Veridian	Large	2.05
Region of York	Powerstream	Large	1.00
City of Toronto	Toronto Hydro	Extra Large	1.48
Region of Peel	Enersource	Large	1.54
City of Hamilton	Horizon Utilities	Large	1.74

The above figures articulate why it is critical that not only quantitative operational and financial metrics be considered, but also qualitative metrics that indicate the customer's experience with their utility and the spinoff impacts of consolidation on utility operations. It is difficult to embrace that consolidation of Ontario LDCs will improve the reliability and responsiveness metrics experienced by all, or even the majority of customers in Ontario, given the current mixture of performance of Ontario's largest utilities.

[13] Places to Grow, Ministry of Infrastructure. 2013. Website
[14] 2011 Yearbook of Electricity Distributors, Ontario Energy Board. 2012.
[15] Within the Large category, there are no LDCs with a customer base in excess of 400,000.

Economies of Scale: Historical Consolidations

The DSRP assumes consolidation could result in net sector-wide cost savings of $1.2 billion. We believe that cost savings are likely. However, it is unclear and unlikely that consolidation and forced M&A would lead to results on such a scale. It is critical to consider historical examples of consolidations and their actual financial results with an objective eye. In determining whether consolidation is the ideal solution to capitalize on efficiencies, it is worthwhile examining historical results and lessons learned. In benchmarking against actual historical examples, a more definitive conclusion can be reached on the overall cost impact to the customer. The following analysis explores the total actual annual OM&A costs per customer, as a result of past LDC consolidations using the best publicly available data. This is in contrast to relying on an assumptions-based projected total cost savings figure over a ten year period, as performed in the DSRP.

Several economic studies have concluded that few real welfare gains have emerged from previous efforts to consolidate LDCs in Ontario. According to Cronin and Motluck (2007), research undertaken for the OEB found little or no evidence of cost savings as the utility size increased, challenging the norm of larger always being better. More recent research has also found that no economies of scale are typically realized by distribution utilities and some economists have actually found diseconomies beyond a certain moderate size[16]. The largest distribution utilities in the province have historically operated on higher OM&A costs per customer and lower productivity rates when compared to smaller municipal electric utilities and restructured municipally-owned LDCs.

The following sections demonstrate that quantitative evidence does not support the claims that OM&A costs per customer have been reduced through consolidation or merger activity in the Ontario sector. These analyses focus on two specific Ontario utilities (Utility A and Utility B), both in the Large LDC size category presently and both having completed several mergers/amalgamations in the province in the past.

On a per-customer basis (levelizing costs to a common factor), trends for Utility A and Utility B (or their precursor LDCs) show no substantial improvement from pre-amalgamation conditions (see Fig. 9 below). During the 1993 – 2005 period when the cost base of both Utility A and Utility B had grown through amalgamation, the average cost per customer had increased over 17% and 5%, respectively. Interestingly, this is by far a long enough operating and change management time period to begin harvesting the expected cost synergies of merger. Since 2003, cost improvements have been made; however, the cost per customer was still higher in 2005 than under the service of various pre-amalgamated LDCs.

Figure 9: Utility A and Utility B Costs Trends (1993 – 2005)[17]

Utility A:	1993	1997	2003	2004	2005
Customers	75,608	81,765	90,867	93,634	100,802
OM&A	$ 11,316,996	$ 11,466,935	$ 21,490,194	$ 19,772,029	$ 17,620,658
OM&A Per Customer	$ 149.7	$ 140.2	$ 236.5	$ 211.2	$ 174.8

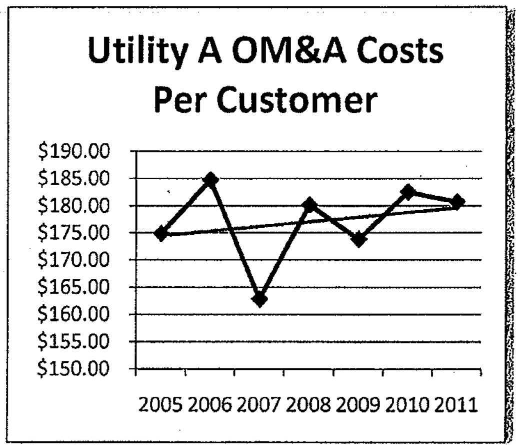
Utility B:	1993	1997	2003	2004	2005
Customers	116,758	134,219	190,201	197,141	203,749
OM&A	22,055,586	20,320,757	33,094,974	36,116,231	40,281,177
OM&A Per Customer	$ 188.9	$ 151.4	$ 174.0	$ 183.2	$ 197.7

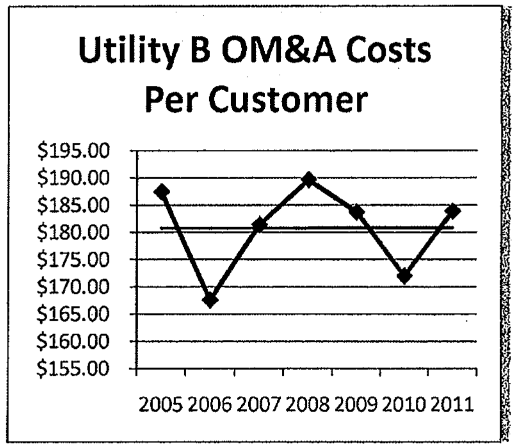
Note: Augmented from 2007 study - *How Effective are M&As in Distribution? Evaluating the Government's Policy of Using Mergers and Amalgamations to Drive Efficiencies into Ontario's LDCs*

[16] How Effective are M&As in Distribution? Evaluating the Government's Policy of Using Mergers and Amalgamations to Drive Efficiencies into Ontario's LDCs. Cronin, Frank J and S.A. Motluck. 2007.
[17] Ibid.

OM&A cost per customer trends for Utility A are clearly increasing over the time horizons studied in Fig. 10. During the establishment of Utility A, through consolidation, mergers & acquisitions, consistent cost efficiency is not demonstrated. The annual OM&A cost per customer are volatile for both Utility A and Utility B. According to this data, Utility B's OM&A cost per customer has remained relatively flat over time, although costs are higher now than during pre-merger conditions prior to 2002 and the level of cost reduction is not stable or consistent with claims made in the DSRP that consolidation leads to 15% to 20% efficiency gains in OM&A. It is, therefore, difficult to conclude that substantial OM&A efficiencies have been experienced during these timeframes.

Figure 10: OM&A Costs per Customer for Utility A and Utility B (2005 to 2011)[18]





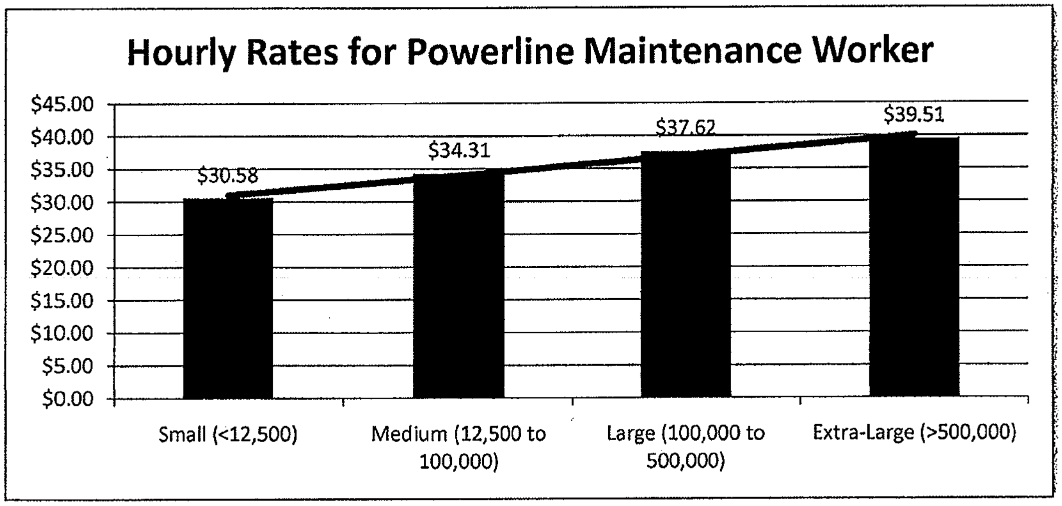
Higher-Cost Service Providers

The DSRP identifies employee labour costs as a component of the administration portion of OM&A costs. Based on the DSRP analysis, administrative labour would appear to be the most significant component of cost and a differentiator in the market between Small and Large LDCs as it relates to OM&A per customer. Correspondingly, an analysis is performed below to determine if the labour costs are higher in Small, community-based utilities vs. Extra-Large, widespread utilities (such as Hydro One Networks or Toronto Hydro).

An immediate challenge to cost containment, where larger utilities acquire or amalgamate with smaller community-based utilities, especially in the case of Hydro One Networks, will be the higher labour costs that these entities are subject to. In fact, ***Section 69 of the Ontario Labour Rights Act*** states that if consolidation were to occur and be viewed as a sale of businesses, the new entity is bound by the higher cost collective bargaining agreements (CBAs) of existing trade unions of either business in the merging of assets. For example, Fig. 11 below demonstrates the up to 31% difference ($30.58 vs. $40.26) between the Small LDC hourly labour cost and the Extra-Large LDC hourly labour cost per power line maintenance worker. It is therefore beyond the control of merging utilities to limited labour cost increases and would be driven by labour laws more than strategic or sound business decision making.

[18] 2005-2011 Yearbooks of Electricity Distributors, Ontario Energy Board. 2012.

Figure 11: 2012 Labour Rates[19,20]



In some amalgamation scenarios, any efficiency gains for larger LDC customers will be at the cost of the smaller LDC customers. As a result of a merger, the smaller LDC customer would begin to absorb the higher cost of labour due to CBAs already in place. Increasing responsibilities and service areas may also lead to higher compensation requirements, while jobs would be added at centralized locations to complete the shared workload, further increasing the costs of employee compensation after mergers.

Staffing reductions combined with more limiting CBA agreements are likely to lead to lowered customer service standards and lower amounts of maintenance and capital work completions. Integration and transfer costs of merging systems/processes, as well as increased training costs will add to the overall cost/risk paradigm. Lastly, an important potential risk is the limited direct access of the municipality to the corporate distribution entity, which helps to ensure customer service and company performance on behalf of customers and community in less densely populated regions of the province. Our experience suggests that labour costs, as a potential source of reduced administration expenses in a merger, could result in reduced service rather than gained efficiency. Each circumstance is subject to unique situational restrictions. Once again, a one-size-fits-all approach cannot hold true in a utility market as diversified as Ontario.

Investments in Innovation

The DSRP presupposes that Ontario's Small and Medium LDCs do not typically invest as often in innovation compared to the Large LDCs. It is thought that their investments tend to focus on maintenance and upkeep instead. While large R&D, innovation and change investments are important, it is also critical to carefully determine their necessity, impact and timing. These investments do not always yield the expected returns (or benefits to the customer) especially if the innovations do not turn out to perform as well as originally forecasted, or if their implementation is not executed well.

Ontario's Small and Medium LDCs have shown a strong ability to maintain the strength of their distribution systems as evidenced by their better than sector average performance on Reliability and Responsiveness indices, in spite of at times, more challenging conditions, particularly in Northern Ontario. The investments being made by these utilities are working and customers are garnering the benefits. In

[19] Compensation, Wages, Benefits. EB-2012-0031 (Hydro One). Ontario Energy Board. 2012.
[20] North Bay Hydro rates comparisons

addition, careful strategic investments in innovation are being made where it makes sense for the customer. Large LDCs are not the only leaders in innovation.

A straightforward example of the ability of smaller LDCs with respect to innovation is the recent smart meter rollout, where all of the Province's LDCs were required to install smart meters and begin charging customers time-of-use rates. Just like the authors of the DSRP stated, pundits at the time claimed that the Small and Medium LDCs would not be able to complete the roll out on budget and that the leverage of the systems would be poor. At the time, the same sector followers used their theory as further support for the argument to consolidate the sector. Ironically, no one was questioning the ability of the Large LDCs to complete the task and we now know various shortcomings have been evident.

In the end, the Small and Medium LDCs took the natural step of working together (28 of them joined London Hydro to purchase smart meters as a collective) and at the time of this report's release, all of their customers are being charged time-of-use rates. One LDC even enhanced the network development and innovation by working together with the local municipality to install a town-wide wireless network in concert with smart meters. In contrast, multiple Large and Extra Large LDCs required substantial project extensions and were unable to charge all of their customers time-of-use rates within the province's mandated timeframes.

Strengths of the Report

It is important to recognize that the DSRP and the process undertaken to develop the report, included some clear strengths, important intentions and made a number of sound recommendations.
The emphasis on putting the customer first is a value held by all of Ontario's Small and Medium LDCs. We encourage this concept as being central to future decision making and believe it will have a positive impact on both policy and planning outcomes. Community-based LDCs have always made decisions and implemented strategies that enhance results for the customer; they will continue to do so as the baseline for doing business in their communities.

The advantages of contiguous LDCs is well articulated in the report, particularly with regards to the duplication that comes from Hydro One's operations centres existing within another LDC's service territory. Putting the puzzle pieces together, creating holistic service territories and eliminating the duplication will cause direct benefits for the municipal LDC's and Hydro One's ratepayers. To paraphrase the authors, fewer boundaries will mean better planning and utilization of assets.

Allowing and/or incenting mechanisms that move Hydro One assets and customers over to municipal utilities, where it ultimately benefits the customer, will result in larger customer bases and have immediate and positive rate impacts as municipal utility rates are adopted by former Hydro One customers. The larger fragmented utility will also be able to focus on serving its rural territories without addressing problems in pockets of service territory nested within areas already serviced by municipal utilities.

The discussion of the LDC of the future and the new world of electricity is also one of the strengths of the DSRP. Considerable change is occurring in the sector as a result of the ongoing innovations in communications technology and shifting of customer behaviour. The authors are astute to recognize that some LDCs find it hard to be innovative in the current regulatory environment – specifically pointing to an OEB decision to prevent Guelph Hydro from recovering the costs of a pilot program for electric vehicles. "The expectations and requirements of the LDCs and the OEB need to be aligned if innovation is to be encouraged in Ontario's distribution sector." Therefore, public policy and consumer behavior must drive the needs of utilities to develop and innovate. If the customer need is present, the regulator will be better equipped to approve investments that support a customer or societal demand. The demand must be clear and the regulatory policy must be aligned with the specific goals to further encourage the innovative requirements of future generations and technologies.

The DSRP recommendation to remove red tape and other barriers, as a way of fast tracking merger activities, is also supported. If voluntary mergers that make clear business sense are to occur, inhibiting barriers need to be removed in order to encourage LDCs (and their shareholders) to take advantage of any potential long-term benefits that could be captured from merging.

In addition to these points, the process used to gather data and opinions was a strength of the report's methodology– it was open and encouraged various stakeholder groups to participate. Nothing precluded relevant stakeholders from submitting opinions and perspectives on the current and future state of the sector.

Looking forward, continued inclusiveness, consensus building and regional involvement in mapping out the objectives and approaches of the sector should be encouraged from the top down.

THE BIGGER PICTURE: WHERE CONSENSUS EXISTS

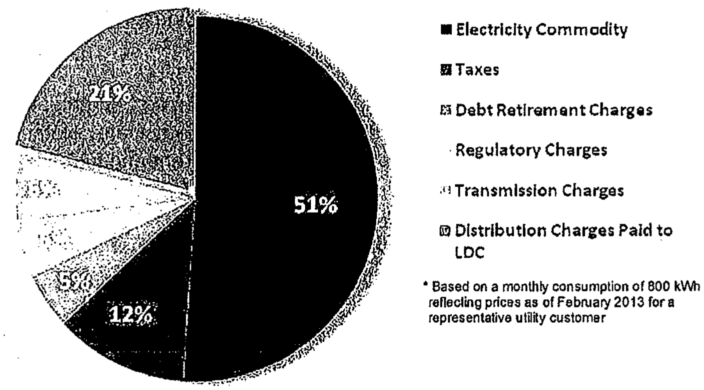
Differences of opinion aside, there are a number of electricity sector facts that cannot be contested. This section offers overwhelming consensus and insight from numerous studies and sources that all point toward several areas within the energy sector, but outside the distribution business, that can be shored up immediately to create cost efficiencies that are much more impactful for consumers.

First and foremost, we believe a lot of undue focus is being placed on the distribution sector in hopes of alleviating price pressures generated more broadly within Ontario's electricity sector and with no linkage to distribution utilities at all. It is generally accepted that the distribution component of customer bills makes up between 20% and 25% of the total, while the supply component makes of 50%. The exact portion changes over time, as the wholesale costs of electricity change, electricity commodity rates and policy adjustments leading to uplifts and other charges change, and as natural economic productivity leads to reduced overall consumption per unit of output. Some studies find the distribution portion to be more than 20%, while others find it less. Generally, the 20% range is by and large acceptable for analytic purposes. Therefore, up to 80% of the electricity bill is outside of the control of LDCs, no matter the size (See Fig. 12 below).

In each area critical to the functioning of the electricity sector (including generation and market mechanisms, transmission, regulation and policy) there has been just as much, if not more, debate and contention as in the distribution sector. D. N. Dewees, professor of the Economics Department at the University of Toronto, points out in his March 2012 paper for *Sustainable Prosperity Policy and Research Network,* that since 1966, inflation-adjusted electricity prices show steady increases with a few periods of significant cost jumps. Although inflation represents much of the overall increase, leaving an average of only 1.42% annual growth, it has become clear that Ontario is no longer a "cheap" electricity jurisdiction as it once was. Our prices are similar or higher than those jurisdictions that surround us, which has led to decreased economic competitiveness on the whole[21].

[21] D.N. Dewees, 2012. *What is Happening to Ontario Electricity Prices*, Sustainable Prosperity Backgrounder.

Figure 12: Components of a Typical Residential Electricity Bill



As an industry, Small and Medium-sized LDCs can accept that they must be part of the solution, and continue to evolve for the benefit of Ontario ratepayers. We believe we are acting on these objectives and continually strive for improvement and innovation.

