Ontario Energy Association
CELEBRATING 10 YEARS

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July 31, 2012

Ontario Distribution Sector Review Panel
c/o Mr. Jonathan Norman
Director - Transmission and Distribution Policy
880 Bay Street - 3rd Floor
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Dear Messrs. Elston, Laughren, and McFadden,

Thank you for providing us the opportunity to meet with the Ontario Distribution Sector Review Panel on June 28, 2012. As a follow up to the Ontario Energy Association's (OEA) presentation, please find attached a written submission that provides extensive information on LDC consolidation and addresses the points raised during our meeting.

As you know, the OEA has more than 150 corporate members who represent the full diversity of the energy industry in Ontario – power producers, firms that transport, transmit, and deliver natural gas and electricity, marketers and retailers, manufacturers, contractors, service providers, and energy consultants. Such diversity allows us to offer a broad perspective on LDC consolidation and its potential impact on Ontario's electricity sector and on the general public.

As is outlined in our submission, now is the ideal time for the Government of Ontario to move decisively to eliminate costly inefficiencies in the LDC sector to the benefit of ratepayers, and unlock the value of each company for its shareholders. Rationalization of LDCs would bring economic benefit to all Ontarians – especially important given the province's fiscal challenges and the broader economic landscape.

We look forward to continuing the dialogue with you and the government on the issue of LDC consolidation. If you have any questions or would like additional information or clarification on any of the points or recommendations we have made in this submission, please contact Tina Arvanitis, Vice President, Communications and Stakeholder Relations at 647.920.3269 or tarvanitis@energyontario.ca.

We look forward to your final report.

Yours truly,

Elise Herzig
President and CEO
Ontario Energy Association


# ONTARIO ENERGY ASSOCIATION
# ONTARIO DISTRIBUTION SECTOR REVIEW PANEL SUBMISSION

The Ontario Energy Association (OEA) represents Ontario's broad energy community and promotes the development of sound public policy. Whether in one-on-one conversations, group committees or our various events, by providing opportunities to explore and debate industry and policy issues, the OEA serves as a unique catalyst for sharing intelligence and building connections between individuals and groups.

The OEA helps educate its members, government and the public to bring clarity and balance to the complex issues of the energy sector. In all energy matters, the OEA's diverse membership gives it a unique capacity to provide a comprehensive body of perspectives and knowledge of the practical considerations affecting energy policy in Ontario.

The OEA has more than 150 corporate members that represent the full diversity of the energy industry in Ontario – power producers, firms that transport, transmit and deliver natural gas and electricity, marketers and retailers, manufacturers, contractors, service providers, and energy consultants.

OEA
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# Executive Summary

In 1998, Ontario had more than 300 electricity distributors, while today it has approximately 75. This consolidation has been unambiguously positive for the ratepayers of the province, but in recent years progress has stalled.

Consolidation allows distributors to eliminate unnecessary duplication of efforts and functions, and gain the efficiencies that result from scale to reduce costs. Nonetheless, there are still many distributors in Ontario that have well under 20,000 customers, and even larger utilities would benefit from further growth.

A number of impediments stand in the way of further consolidation, including the myth that "local control" is valuable in electricity distribution, the varying impact of individual consolidation transactions on particular customer classes, a regulatory regime that is too accommodative of current inefficiencies, and the lack of private sector participation in Ontario electricity distribution because of the province's Transfer Tax.

It is critical that changes be made in the near term so consolidation momentum can be regained, because the distribution sector faces many challenges, and will continue to do so in the future. The industry is in the midst of a demographic shift, with many workers eligible for retirement, and taking their accumulated knowledge and skills with them. At the same time, much of the capital base of the sector is old and requires very costly replacement, all this in a time of stressed capital resources and shareholders who are more likely to require increased rather than decreased dividends.

A variety of strategies to encourage consolidation could be pursued, but each comes with its own customer, stakeholder and economic impacts which must be assessed carefully. In this light, the Ontario Energy Association (OEA) makes the following recommendations:

1. Consolidation Must be Voluntary
2. All Distributors Must be Eligible Buyers and Sellers
3. Transfer Tax is the Most Significant Impediment that Must be Removed
4. Ratepayers Must Visibly Benefit from Consolidation
5. OEB Policies Should be Adjusted to Encourage Rational Consolidation

# OEA Efforts Relating to Distribution Consolidation

The OEA has been working on the issue of electricity distribution consolidation for some time, and has devoted considerable effort to establishing its position. Steps taken include the following:

- One-on-one executive interviews with all distribution members of the OEA;
- Input from OEA committees;
- Meetings with government representatives and officials to better understand current and future policy directions;
- Development of policy positions that were submitted to the Provincial Government as part of the 2012 Pre-Budget Submission;
- Meeting with the Ontario Distribution Sector Review Panel;
- Research for and preparation of this submission to the Ontario Distribution Sector Review Panel.

The majority of this submission is to assist the Panel in its deliberations about the Ontario electricity distribution sector, and the ways in which the sector can be improved to the benefit of ratepayers. Information has been collected from a variety of Ontario sources, as well as from other jurisdictions, to assist the Panel in coming to its own conclusions with the benefit of as many perspectives as possible. As with any such exercise, strategies and options described vary considerably, and are not all consistent with each other, as they come from a wide variety of sources. They do not necessarily reflect the views of the OEA or its members.

The Recommendations at the end of this submission are the official positions of the OEA with respect to the matters before the Panel.

# The Story So Far: Ontario's History of Distribution Consolidation

Electricity distribution is the business of delivering electric power to customers in a form that is useful to them. Unlike transmission, where electricity is transported at voltages that are designed to minimize losses and allow for effective management of the grid, distribution is all about customers: typically providing electricity at the voltage that a customer needs to operate the equipment on site.

In Ontario, there are approximately 75 companies currently in this business.[1] Since distribution is generally considered a natural monopoly, each of these companies operates in an exclusive territory, with both the boundaries and the operations of each distributor regulated by the Ontario Energy Board.[2]

Up until the late-1990s, there were more than 300 entities providing electricity distribution services in Ontario. One was Ontario Hydro,[3] which provided service to most rural areas in the province as well as to a number of smaller towns and villages. A few were owned by companies in the private sector or First Nations communities, and the rest were municipal entities of one sort or another.[4]

Please see the next page for a map of distributor territories in 1999.

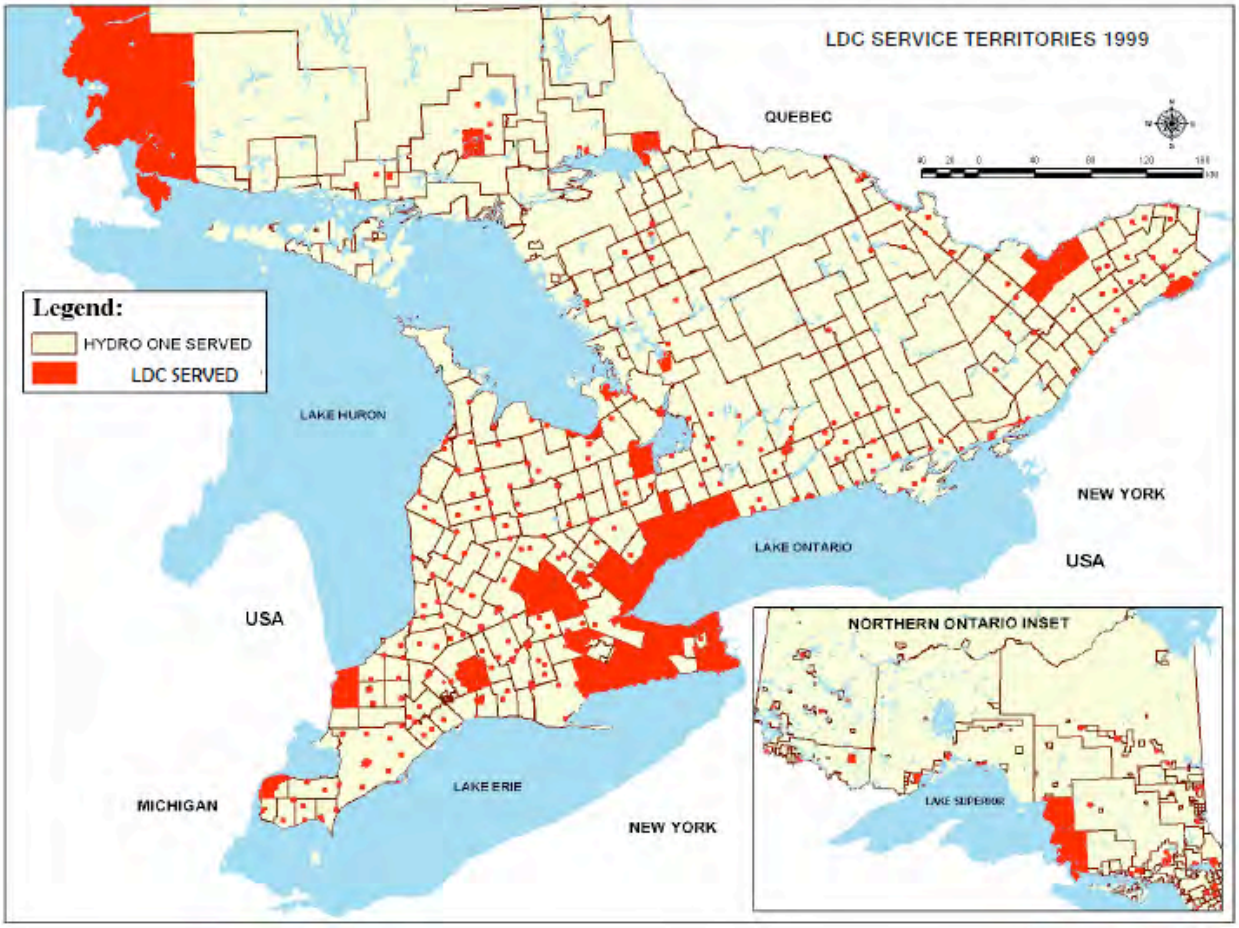
[1] Many Ontario distributors operate in multiple, geographically unconnected ("non-contiguous") licensed territories. Some distributors that have already undergone consolidation may still operate under more than one subsidiary distributor in different territories, each with their own name. As a result, the numbers of licensed distribution territories, operating names and parent companies all vary. 75 refers to the number of parent companies operating distributors in the province.

[2] Note that there is one electricity distributor in Ontario that is not regulated by the Ontario Energy Board: Cornwall Electric, which receives all of its electricity from Hydro Quebec, and which is therefore not part of the Ontario electricity grid. Cornwall Electric is owned by Fortis Inc.

[3] Ontario Hydro was itself broken up into five parts: Ontario Power Generation, Electrical Safety Authority, Ontario Electricity Financial Corporation, Independent Electricity Market Operator, and what would soon become Hydro One, Ontario's largest transmission and distribution company.

[4] Some of these were municipal corporations, but in many cases they were Boards, Commissions or Departments of a municipality, and often the same entity provided other services such as fresh water, sewers, or natural gas delivery.