As noted above, Ontario has always experienced real price increases. Drivers of growth have been fairly evenly distributed between generation, transmission and distribution costs[22]. Although each element has grown at similar rates, the overall proportion of generation related costs indicates that more opportunities for ratepayer savings can be harvested with focus on the commodity supply and market design (51%), taxation (12%), debt retirement (5%) and potentially regulatory (6%). It therefore seems logical to place as much, or more, emphasis and oversight on other aspects of the electricity system, particularly supply, where greater efficiencies, productivity, savings and ultimately value, can be captured.

The DSRP itself, states that the "*province's distribution sector has been able to avoid a lot of attention from consumers because local distribution costs encompass a small proportion of a typical electricity bill*". Although the comment on proportion is true, the notion of lack of attention is not. The diverse nature of the LDC sector and the local connection is exactly why consumer interaction occurs at a local level. LDCs garner significant attention within the communities that they serve. Secondly, as far back as 1996, the Macdonald Committee released *A Framework for Competition,* a report on the electricity sector in which substantial evaluation of the distribution sector was carried out and recommended upon.

The Macdonald Report, similar to the current DSRP, recommended a series of consolidations within the sector to result in shoulder-to-shoulder utilities. Although many municipal electric utilities of the day were subsequently merged with Hydro One and others, no mandatory consolidations were legislated. Furthermore, the results achieved by Hydro One and its merged LDCs are far from clear or encouraging. From a savings-to-customers point of view, Hydro One has provided little upside for the customers they have acquired. Hydro One urban customers pay significantly higher rates than neighbouring customers served by the local LDC. In many cases these neighbouring customers are literally across the street, yet they can pay up to 25% more for the distribution service. This is an extreme example of a system that does not support the best decisions for customers, yet is easily rectifiable.

[22] Ibid.

Our assessment of the market shows that a far greater consensus exists on the following key areas of focus for the sector (beyond distribution) and for policy makers going forward. Well-developed stakeholder consultation and planning can have greater impact on customer bills and the competitiveness of the economy, if emphasis were placed on these critical areas:

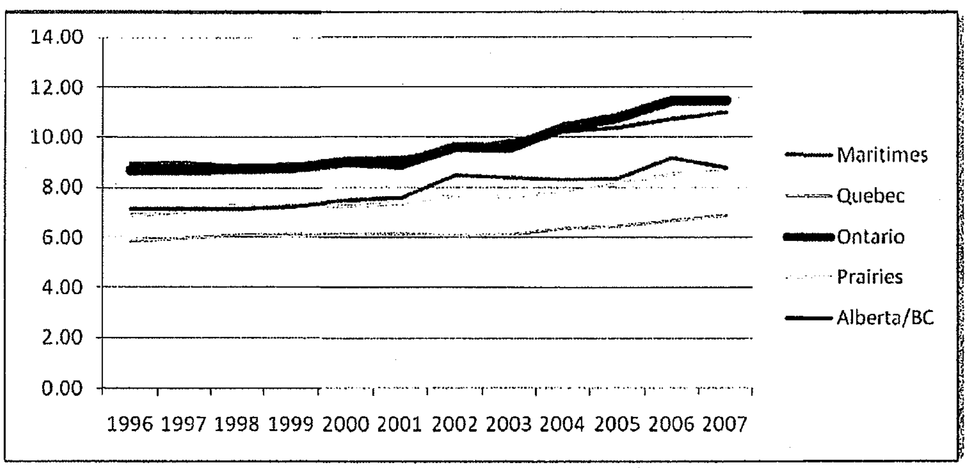
1. Commodity Supply and Market Inefficiencies.
2. The Components of the Global Adjustment Mechanism.
3. Streamlining the Regulatory Frameworks.
4. Streamlining and Enhancing the Transparency of Provincial Agencies.
5. Negative Implications of the Green Energy Act.

Commodity Supply and Market Inefficiencies

The long history of supply (generation) costs driving increases in electricity bills is well documented. As previously noted, the overall inflation-adjusted growth rate of the total consumer electricity price has been relatively low for over 50 years, at 1.42% on an annual average basis. This figure tells us that the diverse and continually enriched value of electricity and its application in the economy, versus the average growth in electricity prices, is actually a great story of success for the province.

The overall landscape of electricity prices across Canada from 1996 to 2007 (most recent year with data available from Statistics Canada) shows that the annual average revenue per kilowatt hour has been steadily increasing. See Fig. 13 below. Ontario has experienced steeper annual growth over the time horizon studied when compared to the other regions of Canada.

Figure 13: Annual Average Revenue per kWh in Nominal Dollars[23],[24]



At times, the relatively modest growth rate in overall electricity price is interrupted by spurts of larger increases and volatility. We postulate that it is these growth spurts that have ultimately led to the declines

[23] Statistics Canada. 2009. *Electric Power Generation, Transmission and Distribution*. Table 4 - Residential and agriculture sales of electric power, 2003 to 2007. Catalogue No. 57-202-X. 2013.
[24] Statistics Canada. 2002. *Electric Power Generation, Transmission and Distribution*. Table 4 - Residential and agriculture sales of electric power, 2003 to 2007. Catalogue No. 57-202-XIB. 2013.

in competitiveness of Ontario's electricity sector. The growth spurts can be seen in Figs. 14 and 15 and are often related to policy activity or investment choices. These factors will be accounted for in following sections.

Fig. 14 below demonstrates the natural productivity of energy use in the economy; this is a key observation because the natural decline in electricity consumption per unit of economic activity actually mutes the degree to which price increases, driven by supply, impact our bills. Put another way, we are getting much better at using electricity as an economy. Therefore, even though the supply portion of the overall price for electricity is by far the largest and growth rates for each portion of the bill have been comparable, growth in generation costs are counteracted by natural productivity. The counteractive effect leads to slower growth in absolute resources spent on our electricity supply as we use less overall. This is troubling because it also means we are leaking away the energy efficiency gains we create. It should be noted that the productivity argument bears more strongly on the electricity supply that it does on distribution. Electricity supply tends to be more heavily weighted toward variable costs, which are of course impacted more strongly by consumption levels, while distribution costs are typically more fixed in nature.

It is clear that attention should be focused on the root causes of the price growth spurts that have occurred over time, and these are nearly always associated with supply-side policy and changes to the market structure and commodity pricing environment.

Figure 14: Generation Cost Increase vs. Electricity Productivity

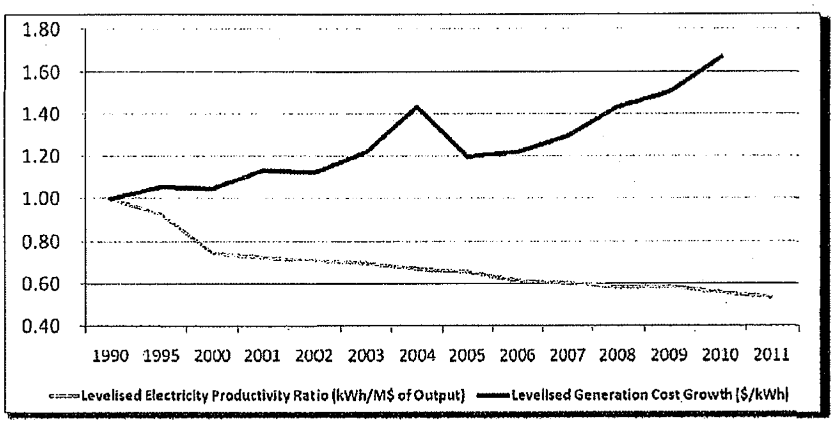


Figure 14 demonstrates that the amount of electricity consumed per unit of economic output (GDP) has declined since 1990 by over 40%. At the same time, consumer electricity bills have been increasing. A 70% rise in generation costs is a main driver.

Through the mid 1970s and again in the early 1990s, capital costs and overruns from building out the province's backbone nuclear generation fleet led to large increases in average electricity prices as they were rolled into consumer pricing and into the approximately $20.9 billion in stranded debt of the former Ontario Hydro, an expense ratepayers continue to absorb[25]. By the time the industry began restructuring in 1998, costs of supply were again on the rise. At market opening in 2002, acute price increases and volatility led to a set of policy measures enacted to manage impacts on customer bills and provide subsequent relief from high growth. Key to the story is that Ontario's electricity system has always been influenced by significant policy intervention and debate. The spinoff consequences of these interventions led to artificially-depressed prices, hiding the true costs of electricity, discouraging ongoing investment in the province's system by the private sector and increasing the debt levels that inevitably must be paid down by future consumers (either ratepayers or taxpayers). These factors eventually have compounding

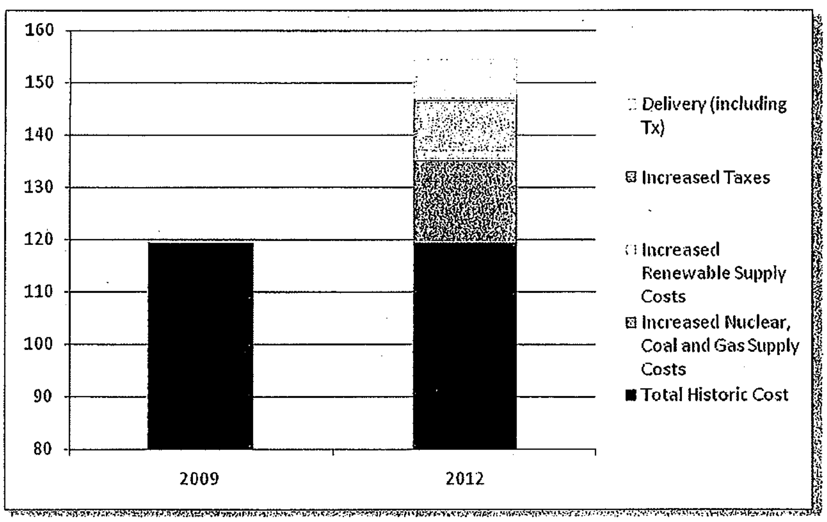
[25] Ontario Auditor General, "2011 Annual Report of the Office of the Auditor General of Ontario," 2011, p. 122

effects, as inflation and other market forces act to increase prices at the same time as artificially low prices, held for long periods of time, get adjusted to reality. We are currently seeing the impacts of convergences like this in the market.

By the later part of the 2000s, the lack of reliable and steady investment in the sector led to the need for further policy interventions that would secure new supply. New supply was needed to replace aging fleets of power plants, implement the coal phase-out and support the Green Energy Act (and its Feed-In Tariff for renewable generation). The costs to consumers for these investments, through long-term power-purchase contracts, is above the historic costs of electricity supply and often far above current wholesale market rates. Other policy actions between 2009 and 2011 moved to cancel contracts made with developers of gas-fired generation facilities in Mississauga and Oakville. These decisions have added further costs for Ontarians to absorb, with little or no benefit. These costs have been estimated to be $600 million by the OPA and Auditor General to $1.2 billion by energy critic Tom Adams.

Another study completed by Power Advisory LLC for the Canadian Wind Energy Association, calculates that costs to the typical consumer have increased by 30% before application of the Clean Energy Benefit[26] between 2009 and 2012. Of concern, is that 50% of the total increase is related to supply costs. The increase in commodity costs is attributable to several sources including those described in Fig. 15 below.

Figure 15: Recent Increases in Consumer Bills ($/kWh)[27]



In addition to these supply side factors, line loss (defined as the electricity lost as it is transmitted through wires and transformers), can also contribute meaningfully to the cost of power borne by customers. Ontario's distribution system losses have averaged over 4% in recent years. New equipment and technology, currently available on the market, has been shown to reduce the loss to less than 3%. This type of improvement can have direct and immediate benefits to customer bills, as less of the power purchased by LDCs is lost arriving to our homes and businesses and direct bill item charges (line loss factor) is reduced. Recognizing these line loss reductions as conservation, based on the improved

[26] The Clean Energy Benefit was implemented to artificially reduce the price impacts of recent policy decisions, including the GEA.
[27] Power Advisory LLC for CanWea. Customer Bill Impacts of Generation Sources in Ontario. 2013

efficiency of the electricity system, and allowing utilities to recover the associated costs of system improvements would allow customers across the province to save.

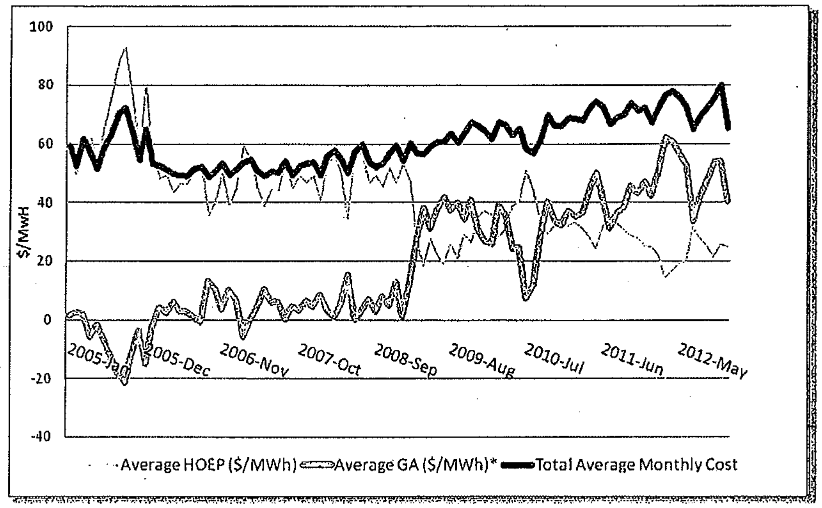
This section has discussed a number of supply cost increases largely driven by legacy policy interventions. It is too late to rectify past decision-making; however, as we look to the future we believe it is in the interest of the province and its consumers that the collective knowledge, experience and intellect of the industry, and its oversight agencies, focus efforts on the following:

1. Through the Long-term Energy Planning process, enhance the precision of supply recommendations and take all reasonable actions to reduce risk in the Province's generation system planning.
2. Leveraging the work of the Global Adjustment (GA) and HOEP Reviews, ensure the future of the wholesale electricity market sends appropriate pricing signals to make operational and investment decisions, while gradually removing the barriers caused by the GA.
3. Implement regional planning and institute infrastructure zoning principals to avoid future project cancellations.
4. Investment in new equipment and technology to reduce line losses, and allowances for utilities to recover these costs.

Components of the Global Adjustment Mechanism

Since 2005, the long-term impacts of policy interventions and new supply arrangements with the province have materialized as part of the Global Adjustment (GA) mechanism on customer bills. The GA is a catch-all customer cost category outside the control of the LDC sector and largely reflects the costs of provincially contracted generation and its distortion to the supply market. Today, the GA represents the greatest portion of the total real costs to supply the grid with electricity (greater that the amount supplied in the marketplace), diminishing the economic principles on which the wholesale-power market was designed. Fig. 16 below demonstrates the growth in GA costs and their impact on the total cost of supply for consumers. In the past four years, the average annual GA cost increase has been 32%. These cost increases are particularly worrisome, given broader market signals that would indicate commodity prices should be declining, as a result of the sustained depression of demand in Ontario and historically low North American natural gas prices, which tend to drive marginal electricity prices.

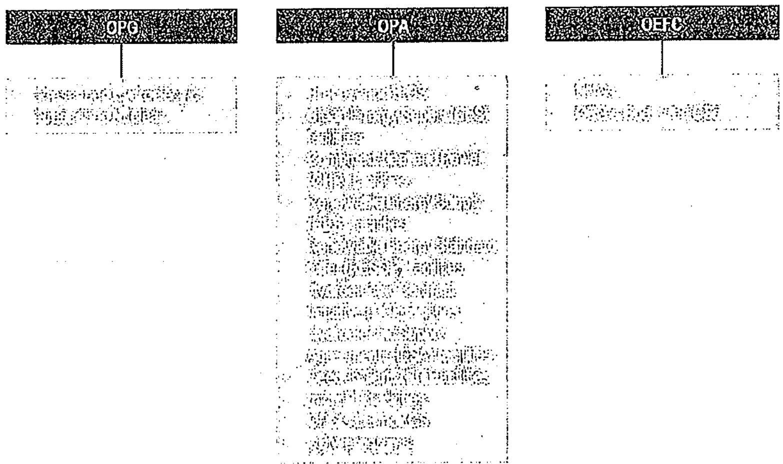
Figure 16: Recent Increases in Consumer Bills ($/kWh)[28]



The GA largely represents the difference between the total payments made to all contracted generation, rate regulated generation facilities and conservation programs, and the total market revenue captured through the HOEP. These costs include the elements noted in the figure below. With the GA costs associates with supply making up a much larger portion of the overall commodity price (70% on July 3rd 2013) we must start to question the resources being consumed managing the wholesale market functions and maintaining the necessary infrastructure. Wholesale market costs are yet another cost absorbed by ratepayers, while the perceived benefit is currently very low.

[28] Independent Electric System Operator. 2013 Market Data.

Figure 17: Global Adjustment Components[29]



Carrying forward from the GA Review process (IESO SE-106), we propose striving towards adoption of the second recommendation of the 2011 Electricity Market Forum and reconnect supply and demand through tighter integration of the supply mix and commodity pricing. Following the key guiding principles of the GA Review, considering administrative complexity, fairness and equality of GA allocation and impacts on market efficiency, adopt restructuring options for the GA and market rules to more appropriately recover costs of supply.

Streamlining the Regulatory Process

To date, the regulatory cost burden for the distribution sector has been significant. The OEB's fixed costs typically represent over $32 million annually to ratepayers, while compliance requirements for utilities lead to substantial variable cost burdens of filing cost of service applications and responding to intervenors. We believe the RRFE will assist in streamlining the process for LDCs of all sizes. We propose to continue working closely with the Board and the Ministry to find further efficiencies in similar spirit of the RRFE.

Similarly, we suggest that costs of intervenors could be substantially reduced with the appropriate controls and screening to reduce the costs associated with their involvement in ratemaking. The intervenor process is an important one to ensure fairness of investment and equity of rates; however, a streamlined process that allows for more precise articulation of noteworthy input requires greater oversight and better screening of participants. Those selected should provide only the greatest value to the ratepayer, while transparently and concisely providing input to the Board.

Streamlining and Enhancing the Transparency of Provincial Agencies

Currently, the OEB regulates the costs and operations of Ontario's LDCs, in addition to nearly every other aspect of the electricity system, including planning (OPA), the implementation of government energy policy (Ministry of Energy), large aspects of generation (OPG, non-utility generators, OPA) and transmission (IESO) of electricity. According to many of Ontario's LDCs, this process has potentially created disincentives for innovation and investment in key infrastructure, and has resulted in increased costs for the end consumer, when it was meant to control or even decrease costs.[30] While the regulatory

[29] Navigant Consulting Ltd. Global Adjustment Review Part 1: Options Identification. 2013
[30] "The Power to Deliver: A Six Point Plan for the Future of Electricity Distribution in Ontario", Electricity Distributors Association. 2012.

process is meant to foster these investments, with the proper cost controls, the process may not be working as it is meant to, even if the spirit and intention to do so exists.
The regulatory costs borne by Ontario utilities, and ultimately by consumers, grew by 24% in the last 3 years ending in 2010, as represented by the below table, published by the EDA. This increase is largely attributed to increased scrutiny by the OEB and the increased costs associated with intervenors. All in, it is costing Ontario's electricity customers close to a quarter of a billion dollars a year to regulate and administer the sector.[31]

Some focus should be placed on streamlining these agencies and the regulatory process to get costs in line with the potential benefit to the end consumer – which, if left unchanged, will continue to rise over time.[32]

Figure 18: Regulatory Costs Incurred by LDCs[33]

$ in Millions	2008	2009	2010
IESO Admin Charges	$ 85.6	$ 86.9	$ 87.6
OPA Admin Fees	$ 38.8	$ 52.0	$ 61.0
OEB License Fee and Cost Assessments	$ 12.9	$ 14.6	$ 14.7
ESA Cost Assessments	$ 1.9	$ 2.0	$ 2.1
LDC Costs for Regulatory Compliance	$ 29.8	$ 36.5	$ 44.6
TOTAL	$ 169.0	$ 192.0	$ 210.0

Negative Implications of the Green Energy Act

The 2013 report of the Fraser Institute, *Environmental and Economic Consequences of Ontario's Green Energy Act*, outlines a number of analyses that present weaknesses of the GEA plan. According to the report, there is considerable uncertainty if the GEA will lead to the expected environmental benefits suggested. Although we believe in the spirit of the GEA and intentions of developing a world leading renewable energy sector in Ontario, the Fraser Report serves to pinpoint alternative policy solutions that will drive market establishment, technology commercialization and real environmental benefits at costs the ratepayers and taxpayers of the province can support. Inefficiencies of the GEA are leading to market losses in the amount of $200 million annually, a figure supported by the Auditor General[34]. The report and the Auditor General have also uncovered the following:

1. $1.3 to $1.7 billion in new grid spending associated with supporting the GEA objectives.
2. $1.1 billion to fund the Clean Energy Benefit on an annual basis.
3. $2.7 billion in renewable energy contracts equaling prices approximately 89% above prevailing market rates.

Savings Possible from Repositioning Retailers

A significant area of contention is the use of electricity retailers in Ontario and the related costs to the residential and small customer of entering into fixed price contracts. As seen in Fig. 19, two scenarios have been developed: Analysis A compares the difference in the monthly electricity bills between an LDC and a retailer for a customer living in a given location in Ontario and Analysis B compares the current cost

[31] Ibid.
[32] Ibid.
[33] Ibid.
[34] Fraser Institute. 2013

of the same LDC for the same customer as Analysis A with the proposed cost savings from consolidation, as projected by the DSRP. This comparison is for illustrative purposes only, as we strongly doubt that the 15% OM&A savings from consolidation projected in the DSRP is achievable in the majority of cases.

Ultimately, the purpose of Fig. 19 is to identify that repositioning retailers in the Ontario electricity market can be optimized to achieve greater cost savings to the customer than consolidation. A discussion of the proposed recommendations in relation to repositioning electricity retailers in Ontario follows the analysis of Fig. 19 below.

Figure 19: Average Size LDC vs. Retailer Cost Comparison

Analysis A - Comparison of LDC to Retailer	Customer Lives in Same Location			
	Average Size LDC in Ontario	Retailer	Diff ($)	Diff (%)
Electricity Charges	$ 69.67	$ 132.33	$ 62.66	90%
Delivery Charges	$ 40.85	$ 40.85	$ -	0%
Regulatory Charges	$ 4.90	$ 4.65	-$ 0.25	-5%
Debt Retirement Charge	$ 5.60	$ 5.60	$ -	0%
Subtotal of Monthly Electricity Bill	$ 121.02	$ 183.43	$ 62.41	52%
Add: HST (13%)	$ 15.73	$ 23.85	$ 8.11	52%
Total of Monthly Electricity Bill	$ 136.75	$ 207.28	$ 70.52	52%
Less: Ontario Clean Energy Benefit (10% off)	$ (13.68)	$ (20.73)	-$ 7.05	52%
Final Monthly Electricity Bill	$ 123.08	$ 186.55	$ 63.47	52%

Analysis B - Comparison of Unconsolidated vs. Consolidated LDC	Average Size LDC in Ontario - Current Landscape	Average Size LDC in Ontario - After Consolidation and OM&A Cost Savings of 15% Realized	Diff ($)	Diff (%)
Electricity Charges	$ 69.67	$ 69.67	$ -	0%
Delivery Charges	$ 40.85	$ 34.72	-$ 6.13	-15%
Regulatory Charges	$ 4.90	$ 4.90	$ -	0%
Debt Retirement Charge	$ 5.60	$ 5.60	$ -	0%
Subtotal of Monthly Electricity Bill	$ 121.02	$ 114.89	-$ 6.13	-5%
Add: HST (13%)	$ 15.73	$ 14.94	-$ 0.80	-5%
Total of Monthly Electricity Bill	$ 136.75	$ 129.83	-$ 6.92	-5%
Less: Ontario Clean Energy Benefit (10% off)	$ (13.68)	$ (12.98)	$ 0.69	-5%
Final Monthly Electricity Bill	$ 123.08	$ 116.85	-$ 6.23	-5%

In Analysis A, the comparison is performed between an average size local LDC and a comparable retailer by customer number, for a household in a given location in Ontario. The analysis shows that the customer pays approximately 52% more on their monthly electricity bills under contract with a Retailer than a customer with the same usage habits in the same town.

In Analysis B, the comparison is performed to assess the impact of a 15% OM&A cost savings passed down to the customer as a result of consolidation. The cost savings for consolidation has been performed consistent with the 15% cost savings assumption of the DSRP. The analysis shows that the customer will save approximately 5% on their monthly electricity bill if OM&A cost savings from consolidation are as high as 15%, assuming reduction in delivery charges. As noted, the level of savings expected in the DSRP is aggressive and may not be the case in practice, as demonstrated from the historical examples discussed previously in this report.

In comparing the two analyses, it is clear that the customer could experience significant cost savings on their monthly electricity bill if the province were to reposition retailers in the Ontario market. In the current state, the LDCs and customer base in Ontario are bearing variable costs of retailers in the form of the billing function, collections and worst of all, expenses related to bad debt. These costs were raised in Westario Power Inc's most recent rates application, where it was found the costs of the utility supporting retailers have been steadily increasing over time and were brought into question. Consolidation-derived benefits impact such a small portion of the total bill and limited pricing reductions may actually be possible through mandatory consolidation. However, retailer rates have been extremely uncompetitive with RPP rates over time and adjustments to these long-term contracts could have considerable benefits for small consumers. Additional costs associated with retailers and absorbed by LDCs (and their customers) only compound the overall burden of retailers in the market. The sector should consider alternatives that mitigate or remove the cost risks of retailers and/or remove the operating cost burden of retailers to utilities.

In addition to these analyses, the Electricity Distributors Association (EDA) released a report in 2012, *The Power to Deliver: A Six Point Plan for the Future of Electricity Distribution in Ontario*, which considered the cost savings for the customer, associated with curtailment of electricity retailers. The findings of the EDA report were consistent with the analyses in Fig. 19. According to the EDA, "*approximately 15 per cent of the Province's customers are currently signed up with a retailer – the result being, that they are paying 35 per cent to 65 per cent more than customers of LDCs (as identified by Ontario's Auditor General). Phasing out the role of electricity retailers for residential customers will save the electricity system (primarily customers) approximately $260-million. Additionally, LDCs and customers will benefit from reduced costs related to billing settlement processes, collections on defaults, and reduced need for regulatory oversight. Most importantly, almost 700,000 residential electricity customers will see the price they pay for power decrease dramatically.*[35]"

When we look at retailers in the marketplace, it is not only the financial cost considerations that impact the customer – there are other associated costs. When *putting the customer first*, we should also consider their personal experiences with the electricity retailers in Ontario. The EDA stated that more than 70% of complaint calls to the OEB are related to retailer practices, including door-to-door sales and the provision of potentially misleading information to customers[36]. The issue here is simple: the electricity retailers are selling contracts on the basis of the customer saving money on their electricity bills, which is clearly not the case in the analysis performed in Figure 19.

Based on the above discussion and analysis, there are a number of ways that electricity retailers can be repositioned to achieve cost savings for customers. First of all, retailers are currently not including the global adjustment in their electricity prices presented to the customer at the time of signing the contract. It is only when the customer receives their bill from the LDC, which performs the billing function for the retailers in the current state, that they can see the global adjustment charges, which are substantial. It is recommended that retailers are required by the OEB to include the global adjustment in their contract prices to show customers the true cost of their monthly electricity. Secondly, retailers are currently not

[35] "The Power to Deliver: A Six Point Plan for the Future of Electricity Distribution in Ontario", Electricity Distributors Association. 2012.
[36] Ibid.

performing their own billing and collections functions; the LDC is responsible for this function. As a result, the LDC spends a significant amount of time and money on billings, collections and ultimately, writing off bad debts associated with unpaid retailer customer bills. If it is believed that there remains a place for Electricity Retailers in the marketplace, it is recommended that the retailers perform their own billing and collections functions, which would reduce the OM&A costs to the LDC and require the retailers to focus on signing electricity contracts with creditworthy customers. In the event that retail customers default on their bills, it should be the responsibility of the retailer to perform the collections and corresponding bad debt write-offs for defunct customer accounts, not the LDC.

The recommendations noted above create real cost savings for the LDC. These savings should not be disregarded as they can benefit customers immediately, rather than over the 10 year period of the recommended consolidation plan as identified in the DSRP report. We believe that if retailers are required to include the global adjustment in their prices and perform their own billing and collection functions, the LDCs will save a greater percentage of OM&A costs on an annual basis, when compared to consolidation, without incurring any of the transition and transaction costs and while still maintaining the advantages of the local utility for the customer.

WHERE CONTROL EXISTS FOR LDCS

Within the 20% of the electricity bill that can be attributed to the distribution sector, focusing on the following areas could yield improvements to service levels while maintaining or reducing costs to the end consumer:

1. Allow LDCs to increase the scope of their operations.
2. Broaden the use of shared services between LDCs to find cost efficiencies.
3. Streamline the OEB Intervenor process.
4. Voluntary consolidation of neighbouring LDCs, beginning with relevant absorption of Hydro One assets.

Allow LDCs to Increase the Scope of their Operations

In the not-so-distant past, a number of electricity distributors operated as public utility commissions, which provided multiple services – such as water and street lighting. As part of the move towards a competitive electricity market in the 1990s, the delivery of electricity was separated from other services. While it made sense at the time, this deregulated model has been largely abandoned and new themes dominate the industry. With increasing amounts of new technology and many new services available, new possibilities for economies of scope have emerged.[37]

Many municipalities continue to operate the water utility as a distinct entity from the electric utility, despite owning both. While some of the efficiencies that could be captured are being achieved through shared services like combined billing, there are additional efficiencies that could be captured through horizontal consolidation at the local level.

Savings will accrue for customers on the water and power side as a result of having a single, combined database and IT system, the potential to eliminate redundancies in administration, operations and customer service, and through integrated management and planning for capital projects. If there is appeal in consolidating electric utilities to capture cost-side savings, why would there not be appeal in consolidating across utilities to more effectively use resources and the customer relationship? As a result

[37] Ibid.

of the existing relationship and the common shareholder, transaction and transition costs would be far lower in comparison to merging with a neighboring LDC. In addition to cost savings, customers would see a benefit in the way they interact with the utilities – they would receive one bill, clearly explaining consumption and rates for each service, and be able to call one number if there are any questions. This improved clarity will save additional phone calls for both the customer and the utility. By efficiently combining activities from more than one type of service, overall costs are reduced.

Examples of utilities that are currently managed as a combined entity, or multi-utilities, exist in the United States and Ontario. It is common in the US to see utilities providing electricity, gas, water and wastewater services, street lighting and energy conservation programs. Examples include larger investor owned utilities such as San Diego Gas and Electric, Avista Utilities and Ameren Illinois.

Utilities Kingston is a prime example in Ontario. The company has been providing electricity, gas, fiber optics and water and waste-water services for the municipality since 2000, under one affiliate. It estimates that it saves a combined total of $1.9 million each year through sharing overhead costs, equipment, metering/billing services and engaging in joint construction projects. [38]

These examples are not the norm; however, through a change in the legislation, more utilities and municipalities will pursue a multi-utility model in order to realize the above benefits to operating costs and customer service.

Broaden the use of Shared Services between LDCs to Find Cost Efficiencies

Shared services are commonly used internally to provide functions and resources used by multiple departments, thereby reducing redundancies and improving cost efficiencies within the organization. Evolving this concept further by sharing services between multiple local distribution companies would add further savings for both ratepayers and shareholders. Evidence of successful collaborations already exist in the Ontario market, as innovative Small and Medium LDCs have cooperated to take advantage of common billing systems, bulk purchasing and general knowledge sharing, among other functions and services. Through these sometimes informal collaborations, one LDC has estimated that it now saves about 10% off its annual equipment purchases as a result of its participation in bulk purchasing programs.

Another success story is summarized in the case below:

> During the installation of smart meters in the province and development of the MDM/R integration, Small and Medium sized LDCs met the province-wide requirements on time and on budgetary costs much lower by comparison to larger LDCs. This demonstrates that Small and Medium LDCs are just as and sometime more efficient and productive than their large counterparts when implementing innovative top down provincial solutions. The OEB has also recognized many from the Small and Medium LDC community for their efforts in maintain excellent cost-per-meter installations in account reconciliations.

Through more formal collaborations, the impact of creating "internal" service providers for the broader sector could mean cost savings to each and every member of the collaboration. Certainly, an amount of local expertise will continue to be needed, but the same level of spending at each LDC will not be required in order to maintain the high service standards that are the norm for Small and Medium LDCs.

[38] Ibid.

Further exploration is needed by the individual players in the market regarding what services in particular could be shared at a more centralized level, in order to reduce OM&A costs while still maintaining current service standards. Several utilities are working towards formalizing initiatives that will produce clear and immediately quantifiable savings. It is evident from both historical evidence and academic literature that there are distinct benefits that can be captured through co-operation that do not require consolidation on a larger scale, as suggested by the DSRP. Through the use of co-operatives and buying groups, among other creative solutions, efficiencies could be realized without incurring significant transaction and transition costs.

Streamline the OEB Intervenor Process

As part of the current rate filing process with the OEB, Intervenors are interested groups or individuals who participate actively by submitting evidence, arguments or interrogatories (written questions) or by cross-examining a witness or witnesses at an oral hearing. Intervenors are free to participate and submit arguments that question and often refute the utility's cost projections and general outlook, thereby making a case for lower rates or smaller rate increases than applied for by the LDC.

Intervenors may include customers and other affected individuals, consumer and trade associations, environmental and regional interest groups, and other public interest groups.[39]

We propose that this process be streamlined to reduce the amount of time needed to review and approve each rate filing, and therefore the cost of the entire process for the utility, the OEB and ultimately, ratepayers. Enhancement of the intervenor approvals process would increase regulatory effectiveness and efficiency. Using best practice, the OEB could use a scorecard system and set of indicators to ensure the appropriateness and avoidance of intervenor costs. This process may be further enhanced for smaller LDC hearings, where community focus is already heightened. Both Direct and indirect interrogatory costs per customer must be fair and necessary to be value added to the customer.

Currently, the eligibility requirements for becoming an Intervenor eligible to recover costs are not overly onerous. Essentially, any individual or organization outside of the government (municipal, provincial or federal) and companies operating in the sector can act as an Intervenor (and recover the associated costs), if they can show they represent ratepayers, the public interest or are an affected landowner. This, as you might expect, represents quite a large group of individuals and organizations.

Correspondingly, we recommend the following:

- Streamlining the regulatory requirements of the OEB and right-sizing them to the size of the LDCs on a case by case basis, which will help limit the need for Intervenors.
- Putting in place a stronger screening process to ensure Intervenors are bringing value to the hearings, and not just using them as a lobbying platform. This could include an Intervenor checklist and a set of evaluation criteria to pre-qualify the matter each could intervene on, and eliminate those who should not have Intervenor status.
- Implementing a system of criteria that defines the amount of time Intervenors have to debate, based on the size and/or complexity of the case and its reach in terms of impact.
- Intervenors identify the people they represent and demonstrate that those people acknowledge and approve their representation.[40]

By raising the eligibility standard for cost recovery of what is 'in the public's interest', a portion of the approximately $4 million that's spent each year on Intervenors, in addition to the time spent by the OEB

[39] "Participating in a Hearing" *Ontario Energy Board*. Date published: 2012-08-07. Date accessed: 2013-06-20. <http://www.ontarioenergyboard.ca/OEB/Industry/Regulatory+Proceedings/Hearings/Participating+in+a+Hearing>
[40] "The Power to Deliver: A Six Point Plan for the Future of Electricity Distribution in Ontario", Electricity Distributors Association. 2012.

and the utility, could be saved. The Accord is encouraged by recent actions undertaken by the OEB to pursue an in-depth inquiry into the role and cost/benefit of intervenors in regulatory matters.