## Map 1: Ontario Electricity Distributors in 1999

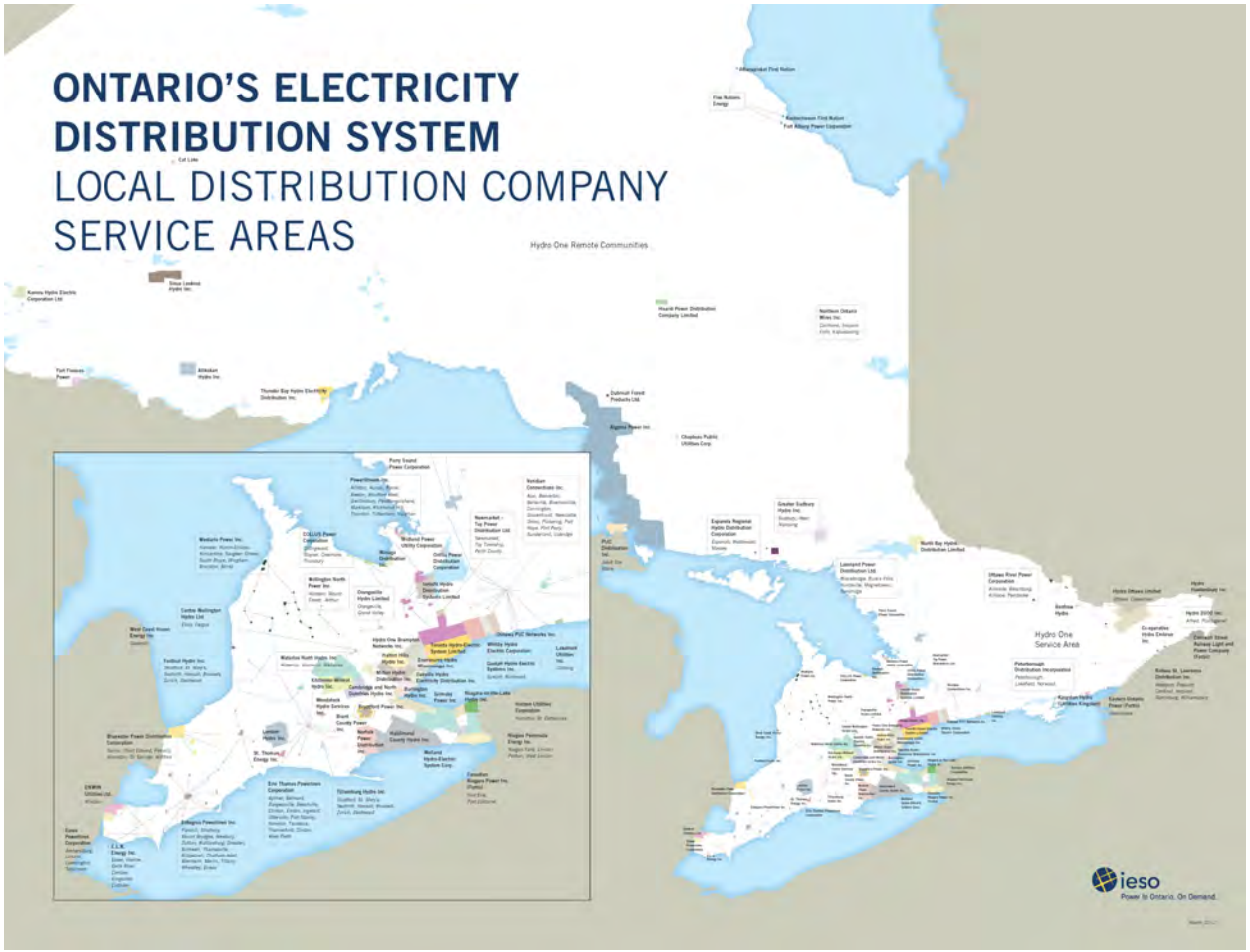



With the passage of the ***Electricity Act, 1998***, as well as the forced amalgamation of many municipalities by the Government of Ontario of the day, the distribution sector entered a period of intensive change. All distributors were required to become shareholder-owned corporations, regulated by the Ontario Energy Board (hereinafter "OEB"). More than 80 municipalities, not wanting to own and operate a regulated distribution business, chose to sell their distribution assets to Hydro One. In many other cases, municipal amalgamations caused several companies to be merged together (for example, the amalgamation of Toronto consolidated six former entities into one, with similar mergers taking place in Ottawa, Sudbury, Hamilton and elsewhere). Some smaller town utilities chose to consolidate and form a larger entity, even if they were separated geographically from each other, resulting in companies such as Westario Power, Festival Hydro and Entegrus.[5] By 2003 there were fewer than 100 electricity distributors in Ontario, with the vast majority owned by municipalities.

Since 2003 the pace of consolidation has lessened dramatically, but there have been some consolidation transactions, such that the total number of distributors has fallen to approximately 75. The following map shows the location of Ontario's electricity distributors, as of March 2012.

[5] Previously known as Chatham-Kent Hydro.

## Map 2: Ontario Electricity Distributors in 2012



# The Benefits of Distribution Consolidation

From a customer's perspective, two issues are paramount: cost and service (including reliability of electricity delivery, and "customer service" including billing, customer communications, etc.). Consolidation has helped to address both of these. The larger companies that have resulted from the consolidation of the industry so far have greater management depth and capacity to manage change, reduced financial risk for shareholders and bondholders, and better access to capital, all of which combine to allow companies to provide customers with better service based on newer equipment and technology. At the same time, consolidation has resulted in cost efficiencies that have been well documented.

Consolidation transactions fall into one of three categories:

1. **Embedded consolidation**: A larger distributor acquires or merges with a smaller distributor that is fully embedded in its territory (Hydro One acquired 89 such distributors between 1999 and 2003);[6]

2. **Contiguous consolidation**: Two distributors that share at least one boundary are joined together through merger or acquisition (there are many examples, including the creation of Toronto Hydro from six separate utilities, the creation of PowerStream from the merger of Markham, Vaughan and Richmond Hill utilities, the creation of Veridian from utilities previously serving Pickering and Ajax, etc.);

3. **Non-contiguous consolidation**: Two or more distributors that share no boundaries are joined together (there are numerous examples of these types of transactions, as can be seen on the map of current electricity distributors on page 8).

## How Consolidation Generates Cost Efficiencies

Consolidation transactions generate cost efficiencies in at least five ways.

1. **Elimination of Executive Management Duplication**: Every electricity distributor in Ontario is required by the *Electricity Act* to be a corporation. This means that each must have a Board of Directors and a full complement of "C-level" executives including a CEO, CFO, Chief Legal Counsel, Board Secretary, etc. Boards typically include 7 to 12 members, while senior management and its support staff could include 3 to 10 or more individuals. A consolidation

[6] "Embedded" can refer to a geographical situation, electrical, or both. If geographically embedded, a distributor is entirely surrounded by the territory of another distributor. Hydro One in fact surrounds almost all other distributors in the province except those situated on a provincial border or on the Great Lakes, because it provides service to rural and remote areas. "Electrically embedded" means that a distributor is not directly connected to the province's high voltage transmission grid through its own assets; instead, the distributor relies on another distribution company to provide power that has already been transformed from higher voltage to lower voltage. There are more than 30 distributors in Ontario that are fully electrically embedded in Hydro One territory, and there are many distributors that have at least some territory which is electrically embedded in the territory of another distributor.

transaction typically results in the elimination of one full complement of these positions, assuming only two distributors are merging. This is a direct benefit to ratepayers, who were paying the full cost of all these positions prior to consolidation.

2. **Rationalization of Operations**: In the case of embedded or contiguous transactions, consolidation leads to savings in the maintenance and operation of the resulting distributor's larger service territory. For example, work crews can be optimized so that they cover more logical territories, specialists can be more efficiently used over a larger territory, the use of outside contractors can be optimized or minimized, as the case may be, etc.

3. **Rationalization of Back Office Services**: In all consolidation transactions, the resulting distributor can achieve savings through more efficient use of billing systems, call centres, accounting services, and administrative services.

4. **Rationalization of Capital Equipment**: The bulk of electricity distributor capital equipment consists of poles, wires and substations. At first blush it would seem that consolidation should not affect capital equipment spending, because all customers must continue to be served by the same poles and wires, regardless of territorial boundaries or corporate organization. However, capital equipment also includes billing systems, head office buildings, work crew centres, substations, communications equipment, trucks, tools, and much more. Over time after a consolidation transaction, all of these capital goods can be optimized to the benefit of ratepayers, particularly in the case of embedded or contiguous consolidations. At a minimum, billing systems can be consolidated, and redundant buildings can be sold. Truck and tool fleets can be optimized, and in some cases the distribution network itself can be rationalized over time by right-sizing and optimally locating substations and switches.

5. **Regulatory Savings**: As highly regulated entities, all electricity distributors must prepare reports to the OEB and periodically apply for new rates, changes to terms of service, license amendments, etc. Each of these regulatory processes requires considerable effort and cost on the part of the distributor and the OEB. In most cases, there is little difference between the work required for smaller distributors vs. larger distributors: each must prepare a full detailed rate application, for example, and all must provide complete reports on finances and services they provide to customers. Consolidation results in fewer applications and licenses, which reduces the work required across the distribution industry and at the regulator. In both instances, these savings would be to the direct benefit of ratepayers, who pay ultimately for all of this activity.

In general, most of these savings opportunities can be summarized as the elimination of duplication and the benefits of scale efficiency. A common theme across these categories of savings is staff reduction. This issue will be addressed in greater depth, as it raises other questions, both positive and negative.

However, it should be pointed out that staff costs are a very significant driver of distribution rates, and hence costs to ratepayers.[7]

The following table lists some of the cost efficiencies that have been publicly reported to the OEB from each of these types of consolidation transaction:

### Table 1: Examples of Consolidation Cost Efficiencies Reported to the OEB

| Utility | Transaction | Impacts |
|---|---|---|
| Hamilton Hydro (pre-Horizon Utilities) | Five municipal electric utilities were merged when the City of Hamilton was itself amalgamated in 2000. | Savings in OMA were estimated at over $3 million per year, and the greater size of the utility allowed for the common adoption of new billing, engineering and record systems. |
| Hydro One | 89 embedded utilities were purchased by Hydro One between 1999 and 2003. | Savings in OMA were estimated at over 30% of the pre-consolidation expenditures of the 89 distributors, amounting to over $170 million per year. In addition Hydro One was able to save over $30 million in capital costs by rationalizing service locations and offices. |
| Lakeland Power Distribution | In 2000, five non-contiguous Central Ontario municipal utilities were merged. | Savings included a 30% reduction in workforce, elimination of 4 out of 6 work centres, and elimination of 4 out of 5 billing systems. |
| Westario Power | In 2000, eight non-contiguous Southwestern Ontario municipal utilities were merged. | Savings included an 18% reduction in workforce, elimination of 7 out of 8 administrative offices and 5 out of 8 work centres, elimination of 7 billing systems, and a reduction in the truck fleet. |
| Veridian | In 1999, Veridian was created through the consolidation of three neighbouring municipal electric utilities: Pickering, Ajax and Clarington. In 2000 and 2001 additional non-contiguous distributors were added in Uxbridge, Port Hope, Brock and Belleville were added. | In its first three years of operation, Veridian reported OMA savings of more than 13% from pre-consolidation levels, with the anticipation of total savings ultimately reaching more than 30% after several rounds of efficiency improvements. |

[7] Not only are staff costs a very high percentage of Operations, Maintenance and Administration for all distributors, but staff costs are also a significant part of all capital projects, which are then embedded for many years in distribution rates through the cost of capital.

The evidence of cost reductions from consolidation transactions is incontrovertible. All consolidation transactions require OEB approval, and in virtually all cases cost-saving expectations have been indicated. In any case where there has been post-transaction reporting to the OEB, savings were also reported.