Voluntary Consolidation of Neighbouring LDCs with Relevant Absorption of Hydro One Assets

Forced consolidation, as recommended by the DSRP, would create pressure on Ontario's Small and Medium LDCs to merge, even if does not does it make good business sense. In the broader economy and in the electricity sector, most mergers and amalgamations have not been successful at increasing shareholder value[41], while considerable questions can be raised on their ability to create cost efficiencies as well.

What does make good business sense is to have contiguous, shoulder-to-shoulder utilities, able to serve all customers within a particular region, without having pockets of customers being served by Hydro One. Many Ontarians are currently able to point to a friend or family member who lives "around the corner", is served by Hydro One instead of the local LDC, and pays more for electricity each month. Putting the Hydro One assets on the table for amalgamation would accomplish numerous goals for the Province – specifically, it could realize cash through the divestment, while also creating contiguous utilities that take advantage of the obvious efficiencies that come from operating a whole and fulsome service territory. The total number of LDCs would decline, potentially reducing the cost to regulate the sector. Planning decisions would be much more integrated and holistic, also providing benefits to the local economy, environment and ratepayers. By encouraging the distribution sector to merge where it makes good business sense, while allowing consolidation of logical assets and customers, Ontario's ratepayers would directly benefit from the likely savings.

With the appropriate support, the market could identify and harvest value in a range of merger activity, with good business as a guiding principle. These mergers would be successful when the appropriate organizational alignment is in place, and change management plans are executed, yielding the greatest possible synergies. Mass-mergers with an aim to reduce the quantity of LDCs in Ontario five-fold, will likely end in difficult transitions and far less of the $1.2 billion in estimated cost savings being actually achieved. In voluntary and fundamentally sound mergers, the risk of failed integration is dramatically reduced, as are the transaction and transition costs, ultimately absorbed by ratepayers.

ALTERNATIVES

Consolidation is not the only way to achieve cost savings or scale. Numerous collaborations over the years have led to not only cost savings, but innovation, new expanded opportunities and new revenue stream as well. Some of these past collaborations are mentioned by the DSRP. Through co-operative or non-profit business models, many of Ontario's Small and Medium LDCs have, in some form or another, benefitted from collaborating with each other, while incurring minimal transaction or transition costs without giving up local control and direct community interaction. Collaborative service elements have included group buying of equipment and services, regulatory filing support, billing, CDM program management, common conditions of service, industry research, and others. These accomplishments have been achieved through open and trusting relationships among utilities with common values.

Two often-discussed examples in the Ontario market include Cornerstone Hydro Electric Concepts (CHEC) and Utility Collaborative Services (UCS). Established in 2000 and 2005, respectively, both collaborations share in common a membership that includes only Small and Medium LDCs – those

[41] Becker-Blease, J, L.Goldberg and F Kaen. 2008. "Mergers and Acquisitions as a Response to the Deregulation of the Electric Power Industry: Value Creation or Value Destruction?" *Journal of Regulatory Economics*

utilities that seek the benefits of scaling up certain activities while working together to further the growth of the sector. Another even broader example of collaboration includes the Utilities Standards Forum (USF). USF represents the combined efforts of 50 utilities of all sizes and services members with approximately 2 million customers. While these collaborations provide real services to their membership, a key benefit of the relationship is the knowledge sharing that occurs on an ongoing basis and formally at periodic meetings and functions. Members pay annual dues and usage fees to cover the cost of running the collaboration, and benefit from reduced costs for services and equipment and from the increased awareness of the latest industry developments and sharing of best practices among peers facing similar challenges.

Looking south of the border also offers some good examples of how Ontario's Small and Medium LDCs could benefit from collaboration without consolidation – the National Rural Electric Co-operative Association (NRECA). NRECA represents over 900 rural electric co-operatives (mainly distributors) and provides members with industry research, political advocacy and lobbying, education and training, management consulting, pension plan administration, executive search, management of the national co-op brand (Touchstone Energy), development and administration of youth trades and international development programs, and the publishing of an industry magazine. All of this is done for the benefit of the members, who do not necessarily need to build these skills and capacities internally. Local value is maintained, while the shared benefits of scaled operations are captured for ratepayers and shareholders.

Keys to success lie in the collective trust of the group and their shared values. Each member is committed to collaboration as a way of growing their bottom line and their local impact. While consolidating would formally bring organizations together, the benefits to the bottom line and/or the local community are not proven – often the value allocated to the lawyers and advisors that help to consummate the deal (projected, together with transition costs, to be $500 million over 10 years by the DSRP) is greater than the benefits that shareholders and/or ratepayers will gain collectively.

ADVANTAGES OF THE LOCAL LDC

The local LDC provides substantial value to the community it serves, so new alternative efficiency strategies require consideration of the advantages of the local LDC, particularly when considering the DSRP's recommendation to consolidate the existing 75 LDCs in Ontario down to 8 to 12 regional distributors. In putting the customer first, it is not only the monthly electricity bill that needs to be considered, there are a number of important considerations for the customer to bear in mind:

1. Higher levels of service and responsiveness.
2. Community access to decision makers.
3. Greater focus on the community in decision making and in overall economic effectiveness.
4. Local jobs and economic activity.
5. Community involvement in long-term regional energy planning.

Higher Levels of Service and Responsiveness

The DSRP noted a fundamental necessity of all utility serviced customers: *"All electricity customers should be able to access immediate and responsive service from their LDC, whether it is a large utility or a small one"*. It is the quality of service and the level of responsiveness that drives the customer's direct experience with their electric utility.

As discussed earlier in this report, it was noted that the smaller, community-based utilities are considered by many to be more responsive and reliable to their customers when compared with larger ones. In comparing local LDCs to Hydro One (the largest utility in Ontario), it is clear that the SAIDI, SAIFI and CAIDI metrics demonstrate that smaller LDCs have higher levels of service and responsiveness around interruptions. The value in these metrics is not to be understated. Ultimately, the customer deserves cost effective electricity with reliable and responsive service from their LDC. This is one of the major advantages of a locally operated utility.

Community Access to Decision Makers

Another advantage of the local LDC is the community access to key decision makers within the utility. Smaller communities place significant value on having their viewpoints heard by those who can influence outcomes. Individual ratepayers have the opportunity to provide their input into the decisions that ultimately affect their monthly electricity bills and their overall experience with their electric utility. Often, under local control, citizens have an avenue to drive business policy through their local representatives, who make up councils in direct influence of the utility.

Locally-based LDCs give customers and their communities the ability to have their voice heard by key individuals from their utility. This enables the community messages to be escalated to a higher-level where decisions are made. First hand interaction often creates greater impact as the consumer voice is directly heard and incorporated into decision making. In the case of larger utilities, such as Toronto Hydro or Hydro One, the customer is sometimes limited to virtual communication with utility managers due to the widespread physical location of coverage and multiple layers of administration. As a result, the customer experience may be significantly diminished. In putting the customer first, it is critical to give the customer a voice.

Greater Focus on the Community in Decision Making and Economic Effectiveness

Individuals who are decision makers at the local LDCs are also community members. In this sense, there is increased incentive for the decision makers at local LDCs to stimulate the local economy wherever possible. This includes hiring locally, purchasing locally and investing in the local community. There is a stronger connection between the local LDC and the community in which it operates. This translates to a more significant consideration of the impacts of decisions made at the utility-level on the local community.

Local Jobs and Economic Activity

Smaller communities benefit more significantly from the jobs created and maintained by their local LDC compared to larger, more widespread LDCs. For example, Algoma Power Inc. has a total of 62 full time employees serving a total population of 16,789[42]. The percentage of the total population employed by Algoma Power is 0.36%. Toronto Hydro has a total of 1,740 full time employees serving a total population of 2.5 million[43]. The percentage of the total population employed by Toronto Hydro is 0.07%. Algoma Power on a per capita basis therefore creates five times as many jobs for the population it serves. In creating and maintaining a higher percentage of local jobs, the community's economic activity is stimulated through increased local spending.

Community Involvement in Long-term Regional Energy Planning

Local LDC decision makers are not only hearing first-hand what their customers and their communities have to say about the future of the electricity sector in Ontario; decision makers are taking these real messages from their customers into consideration in determining the future direction of the utility. In addition, the local LDCs are representing their communities when discussing the long-term energy plans with the OEB.

This approach is becoming more and more important to the future of the entire energy sector, evidenced by the Minister of Energy's May 30th, 2013 announcement indicating the adaptation of policies to better include the meet the needs of communities. Energy planners and developers are to work directly with municipalities to identify appropriate actions and locations for development.

As discussed previously, the local community is a key focus for the LDCs. The voice of the community will contribute not only to existing energy issues, but also with long-term planning with regulators and policymakers.

[42] 2011 Yearbook of Electricity Distributors, Ontario Energy Board. 2012.
[43] Ibid.

RECOMMENDATIONS

Development of Facilitative Policy to Incent Strong Business-Based Merger Activity and Remove Simple Barriers to Increase the Flexibility for Innovative Solutions to Enhanced Efficiency for LDCs

Numerous studies and researchers, in addition to the DSRP and the authors of this report, have pointed out that certain specific barriers exist which are inhibiting the sector from taking advantage of opportunities for efficiency improvements.

Many municipalities continue to operate the water utility as a distinct entity from the electric utility, despite owning both. While some of the efficiencies that could be captured are being achieved through shared services like combined billing, there are additional efficiencies that could be captured through horizontal consolidation at the local level. Removing regulatory restrictions around the nature of LDC operations to allow for municipally-owned LDCs to merge services such as water and street lighting, for example, into their organizations would allow them to take advantage of economies of scope, and pass on cost savings to customers for these services and electricity.

In addition, the 33% transfer tax and departure tax (imposed on municipally owned utilities when more than 10% is owned by a private sector investor, forcing them to lose tax exempt status) have often been pointed to as impediments to consolidation activity in the sector. The removal of these taxes would facilitate the kind of smart, broadly beneficial investments and mergers that could potentially drive overall sector efficiencies and create a level playing field for all parties.

Localized Long-Term Energy Planning that Includes Local Distribution Companies and Their Local Communities

The benefits of taking a local, community-based approach have been demonstrated in the discussion above on the advantages of a local LDC. We recommend that provincial long-term energy planning takes a localized focus in order to address the unique circumstances of each diverse region of Ontario. We believe that a critical aspect to putting the customer first requires giving the customer a voice. It is important to involve the local communities in planning discussions that will ultimately affect their experience with their utility.

In fostering community involvement in long-term energy planning, the advantages of a local LDC cannot be understated. Access to key decision makers within the local utilities is an important requirement. It is recommended that local utilities hold an annual meeting for their customers and the community they serve to enable an open forum for discussions of existing issues and inefficiencies, as well as their thoughts on the future of the electricity sector in Ontario.

Focus on Regulatory Efficiency to Promote Improvement of Mechanisms to Deliver Sector-Wide Efficiencies and Minimize Costs of Regulation

As discussed earlier in this report, within a typical residential electricity bill, 20% of the costs are within the LDC's control and 80% of the costs are outside of the LDC's control. In both cases, we believe there are efficiencies to be obtained that ultimately represent cost savings to the customer upon implementation.

Firstly, we recommend that LDC's are permitted to increase the scope of their operations through horizontal consolidation at the local level. The potential efficiencies to be gained include cost savings from a single, combined billing system, elimination of redundancies in administration, operations and customer service, integrated capital management and an improved customer experience in their interactions with the utilities. In this sense, we believe the Ministry and the OEB should focus their regulatory efforts on reducing the 80% of costs outside of the LDC's control to create more significant cost savings for customers in the long-term.

Secondly, we recommend that the OEB streamlines the intervenor process to achieve cost savings associated with the current intervenor costs incurred by the utilities. In order to achieve these cost savings, there needs to be a reduction in the amount of time required for each rate filing. Our recommendation includes the following aspects: (1) Streamline the regulatory requirements by the OEB and adapt these requirements on a case-by-case basis depending on the size of the utility; (2) Implement a stronger screening process for intervenors to ensure they are bringing value to the hearings; and (3) implement a system of criteria that limits the amount of time spent on intervenors during hearings.

Thirdly, we recommend streamlining and enhancing the transparency of provincial agencies. This includes taking a closer look at the regulatory costs borne by the Ontario utilities (and ultimately passed down to the customers on their monthly electricity bills) to consider where cost savings could be achieved through the elimination of redundancies in regulatory activities performed across the various provincial agencies.

Finally, we recommend considering the repositioning of retailers in the Ontario electricity sector to achieve significant cost savings for all customers. As noted in Fig. 19, the monthly electricity bills of customers in contracts with electricity retailers are between 35% to 65% higher than the monthly electricity bills of customers subject to time-of-use pricing with their utilities. It is recommended that retailers are required by the OEB to include the global adjustment in their contract prices to show customers the true cost of their monthly electricity. In addition, it is recommended that retailers perform their own billing and collections functions, which reduces the costs of bad debts currently absorbed by the LDCs. In implementing these two recommendations to reposition retailers, significant cost savings can be achieved for the LDCs. These savings will be passed onto the customer in the form of reduce OM&A costs at the LDC level.

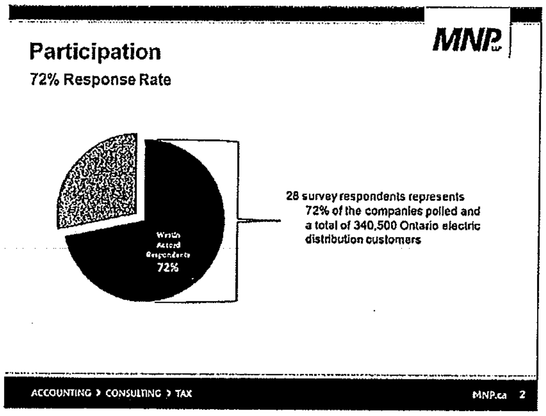
Voluntary Consolidation and Collaboration, Where Clear Benefits and a Strong Business Case Exists, Including Amalgamation of Hydro One Distribution Assets

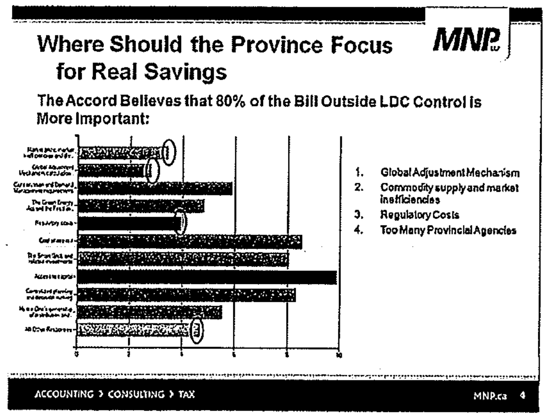
There is no clearly definable and uniform minimum customer base that creates the optimal situation for net benefits to the customer. Each LDC in Ontario faces a set of unique circumstances, including opportunities and challenges relative to their geographical location, the population being served and the overall regulatory framework. As with all businesses, there are situations where logical synergies exist and there are others where none can be found. Correspondingly, we do not agree with the widespread consolidation recommendation of the DSRP; however, we recognize and believe in many of the DSRP's underlying principles regarding mergers including putting the customer first, the need for shoulder-to-shoulder, whole boundaries in Ontario, the need for increased efficiencies and the need for removal of blockades preventing mergers and acquisitions when they make good business sense for the province.

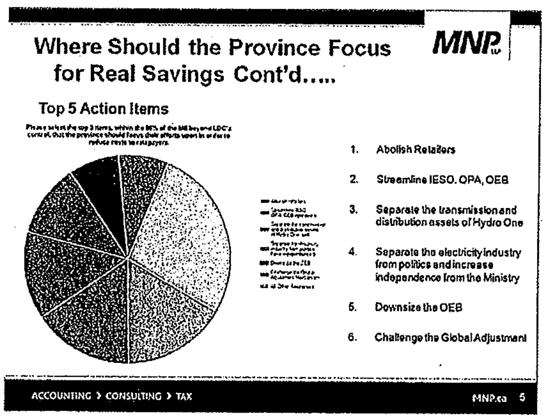
As such, we recommend encouraging voluntary mergers in order to move toward creating shoulder-to-shoulder utilities across Ontario, but only where good business cases can be made. In this sense, we mean that mergers and acquisitions should only be pursued if there are real efficiency gains to be realized that would ultimately benefit the customer and the shareholders. This includes merging the pockets of Hydro One customers with the local LDCs that currently serve surrounding territory. We believe this process will involve investing time and resources into feasibility studies and due diligence, including using historical examples to identify potential best practices and those to avoid as well. This will enable more carefully thought-out and informed business decisions. Ultimately, the province and the consumer will benefit from this approach.

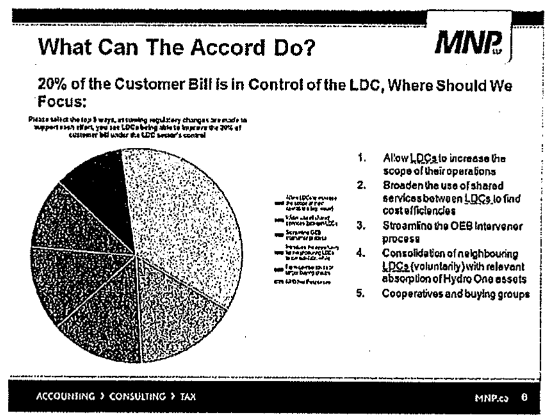
Furthermore, we strongly believe that all Ontario LDCs should enter into discussions with each other to explore opportunities for collaboration, without formally merging. The Small and Medium utilities may be able to achieve synergies at the core of their business (for example, through regular knowledge-sharing and development of industry best practices) and cost efficiencies (for example, through common billing systems or shared purchasing of equipment and other necessary supplies). Cooperation among utilities will spark creativity and innovation without placing undue pressure (and incurring transaction and transition costs) on the LDCs to consolidate. Ultimately, the use of cooperation and shared services between utilities will present a more immediate benefit to the customer in terms of reduced costs and improved service.

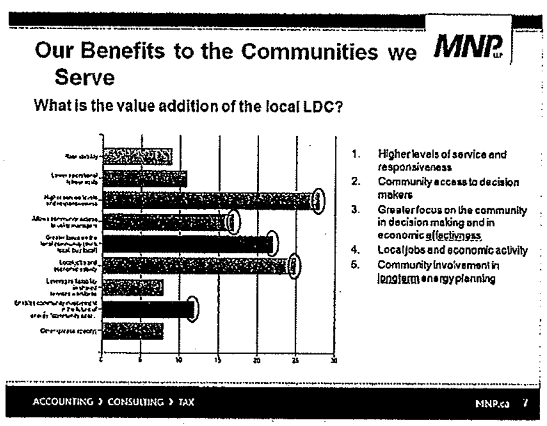
APPENDIX A: SURVEY OF KEY SECTOR ISSUES AND ACTIONS THAT WILL DIRECTLY BENEFIT CUSTOMERS











Company	Year	Efficiency Assessment 2010	2011	2012	2013	Three Year	Cost per Customer	Cost per km of Line
HYDRO HAWKESBURY INC.	2013	-61.8%	-59.4%	-55.8%	-51.1%	-55.5%	284	23,045
WASAGA DISTRIBUTION INC.	2013	-46.8%	-46.3%	-37.8%	-41.6%	-42.1%	407	20,238
HEARST POWER DISTRIBUTION COMPANY LIMITED	2013	-26.3%	-30.1%	-28.4%	-33.1%	-30.6%	414	16,980
HALTON HILLS HYDRO INC.	2013	-27.2%	-24.9%	-27.5%	-35.7%	-29.5%	642	9,034
E.L.K. ENERGY INC.	2013	-28.2%	-26.2%	-25.4%	-33.2%	-28.3%	401	29,697
NORTHERN ONTARIO WIRES INC.	2013	-38.5%	-35.7%	-25.8%	-21.5%	-27.6%	687	11,268
HALDIMAND COUNTY HYDRO INC.	2013	-27.6%	-24.1%	-18.7%	-23.7%	-22.2%	681	8,310
COOPERATIVE HYDRO EMBRUN INC.	2013	-19.3%	-16.9%	-26.4%	-18.9%	-21.2%	568	39,819
KITCHENER	2013	-22.9%	-22.8%	-20.7%	-19.3%	-21.1%	466	22,062
NEWMARKET	2013	-14.6%	-21.0%	-19.5%	-19.5%	-20.1%	543	22,272
ESPANOLA REGIONAL HYDRO DISTRIBUTION CORPORATION	2013	-22.6%	-21.8%	-15.5%	-19.3%	-18.9%	612	14,642
OSHAWA PUC NETWORKS INC.	2013	-21.7%	-18.0%	-14.5%	-17.4%	-16.7%	505	27,050
MILTON HYDRO DISTRIBUTION INC.	2013	-4.1%	-3.0%	-37.6%	-4.5%	-15.7%	654	22,402
ESSEX POWERLINES CORPORATION	2013	-17.0%	-17.1%	-12.6%	-17.2%	-15.7%	482	29,323
GRIMSBY POWER INCORPORATED	2013	-23.1%	-18.6%	-9.6%	-16.9%	-15.2%	538	23,739
WELLAND HYDRO-ELECTRIC SYSTEM CORP.	2013	-19.6%	-16.2%	-10.4%	-15.2%	-14.0%	472	23,533
LAKEFRONT UTILITIES INC.	2013	-14.7%	-12.5%	-18.7%	-7.4%	-12.9%	465	39,825
ENERSOURCE HYDRO MISSISSAUGA INC.	2013	-9.5%	-16.1%	-9.5%	-10.7%	-12.3%	692	26,742
Entegrus Powerlines	2013	-13.1%	-13.4%	-10.9%	-12.5%	-12.3%	531	22,407
LONDON HYDRO INC.	2013	-16.8%	-10.1%	-11.1%	-11.0%	-10.8%	466	24,430
LAKELAND POWER DISTRIBUTION LTD.	2013	-7.5%	-10.0%	-13.6%	-6.4%	-10.1%	700	22,852
RIDEAU ST. LAWRENCE DISTRIBUTION INC.	2013	-10.6%	-13.8%	-6.7%	-7.2%	-9.3%	489	27,552
HORIZON UTILITIES CORPORATION	2013	-13.0%	-13.7%	-6.9%	-5.5%	-8.8%	499	35,054
BURLINGTON HYDRO INC.	2013	-7.6%	-7.1%	-9.0%	-7.5%	-8.0%	587	25,773
HYDRO ONE BRAMPTON NETWORKS INC.	2013	-5.8%	-7.4%	-9.2%	-5.7%	-7.8%	586	27,565
COLLUS POWER CORPORATION	2013	-8.2%	-9.5%	-1.2%	-12.3%	-7.7%	500	23,849
KENORA HYDRO ELECTRIC CORPORATION LTD.	2013	-11.5%	-4.6%	-5.2%	-11.2%	-6.8%	532	30,201
HYDRO 2000 INC.	2013	-14.8%	-12.2%	-0.8%	-1.0%	-4.7%	531	30,838
WHITBY HYDRO ELECTRIC CORPORATION	2013	0.4%	-3.0%	-7.0%	-0.9%	-4.1%	642	24,806
INNISFIL HYDRO DISTRIBUTION SYSTEMS LIMITED	2013	-7.1%	-6.2%	-2.4%	-2.8%	-3.9%	732	14,168
CAMBRIDGE and NORTH DUMFRIES HYDRO INC.	2013	-10.1%	-7.8%	-3.3%	0.5%	-3.7%	624	28,714
ORILLIA POWER DISTRIBUTION CORPORATION	2013	-3.5%	-1.9%	-3.7%	-4.7%	-3.5%	591	32,280
VERIDIAN CONNECTIONS INC.	2013	-4.7%	-4.5%	2.4%	-4.5%	-2.3%	529	23,757
CENTRE WELLINGTON HYDRO LTD.	2013	-8.7%	-4.9%	0.4%	0.4%	-1.5%	614	27,271
POWERSTREAM INC.	2013	-7.4%	-6.4%	1.2%	3.0%	-1.0%	653	29,912
WESTARIO POWER INC.	2013	-3.1%	-0.2%	-1.4%	2.2%	0.2%	550	24,220
ST. THOMAS ENERGY INC.	2013	-6.4%	-4.5%	6.8%	-0.3%	0.6%	533	33,412
ORANGEVILLE HYDRO LIMITED	2013	-2.7%	1.6%	0.8%	0.1%	0.7%	577	32,555
BRANTFORD POWER INC.	2013	3.8%	-2.5%	4.7%	0.7%	0.9%	507	39,373
NORFOLK POWER DISTRIBUTION INC.	2013	-1.8%	-2.6%	6.0%	1.2%	1.5%	689	16,915
OTTAWA RIVER POWER CORPORATION	2013	-2.9%	2.7%	0.0%	4.3%	2.3%	505	32,410
NIAGARA-ON-THE-LAKE HYDRO INC.	2013	7.6%	6.5%	2.7%	-0.7%	2.7%	699	18,516
KINGSTON HYDRO CORPORATION	2013	0.1%	2.2%	2.4%	3.7%	2.8%	517	38,667
SIOUX LOOKOUT HYDRO INC.	2013	0.6%	-1.4%	7.2%	2.9%	2.9%	802	7,845
GUELPH HYDRO ELECTRIC SYSTEMS INC.	2013	12.4%	14.7%	-2.0%	0.8%	4.2%	608	28,952
THUNDER BAY HYDRO ELECTRICITY DISTRIBUTION INC.	2013	9.6%	8.0%	-2.8%	8.2%	4.4%	585	25,631
HYDRO OTTAWA LIMITED	2013	-0.1%	-2.6%	7.8%	8.5%	4.5%	579	33,222
BLUEWATER POWER DISTRIBUTION CORPORATION	2013	-3.2%	1.7%	6.4%	5.9%	4.6%	646	29,017
NIAGARA PENINSULA ENERGY INC.	2013	5.4%	5.2%	10.2%	1.1%	5.4%	672	17,408
NORTH BAY HYDRO DISTRIBUTION LIMITED	2013	3.6%	5.5%	5.8%	5.4%	5.5%	614	25,228
WATERLOO NORTH HYDRO INC.	2013	-3.1%	6.4%	4.3%	10.6%	7.0%	728	25,066
PARRY SOUND POWER CORPORATION	2013	4.7%	4.6%	2.4%	13.9%	7.0%	805	21,599
ERIE THAMES POWERLINES CORPORATION	2013	14.9%	14.4%	3.9%	7.9%	8.7%	610	32,792
FORT FRANCES POWER CORPORATION	2013	14.8%	10.5%	11.7%	6.4%	9.6%	622	30,237
PUC DISTRIBUTION INC.	2013	-8.5%	-5.2%	13.4%	22.7%	10.2%	687	30,950
GREATER SUDBURY HYDRO INC.	2013	-2.4%	14.1%	16.7%	4.8%	11.9%	560	26,887
OAKVILLE HYDRO ELECTRICITY DISTRIBUTION INC.	2013	7.6%	12.4%	10.6%	13.8%	12.0%	730	26,377
BRANT COUNTY POWER INC.	2013	15.6%	22.4%	11.5%	5.5%	13.0%	731	13,939
CANADIAN NIAGARA POWER INC.	2013	16.4%	15.6%	10.0%	13.8%	13.2%	726	20,275
TILLSONBURG HYDRO INC.	2013	13.5%	10.7%	12.2%	19.5%	14.1%	736	32,796
PETERBOROUGH DISTRIBUTION INCORPORATED	2013	14.0%	15.6%	13.2%	14.5%	14.4%	562	35,731
WELLINGTON NORTH POWER INC.	2013	7.4%	18.0%	12.8%	17.7%	16.1%	785	38,175
ENWIN UTILITIES LTD.	2013	17.8%	16.8%	23.9%	10.3%	16.9%	652	48,500
RENFREW HYDRO INC.	2013	15.3%	18.3%	18.3%	15.7%	17.4%	561	39,493
ATIKOKAN HYDRO INC.	2013	14.9%	7.7%	32.9%	11.6%	17.5%	908	16,430
MIDLAND POWER UTILITY CORPORATION	2013	16.4%	17.0%	19.6%	18.6%	18.2%	662	34,376
FESTIVAL HYDRO INC.	2013	20.5%	18.0%	20.2%	19.6%	19.2%	627	49,466
CHAPLEAU PUBLIC UTILITIES CORPORATION	2013	17.5%	14.8%	24.0%	20.5%	19.8%	653	30,175
WOODSTOCK HYDRO SERVICES INC.	2013	33.5%	32.9%	29.0%	28.1%	30.0%	739	48,418
WEST COAST HURON ENERGY INC.	2013	14.4%	16.0%	34.8%	41.4%	30.7%	820	50,545
TORONTO HYDRO-ELECTRIC SYSTEM LIMITED	2013	41.7%	47.7%	45.1%	48.4%	47.0%	924	66,793
HYDRO ONE NETWORKS INC.	2013	58.6%	57.3%	58.7%	27.6%	47.8%	1,046	10,682
ALGOMA POWER INC.	2013	62.0%	68.1%	66.4%	71.2%	68.5%	1,952	12,302

Comparison of Distribution Rate Increases 2005 to 2013 to 2019 - Hydro One Acquired Distributors - Residential

Monthly Consumption ***1000 kwhr***

Acquired Distributor	Rate	2005 Dx. Rates			2013 Dx. Rates			Inc. 2005	2019 Dx. Rates			Inc. 2013	Inc. 2005
	Class	Fixed	Variable	Annual	Fixed	Variable	Annual	to 2013	Fixed	Variable	Annual	to 2019	to 2019
Hydro One (Ailsa Craig)	R1	$7.67	0.00660	$171.24	$23.85	0.03353	$688.56	302.10%	$27.89	0.03227	$721.92	4.84%	321.58%
Hydro One (Arkona)	R1	$3.93	0.00210	$72.36	$23.85	0.03353	$688.56	851.58%	$27.89	0.03227	$721.92	4.84%	897.68%
Hydro One (Arnprior	R1	$8.49	0.01170	$242.28	$23.85	0.03353	$688.56	184.20%	$27.89	0.03227	$721.92	4.84%	197.97%
Hydro One (Arran-Elderside)	R1	$6.47	0.00760	$168.84	$23.85	0.03353	$688.56	307.82%	$27.89	0.03227	$721.92	4.84%	327.58%
Hydro One (Artemesia)	R1	$9.44	0.00590	$184.08	$23.85	0.03353	$688.56	274.05%	$27.89	0.03227	$721.92	4.84%	292.18%
Hydro One (Bancroft)	R1	$10.04	0.00760	$211.68	$23.85	0.03353	$688.56	225.28%	$27.89	0.03227	$721.92	4.84%	241.04%
Hydro One (Bath)	R1	$9.96	0.00690	$202.32	$23.85	0.03353	$688.56	240.33%	$27.89	0.03227	$721.92	4.84%	256.82%
Hydro One (Blandford-Blenheim)	R1	$8.56	0.00720	$189.12	$23.85	0.03353	$688.56	264.09%	$27.89	0.03227	$721.92	4.84%	281.73%
Hydro One (Blyth)	R1	$5.01	0.00730	$147.72	$23.85	0.03353	$688.56	366.13%	$27.89	0.03227	$721.92	4.84%	388.71%
Hydro One (Bobcaygeon)	R1	$10.83	0.00780	$223.56	$23.85	0.03353	$688.56	208.00%	$27.89	0.03227	$721.92	4.84%	222.92%
Hydro One (Brighton)	R1	$8.54	0.00860	$205.68	$23.85	0.03353	$688.56	234.77%	$27.89	0.03227	$721.92	4.84%	250.99%
Hydro One (Caledon CH 02)	R1	$11.41	0.00820	$235.32	$23.85	0.03353	$688.56	192.61%	$27.89	0.03227	$721.92	4.84%	206.78%
Hydro One (Campbellford/Seymour)	R1	$9.10	0.00860	$212.40	$23.85	0.03353	$688.56	224.18%	$27.89	0.03227	$721.92	4.84%	239.89%
Hydro One (Cavan-Millbrook-N. Monaghan)	R1	$11.27	0.01070	$263.64	$23.85	0.03353	$688.56	161.17%	$27.89	0.03227	$721.92	4.84%	173.83%
Hydro One (Centre Hastings)	R1	$8.59	0.00770	$195.48	$23.85	0.03353	$688.56	252.24%	$27.89	0.03227	$721.92	4.84%	269.31%
Hydro One (Chalk River)	R1	$10.48	0.01090	$256.56	$23.85	0.03353	$688.56	168.38%	$27.89	0.03227	$721.92	4.84%	181.38%
Hydro One (Champlain Twp.)	R1	$7.55	0.00710	$175.80	$23.85	0.03353	$688.56	291.67%	$27.89	0.03227	$721.92	4.84%	310.65%
Hydro One (Clarence-Rockland)	R1	$6.78	0.00740	$170.16	$23.85	0.03353	$688.56	304.65%	$27.89	0.03227	$721.92	4.84%	324.26%
Hydro One (Cobden)	R1	$9.86	0.01410	$287.52	$23.85	0.03353	$688.56	139.48%	$27.89	0.03227	$721.92	4.84%	151.09%
Hydro One (Deep River)	R1	$12.55	0.01830	$370.20	$23.85	0.03353	$688.56	86.00%	$27.89	0.03227	$721.92	4.84%	95.01%
Hydro One (Deseronto)	R1	$9.57	0.00890	$221.64	$23.85	0.03353	$688.56	210.67%	$27.89	0.03227	$721.92	4.84%	225.72%
Hydro One (Dundalk)	R1	$10.83	0.00870	$234.36	$23.85	0.03353	$688.56	193.80%	$27.89	0.03227	$721.92	4.84%	208.04%
Hydro One (Durham)	R1	$12.34	0.00990	$266.88	$23.85	0.03353	$688.56	158.00%	$27.89	0.03227	$721.92	4.84%	170.50%
Hydro One (Eganville)	R1	$10.34	0.01220	$270.48	$23.85	0.03353	$688.56	154.57%	$27.89	0.03227	$721.92	4.84%	166.90%
Hydro One (Erin)	R1	$9.76	0.01520	$299.52	$23.85	0.03353	$688.56	129.89%	$27.89	0.03227	$721.92	4.84%	141.03%
Hydro One (Exeter)	R1	$11.34	0.00770	$228.48	$23.85	0.03353	$688.56	201.37%	$27.89	0.03227	$721.92	4.84%	215.97%
Hydro One (Fenelon Falls)	R1	$4.13	0.00770	$141.96	$23.85	0.03353	$688.56	385.04%	$27.89	0.03227	$721.92	4.84%	408.54%
Hydro One (Forest)	R1	$11.46	0.00760	$228.72	$23.85	0.03353	$688.56	201.05%	$27.89	0.03227	$721.92	4.84%	215.63%
Hydro One (Georgian Bay Energy - Chatsworth)	R1	$7.00	0.00760	$175.20	$23.85	0.03353	$688.56	293.01%	$27.89	0.03227	$721.92	4.84%	312.05%
Hydro One (Georgina)	R1	$8.63	0.00790	$198.36	$23.85	0.03353	$688.56	247.13%	$27.89	0.03227	$721.92	4.84%	263.94%
Hydro One (Glencoe)	R1	$9.58	0.00620	$189.36	$23.85	0.03353	$688.56	263.62%	$27.89	0.03227	$721.92	4.84%	281.24%
Hydro One (Grand Bend)	R1	$10.12	0.00700	$205.44	$23.85	0.03353	$688.56	235.16%	$27.89	0.03227	$721.92	4.84%	251.40%
Hydro One (Hastings)	R1	$12.41	0.01080	$278.52	$23.85	0.03353	$688.56	147.22%	$27.89	0.03227	$721.92	4.84%	159.20%
Hydro One (Havelock-Belmont-Methuen)	R1	$11.40	0.00910	$246.00	$23.85	0.03353	$688.56	179.90%	$27.89	0.03227	$721.92	4.84%	193.46%
Hydro One (Kirkfield)	R1	$3.53	0.00800	$138.36	$23.85	0.03353	$688.56	397.66%	$27.89	0.03227	$721.92	4.84%	421.77%
Hydro One (Lanark Highlands)	R1	$8.30	0.00820	$198.00	$23.85	0.03353	$688.56	247.76%	$27.89	0.03227	$721.92	4.84%	264.61%
Hydro One (Larder Lake)	R1	$11.93	0.00810	$240.36	$23.85	0.03353	$688.56	186.47%	$27.89	0.03227	$721.92	4.84%	200.35%
Hydro One (Latchford)	R1	$9.90	0.00710	$204.00	$23.85	0.03353	$688.56	237.53%	$27.89	0.03227	$721.92	4.84%	253.88%