There is no question that the cost of the distribution system today is less than it otherwise would have been had the industry not consolidated from more than 300 companies to approximately 75, and it is also beyond doubt that further consolidation would continue to deliver cost reduction opportunities. Ultimately, cost reduction is a benefit to the ratepayers of the province, making further consolidation an important priority for the sector.

# Is There an Optimum Number of Distributors?

If consolidation brings about cost savings for ratepayers, then an obvious question is the degree to which consolidation should continue. Should consolidation lead to a single distributor for the entire province, or is there some other "optimal" number of distributors to cover the province's territory?

## Experience in Other Jurisdictions

Electricity distributors around the world range in size from the hundreds of customers to the millions, with all sizes in between.

The following table provides a comparison of electricity distributors in several English-speaking countries:

**Table 2: Size of Electricity Distributors in Sample Countries**

| Country | Distributors | Customers (millions) | Average Size (thousands) | Ownership |
|---|---|---|---|---|
| Australia | 16 | 10 | 1,600 | Mix of state and investor ownership |
| New Zealand | 29 | 2 | 69 | Mix of municipal and investor ownership |
| United Kingdom | 7 | 29 | 4,143 | Investor ownership |
| United States | 3150 | 143 | 45 | Mix of investor and municipal ownership, as well as rural cooperatives |

Each of these jurisdictions has developed very differently over time. It is important to note that historical accident plays a substantial role in the current structure of the electricity industry in each jurisdiction. In places where electricity was adopted early, it may have been structured on a municipal basis, while in rural areas distribution entities were often created by governments in order to promote rural electrification.

Since the 1980s, some governments have been actively reshaping their electricity sectors, including electricity distribution. In many cases this has included the sale of publicly-owned assets to the private sector and the unbundling of vertically integrated electricity companies into separate electricity generation, transmission and distribution companies. Active government policy-making has in some places played a more central role than in others.

In Australia, electricity is legislated at the state level (similar to Canadian provinces), and several states undertook reforms in the 1990s. In both Victoria and New South Wales, governments amalgamated a number of distribution utilities by legislation and subsequently commercialized and privatized them. As a result, electricity distributor numbers decreased from approximately 55 to less than a dozen. These changes occurred in the context of the creation of a multi-state interconnected and competitive electricity market serving the eastern and southern portions of Australia. Notably, two other states in Australia – Western Australia and the Northern Territory – are not connected to that grid and maintain their own separate systems, with large state-owned integrated electricity companies. Australia's large size relative to its population and the location of its cities plays a significant role in the structure of the electricity industry nationally, but the experience of legislated consolidation in the more populous states demonstrates the drive towards scale efficiencies.

The United Kingdom began its electricity transformation in the 1980s, ultimately converting from a series of public monopolies to unbundled privately owned competitors. For electricity distribution specifically, 14 public boards were privatized to create an investor-owned distribution sector. The same licensed territories continue to exist, but industry consolidation has resulted in only 7 companies now owning the licensed distributors, as per the map below:

**Map 3: UK Electricity Distributors**

It should be noted that distribution consolidation in the UK was entirely voluntary, and carried out by the private sector owners of the companies, without government intervention.

In the United States, there are three kinds of distribution utilities, each with a separate history. A large majority of customers are served by investor-owned utilities, which after many years of consolidation are now relatively few in number. Many towns and cities are served by publicly-owned electricity distributors, some of the more famous being the Los Angeles Department of Water and Power and the Sacramento Municipal Utility District. Finally, 75% of the landmass of the United States is served by rural electric cooperatives, which were created by the Rural Electrification Act of 1936 specifically to ensure that electric service was extended to rural areas of the United States. The following table provides information on the division of the market among these different types of electricity distributors, as of 2010.

**Table 3: Categories of US Electricity Distributors**

| | Investor-Owned | Publicly Owned | Cooperatives | Total |
|---|---|---|---|---|
| Revenue ($ billions) | 277 | 50 | 37 | 364 |
| Organizations | 220 | 2,000 | 930 | 3,150 |
| Customers (millions) | 104 | 21 | 18 | 143 |
| Median Size (customers) (thousands) | 400 | 2 | 12.5 | |
| Customers, percent of total | 73 | 15 | 12 | |
| Revenues, percent of total | 76 | 14 | 10 | |
| Kilowatt-hour sales, percent of total | 73 | 15 | 10 | |

It is particularly notable that investor-owned utilities in the United States have consolidated to the point that they are relatively few in number and very large in size. Nevertheless, the consolidation process continues with a number of notable mergers approved by regulators over the past few years, including the very recently completed merger of Duke Energy and Progress Energy.[8]

Publicly-owned utilities and cooperatives, by contrast, have generally not pursued consolidation as an efficiency strategy and hence remain much more numerous. However, many such distributors have

[8] Completed on July 2, 2012. Duke is now the largest regulated utility in the United States, serving 7 million customers across six states.

formed partnerships, buying groups, "super co-ops" or other arrangements for the purposes of buying generation or transmission services or for procurement of critical capital goods and supplies.

Further examples of electricity distribution structures can be found in other countries around the world, but in every case, local and historical circumstances play a very significant role in determining the current structure of the industry.

## Optimal Size?

While there has been substantial academic study of efficiency in regulated utilities, there is no consensus on an optimal size. Numerous studies have focused on the concept of "minimum efficient scale", and various electricity-related functions have been examined through this prism. In many instances, minimum efficient scale has been defined in relation to the market in which companies are operating; for example, a minimum efficient scale would be 10% of a given market.

The Staff of the Ontario Energy Board examined this issue in a paper in 2004, and concluded that for electricity distribution a low boundary for minimum efficient scale would be 20,000 customers.[9] While this would only be a fraction of a percent of the Ontario electricity distribution market, it should be noted that Ontario still has more than 35 distributors with less than 20,000 customers each.

On the opposite end of the scale, it is logical to question whether the most efficient structure would be a single electricity distribution monopoly. In this case, presumably, economies of scale could be maximized and costs reduced accordingly, to the benefit of ratepayers. Two principal objections to this conjecture can be briefly stated: first, *diseconomies* of scale may potentially appear if utilities exceed a certain size, or if a utility exceeds a certain proportion of the market in which it operates (at the extreme becoming a jurisdictional monopoly); and second, as a regulated utility industry it is critical that an appropriate power relationship between electricity distributors and their regulator be maintained, which may not be feasible in the case of a single distributor.

Diseconomies of scale might appear if the distributor became too large and difficult to manage, particularly in relation to maintaining quality customer service, which is often thought to include the need for close customer communication (larger utilities presumably have greater difficulty in maintaining such customer relationships). In addition, diseconomies might arise if labour and other supply chain markets become barriers to efficiency (for example, if a single large distributor faced a single powerful union for all of its labour, without competitive flexibility, then it might face substantial inefficiency over time). However, it should be noted that there are a number of utilities around the world whose customer bases exceed Ontario's total of 4.5 million electricity distribution customers. Diseconomies of scale do not appear to be a concern at this size.

[9] "Review of Further Efficiencies in the Electricity Distribution Sector", Ontario Energy Board Staff Discussion Paper, February 10, 2004. The OEB relied primarily on Yatchew, A. (2000) 'Scale Economies in Electricity Distribution – A Semiparametric Analysis', Journal of Applied Econometrics, 15, pp. 187-210. A similar study based on Norwegian electricity distributors also found that 20,000 customers is a minimum optimal size, Salvanes, K. G. and Tjøtta, S. (1994) 'Productivity Differences in Multiple Output Industries: An Empirical Application to Electricity Distribution', Journal of Productivity Analysis, 5, pp. 23-43.

The regulatory issue is perhaps more salient: it is of paramount importance that an appropriate balance of power be maintained between a regulator and regulated utilities in its jurisdiction. This is made far more likely if there are multiple utilities being regulated within one jurisdiction, so that each can act as a benchmark and counterweight to others. While it is of course necessary for regulators to look outward to other jurisdictions for benchmarking purposes, the difficulties of making comparisons across jurisdictions suggests that doing so is a second-best regulatory strategy.

## More than One, but Less than 75

The foregoing suggests that while Ontario would be well advised to avoid pursuing consolidation of the electricity distribution industry down to only one company, there is certainly scope for consolidation to bring benefits to ratepayers. At a minimum, if all utilities in Ontario were at least 20,000 customers in size, this would suggest consolidation down to fewer than 50 utilities. Alternatively, if consolidation were to reach the point where the minimum size of utilities were 10% of the Ontario market, then 5 to 7 utilities would likely result.

The “final” number of utilities is not of primary importance. The critical fact is that substantial opportunity and justification for consolidation exists.

# Challenges to Distribution Consolidation

The Ontario electricity distribution industry has already consolidated from over 300 distributors to approximately 75. However, in the past few years, the pace of consolidation has slowed to a trickle, despite the fact that there are considerable efficiency opportunities yet to be explored. There are several factors that appear to be holding back further consolidation.

## The Myth of Local Control

In many cases where consolidation has been pursued, objections have arisen that consolidation of electricity distributors leads to a loss of "local control" and the benefits that such control brings to communities. This argument often arises in public contexts, either at meetings of City Councils or in the media.

Electricity distribution in Ontario is a closely regulated industry. Rates are set by the OEB, quality standards are applied across the province, performance is closely monitored through regular reporting to the regulator, and the provincial government directs all distributors with respect to new initiatives such as smart meters and the connection of distributed renewable generation. There is very little of substance that is actually left in the control of individual companies other than the day-to-day operation of the distribution system.

Over the past 10 years, the OEB has been working to reduce the differences between distributors, requiring all distributors to adopt similar cost allocation formulas for rate-setting purposes, and creating incentives designed to bring all distributors to a similar level of cost efficiency. While all of this effort will never completely eliminate the differences between distributors, because each distributor has its own customer density and legacy of system design and equipment purchases, the degree of local differentiation has been and continues to be progressively reduced.

A few communities have engaged their local distributor in community efforts such as local energy planning, but this appears to the exception rather than the rule. By and large, distributors operate largely autonomously from their shareholders, and deliver services according to OEB requirements.

Whether or not distribution services are provided by a locally-owned utility appears to matter very little with respect to the substance of the services performed. Public opposition to "losing local control" of a distributor appears to be founded on a misperception of what distributors actually do, and what they are allowed by regulation to do.

There are, however, some aspects of local ownership that are visible, and are sometimes of concern when a consolidation transaction is proposed. For example, local ownership means that a head office will be located in a community; consolidation might mean the loss of that office and of the local employment associated with it. As has been noted above, consolidation does not make a difference to the capital equipment located in a territory since the poles and wires will not move, nor will the need for local operations and maintenance of those assets disappear. But back office functions such as billing, customer call management, and administration can be centralized in one location rather than being

spread out in the various communities served. Similarly, local ownership of a distributor means that the municipal council has the opportunity to appoint a board of directors, which is not insignificant. It is the rationalization of these functions that allows for some of the most immediate cost efficiencies that are a benefit to ratepayers.

There is an undeniable inverse relationship between local employment and consolidation. The fact that ratepayers are directly paying the cost of these local jobs through their electricity bills is seldom highlighted in the media and public controversies that sometimes erupt when consolidation opportunities are discussed. The beneficiaries of the existing inefficiencies – the local board members and staff whose positions might be consolidated away – are much more visible and obvious than the costs of maintaining those positions that are spread out amongst all customers of the utility.

## Alternative Use of Funds

Consolidation transactions typically take one of two forms: the current owners of a utility being consolidated may receive shares in a new and larger utility, or the current owners might receive cash for the sale of their utility.