Hydro One (Lucan/Granton)	R1	$8.63	0.01130	$239.16	$23.85	0.03353	$688.56	187.91%	$27.89	0.03227	$721.92	4.84%	201.86%
Hydro One (Malahide Twp.)	R1	$8.19	0.00700	$182.28	$23.85	0.03353	$688.56	277.75%	$27.89	0.03227	$721.92	4.84%	296.05%
Hydro One (Mapleton Twp.)	R1	$10.03	0.00740	$209.16	$23.85	0.03353	$688.56	229.20%	$27.89	0.03227	$721.92	4.84%	245.15%
Hydro One (Markdale)	R1	$10.70	0.00690	$211.20	$23.85	0.03353	$688.56	226.02%	$27.89	0.03227	$721.92	4.84%	241.82%
Hydro One (Marmora)	R1	$8.53	0.00740	$191.16	$23.85	0.03353	$688.56	260.20%	$27.89	0.03227	$721.92	4.84%	277.65%
Hydro One (McGarry Twp.)	R1	$9.54	0.00750	$204.48	$23.85	0.03353	$688.56	236.74%	$27.89	0.03227	$721.92	4.84%	253.05%
Hydro One (Meaford)	R1	$9.46	0.00780	$207.12	$23.85	0.03353	$688.56	232.44%	$27.89	0.03227	$721.92	4.84%	248.55%
Hydro One (Middlesex Centre)	R1	$10.61	0.00630	$202.92	$23.85	0.03353	$688.56	239.33%	$27.89	0.03227	$721.92	4.84%	255.77%
Hydro One (Napanee)	R1	$11.02	0.00820	$230.64	$23.85	0.03353	$688.56	198.54%	$27.89	0.03227	$721.92	4.84%	213.01%
Hydro One (Nipigon Twp.)	R1	$11.33	0.01310	$293.16	$23.85	0.03353	$688.56	134.88%	$27.89	0.03227	$721.92	4.84%	146.25%
Hydro One (North Dorchester Twp.)	R1	$6.43	0.00690	$159.96	$23.85	0.03353	$688.56	330.46%	$27.89	0.03227	$721.92	4.84%	351.31%
Hydro One (North Dundas Twp.)	R1	$8.19	0.00780	$191.88	$23.85	0.03353	$688.56	258.85%	$27.89	0.03227	$721.92	4.84%	276.24%
Hydro One (North Glengarry Twp.)	R1	$5.45	0.00820	$163.80	$23.85	0.03353	$688.56	320.37%	$27.89	0.03227	$721.92	4.84%	340.73%
Hydro One (North Grenville - Kemptville)	R1	$10.78	0.01320	$287.76	$23.85	0.03353	$688.56	139.28%	$27.89	0.03227	$721.92	4.84%	150.88%
Hydro One (North Perth - Listowel)	R1	$11.04	0.00840	$233.28	$23.85	0.03353	$688.56	195.16%	$27.89	0.03227	$721.92	4.84%	209.47%
Hydro One (North Stormont)	R1	$3.59	0.00740	$131.88	$23.85	0.03353	$688.56	422.11%	$27.89	0.03227	$721.92	4.84%	447.41%
Hydro One (Omemee)	R1	$11.25	0.01200	$279.00	$23.85	0.03353	$688.56	146.80%	$27.89	0.03227	$721.92	4.84%	158.75%
Hydro One (Perth East Twp.)	R1	$4.02	0.00630	$123.84	$23.85	0.03353	$688.56	456.01%	$27.89	0.03227	$721.92	4.84%	482.95%
Hydro One (Prince Edward County)	R1	$10.66	0.00840	$228.72	$23.85	0.03353	$688.56	201.05%	$27.89	0.03227	$721.92	4.84%	215.63%
Hydro One (Quinte West - Frankford)	R1	$4.52	0.00740	$143.04	$23.85	0.03353	$688.56	381.38%	$27.89	0.03227	$721.92	4.84%	404.70%
Hydro One (Rainy River)	R1	$11.41	0.00840	$237.72	$23.85	0.03353	$688.56	189.65%	$27.89	0.03227	$721.92	4.84%	203.69%
Hydro One (Ramara Twp.)	R1	$4.47	0.00760	$144.84	$23.85	0.03353	$688.56	375.39%	$27.89	0.03227	$721.92	4.84%	398.43%
Hydro One (Red Rock Twp.)	R1	$12.04	0.01800	$360.48	$23.85	0.03353	$688.56	91.01%	$27.89	0.03227	$721.92	4.84%	100.27%
Hydro One (Russell)	R1	$9.74	0.01150	$254.88	$23.85	0.03353	$688.56	170.15%	$27.89	0.03227	$721.92	4.84%	183.24%
Hydro One (Schreiber Twp.)	R1	$12.31	0.01470	$324.12	$23.85	0.03353	$688.56	112.44%	$27.89	0.03227	$721.92	4.84%	122.73%
Hydro One (Severn Twp)	R1	$7.74	0.00720	$179.28	$23.85	0.03353	$688.56	284.07%	$27.89	0.03227	$721.92	4.84%	302.68%
Hydro One (Shelburne)	R1	$10.57	0.01060	$254.04	$23.85	0.03353	$688.56	171.04%	$27.89	0.03227	$721.92	4.84%	184.18%
Hydro One (South Bruce Peninsula - Wiarton)	R1	$11.92	0.01240	$291.84	$23.85	0.03353	$688.56	135.94%	$27.89	0.03227	$721.92	4.84%	147.37%
Hydro One (South Glengarry)	R1	$6.82	0.00600	$153.84	$23.85	0.03353	$688.56	347.58%	$27.89	0.03227	$721.92	4.84%	369.27%
Hydro One (South River)	R1	$10.63	0.01000	$247.56	$23.85	0.03353	$688.56	178.14%	$27.89	0.03227	$721.92	4.84%	191.61%
Hydro One (Springwater Twp.)	R1	$8.69	0.00660	$183.48	$23.85	0.03353	$688.56	275.28%	$27.89	0.03227	$721.92	4.84%	293.46%
Hydro One (Stirling-Rawdon Twp.)	R1	$9.30	0.00830	$211.20	$23.85	0.03353	$688.56	226.02%	$27.89	0.03227	$721.92	4.84%	241.82%
Hydro One (Thedford)	R1	$9.46	0.00650	$191.52	$23.85	0.03353	$688.56	259.52%	$27.89	0.03227	$721.92	4.84%	276.94%
Hydro One (Thessalon)	R1	$11.70	0.00840	$241.20	$23.85	0.03353	$688.56	185.47%	$27.89	0.03227	$721.92	4.84%	199.30%
Hydro One (Thorndale)	R1	$2.71	0.00710	$117.72	$23.85	0.03353	$688.56	484.91%	$27.89	0.03227	$721.92	4.84%	513.25%
Hydro One (Tweed)	R1	$2.84	0.00760	$125.28	$23.85	0.03353	$688.56	449.62%	$27.89	0.03227	$721.92	4.84%	476.25%
Hydro One (Wardsville)	R1	$6.97	0.00780	$177.24	$23.85	0.03353	$688.56	288.49%	$27.89	0.03227	$721.92	4.84%	307.31%
Hydro One (Warkworth)	R1	$11.45	0.00940	$250.20	$23.85	0.03353	$688.56	175.20%	$27.89	0.03227	$721.92	4.84%	188.54%
Hydro One (West Elgin)	R1	$9.89	0.01130	$254.28	$23.85	0.03353	$688.56	170.79%	$27.89	0.03227	$721.92	4.84%	183.91%
Hydro One (Woodville)	R1	$2.28	0.00760	$118.56	$23.85	0.03353	$688.56	480.77%	$27.89	0.03227	$721.92	4.84%	508.91%
Hydro One (Wyoming)	R1	$8.47	0.00650	$179.64	$23.85	0.03353	$688.56	283.30%	$27.89	0.03227	$721.92	4.84%	301.87%
Averages - Hydro One Medium Density Acquireds		$8.92	0.00877	$212.21	$23.85	0.03353	$688.56	224.46%	$27.89	0.03227	$721.92	4.84%	240.18%

Hydro One (Brockville)	UR	$9.12	0.00750	$199.44	$16.50	0.02529	$501.48	151.44%	$19.57	0.01779	$448.32	-10.60%	124.79%
Hydro One (Caledon OH 01)	UR	$14.07	0.00460	$224.04	$16.50	0.02529	$501.48	123.84%	$19.57	0.01779	$448.32	-10.60%	100.11%
Hydro One (Carleton Place)	UR	$10.59	0.01430	$298.68	$16.50	0.02529	$501.48	67.90%	$19.57	0.01779	$448.32	-10.60%	50.10%
Hydro One (Dryden)	UR	$10.68	0.01320	$286.56	$16.50	0.02529	$501.48	75.00%	$19.57	0.01779	$448.32	-10.60%	56.45%
Hydro One (Georgian Bay Energy - Owen Sound)	UR	$7.00	0.00860	$187.20	$16.50	0.02529	$501.48	167.88%	$19.57	0.01779	$448.32	-10.60%	139.49%
Hydro One (Lindsay)	UR	$11.90	0.00810	$240.00	$16.50	0.02529	$501.48	108.95%	$19.57	0.01779	$448.32	-10.60%	86.80%
Hydro One (Perth)	UR	$10.83	0.00970	$246.36	$16.50	0.02529	$501.48	103.56%	$19.57	0.01779	$448.32	-10.60%	81.98%
Hydro One (Quinte West - Trenton)	UR	$4.52	0.00740	$143.04	$16.50	0.02529	$501.48	250.59%	$19.57	0.01779	$448.32	-10.60%	213.42%
Hydro One (Smiths Falls)	UR	$9.36	0.01130	$247.92	$16.50	0.02529	$501.48	102.27%	$19.57	0.01779	$448.32	-10.60%	80.83%
Hydro One (Thorold)	UR	$10.20	0.01170	$262.80	$16.50	0.02529	$501.48	90.82%	$19.57	0.01779	$448.32	-10.60%	70.59%
Hydro One (Whitchurch-Stouffville)	UR	$7.69	0.00820	$190.68	$16.50	0.02529	$501.48	163.00%	$19.57	0.01779	$448.32	-10.60%	135.12%
Averages - Hydro One Urban Acquireds		$9.63	0.00951	$229.70	$16.50	0.02529	$501.48	118.32%	$19.57	0.01779	$448.32	-10.60%	95.17%
Hydro One Legacy	R1	$15.99	0.02100	$443.88	$23.85	0.03353	$688.56	55.12%	$27.89	0.03227	$721.92	4.84%	62.64%
Hydro One Legacy	UR	$11.82	0.01610	$335.04	$16.50	0.02529	$501.48	49.68%	$19.57	0.01779	$448.32	-10.60%	33.81%

Comparison of Distribution Rate Increases 2005 to 2013 to 2019 - Hydro One Acquired Distributors - Small General Service

Monthly Consumption 250 kW

Acquired Distributor	Rate Class	2005 Dx. Rates Fixed	2005 Dx. Rates Variable	2005 Dx. Rates Annual	2013 Dx. Rates Fixed	2013 Dx. Rates Variable	2013 Dx. Rates Annual	Inc. 2005 to 2013	2019 Dx. Rates Fixed	2019 Dx. Rates Variable	2019 Dx. Rates Annual	Inc. 2013 to 2019	Inc. 2005 to 2019
Hydro One (Ailsa Craig)	GSd	$13.11	3.35000	$10,207.32	$55.62	11.37000	$34,777.44	240.71%	$106.94	20.25300	$62,042.28	78.40%	507.82%
Hydro One (Arkona)	GSd	$1.82	1.58000	$4,761.84	$55.62	11.37000	$34,777.44	630.34%	$106.94	20.25300	$62,042.28	78.40%	1202.91%
Hydro One (Arnprior	GSd	$16.36	2.96000	$9,076.32	$55.62	11.37000	$34,777.44	283.17%	$106.94	20.25300	$62,042.28	78.40%	583.56%
Hydro One (Arran-Elderside)	GSd	$6.32	2.63000	$7,965.84	$55.62	11.37000	$34,777.44	336.58%	$106.94	20.25300	$62,042.28	78.40%	678.85%
Hydro One (Artemesia)	GSd	$14.95	4.40000	$13,379.40	$55.62	11.37000	$34,777.44	159.93%	$106.94	20.25300	$62,042.28	78.40%	363.71%
Hydro One (Bancroft)	GSd	$18.78	2.96000	$9,105.36	$55.62	11.37000	$34,777.44	281.94%	$106.94	20.25300	$62,042.28	78.40%	581.38%
Hydro One (Bath)	GSd	$7.78	3.01000	$9,123.36	$55.62	11.37000	$34,777.44	281.19%	$106.94	20.25300	$62,042.28	78.40%	580.04%
Hydro One (Blandford-Blenheim)	GSd	$18.34	2.90000	$8,920.08	$55.62	11.37000	$34,777.44	289.88%	$106.94	20.25300	$62,042.28	78.40%	595.54%
Hydro One (Blyth)	GSd	$16.56	2.69000	$8,268.72	$55.62	11.37000	$34,777.44	320.59%	$106.94	20.25300	$62,042.28	78.40%	650.33%
Hydro One (Bobcaygeon)	GSd	$17.82	3.48000	$10,653.84	$55.62	11.37000	$34,777.44	226.43%	$106.94	20.25300	$62,042.28	78.40%	482.35%
Hydro One (Brighton)	GSd	$17.58	3.39000	$10,380.96	$55.62	11.37000	$34,777.44	235.01%	$106.94	20.25300	$62,042.28	78.40%	497.65%
Hydro One (Caledon CH 02)	GSd	$18.62	4.58000	$13,963.44	$55.62	11.37000	$34,777.44	149.06%	$106.94	20.25300	$62,042.28	78.40%	344.32%
Hydro One (Campbellford/Seymour)	GSd	$12.21	3.01000	$9,176.52	$55.62	11.37000	$34,777.44	278.98%	$106.94	20.25300	$62,042.28	78.40%	576.10%
Hydro One (Cavan-Millbrook-N. Monaghan)	GSd	$17.08	3.74000	$11,424.96	$55.62	11.37000	$34,777.44	204.40%	$106.94	20.25300	$62,042.28	78.40%	443.04%
Hydro One (Centre Hastings)	GSd	$13.96	2.46000	$7,547.52	$55.62	11.37000	$34,777.44	360.78%	$106.94	20.25300	$62,042.28	78.40%	722.02%
Hydro One (Chalk River)	GSd	$16.32	4.56000	$13,875.84	$55.62	11.37000	$34,777.44	150.63%	$106.94	20.25300	$62,042.28	78.40%	347.12%
Hydro One (Champlain Twp.)	GSd	$15.73	2.31000	$7,118.76	$55.62	11.37000	$34,777.44	388.53%	$106.94	20.25300	$62,042.28	78.40%	771.53%
Hydro One (Clarence-Rockland)	GSd	$5.07	2.07000	$6,270.84	$55.62	11.37000	$34,777.44	454.59%	$106.94	20.25300	$62,042.28	78.40%	889.38%
Hydro One (Cobden)	GSd	$16.80	5.19000	$15,771.60	$55.62	11.37000	$34,777.44	120.51%	$106.94	20.25300	$62,042.28	78.40%	293.38%
Hydro One (Deep River)	GSd	$18.41	5.75000	$17,470.92	$55.62	11.37000	$34,777.44	99.06%	$106.94	20.25300	$62,042.28	78.40%	255.12%
Hydro One (Deseronto)	GSd	$7.37	3.08000	$9,328.44	$55.62	11.37000	$34,777.44	272.81%	$106.94	20.25300	$62,042.28	78.40%	565.09%
Hydro One (Dundalk)	GSd	$18.11	4.14000	$12,637.32	$55.62	11.37000	$34,777.44	175.20%	$106.94	20.25300	$62,042.28	78.40%	390.94%
Hydro One (Durham)	GSd	$18.55	3.45000	$10,572.60	$55.62	11.37000	$34,777.44	228.94%	$106.94	20.25300	$62,042.28	78.40%	486.82%
Hydro One (Eganville)	GSd	$16.34	5.88000	$17,836.08	$55.62	11.37000	$34,777.44	94.98%	$106.94	20.25300	$62,042.28	78.40%	247.85%
Hydro One (Erin)	GSd	$31.56	1.89000	$6,048.72	$55.62	11.37000	$34,777.44	474.96%	$106.94	20.25300	$62,042.28	78.40%	925.71%
Hydro One (Exeter)	GSd	$8.34	3.29000	$9,970.08	$55.62	11.37000	$34,777.44	248.82%	$106.94	20.25300	$62,042.28	78.40%	522.28%
Hydro One (Fenelon Falls)	GSd	$15.10	2.42000	$7,441.20	$55.62	11.37000	$34,777.44	367.36%	$106.94	20.25300	$62,042.28	78.40%	733.77%
Hydro One (Forest)	GSd	$19.18	2.99000	$9,200.16	$55.62	11.37000	$34,777.44	278.01%	$106.94	20.25300	$62,042.28	78.40%	574.36%
Hydro One (Georgian Bay Energy - Chatsworth)	GSd	$7.88	2.91000	$8,824.56	$55.62	11.37000	$34,777.44	294.10%	$106.94	20.25300	$62,042.28	78.40%	603.06%
Hydro One (Georgina)	GSd	$13.18	4.08000	$12,398.16	$55.62	11.37000	$34,777.44	180.50%	$106.94	20.25300	$62,042.28	78.40%	400.42%
Hydro One (Glencoe)	GSd	$8.35	2.04000	$6,220.20	$55.62	11.37000	$34,777.44	459.10%	$106.94	20.25300	$62,042.28	78.40%	897.43%
Hydro One (Grand Bend)	GSd	$17.01	3.12000	$9,564.12	$55.62	11.37000	$34,777.44	263.62%	$106.94	20.25300	$62,042.28	78.40%	548.70%
Hydro One (Hastings)	GSd	$17.57	4.26000	$12,990.84	$55.62	11.37000	$34,777.44	167.71%	$106.94	20.25300	$62,042.28	78.40%	377.58%
Hydro One (Havelock-Belmont-Methuen)	GSd	$17.00	3.86000	$11,784.00	$55.62	11.37000	$34,777.44	195.12%	$106.94	20.25300	$62,042.28	78.40%	426.50%
Hydro One (Kirkfield)	GSd	$11.01	4.73000	$14,322.12	$55.62	11.37000	$34,777.44	142.82%	$106.94	20.25300	$62,042.28	78.40%	333.19%
Hydro One (Lanark Highlands)	GSd	$14.00	4.21000	$12,798.00	$55.62	11.37000	$34,777.44	171.74%	$106.94	20.25300	$62,042.28	78.40%	384.78%
Hydro One (Larder Lake)	GSd	$15.40	3.44000	$10,504.80	$55.62	11.37000	$34,777.44	231.06%	$106.94	20.25300	$62,042.28	78.40%	490.61%
Hydro One (Latchford)	GSd	$1.56	1.95000	$5,868.72	$55.62	11.37000	$34,777.44	492.59%	$106.94	20.25300	$62,042.28	78.40%	957.17%
Hydro One (Lucan/Granton)	GSd	$12.85	3.69000	$11,224.20	$55.62	11.37000	$34,777.44	209.84%	$106.94	20.25300	$62,042.28	78.40%	452.75%
Hydro One (Malahide Twp.)	GSd	$12.05	4.34000	$13,164.60	$55.62	11.37000	$34,777.44	164.17%	$106.94	20.25300	$62,042.28	78.40%	371.28%
Hydro One (Mapleton Twp.)	GSd	$16.50	4.34000	$13,218.00	$55.62	11.37000	$34,777.44	163.11%	$106.94	20.25300	$62,042.28	78.40%	369.38%
Hydro One (Markdale)	GSd	$17.66	2.03000	$6,301.92	$55.62	11.37000	$34,777.44	451.85%	$106.94	20.25300	$62,042.28	78.40%	884.50%
Hydro One (Marmora)	GSd	$7.27	2.66000	$8,067.24	$55.62	11.37000	$34,777.44	331.09%	$106.94	20.25300	$62,042.28	78.40%	669.06%