In the first instance, the consolidation usually has relatively modest financial impacts on shareholders. Presumably, the consolidation transaction will generate efficiency benefits, and all shareholders in the new consolidated entity will benefit by having increased dividends in the future. An increase in dividends or other cash flows from a utility is an unambiguous benefit, and is obviously not a challenge that requires management.

In the case of a cash sale, however, the selling shareholder has given up a long-term source of dividends in exchange for a single large lump sum of cash. While the selling shareholder has presumably received greater value in lump sum form than the present value of all expected future cash flows from the electricity distributor,[10] the shareholder must make efficient use of these sale proceeds if the transaction is ultimately to be a benefit to the community.

For many municipal owners of electricity distributors, the distribution company may be the most valuable asset on the municipal balance sheet. If the municipality does not have an immediate use for the funds generated from a cash sale of the distributor, then the proceeds will need to be reinvested until such time as the capital is required for some other use. However, as can be seen from even a cursory examination of rates of return on various investments, it is unlikely that a municipality will have access to investment opportunities that pay as well as electricity distributors at the same level of risk. Sale proceeds can of course be placed into trust on a temporary basis, but such investment products pay only modest returns, rather than the 7% to 10% annual return on equity generated by a distributor.

If a municipality has immediate need for the proceeds of a sale, for example to retire municipal debt or fund some other municipal infrastructure such as a sewer or water project, a bridge, a community

[10] In other words, the distributor is assumed to be sold at a premium to its standalone value. See below for further discussion.

centre, etc., then the question of reinvestment of sale proceeds becomes moot. However, over the past decade, municipalities have benefited from tremendous access to capital from both federal and provincial infrastructure programs, so few municipalities have seen the need to generate funds locally by monetizing their investments in electricity distributors. This may be changing with the fiscal austerity that has recently gripped all levels of government in Canada. It may well be that municipalities will in future find more immediate use, and even need for the proceeds of a sale of an electricity distributor.

## Customer Rate Impacts

As noted above, the OEB has pursued a deliberate policy of harmonization across all distributors in Ontario in terms of rate-setting. The adoption of more consistent cost allocation formulas, more consistent definitions of customer classes, and the effect of cost control incentives has meant that the differences in rates charged to customers by different utilities has been reduced.

However, rates do continue to vary considerably between distributors, for a host of reasons:

- Each distributor has different customer densities and local geographies, which powerfully affect the cost of building and operating a distribution system (for example, more customers per kilometer of line means each customer pays less for the maintenance of the line; likewise, planting poles in solid granite is far more expensive than doing so in soft ground);
- Each distributor faces local labour cost pressures, which vary considerably across the province;
- Each distributor purchased capital equipment at different periods of time, and therefore has different capital costs based on the pricing of the goods at the time, and the expected timing of replacement of major capital assets;
- Each distributor has its own access to capital and has its own relationships to suppliers (larger distributors typically have an advantage on these fronts, as per the earlier discussion of economies of scale);
- Each distributor has its own legacy of rate-making decisions from the period before the OEB was applying standard requirements across the province. Before the OEB became the regulator of local distribution utilities over a decade ago, it was not atypical for neighbouring utilities to make radically different choices about the allocation of costs among its customers. For example, utility A might choose to charge industrial customers high distribution fees so as to keep costs to residential customers low, while utility B might choose the opposite approach and charge industrial customers lower rates in order to attract more. The imposition of OEB cost allocation formulas has largely ended the ability to make this kind of choice. In practice, however, historical legacies do remain embedded in rates because the OEB has insisted on slow, incremental changes to customer rates, rather than subjecting customers to significant rate shocks.

All of this is relevant to consolidation transactions because of the impact such transactions can have on customer rates. While consolidation is unambiguously positive for reducing **total** distribution costs, in any given specific consolidation transaction, it is not necessarily true that every individual **customer** or **customer class** will benefit. For example:

- If utility A has a history of higher rates for industrial customers and lower rates for residential customers, and utility B has the opposite history, then in a merger of the two utilities some customers may not benefit from the transaction. While total costs of the merged entity will be lower, if the utility adopts the overall rate bias of utility A, then the former customers of utility A will likely be pleased, as they will see lower costs over time, and their rates will either go down or at a minimum not rise as much as they otherwise would have. However, for the former customers of utility B, applying the rate design bias of utility A will mean that industrial customers will see an increase in rates over time, which they would obviously oppose. Of course, residential customers of utility B should be extremely happy, since they will receive the benefit not only of consolidation efficiency, but also of the new bias towards lower residential rates that results from the adoption of utility A's rate choices. It is quite possible that the industrial customers of utility B, knowing that a merger might result in an increase in their rates, would vocally oppose the transaction, despite the fact that it would be positive for all other customers.

- An alternative example would be the potential merger of utility X, which serves a long-established and dense urban community, with utility Y, which operates in a less dense but still growing suburban community next door. In this case, utility X might have lower rates because its assets are in general older and it benefits from high customer density. Utility Y not only bears the burden of lower customer density, but its balance sheet is also growing quickly as it adds expensive new equipment to build out its system. A merger of these two utilities would reduce the total cost of operating the system as a whole. However, if rates were simply averaged across the combined population of customers, then rates for the former customers of utility X might still rise more than they otherwise would have if the consolidation did not occur. Of course, for customers of utility Y the consolidation would be unambiguously positive since their rates would be lower than they otherwise would be, both because of the consolidation savings and because they are being averaged with less expensive customers in the territory next door. A solution to this problem would be to keep two separate rate classes for a period of time, despite the consolidation. In this case, the rates for former customers of utility X could be allowed to increase over time faster than the rates of the former customers of utility Y until they could be harmonized. Even though this would be a more gradual adjustment to rates, the benefits of consolidation would still be spread out unequally across customers.

## Special Case of Embedded Utilities

As mentioned above, there are a number of distributors in Ontario that are fully electrically and geographically embedded in the territory of another distributor. Typically, but not exclusively, the larger distributor is Hydro One and the embedded distributor is a town that has historically had and continues

to have its own distributor (or in other cases it would be a town distributor which has gone through some consolidation and is now part of a larger non-contiguous distributor, some of which might be embedded and other parts having direct connections to the transmission grid).

As an electrically embedded distributor, the smaller entity receives electricity from the larger distributor at distribution-level voltage (44 kV or less). This means that the larger distributor has already performed a service in transforming the power from the transmission grid down to a more useful level. The embedded distributor therefore does not need to design, build, own, operate or maintain the capital assets required for the transformation function, but can simply concentrate on managing and distributing power at lower voltage.

Hydro One, which most commonly faces this situation, charges embedded utilities for this service based on the same rates used for large industrial customers (the "Sub-Transmission" rate). Many large industrial customers require substantial amounts of power, and hence receive it from Hydro One (or any other distributor whose territory they might be in) at relatively high voltages (e.g., 44 kV, 27.6 kV, or 13.8 kV), rather than at a more typical consumer or small business level (e.g., 220 V, 600 V, etc.). These customers are charged on the basis of the specific Hydro One assets used to deliver the power (e.g., the number of kilometres of 44 kV and 27.6 kV lines that are traveled to reach the customer, etc.), as well as for the use of more general infrastructure (such as the shared use of Hydro One substations, etc.).

For embedded utilities, the use of this rate means that the utilities are being charged what amounts to Hydro One's average cost of service for power at this level, in this customer class. It should be obvious that this cost bears little relationship to what it would cost for the embedded utility to build its own connection to the transmission grid, and the lines necessary to bring that power from the transmission grid to its customers. Not only is the embedded distributor getting the benefit of pooling its needs with other Hydro One customers, the embedded utility does not need to have the planners, engineers and other specialists required to design, operate and maintain the connection to the transmission grid. For the embedded utility, buying lower voltage power from Hydro One is far cheaper than the cost of doing the work independently.

For customers of the embedded utility, this is a very good thing. Rates for customers in such embedded utilities are much lower than they otherwise would be. In fact, in all embedded utilities, rates are currently lower than the rates paid by customers in the Hydro One territory surrounding them (this is a combination of the relatively low cost of receiving the lower voltage power from Hydro One, plus the fact that the embedded utility is a town, and hence typically much more densely populated than the surrounding Hydro One territory).

However, it is not necessarily clear that this situation is positive for the system as a whole. If embedded utilities were not allowed to receive power at distribution voltages, they would face one of two choices: build and maintain their own infrastructure at a much higher cost than what they currently pay for the low voltage power services, or sell to the surrounding utility. For the customers of the embedded utility, selling would almost certainly be the better option (this is particularly true the smaller the utility). Even though, for example, Hydro One has rates that are higher than most embedded utilities, if those

embedded utilities had to maintain their own connection to the transmission grid their rates likely would be higher than Hydro One's.

Embedded utilities are allowed to exist, and hence embedded utilities feel no need to merge with the surrounding utility. In fact, for the customers of the embedded utility, selling would be a negative outcome, since their rates would almost certainly rise. They are taking advantage of a historical anomaly, and are benefitting disproportionately from the current rate design across the province.

The OEB examined the issue of embedded utilities in 2004.[11] It determined that it would be inefficient to allow any more embedded utilities, and therefore set a policy to not license any in the future. The Board recognized that for historical reasons many embedded utilities exist, and suggested that rationalization would be preferable for the system as a whole and ratepayers on average, but since then it has taken no decisive policy action to encourage rationalization of embedded utilities.

The continued existence of embedded utilities, and their continued access to low voltage power at relatively low cost, is a major disincentive to consolidation, particularly for many of the smallest distributors in the province.

## Lack of Private Sector Participation

Ontario's electricity distribution sector consists of Hydro One, a provincially-owned utility (with about 40% of the customers in the province), approximately 75 municipally owned utilities (with about 58% of customers), a First Nations utility providing service on several band territories, and one private sector utility, Fortis, serving several communities across the province under various operating names. All of the Fortis territories, except Port Colborne, have been privately owned since they were first built, in some cases a century ago. Fortis slowly acquired all of these territories from their previous owners.

Ontario's Transfer Tax (please see below and Appendix A for additional information) strongly discourages the sale of any municipally-owned utility to a private sector buyer, and therefore impedes the entry of new players into the Ontario distribution sector. This is problematic for several reasons:

- Private sector distributors around the world have demonstrated that they are most likely to pursue consolidation in order to generate maximum possible efficiencies, to the benefit of both ratepayers and shareholders (for example, in the United States, investor-owned utilities have constantly pursued consolidation while public utilities and rural cooperatives have not; in the UK and Europe private sector and recently privatized utilities have also been rapidly pursuing consolidation); even in Ontario, one company, Fortis, has successfully consolidated all available distributors not subject to the transfer tax;

- Increasing the number of players interested in the Ontario distribution sector would create the opportunity for more innovative consolidation strategies, combinations of territories, and greater willingness to experiment;

[11] See Decision RP-2003-0044.

- Private sector buyers of utilities have demonstrated they are willing to pay substantial premiums above the Rate Base value of distributors,[12] which would make sale of distributors more attractive for existing shareholders.[13]

### Table 4: Sample Transactions for Distribution Utilities, 2000 - 2012[14]

| Date Announced | Target | Acquirer | EV[15] | EV/ Rate Base |
|---|---|---|---|---|
| | | | (millions) | |
| Feb 2012 | Central Hudson Energy | Fortis Inc. | $1,500.0 | 1.21x |
| Feb 2012 | SEMCO Holdings | Altagas Ltd. | $1,135.0 | 1.56x |
| Oct 2011 | Pacific Northern Gas Ltd. | Altagas Ltd. | $235.8 | 1.35x |
| Nov 2009 | Heritage Gas Limited | Altagas Income Fund (now Altagas Inc.) | $109.8 | 1.21x |
| Aug 2009 | Altagas Utility Group Inc. | Altagas Income Fund (now Altagas Inc.) | $210.4 | 1.21x |
| Jun 2009 | Great Lakes Power Distribution Inc. | Fortis Inc. | $75.0 | 1.17x |
| Apr 2009 | California utility assets of NV Energy | Algonquin Power/Emera Inc. JV | $116.0 | 1.19x |
| Feb 2007 | Terasen Gas Inc. | Fortis Inc. | $3,672.2 | 1.24x |
| Aug 2005 | Terasen Inc. | Kinder Morgan, Inc. | $6,763.5 | 1.58x |
| Mar 2005 | Aurora Hydro Connections Ltd | PowerStream Inc | $34.5 | 1.33x |
| Mar 2005 | Gravenhurst Hydro Electric Inc. | Veridian Connections Inc. | $11.2 | 1.27x |
| Dec 2004 | Princeton Light & Power Co. Ltd. | Fortis Inc. | $7.1 | 1.15x |
| Sep 2003 | Aquila Networks Canada Ltd. | Fortis Inc. | $1,360.0 | 1.44x |
| May 2002 | Cornwall Electric | Fortis Inc. | $67.0 | 2.13x |
| Sep 2002 | Winnipeg Hydro | Manitoba Hydro | $385.1 | 1.03x |
| Aug 2001 | Port Colborne Hydro Inc. | Canadian Niagara Power Inc. | $15.7 | 1.48x |
| Jun 2000 | Bangor Hydro-Electric Co. | Emera, Inc. | $402.1 | 1.55x |
| Feb 2000 | TransAlta (Distribution and Retail) | Utilicorp United Inc | $700.0 | 1.48x |

[12] "Rate Base" is a concept used in regulatory economics which typically consists of the Net Property, Plant and Equipment assets used in the regulated business, plus an allowance for Working Capital. Rate Base is then used to calculate the distributor's required level of Equity and Debt, and the allowed Return on Equity that is included regulated customer rates.

[13] Note that the theoretical value of a corporate asset is the Present Value of all future dividends that the corporation would be expected to pay. For a fully regulated asset, this value at any given time is equal to the "Rate Base". A sale price above the Rate Base of a utility is therefore said to be at a premium, and is economically beneficial for the seller.

[14] The table includes transactions for North American targets whose primary business is regulated distribution of electricity and/or natural gas. Over the past decade there have been dozens of other transactions for vertically integrated electricity companies (such as Exelon/Constellation, Duke/Progress, GazMet/Central Vermont Public Service, Northeast/NSTAR, PPL/LGE, etc.). Price comparisons with such transactions are difficult because the targets in question include both regulated distribution assets as well as varying amounts of generation and retailing assets that are often not regulated.

[15] Enterprise Value, or EV, is the total consideration for the sale, including cash or share payment, plus the assumption of pre-existing long-term debt.

As long as the Transfer Tax remains in place, it is extremely unlikely that there will be successful entry into the Ontario distribution sector by new private sector buyers, as the following example shows:

- Assume that a municipal distributor could be sold for $96 million, and that the Rate Base value of the distributor was $80 million (a premium of 20% over the Rate Base value), with $48 million of debt, and $32 million of book equity at the time of the sale.
- Assume further that the distributor has paid an average of $1.25 million per year in Payments in Lieu of Tax ("PILs", which are Ontario's substitute for combined federal and provincial corporate income taxes, applicable to publicly-owned distributors only) for 12 years, for a total of $15 million.
- Transfer tax would be assessed as one third of the total sale price, hence $32 million, less the accumulated PILs of $15 million, which would mean the municipality would be required to pay $17 million in Transfer Tax.
- For its efforts in selling the utility, the municipality would receive $96 million, less $17 million in Transfer Tax, less $48 million in debt, for total proceeds of $31 million, which is less than the book value of the equity to begin with. No rational shareholder would undertake this transaction.

For the Government of Ontario, however, eliminating the Transfer Tax is not currently a viable option because it represents a significant loss of future value, particularly when the province is facing years of fiscal austerity.

Taking the example above, the annual PILs of $1.25 million is calculated based on the *combined* Federal and Provincial corporate income tax rates (currently 26.5%). Provincial and municipal utilities are exempted from Federal Income Tax, so Ontario can set its PILs rate at a level that combines the federal and provincial rates without disadvantaging municipal corporations as compared to the private sector. However, if a municipality were to sell its distributor to a private sector buyer, then Ontario would receive only the provincial portion of corporate income tax (currently 11.5%), and the distributor would then pay normal federal corporate income tax (currently 15% of taxable income). In the example above, where the distributor paid approximately $1.25 million per year, this would represent a loss of approximately $700 thousand of tax revenue per year, forever (on a present value basis at a discount rate of 5%, this would be equivalent to $14 million of future taxes, which is coincidentally similar to the expected transfer tax in this example). If this example were repeated across the Ontario distribution sector, then the province would suffer a significant loss in future tax value. The transfer tax is designed to compensate for this loss.

## A Potential Solution

The Federal Government does not currently receive corporate income taxes from provincially or municipally-owned utilities, and as such has no economic interest in them. Historically, until the legislation expired in 1999, the *Public Utilities Income Tax Transfer Act* ("PUITTA") put privately-owned

and publicly owned utilities on the same footing by requiring that the Federal Government remit to the provinces 95% of the federal corporate income tax paid by utilities owned by the private sector. In other words, provinces would receive basically all of the taxes paid by private utilities, equal to what publicly-owned utilities paid, making provinces indifferent to whether utilities were privately or publicly-owned.

While this legislation was in place, such public utilities as Nova Scotia Power, Alberta Government Telephone and Edmonton Telephone were all privatized, at limited impact to provincial government revenues.

If this type of legislation were revived by the Federal Government, then the impact on the Province of Ontario of the repeal of the Transfer Tax, and subsequent sale of some publicly-owned electricity distributors would be dramatically lessened.

For example, if the Federal Government were to legislate that it would remit to the province 95% of the federal corporate income tax paid by a distributor sold to the private sector for 10 years, then the Province could expect that it would receive approximately 50% - 60% or more of the full present value of all future taxes within that time period. This would mean that the loss to the province would be only $5 to $7 million of future taxes, rather than $14 million. Moreover, if the utility were to become more efficient in the future, then some of that efficiency would result in higher profits (some efficiency gains would benefit ratepayers in the form of lower rates), which would further increase taxes paid during the 10 year period.

From the Federal Government perspective, taking this step would have no net impact, since the Federal Government does not currently receive any corporate income tax from publicly-owned utilities. On the other hand, if such legislation encouraged the province to remove the Transfer Tax and spurred private sector investment, then the Federal Government could look forward to ultimately receiving new sources of corporate income tax revenue in the future, after the 10-year period had passed.

Cooperation between the Government of Canada and the Government of Ontario is crucial to the successful management of the Transfer Tax impediment to consolidation of the Ontario distribution sector.

# The Need to Act

Consolidation of the electricity distribution sector has been stalled in Ontario for the last several years. There are several reasons why this is a pressing problem which should be addressed decisively.

## Labour and Demographics

The electricity distribution sector employs thousands of people across the province. This workforce is highly specialized and trained, from linesmen who require extensive apprenticeships to work on dangerously high voltage wires and transformers, to engineers and planners that require extensive training and experience to design and maintain systems, to specialized accountants and lawyers that manage the complex and highly regulated business of a utility.

The industry grew with the Province of Ontario, especially during the boom years of construction in the 1950s, 60s and 70s. Thousands of employees are of the "Baby Boom" generation, who are now becoming eligible for retirement. Moreover, the generous pension plans in place in the sector encourage workers to retire once they reach specified combinations of years of service plus age. A further complicating factor is the loss of a cohort of workers in many distribution companies when hiring freezes were put in place during the leaner years at the beginning of the 1990s and again during the turmoil of industry restructuring from 1998 to 2003. The result is that a substantial portion of the industry's workforce is eligible for retirement within the next five years,[16] and in fact that demographic wave has already started.

The response of distributors to this challenge is to hire and train new workers to replace departing workers. This is the responsible thing to do, all other things being equal, because service must be delivered to customers in a safe and reliable manner.

This is both a challenge and an opportunity in terms of consolidation. Consolidation, as has been discussed above, typically results in redundancies, so some workers lose their positions. In the context of a substantial wave or retirements, however, it should be possible to manage many of the departures through retirements. This is both a better, less confrontational way to "right-size" a post-consolidation company and it avoids the need to increase expenditures on hiring and training.

On the other hand, if the opportunity to consolidate is not taken now, and distributors across the province spend substantial resources hiring and training new workers, then consolidation in the future will result both in surplus workers, and sunk costs in hiring and training that could have been avoided. This would be an extremely unfortunate outcome for ratepayers across the province.

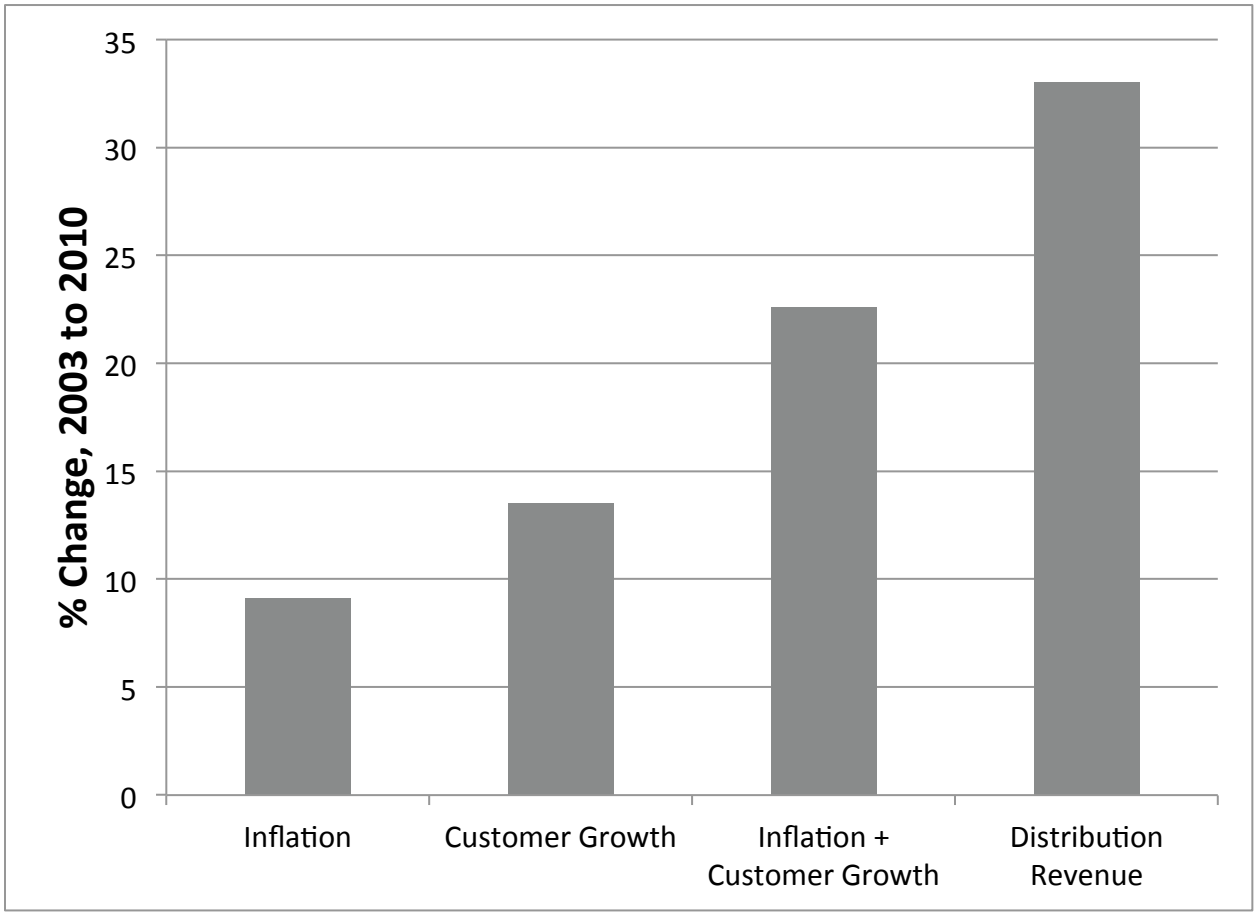
[16] In a speech to the Specialist High Skills Major Energy Conference in February 2010, Hydro One CEO Laura Formusa referred to impending retirements of more than 30% of the workforce.