Hydro One (McGarry Twp.)	GSd	$15.40	4.54000	$13,804.80	$55.62	11.37000	$34,777.44	151.92%	$106.94	20.25300	$62,042.28	78.40%	349.43%
Hydro One (Meaford)	GSd	$18.49	3.12000	$9,581.88	$55.62	11.37000	$34,777.44	262.95%	$106.94	20.25300	$62,042.28	78.40%	547.50%
Hydro One (Middlesex Centre)	GSd	$13.14	2.64000	$8,077.68	$55.62	11.37000	$34,777.44	330.54%	$106.94	20.25300	$62,042.28	78.40%	668.07%
Hydro One (Napanee)	GSd	$16.99	3.23000	$9,893.88	$55.62	11.37000	$34,777.44	251.50%	$106.94	20.25300	$62,042.28	78.40%	527.08%
Hydro One (Nipigon Twp.)	GSd	$17.91	2.70000	$8,314.92	$55.62	11.37000	$34,777.44	318.25%	$106.94	20.25300	$62,042.28	78.40%	646.16%
Hydro One (North Dorchester Twp.)	GSd	$11.96	2.28000	$6,983.52	$55.62	11.37000	$34,777.44	397.99%	$106.94	20.25300	$62,042.28	78.40%	788.41%
Hydro One (North Dundas Twp.)	GSd	$10.07	1.94000	$5,940.84	$55.62	11.37000	$34,777.44	485.40%	$106.94	20.25300	$62,042.28	78.40%	944.34%
Hydro One (North Glengarry Twp.)	GSd	$13.43	2.26000	$6,941.16	$55.62	11.37000	$34,777.44	401.03%	$106.94	20.25300	$62,042.28	78.40%	793.83%
Hydro One (North Grenville - Kemptville)	GSd	$15.59	4.33000	$13,177.08	$55.62	11.37000	$34,777.44	163.92%	$106.94	20.25300	$62,042.28	78.40%	370.83%
Hydro One (North Perth - Listowel)	GSd	$22.87	2.53000	$7,864.44	$55.62	11.37000	$34,777.44	342.21%	$106.94	20.25300	$62,042.28	78.40%	688.90%
Hydro One (North Stormont)	GSd	$3.55	2.02000	$6,102.60	$55.62	11.37000	$34,777.44	469.88%	$106.94	20.25300	$62,042.28	78.40%	916.65%
Hydro One (Omemee)	GSd	$16.28	3.71000	$11,325.36	$55.62	11.37000	$34,777.44	207.08%	$106.94	20.25300	$62,042.28	78.40%	447.82%
Hydro One (Perth East Twp.)	GSd	$10.98	3.26000	$9,911.76	$55.62	11.37000	$34,777.44	250.87%	$106.94	20.25300	$62,042.28	78.40%	525.95%
Hydro One (Prince Edward County)	GSd	$17.54	3.56000	$10,890.48	$55.62	11.37000	$34,777.44	219.34%	$106.94	20.25300	$62,042.28	78.40%	469.69%
Hydro One (Quinte West - Frankford)	GSd	$2.25	2.65000	$7,977.00	$55.62	11.37000	$34,777.44	335.97%	$106.94	20.25300	$62,042.28	78.40%	677.76%
Hydro One (Rainy River)	GSd	$14.69	4.47000	$13,586.28	$55.62	11.37000	$34,777.44	155.97%	$106.94	20.25300	$62,042.28	78.40%	356.65%
Hydro One (Ramara Twp.)	GSd	$16.03	2.68000	$8,232.36	$55.62	11.37000	$34,777.44	322.45%	$106.94	20.25300	$62,042.28	78.40%	653.64%
Hydro One (Red Rock Twp.)	GSd	$16.57	4.92000	$14,958.84	$55.62	11.37000	$34,777.44	132.49%	$106.94	20.25300	$62,042.28	78.40%	314.75%
Hydro One (Russell)	GSd	$14.67	5.68000	$17,216.04	$55.62	11.37000	$34,777.44	102.01%	$106.94	20.25300	$62,042.28	78.40%	260.37%
Hydro One (Schreiber Twp.)	GSd	$15.82	5.89000	$17,859.84	$55.62	11.37000	$34,777.44	94.72%	$106.94	20.25300	$62,042.28	78.40%	247.38%
Hydro One (Severn Twp)	GSd	$16.99	2.68000	$8,243.88	$55.62	11.37000	$34,777.44	321.86%	$106.94	20.25300	$62,042.28	78.40%	652.59%
Hydro One (Shelburne)	GSd	$15.26	2.23000	$6,873.12	$55.62	11.37000	$34,777.44	405.99%	$106.94	20.25300	$62,042.28	78.40%	802.68%
Hydro One (South Bruce Peninsula - Wiarton)	GSd	$18.28	4.79000	$14,589.36	$55.62	11.37000	$34,777.44	138.38%	$106.94	20.25300	$62,042.28	78.40%	325.26%
Hydro One (South Glengarry)	GSd	$13.19	1.90000	$5,858.28	$55.62	11.37000	$34,777.44	493.65%	$106.94	20.25300	$62,042.28	78.40%	959.05%
Hydro One (South River)	GSd	$16.94	3.90000	$11,903.28	$55.62	11.37000	$34,777.44	192.17%	$106.94	20.25300	$62,042.28	78.40%	421.22%
Hydro One (Springwater Twp.)	GSd	$15.68	2.73000	$8,378.16	$55.62	11.37000	$34,777.44	315.10%	$106.94	20.25300	$62,042.28	78.40%	640.52%
Hydro One (Stirling-Rawdon Twp.)	GSd	$18.55	3.29000	$10,092.60	$55.62	11.37000	$34,777.44	244.58%	$106.94	20.25300	$62,042.28	78.40%	514.73%
Hydro One (Thedford)	GSd	$13.52	2.70000	$8,262.24	$55.62	11.37000	$34,777.44	320.92%	$106.94	20.25300	$62,042.28	78.40%	650.91%
Hydro One (Thessalon)	GSd	$14.38	2.58000	$7,912.56	$55.62	11.37000	$34,777.44	339.52%	$106.94	20.25300	$62,042.28	78.40%	684.10%
Hydro One (Thorndale)	GSd	$10.87	2.60000	$7,930.44	$55.62	11.37000	$34,777.44	338.53%	$106.94	20.25300	$62,042.28	78.40%	682.33%
Hydro One (Tweed)	GSd	$5.87	2.49000	$7,540.44	$55.62	11.37000	$34,777.44	361.21%	$106.94	20.25300	$62,042.28	78.40%	722.79%
Hydro One (Wardsville)	GSd	$9.11	2.53000	$7,699.32	$55.62	11.37000	$34,777.44	351.69%	$106.94	20.25300	$62,042.28	78.40%	705.82%
Hydro One (Warkworth)	GSd	$16.31	3.58000	$10,935.72	$55.62	11.37000	$34,777.44	218.02%	$106.94	20.25300	$62,042.28	78.40%	467.34%
Hydro One (West Elgin)	GSd	$11.57	1.77000	$5,448.84	$55.62	11.37000	$34,777.44	538.25%	$106.94	20.25300	$62,042.28	78.40%	1038.63%
Hydro One (Woodville)	GSd	$12.77	3.47000	$10,563.24	$55.62	11.37000	$34,777.44	229.23%	$106.94	20.25300	$62,042.28	78.40%	487.34%
Hydro One (Wyoming)	GSd	$13.15	3.66000	$11,137.80	$55.62	11.37000	$34,777.44	212.25%	$106.94	20.25300	$62,042.28	78.40%	457.04%
Averages - Hydro One Medium Density Acquireds		$14.10	3.30544	$10,085.56	$55.62	11.37000	$34,777.44	244.82%	$106.94	20.25300	$62,042.28	78.40%	515.16%

Hydro One (Brockville)	UGd	$16.58	1.99000	$6,168.96	$32.32	6.91400	$21,129.84	242.52%	$111.74	11.54800	$35,984.88	70.30%	483.32%
Hydro One (Caledon OH 01)	UGd	$19.71	4.28000	$13,076.52	$32.32	6.91400	$21,129.84	61.59%	$111.74	11.54800	$35,984.88	70.30%	175.19%
Hydro One (Carleton Place)	UGd	$18.18	4.25000	$12,968.16	$32.32	6.91400	$21,129.84	62.94%	$111.74	11.54800	$35,984.88	70.30%	177.49%
Hydro One (Dryden)	UGd	$14.55	2.64000	$8,094.60	$32.32	6.91400	$21,129.84	161.04%	$111.74	11.54800	$35,984.88	70.30%	344.55%
Hydro One (Georgian Bay Energy - Owen Sound)	UGd	$7.88	2.91000	$8,824.56	$32.32	6.91400	$21,129.84	139.44%	$111.74	11.54800	$35,984.88	70.30%	307.78%
Hydro One (Lindsay)	UGd	$18.41	3.49000	$10,690.92	$32.32	6.91400	$21,129.84	97.64%	$111.74	11.54800	$35,984.88	70.30%	236.59%
Hydro One (Perth)	UGd	$15.19	2.30000	$7,082.28	$32.32	6.91400	$21,129.84	198.35%	$111.74	11.54800	$35,984.88	70.30%	408.10%
Hydro One (Quinte West - Trenton)	UGd	$2.25	2.65000	$7,977.00	$32.32	6.91400	$21,129.84	164.88%	$111.74	11.54800	$35,984.88	70.30%	351.11%
Hydro One (Smiths Falls)	UGd	$7.13	2.66000	$8,065.56	$32.32	6.91400	$21,129.84	161.98%	$111.74	11.54800	$35,984.88	70.30%	346.15%
Hydro One (Thorold)	UGd	$17.36	3.81000	$11,638.32	$32.32	6.91400	$21,129.84	81.55%	$111.74	11.54800	$35,984.88	70.30%	209.19%
Hydro One (Whitchurch-Stouffville)	UGd	$16.73	2.35000	$7,250.76	$32.32	6.91400	$21,129.84	191.42%	$111.74	11.54800	$35,984.88	70.30%	396.29%
Averages - Hydro One Urban Acquireds		$14.00	3.03000	$9,257.97	$32.32	6.91400	$21,129.84	128.23%	$111.74	11.54800	$35,984.88	70.30%	288.69%
Hydro One Legacy	GSd	$40.47	8.74000	$26,705.64	$55.62	11.37000	$34,777.44	30.23%	$106.94	20.25300	$62,042.28	78.40%	132.32%
Hydro One Legacy	UGd	$13.11	7.45000	$22,507.32	$32.32	6.91400	$21,129.84	-6.12%	$111.74	11.54800	$35,984.88	70.30%	59.88%

Appendix A

To Decision and Rate Order

Woodstock Hydro Services Inc.

Draft Tariff of Rates and Charges

Board File No: EB-2013-0182

DATED: March 13, 2014

Woodstock Hydro Services Inc.

TARIFF OF RATES AND CHARGES

Effective and Implementation Date May 1, 2014

This schedule supersedes and replaces all previously approved schedules of Rates, Charges and Loss Factors

EB-2013-0182

RESIDENTIAL SERVICE CLASSIFICATION

This classification applies to an account taking electricity at 750 volts or less where the electricity is used exclusively in a separate metered living accommodation. Customers shall be residing in single-dwelling units that consist of a detached house or one unit of a semi-detached, duplex, triplex or quadruplex house, with a residential zoning. Separately metered dwellings within a town house complex or apartment building also qualify as residential customers. Further servicing details are available in the distributor's Conditions of Service

APPLICATION

The application of these rates and charges shall be in accordance with the Licence of the Distributor and any Code or Order of the Board, and amendments thereto as approved by the Board, which may be applicable to the administration of this schedule.

No rates and charges for the distribution of electricity and charges to meet the costs of any work or service done or furnished for the purpose of the distribution of electricity shall be made except as permitted by this schedule, unless required by the Distributor's Licence or a Code or Order of the Board, and amendments thereto as approved by the Board, or as specified herein.

Unless specifically noted, this schedule does not contain any charges for the electricity commodity, be it under the Regulated Price Plan, a contract with a retailer or the wholesale market price, as applicable. In addition, the charges in the MONTHLY RATES AND CHARGES - Regulatory Component of this schedule do not apply to a customer that is an embedded wholesale market participant.

It should be noted that this schedule does not list any charges, assessments or credits that are required by law to be invoiced by a distributor and that are not subject to Board approval, such as the Debt Retirement Charge, the Global Adjustment, the Ontario Clean Energy Benefit and the HST.

MONTHLY RATES AND CHARGES - Delivery Component

Service Charge	$	12.98
Rate Rider for Smart Metering Entity Charge - effective until October 31, 2018	$	0.79
Rate Rider for Recovery of Smart Meter Incremental Revenue Requirements - in effect until the effective date of the next cost of service application	$	0.64
Distribution Volumetric Rate	$/kWh	0.0222
Rate Rider for Recovery of Incremental Capital - effective until April 30, 2015	$/kWh	0.0008
Rate Rider for Disposition of Deferral/Variance Accounts (2014) - effective until April 30, 2015	$/kWh	(0.0012)
Rate Rider for Disposition of Global Adjustment Account (2014) - effective until April 30, 2015 Applicable only for Non-RPP Customers	$/kWh	(0.0018)
Retail Transmission Rate - Network Service Rate	$/kWh	0.0075
Retail Transmission Rate - Line and Transformation Connection Service Rate	$/kWh	0.0054

MONTHLY RATES AND CHARGES - Regulatory Component

Wholesale Market Service Rate	$/kWh	0.0044
Rural or Remote Electricity Rate Protection Charge (RRRP)	$/kWh	0.0013
Standard Supply Service - Administrative Charge (if applicable)	$	0.25

Woodstock Hydro Services Inc.
TARIFF OF RATES AND CHARGES
Effective and Implementation Date May 1, 2014

This schedule supersedes and replaces all previously approved schedules of Rates, Charges and Loss Factors

EB-2013-0182

GENERAL SERVICE LESS THAN 50 KW SERVICE CLASSIFICATION

This classification applies to a non residential account taking electricity at 750 volts or less whose average monthly maximum demand is less than, or is forecast to be less than, 50 kW. Further servicing details are available in the distributor's Conditions of Service.

APPLICATION

The application of these rates and charges shall be in accordance with the Licence of the Distributor and any Code or Order of the Board, and amendments thereto as approved by the Board, which may be applicable to the administration of this schedule.