## Cost Containment

Energy costs have been rising substantially for the past 10 years: not only electricity, but oil, gasoline and heating oil are all substantially more expensive than they were a decade ago. Natural gas is the exception to the trend, having suffered a period of high prices between 2003 and 2008 but recently benefitting from the new availability of shale gas, which has brought prices down substantially.

The total revenues of the electricity distribution sector in Ontario rose by 33% from 2003 to 2010, the period for which figures are publicly available.[17] In fact, electricity distribution costs have risen faster than the market cost of electric power and the cost of transmission.[18] All of these cost increases put substantial pressure on consumers, particularly since the increases have been substantially ahead of inflation and customer growth.

**Graph 1: Distribution Revenue Growth, 2003 - 2010**

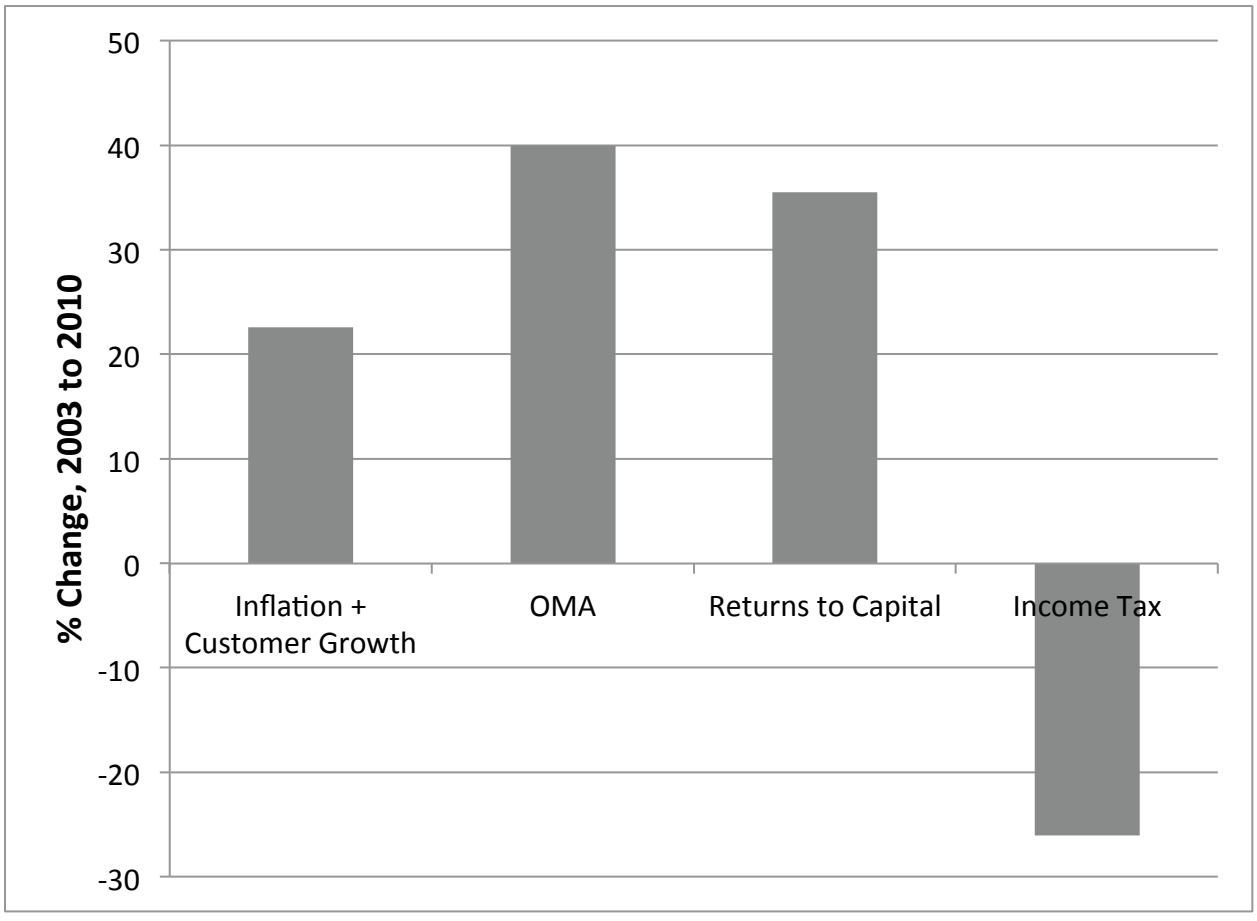



[17] All data as reported to the Ontario Energy Board, and available on the OEB website.
[18] Note that the market cost of power includes both IESO market prices as well as the Global Adjustment, but excludes the impact of rebates, consumer price freezes, etc., in order to make it comparable to distribution and transmission.

Distribution costs are made up of three components: day to day expenses consisting of operations, maintenance and administration (known as "OMA"); returns to capital consisting of depreciation, debt interest and profits; and income taxes, whether paid to the province in the form of PILs, or paid as normal federal and provincial corporate income tax.

Between 2003 and 2010, OMA costs rose by over 40%, while inflation rose by 13.5% and customers counts rose by 9.1%. Increasing customer numbers should be expected to put upward pressure on OMA costs (more customers means more bills to issue, more calls to answer, more opportunity for line failures or tree-cutting, etc.), but when customers numbers increase by 1%, OMA should increase by *less than* 1%, because many costs are relatively fixed and do not grow with incremental customer changes (e.g. overheads, planning, regulatory costs, billing systems, substation maintenance, etc.).

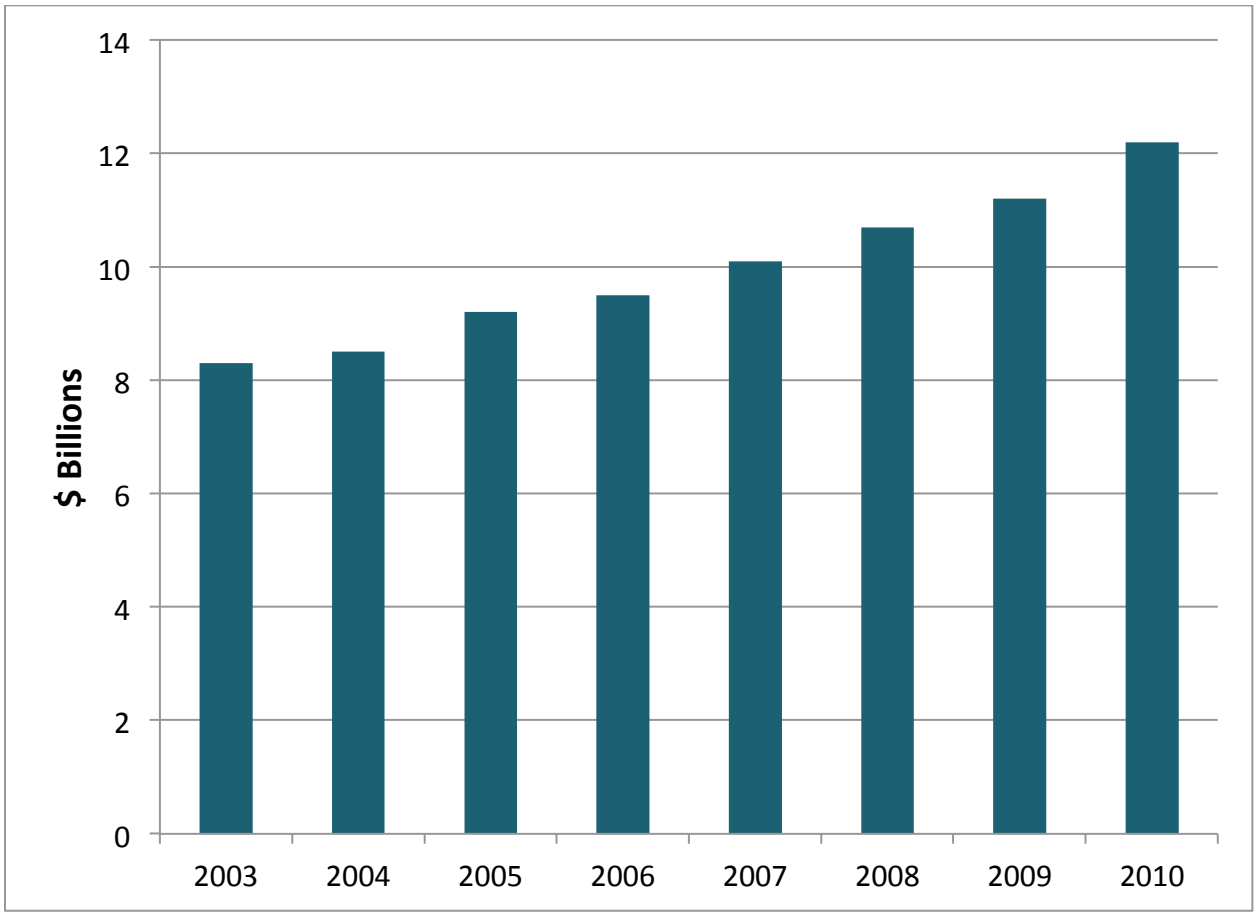
**Graph 2: Growth in OMA, Returns to Capital, and Tax, 2003 - 2010**




Over this time period, however, distributors were beginning to deal with the demographic wave of retirements discussed above, which brings with it dramatically increased costs for recruitment and training. In addition, they were required by the Province to undertake the smart meter initiative and to connect distributed generation under the RESOP and FIT programs, both initiatives being completely new and costly to distributors.

Returns to capital rose by 35% over the eight years in question. This in turn was driven by a 48% increase in the book value of property, plant and equipment (basically, distribution assets). Purchases of new assets have been driven by customer growth and system expansion, by the need for new types of assets such as smart meters and switches to manage new connections of solar and wind generators, and most importantly by the replacement of old assets. As mentioned above, much of the province's distribution network was built simultaneous with the rapid population increase of the province between 1950 and 1980.[19] Many assets built back then have reached the end of their useful lives, and now need to be replaced in substantial numbers. The cost of such replacements has increased by multiple times their original cost, hence the dramatic increase in book value of assets. This trend will continue for years to come, putting upward pressure on distribution rates.

**Graph 3: Book Value of Property, Plant and Equipment, 2003 - 2010**




The only positive comparison between 2003 and 2010 is that income taxes paid by distributors have fallen, partly as a result of the fact that corporate income tax rates have declined, and partly because

[19] According to Statistics Canada, Ontario's urban population more than doubled between 1951 and 1981, growing from 3.2 million to over 7 million people. In the following 25 years, Ontario added another 3 million people.

higher interest and depreciation costs resulting from capital investments reduces the net income upon which tax is calculated.[20]

These ongoing cost pressures mean that, all other things being equal, distribution costs will continue to increase in Ontario at a rate faster than inflation and customer growth, meaning that all customers will face a heavier burden in the future. In this context, every opportunity to pursue efficiencies, including industry consolidation, should be pursued.

## Public Sector Finances

As mentioned above, over the past number of years municipalities have had access to multiple sources of revenue and capital. The strength of the economy between 2003 and 2008, coupled with a succession of federal and provincial infrastructure programs in the past decade have meant that municipalities were not in significant need of financial resources. Monetizing the value trapped in a distributor was not typically a priority.

Recently, both the Federal and Provincial governments have committed to programs of fiscal austerity, part of which includes a lesser commitment to funding municipal infrastructure. While this change will no doubt take time to fully affect municipal finances, it will over time become apparent that the capital held by municipalities in the form of electricity distributors is misallocated. The private sector is more than willing to purchase distribution utilities, at a substantial premium, which would allow municipalities to commit that scarce capital to other public purposes which might not otherwise be funded.

For the Province of Ontario, encouraging the reallocation of this capital resource for municipalities by removing the Transfer Tax would also be a means of reducing its own fiscal pressure, since it could result in fewer demands on the province's own fiscal resources.

## Capital Requirements

As discussed above, many distributors across the province require substantial capital in the coming years to replace ageing equipment. Traditionally, and by regulatory requirement, electricity distributors are financed overall on a 60:40 long-term debt to equity basis. In other words, a distributor's long-term liabilities should consist of approximately 60% debt, and 40% value of equity. When new equipment is purchased, it should be financed in a way that maintains that basic target ratio.

Debt for electricity distribution assets is readily available. However, the efficiency of debt financing is often affected by the size of the capital requirement: larger companies have access to a wider variety of capital markets, and hence can achieve the lowest debt costs and best terms.

Equity resources are a particular challenge for municipally-owned electricity distributors. Their only source for equity is retained earnings. Typically, a municipal owner expects regular dividends to be paid from annual net income generated. The retained earnings over and above the dividends paid represent

[20] In 2003, combined Federal and Ontario corporate income tax rates were 33%, rising to 36% in 2005, and then falling to 31% by 2010. For 2012, the combined corporate income tax rate has fallen to 26.5%.

the municipality's reinvestment in the business, and provide financial resources to purchase new equipment. However, as the burden of replacing ageing infrastructure becomes more acute, distributors may find it to be more difficult to maintain their dividend payments to their shareholder while still maintaining their debt to equity ratio. In the extreme, even retaining all earnings might still not represent sufficient equity investment in the business. The result will presumably be either a breaching of the 60:40 debt to equity ratio, or the delay of new purchases until sufficient equity can be accumulated.

It is extremely unlikely that any municipality would wish to actually invest new cash into its electricity distributor, especially given the public sector fiscal environment just described. In fact, it is quite possible that conflicts will arise between distributors' needs for retained earnings, and municipal shareholders' desire for dividends.

All of this should be contrasted with private sector owners of utilities: for these owners, investment in distribution is considered to be an *opportunity to put capital to work*. Typically, private sector utilities will raise equity in the capital markets when it is needed for major investments, since those investments will earn a return over time. Moreover, private sector utilities can often raise new equity at rates that are below the returns allowed by regulators in rates, making the investments that much more attractive.[21]

To the extent that consolidation were to occur in Ontario without private sector participation, the benefits in terms of capital resources would principally arise from greater scale and efficiency. However, if consolidation includes the entrance of private sector players, then access to capital for Ontario distributors would be fundamentally improved.

[21] This ability to raise equity inexpensively is part of the source for premiums paid to purchase distributors. An acquisition is simply a one-time investment in a distributor. If the buyer has an equity cost advantage over the seller, as many private sector buyers have when compared to municipal owners, it can justify paying a premium. The other justification may be the opportunity for consolidation of operations, as discussed above.

# Alternatives to Consolidation: Other Rationalization Options

Consolidation is not the only route to efficiency in the electricity distribution sector; other, perhaps less dramatic options are possible. However, while all of these options can be pursued, they are fundamentally less all-encompassing than consolidation, and are likely to have less significant impacts on efficiency and hence customer rates over time.

## Partnerships and Procurement Groups

Scale efficiencies can be achieved by distributors on a voluntary and selective basis through the formation of various types of groups that perform functions in concert. The simplest version of this would be an agreement between several distributors to jointly procure certain classes of new equipment so as to achieve "bulk" discounts on the purchases. In fact, there are a number of instances across the province where distributors have done exactly this. Recent examples include the procurement of smart meter systems, where groups of distributors with similar requirements banded together to make deals with suppliers.

This kind of practice can be made more or less formal, and more or less permanent. To the extent that these structures become formalized, they can be viewed as a form of "partial consolidation", since a formal group with rules and restrictions of its own will take away some of the decision-making authority of individual member distributors in order to generate the economic savings desired. In the United States, where utilities are often required to procure their own transmission and generation services on the open market, groups of public utilities or rural cooperatives have formed highly structured partnerships which have in effect become enterprises of their own, with each of the distributors being a member/shareholder.

In Ontario, one interesting example of this kind of effort was the agreement in 2002 by five distributors to jointly raise debt capital in the amount of $175 million for a 10-year term.[22] The desire to bring together multiple distributors to raise this capital both demonstrates the benefits that are possible from scale, and the potential for partnerships and joint arrangements of various kinds. Interestingly, four of the five participants in this arrangement ultimately merged together to form PowerStream, such that the outstanding debt only included two distributors by 2009. A more traditional grouping of smaller distributors in Ontario is CHEC, or Cornerstone Hydro Electric Concepts, which includes more than 15 distributors, each of which has fewer than 15,000 customers.

## Outsourcing and Subcontracting

Instead of partnering with other distributors to perform functions jointly, distributors can achieve some of the benefits of scale by outsourcing certain functions to a larger-sized provider. For example, not every one of Ontario's municipal distributors owns a billing system: some of the smaller utilities

[22] For additional details, please see www.edfin.ca

outsource their billing function to a larger distributor or a specialty provider. As a result, the billing function becomes a pure expense for the distributor, instead of a combination of operating expenses and the capital costs of buying a system. Even including a profit margin for the provider, outsourcing the service can be cheaper for ratepayers of a small utility than the cost of purchasing and maintaining a standalone billing system.

Similarly, other functions can be outsourced if they are not central to day-to-day operations. For example, if a smaller utility does not often require planning and design services because it only rarely has to replace assets, it may make sense to hire planners and designers on a consulting basis only when required.

Taken to an extreme, it is possible for a distributor to outsource all of its functions, with the shareholder maintaining only the ownership of the underlying capital assets. In fact, Grand Valley Energy Inc., the distributor for the former village of Grand Valley consisting of fewer than 1000 customers, was for a time operated by nearby Orangeville Hydro. In 2008 Grand Valley was formally merged with Orangeville Hydro, ending that particular experiment.

Ultimately, outsourcing of distribution functions in order to achieve scale efficiencies raises the issue presented by the circumstances of Grand Valley: while outsourcing of some functions is potentially more efficient for small distributors and their ratepayers than independently performing all tasks, it would undoubtedly be even more efficient and better for ratepayers if the utility were simply consolidated into a larger entity. Outsourcing is merely a partial substitute.

## The Special Case of Port Colborne

In 2001, an Ontario subsidiary of Fortis Inc. entered into an agreement with Port Colborne Hydro to "lease" its distribution assets for 10 years.[23] In some ways, this transaction can be characterized as the ultimate outsourcing agreement, and in other ways it has the characteristics of a progressive sale of the assets in question.

Port Colborne Hydro, and its shareholder the City of Port Colborne, agreed that in exchange for 10 years of equal monthly payments Fortis would take over operation of the entire electricity distributor. Over that time, all of the Port Colborne Hydro's assets would be depreciated, and taken out of service at the end of their useful lives. In any instance where new assets were required, Fortis was to be responsible for providing them. From a regulation and rates perspective, the total assets put into use in the territory of Port Colborne were the pre-existing assets plus all new assets provided by Fortis. In this way, over the course of 10 years Fortis came to own the majority of assets in use in Port Colborne.

At the end of the 10 year period, Fortis had the option to buy the remaining assets of Port Colborne for a fixed price of $6.9 million, after having paid approximately $15 million of lease payments over 10 years. Fortis exercised this option, and has now purchased those remaining assets.[24]

[23] For detailed information on this transaction, please see OEB case number EB-2001-0492.
[24] Please see OEB case number EB-2011-0367.

The most interesting feature of this transaction was that the City of Port Colborne was NOT required to pay transfer tax on the 10 years of lease payments received from Fortis. The lease payments were revenue for Port Colborne Hydro, against which the company charged interest on its outstanding debt, administrative costs, depreciation of its assets and other expenses. Port Colborne Hydro continued to pay PILs as would any other municipal utility. Fortis, on the other hand, paid normal federal and provincial corporate income tax on its earnings from operating the Port Colborne territory, and from its return on equity generated from investing in distribution assets in Port Colborne.

When the remaining assets were sold this year, the City of Port Colborne was required to pay Transfer Tax on the $6.9 million purchase price, calculated in the usual way. Given the accumulated PILs paid by Port Colborne Hydro over the course of the 10 year period, it is unlikely that substantial Transfer Tax was ultimately due to the Province.

This was by all accounts a complicated and difficult transaction, and it has not been repeated by any other distributor in Ontario. However, it appears that the City of Port Colborne effectively privatized its utility over the course of 10 years, and effectively avoided most of the Transfer Tax impact that would otherwise have attended on a sale. The Provincial Government did receive 10 years of PILs from Port Colborne Hydro, plus simultaneous corporate income tax from Fortis for its earnings in the territory, but as of 2012 it will receive no further PILs and only provincial corporate income tax.

If other distributors were to explore this type of transaction, it is possible that the province could legislate or regulate against it occurring through some change to the *Electricity Act*.

# What to Do? Options for Consolidation Mechanics

Given the benefits for ratepayers of further distribution industry consolidation, how could it be achieved?

## Legislation

In the Australian states of Victoria and New South Wales, governments decided that as part of electricity industry restructuring in the mid-1990s the number of distributors should be reduced. In the former, 29 distributors were consolidated into 5 and then privatized, while in the latter 25 distributors were consolidated down to 6, and subsequently down to 3.

Many other instances of legislated consolidation with or without privatization can be cited from around the world.[25] Typically a national or sub-national government has acted to force the consolidation of distributors that were primarily local in nature, in order to try to achieve reasonable economies of scale and efficiency.

In Ontario in 1995, the MacDonald Commission considered this issue when Ontario had more than 300 distributors, most of them municipal entities. One of the options considered at the time was a similar process of consolidation and privatization to that pursued in Australia. Instead, the provincial government of the day chose to require the corporatization of all distributors, and allowed them to merge or sell voluntarily, if they chose.