No rates and charges for the distribution of electricity and charges to meet the costs of any work or service done or furnished for the purpose of the distribution of electricity shall be made except as permitted by this schedule, unless required by the Distributor's Licence or a Code or Order of the Board, and amendments thereto as approved by the Board, or as specified herein.

Unless specifically noted, this schedule does not contain any charges for the electricity commodity, be it under the Regulated Price Plan, a contract with a retailer or the wholesale market price, as applicable. In addition, the charges in the MONTHLY RATES AND CHARGES - Regulatory Component of this schedule do not apply to a customer that is an embedded wholesale market participant.

It should be noted that this schedule does not list any charges, assessments or credits that are required by law to be invoiced by a distributor and that are not subject to Board approval, such as the Debt Retirement Charge, the Global Adjustment, the Ontario Clean Energy Benefit and the HST.

MONTHLY RATES AND CHARGES - Delivery Component

Service Charge	$	25.19
Rate Rider for Smart Metering Entity Charge - effective until October 31, 2018	$	0.79
Rate Rider for Recovery of Smart Meter Incremental Revenue Requirements - in effect until the effective date of the next cost of service application	$	4.24
Distribution Volumetric Rate	$/kWh	0.0145
Rate Rider for Recovery of Incremental Capital - effective until April 30, 2015	$/kWh	0.0007
Rate Rider for Disposition of Deferral/Variance Accounts (2014) - effective until April 30, 2015	$/kWh	(0.0012)
Rate Rider for Disposition of Global Adjustment Account (2014) - effective until April 30, 2015 Applicable only for Non-RPP Customers	$/kWh	(0.0018)
Retail Transmission Rate - Network Service Rate	$/kWh	0.0068
Retail Transmission Rate - Line and Transformation Connection Service Rate	$/kWh	0.0051

MONTHLY RATES AND CHARGES - Regulatory Component

Wholesale Market Service Rate	$/kWh	0.0044
Rural or Remote Electricity Rate Protection Charge (RRRP)	$/kWh	0.0013
Standard Supply Service - Administrative Charge (if applicable)	$	0.25

Woodstock Hydro Services Inc.
TARIFF OF RATES AND CHARGES
Effective and Implementation Date May 1, 2014

This schedule supersedes and replaces all previously approved schedules of Rates, Charges and Loss Factors

EB-2013-0182

GENERAL SERVICE 50 TO 999 KW SERVICE CLASSIFICATION

This classification applies to a non residential account whose average monthly maximum demand used for billing purposes is equal to or greater than, or is forecast to be equal to or greater than, 50 kW but less than 1,000 kW. Further servicing details are available in the distributor's Conditions of Service.

APPLICATION

The application of these rates and charges shall be in accordance with the Licence of the Distributor and any Code or Order of the Board, and amendments thereto as approved by the Board, which may be applicable to the administration of this schedule.

No rates and charges for the distribution of electricity and charges to meet the costs of any work or service done or furnished for the purpose of the distribution of electricity shall be made except as permitted by this schedule, unless required by the Distributor's Licence or a Code or Order of the Board, and amendments thereto as approved by the Board, or as specified herein.

Unless specifically noted, this schedule does not contain any charges for the electricity commodity, be it under the Regulated Price Plan, a contract with a retailer or the wholesale market price, as applicable. In addition, the charges in the MONTHLY RATES AND CHARGES - Regulatory Component of this schedule do not apply to a customer that is an embedded wholesale market participant.

It should be noted that this schedule does not list any charges, assessments or credits that are required by law to be invoiced by a distributor and that are not subject to Board approval, such as the Debt Retirement Charge, the Global Adjustment, the Ontario Clean Energy Benefit and the HST.

MONTHLY RATES AND CHARGES - Delivery Component

Service Charge	$	139.96
Distribution Volumetric Rate	$/kW	2.5777
Rate Rider for Recovery of Incremental Capital - effective until April 30, 2015	$/kW	0.3251
Rate Rider for Disposition of Deferral/Variance Accounts (2014) - effective until April 30, 2015	$/kW	(0.4520)
Rate Rider for Disposition of Global Adjustment Account (2014) - effective until April 30, 2015		
Applicable only for Non-RPP Customers	$/kW	(0.6347)
Retail Transmission Rate - Network Service Rate	$/kW	2.9187
Retail Transmission Rate - Line and Transformation Connection Service Rate	$/kW	2.1784

MONTHLY RATES AND CHARGES - Regulatory Component

Wholesale Market Service Rate	$/kWh	0.0044
Rural or Remote Electricity Rate Protection Charge (RRRP)	$/kWh	0.0013
Standard Supply Service - Administrative Charge (if applicable)	$	0.25

Woodstock Hydro Services Inc.
TARIFF OF RATES AND CHARGES
Effective and Implementation Date May 1, 2014

This schedule supersedes and replaces all previously approved schedules of Rates, Charges and Loss Factors

EB-2013-0182

GENERAL SERVICE GREATER THAN 1,000 KW SERVICE

This classification applies to a non-residential account whose average monthly maximum demand used for billing purposes is equal to or greater than, or is forecast to be equal to or greater than, 1,000 kW. Further servicing details are available in the distributor's Conditions of Service

APPLICATION

The application of these rates and charges shall be in accordance with the Licence of the Distributor and any Code or Order of the Board, and amendments thereto as approved by the Board, which may be applicable to the administration of this schedule.

No rates and charges for the distribution of electricity and charges to meet the costs of any work or service done or furnished for the purpose of the distribution of electricity shall be made except as permitted by this schedule, unless required by the Distributor's Licence or a Code or Order of the Board, and amendments thereto as approved by the Board, or as specified herein.

Unless specifically noted, this schedule does not contain any charges for the electricity commodity, be it under the Regulated Price Plan, a contract with a retailer or the wholesale market price, as applicable. In addition, the charges in the MONTHLY RATES AND CHARGES - Regulatory Component of this schedule do not apply to a customer that is an embedded wholesale market participant.

It should be noted that this schedule does not list any charges, assessments or credits that are required by law to be invoiced by a distributor and that are not subject to Board approval, such as the Debt Retirement Charge, the Global Adjustment, the Ontario Clean Energy Benefit and the HST.

MONTHLY RATES AND CHARGES - Delivery Component

Service Charge	$	518.85
Distribution Volumetric Rate	$/kW	2.7398
Rate Rider for Recovery of Incremental Capital - effective until April 30, 2015	$/kW	0.4795
Rate Rider for Disposition of Deferral/Variance Accounts (2014) - effective until April 30, 2015	$/kW	(0.5640)
Rate Rider for Disposition of Global Adjustment Account (2014) - effective until April 30, 2015		
Applicable only for Non-RPP Customers	$/kW	(0.7884)
Retail Transmission Rate - Network Service Rate	$/kW	2.9187
Retail Transmission Rate - Line and Transformation Connection Service Rate	$/kW	2.1784

MONTHLY RATES AND CHARGES - Regulatory Component

Wholesale Market Service Rate	$/kWh	0.0044
Rural or Remote Electricity Rate Protection Charge (RRRP)	$/kWh	0.0013
Standard Supply Service - Administrative Charge (if applicable)	$	0.25

Woodstock Hydro Services Inc.
TARIFF OF RATES AND CHARGES
Effective and Implementation Date May 1, 2014

This schedule supersedes and replaces all previously approved schedules of Rates, Charges and Loss Factors

EB-2013-0182

UNMETERED SCATTERED LOAD SERVICE CLASSIFICATION

This classification applies to an account taking electricity at 750 volts or less whose average monthly maximum demand is less than, or is forecast to be less than, 50 kW and the consumption is unmetered. Such connections include cable TV power packs, bus shelters, telephone booths, traffic lights, railway crossings, etc. The level of the consumption will be agreed to by the distributor and the customer, based on detailed manufacturer information/ documentation with regard to electrical consumption of the unmetered load or periodic monitoring of actual consumption. Further servicing details are available in the distributor's Conditions of Service.

APPLICATION

The application of these rates and charges shall be in accordance with the Licence of the Distributor and any Code or Order of the Board, and amendments thereto as approved by the Board, which may be applicable to the administration of this schedule.

No rates and charges for the distribution of electricity and charges to meet the costs of any work or service done or furnished for the purpose of the distribution of electricity shall be made except as permitted by this schedule, unless required by the Distributor's Licence or a Code or Order of the Board, and amendments thereto as approved by the Board, or as specified herein.

Unless specifically noted, this schedule does not contain any charges for the electricity commodity, be it under the Regulated Price Plan, a contract with a retailer or the wholesale market price, as applicable. In addition, the charges in the MONTHLY RATES AND CHARGES - Regulatory Component of this schedule do not apply to a customer that is an embedded wholesale market participant.

It should be noted that this schedule does not list any charges, assessments or credits that are required by law to be invoiced by a distributor and that are not subject to Board approval, such as the Debt Retirement Charge, the Global Adjustment, the Ontario Clean Energy Benefit and the HST.

MONTHLY RATES AND CHARGES - Delivery Component

Service Charge	$	10.53
Distribution Volumetric Rate	$/kWh	0.0122
Rate Rider for Recovery of Incremental Capital - effective until April 30, 2015	$/kWh	0.0008
Rate Rider for Disposition of Deferral/Variance Accounts (2014) - effective until April 30, 2015	$/kWh	(0.0012)
Retail Transmission Rate - Network Service Rate	$/kWh	0.0068
Retail Transmission Rate - Line and Transformation Connection Service Rate	$/kWh	0.0051

MONTHLY RATES AND CHARGES - Regulatory Component

Wholesale Market Service Rate	$/kWh	0.0044
Rural or Remote Electricity Rate Protection Charge (RRRP)	$/kWh	0.0013
Standard Supply Service - Administrative Charge (if applicable)	$	0.25

Woodstock Hydro Services Inc.
TARIFF OF RATES AND CHARGES
Effective and Implementation Date May 1, 2014

This schedule supersedes and replaces all previously approved schedules of Rates, Charges and Loss Factors

EB-2013-0182

STREET LIGHTING SERVICE CLASSIFICATION

This classification applies to an account for roadway lighting with a Municipality, Regional Municipality, Ministry of Transportation and private roadway lighting, controlled by photo cells. The consumption for these customers will be based on the calculated connected load times the required lighting times established in the approved OEB street lighting load shape template. Further servicing details are available in the distributor's Conditions of Service

APPLICATION

The application of these rates and charges shall be in accordance with the Licence of the Distributor and any Code or Order of the Board, and amendments thereto as approved by the Board, which may be applicable to the administration of this schedule.

No rates and charges for the distribution of electricity and charges to meet the costs of any work or service done or furnished for the purpose of the distribution of electricity shall be made except as permitted by this schedule, unless required by the Distributor's Licence or a Code or Order of the Board, and amendments thereto as approved by the Board, or as specified herein.

Unless specifically noted, this schedule does not contain any charges for the electricity commodity, be it under the Regulated Price Plan, a contract with a retailer or the wholesale market price, as applicable. In addition, the charges in the MONTHLY RATES AND CHARGES - Regulatory Component of this schedule do not apply to a customer that is an embedded wholesale market participant.

It should be noted that this schedule does not list any charges, assessments or credits that are required by law to be invoiced by a distributor and that are not subject to Board approval, such as the Debt Retirement Charge, the Global Adjustment, the Ontario Clean Energy Benefit and the HST.

MONTHLY RATES AND CHARGES - Delivery Component

Service Charge	$	3.09
Distribution Volumetric Rate	$/kW	12.4552
Rate Rider for Recovery of Incremental Capital - effective until April 30, 2015	$/kW	0.2187
Rate Rider for Disposition of Deferral/Variance Accounts (2014) - effective until April 30, 2015	$/kW	(0.3501)
Rate Rider for Disposition of Global Adjustment Account (2014) - effective until April 30, 2015		
Applicable only for Non-RPP Customers	$/kW	(0.6283)
Retail Transmission Rate - Network Service Rate	$/kW	2.1541
Retail Transmission Rate - Line and Transformation Connection Service Rate	$/kW	1.6078

MONTHLY RATES AND CHARGES - Regulatory Component

Wholesale Market Service Rate	$/kWh	0.0044
Rural or Remote Electricity Rate Protection Charge (RRRP)	$/kWh	0.0013
Standard Supply Service - Administrative Charge (if applicable)	$	0.25

Woodstock Hydro Services Inc.
TARIFF OF RATES AND CHARGES
Effective and Implementation Date May 1, 2014

This schedule supersedes and replaces all previously approved schedules of Rates, Charges and Loss Factors

EB-2013-0182

microFIT SERVICE CLASSIFICATION

This classification applies to an electricity generation facility contracted under the Ontario Power Authority's microFIT program and connected to the distributor's distribution system. Further servicing details are available in the distributor's Conditions of Service.

APPLICATION

The application of these rates and charges shall be in accordance with the Licence of the Distributor and any Code or Order of the Board, and amendments thereto as approved by the Board, which may be applicable to the administration of this schedule.

No rates and charges for the distribution of electricity and charges to meet the costs of any work or service done or furnished for the purpose of the distribution of electricity shall be made except as permitted by this schedule, unless required by the Distributor's Licence or a Code or Order of the Board, and amendments thereto as approved by the Board, or as specified herein.

Unless specifically noted, this schedule does not contain any charges for the electricity commodity, be it under the Regulated Price Plan, a contract with a retailer or the wholesale market price, as applicable.

It should be noted that this schedule does not list any charges, assessments or credits that are required by law to be invoiced by a distributor and that are not subject to Board approval, such as the Debt Retirement Charge, the Global Adjustment, the Ontario Clean Energy Benefit and the HST.

MONTHLY RATES AND CHARGES - Delivery Component

Service Charge	$	5.40

Woodstock Hydro Services Inc.
TARIFF OF RATES AND CHARGES
Effective and Implementation Date May 1, 2014

This schedule supersedes and replaces all previously approved schedules of Rates, Charges and Loss Factors

EB-2013-0182

ALLOWANCES

Transformer Allowance for Ownership - per kW of billing demand/month	$/kW	(0.60)
Primary Metering Allowance for transformer losses – applied to measured demand and energy	%	(1.00)

SPECIFIC SERVICE CHARGES

APPLICATION

The application of these rates and charges shall be in accordance with the Licence of the Distributor and any Code or Order of the Board, and amendments thereto as approved by the Board, which may be applicable to the administration of this schedule.

No charges to meet the costs of any work or service done or furnished for the purpose of the distribution of electricity shall be made except as permitted by this schedule, unless required by the Distributor's Licence or a Code or Order of the Board, and amendments thereto as approved by the Board, or as specified herein.

It should be noted that this schedule does not list any charges, assessments, or credits that are required by law to be invoiced by a distributor and that are not subject to Board approval, such as the Debt Retirement Charge, the Global Adjustment, the Ontario Clean Energy Benefit and the HST.

Customer Administration		
Notification charge	$	15.00
Returned cheque (plus bank charges)	$	15.00
Legal letter	$	15.00
Account set up charge/change of occupancy charge (plus credit agency costs if applicable)	$	30.00
Meter dispute charge plus Measurement Canada fees (if meter found correct)	$	30.00
Statement of Account	$	15.00
Account History	$	15.00
Non-Payment of Account		
Late Payment – per month	%	1.50
Late Payment – per annum	%	19.56
Collection of account charge – no disconnection	$	30.00
Disconnect/Reconnect Charge – At Meter – During Regular Hours	$	65.00
Disconnect/Reconnect Charge – At Meter – After Hours	$	185.00
Install/Remove load control device – during regular hours	$	65.00
Install/Remove load control device – after regular hours	$	185.00
Special meter reads	$	30.00
Specific Charge for Access to the Power Poles - $/pole/year	$	22.35

Woodstock Hydro Services Inc.
TARIFF OF RATES AND CHARGES
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RETAIL SERVICE CHARGES (if applicable)

The application of these rates and charges shall be in accordance with the Licence of the Distributor and any Code or Order of the Board, and amendments thereto as approved by the Board, which may be applicable to the administration of this schedule.

No rates and charges for the distribution of electricity and charges to meet the costs of any work or service done or furnished for the purpose of the distribution of electricity shall be made except as permitted by this schedule, unless required by the Distributor's Licence or a Code or Order of the Board, and amendments thereto as approved by the Board, or as specified herein.

Unless specifically noted, this schedule does not contain any charges for the electricity commodity, be it under the Regulated Price Plan, a contract with a retailer or the wholesale market price, as applicable.

It should be noted that this schedule does not list any charges, assessments, or credits that are required by law to be invoiced by a distributor and that are not subject to Board approval, such as the Debt Retirement Charge, the Global Adjustment, the Ontario Clean Energy Benefit and the HST.

Retail Service Charges refer to services provided by a distributor to retailers or customers related to the supply of competitive electricity.

One-time charge, per retailer, to establish the service agreement between the distributor and the retailer	$	100.00
Monthly Fixed Charge, per retailer	$	20.00
Monthly Variable Charge, per customer, per retailer	$/cust.	0.50
Distributor-consolidated billing monthly charge, per customer, per retailer	$/cust.	0.30
Retailer-consolidated billing monthly credit, per customer, per retailer	$/cust.	(0.30)
Service Transaction Requests (STR)		
Request fee, per request, applied to the requesting party	$	0.25
Processing fee, per request, applied to the requesting party	$	0.50
Request for customer information as outlined in Section 10.6.3 and Chapter 11 of the Retail Settlement Code directly to retailers and customers, if not delivered electronically through the Electronic Business Transaction (EBT) system, applied to the requesting party		
Up to twice a year	$	no charge
More than twice a year, per request (plus incremental delivery costs)	$	2.00

LOSS FACTORS

If the distributor is not capable of prorating changed loss factors jointly with distribution rates, the revised loss factors will be implemented upon the first subsequent billing for each billing cycle.

Total Loss Factor – Secondary Metered Customer < 5,000 kW	1.0431
Total Loss Factor – Secondary Metered Customer > 5,000 kW	1.0145
Distribution Loss Factor - Primary Metered Customer < 5,000 kW	1.0326
Distribution Loss Factor - Primary Metered Customer > 5,000 kW	1.0044