There is no question that the Government of Ontario has the legislative authority to consolidate the electricity distribution industry, and could in addition require privatization of any or all of the currently publicly-owned assets. However, the provincial government could potentially face a backlash from all of those individuals and stakeholders who continue to believe in the value of "local control" of their electricity distributor, as discussed above. Moreover, if the provincial government were to take on the burden of redesigning the map of electricity distribution territories across Ontario, it would be required to make numerous decisions about boundaries, disposition of assets, selections of new boards of directors and management, and many other practical details that it may not wish to address directly. One particularly fundamental issue that would need to be addressed explicitly in legislation is the treatment of the labour agreements and union representation of the distributors being consolidated, since these vary considerably from one distributor to the next. One potential unintended outcome of legislated consolidation could be the migration of all consolidated labour agreements to the highest paying of all the pre-existing contracts, which would potentially erase at a stroke the efficiency benefits sought through consolidation in the first place.

[25] For example, France consolidated most of the electricity assets in the country in 1946 to create Electricite de France, which continues to be majority owned by the French state.

## Regional Mergers Based on Division of Hydro One

A second option for consolidation would be for the Government of Ontario to divide Hydro One Distribution into a series of regional corporations, which could then be merged with distributors local to each region on a voluntary basis. In this scenario, all assets could be pooled on a book value basis, for example, such that every pre-existing shareholder would receive shares in the new entity commensurate with the assets contributed. The province could be a minority shareholder in most of the regions, with no single majority shareholder for any resulting distributor, assuming most current distributors participated.[26]

Again, there are practical difficulties with this option. Labour issues would likely dominate discussion, as would concerns about local control. In at least some of the regions it is quite likely that Hydro One would represent well over 60% of the value of pooled assets, meaning that corporate governance would be a significant issue. At the same time, division of Hydro One, and loss of the existing economies of scale that the company currently enjoys, could only be justified if the willingness to merge existing distributors was nearly universal. If large numbers of small distributors refused to participate, then the inefficiencies created by dividing Hydro One might outweigh any gains from subsequent mergers.

Practically, this option blends into the legislative option, as legislation might be the only way to actually enforce successful and efficient regional consolidation.

## Voluntary Consolidation with Increased Incentives

As has been noted, consolidation in Ontario has slowed to a trickle in recent years. Although there is no barrier to mergers or acquisitions between the publicly-owned distributors, whether provincially or municipally-owned, few of these transactions have occurred in recent years. As a result, simply allowing continued voluntary consolidation, all other things being equal, is not a viable strategy to achieve rapid and significant consolidation. Some changes will be required in order to spur further consolidation. A variety of possible options exist and could be considered, such as:

*Remove the Transfer Tax in conjunction with an arrangement with the Federal Government*: As discussed above, removal of the Transfer Tax is a practical prerequisite for the entry of the private sector into the distribution sector in Ontario. Allowing the private sector to purchase distributors would increase both the size of the market of potential consolidators, as well as the price premiums that would be offered to existing shareholders. This change would likely have a dramatic impact on the course of consolidation in Ontario.

*Revise policy on electrically embedded distribution*: In the most extreme case, electrically embedded distributors could simply be disallowed after a reasonable notice period. This would likely be equivalent to forcing many distributors to sell all or part of their business to Hydro One, as well as requiring that a number of boundaries between distributors across the province be adjusted. In some cases, new

[26] As of 2010, Hydro One's distribution business reported to the OEB $5 billion of net property plant and equipment, while all other distributors combined reported $7 billion.

connections to the transmission grid might be viable construction projects, but it is difficult to see such an outcome as beneficial to customers (if they are not currently served by a direct connection to transmission, why should they need one?). A less extreme change in policy would be to change the pricing of embedded distribution services. As described above, services to embedded distributors are currently priced on an average cost basis to the surrounding distributor, rather than on the basis of the costs being avoided by the embedded distributor. If a larger part of the cost burden were shifted to embedded distributors, closer to what they would be required to spend to have their own independent connection to the transmission grid, then customer rates would more accurately reflect real opportunity costs for both the embedded distributor and the larger service provider. The embedded distributors could then make their own choices about what would be advantageous for their ratepayers and communities.

*Amend regulatory cost allocation to better reflect work performed*: The Ontario Energy Board regulates all electricity distributors. Each distributor must maintain its license, meet quality of service standards, report regularly to the OEB, periodically go through a rate-setting exercise, and from time to time participate in other OEB consultations and processes.[27] The vast majority of the cost of this regulation is apportioned to regulated entities by the OEB through annual assessments, first to each class of regulated entity (e.g., natural gas distributors, electricity transmitters, electricity distributors, energy marketers, etc.) based on how much work that class generates, and then to the regulated companies within each class. In the case of electricity distributors, costs are apportioned on the basis of electricity distribution revenue: in other words, larger distributors pay more, and smaller distributors pay less. This cost allocation methodology is justified on the basis of relative burden to each distributor, so that no distributor is unduly affected by its share of the regulatory cost overhead. However, given that regulatory workload is directly related to the number of distributors in the industry, and the interaction by the regulator with every distributor is similar, it is not clear that this allocation methodology makes sense in the context of customer benefits that would be generated by consolidation. If all distributors shared equally in the regulatory burden, then the relative burden on smaller distributors would be much larger. This cost burden would better reflect the cost to the system as a whole of having so many distributors. In short, consolidation would be encouraged, particularly among the smallest distributors.

*Amend the regulatory treatment of consolidation transactions*: When two distributors are consolidated, the OEB allows the post-consolidated company to avoid a rate review and re-setting process for up to five years. The theory is that a merged company will be able to take advantage of efficiency opportunities to generate superior returns, which will help compensate the parties for the costs of consolidation, and potentially for any premiums paid to encourage the transaction. In practice, however,

[27] It should be noted that the OEB has some history of allocating the burdens of the regulatory process unequally among the various distributors it regulates. Typically, larger distributors have been required to participate to a greater degree in policy consultations, studies, reviews and new initiatives, which has placed a significant cost burden on larger distributors vs. smaller distributors. One particularly explicit example of differing treatment concerns the rollout of smart meters. In the OEB's proposed smart meter rollout plan, see *Smart Meter Rollout Plan, Report of the Board to the Minister, January 26, 2005*, "large urban distributors" with more than 100,000 customers were to be required to achieve smart meter targets prior to December 31, 2007, while all other distributors were to meet requirements by December 31, 2010.

two problems arise: first, five years may not be a long enough period to incentivize consolidation. Given the sometimes considerable expenses generated during the first year or two after consolidation, three additional years of recouping costs may simply not be enough. The possibility of extending the period beyond five years might be considered. Second, given the impending cost pressures across Ontario from the replacement of capital equipment, it may be unreasonable for a consolidated distributor to avoid a rate review. In this case, while consolidation may generate many efficiencies in operations and administration, the need to spend significant capital on new equipment could swamp these effects. Rate review and resetting would result in higher rates to compensate for new capital spending, but would allocate to ratepayers the benefits of consolidation efficiencies. In order to address this issue, some division in rates between operating costs and capital costs would be required. Distributors could be allowed to review one part of their rates independently from the other, so that a consolidated distributor might be able to reap the benefits of operational efficiency for a few years, while not being forced to swallow dramatic capital cost increases.

# Ontario Energy Association Recommendations

### 1. Consolidation Must be Voluntary

Every company and shareholder should be free to determine the best outcome for them, based on their particular interests.

### 2. All Distributors Must be Eligible Buyers and Sellers

It is essential that all distributors be eligible to participate in transactions that are economically sensible, whether this includes buying, selling, or adjusting territorial boundaries. Legislative, regulatory or policy restrictions on the participation of any distributor would result in less than rational transactions across the province, to the ultimate detriment of ratepayers.

### 3. Transfer Tax is the Most Significant Impediment that Must be Removed

The entry of private sector players into the Ontario distribution market would almost certainly speed consolidation, and lead to a wider variety of options for all concerned. In addition, the entry of new sources of capital would effectively address the challenge of capital requirements for the replacement and upgrading of older distribution assets that is essential to the functioning of the system across the province. Cooperation between the Provincial and Federal governments on this issue is required in order to achieve a sensible solution that is in the long-term best interests of all parties.

### 4. Ratepayers Must Visibly Benefit from Consolidation

Consolidation is ultimately beneficial to all ratepayers because cost efficiencies accrue to customers' bottom lines. However, the process of consolidation - which often focuses on shareholder decision-making and regulatory approvals - is often opaque to ratepayers. A clear message to ratepayers, exemplified by some immediate and obvious benefit to them such as a rate freeze for a period of time post-consolidation, is required to encourage public understanding of and support for necessary transactions.

### 5. OEB Policies Should be Adjusted to Encourage Rational Consolidation

Incentives for consolidation, including post-transaction rate-setting policies, should be reviewed and improved. Existing policies that unfairly advantage smaller distributors, such as the treatment of embedded distribution and the allocation of regulatory costs, should be revisited.

# Appendix 1

## The Ontario Transfer Tax

Hydro One and all municipally-owned distributors in the province pay "payments in lieu of taxes" (PILs) exclusively to the Province of Ontario. The amount of PILs paid is identical to what a normal business corporation would pay in income taxes to the federal and provincial governments combined. In 2012, this is 15% federally, and 11.5% for Ontario, for a total PILs rate of 26.5%.

It is a historical anomaly of the federal Income Tax Act that all provincially or municipally-owned assets are exempt from federal tax, regardless of their form of organization (i.e., whether a government department, agency, public commission, or business corporation). Hence, as long as a distributor remains more than 90% owned by the province or municipal shareholders, the province benefits from not only provincial income tax revenue, but also from revenue that would normally be remitted to the federal government in the form of income tax. In effect, if all of the distributors in the province were sold to private sector buyers, the province would lose more than half of all of its PILs revenues from the sector (in 2010 the province received $105 million in PILs, so complete privatization would jeopardize $60 million per year).

In order to protect this stream of income, or its equivalent economic value, the provincial government instituted in the *Electricity Act, 1998* the "transfer tax" on municipally-owned distributors. This is a charge that is applied to the proceeds of any sale of a municipally-owned electricity distributor which results in a change in tax status. In other words, if as a result of a transaction municipal shareholders no longer own and control at least 90% of the equity of a distributor, then transfer tax is payable. The transfer tax is meant to approximate the present value of many years of the future PILs that will be lost by the provincial government in the event of such a sale.

The transfer tax is one third of the enterprise value of the distributor in question. In the context of a sale transaction, this is the total value of the distributor, including debt. From the perspective of a shareholder of a municipal distributor, this is an extremely punitive tax, as the following example demonstrates:

- Assume that a distributor has $10 million of assets in the business
- Assume debt amounts to $6 million, and equity $4 million
- If the distributor were sold at book value of $10 million, then the transfer tax would be $3.3 million
- After paying off debt of $6 million, and paying the transfer tax of $3.3 million, the shareholder would receive proceeds on the sale of only $0.7 million
- Instead of selling, the shareholder would instead simply continue to own the distributor and earn returns on the investment on an annual basis

It should be noted that this transfer tax policy is NOT related to the "stranded debt" left over from the break-up of Ontario Hydro. While there is a popular misconception that the transfer tax somehow expires in conjunction with the full payment of the stranded debt, this is not in fact the case. The province permanently receives all PILs from municipal distributors, and the transfer tax is indefinite.

If this were the complete policy, then sales of municipal distributors would never occur. However, there are two wrinkles: first, the transfer tax does not apply to transactions between provincially or municipally-owned entities, since such transactions do not change the tax status of any of the distributors involved, and second, "credits" build up over time which can be applied to reduce the transfer tax burden.

As distributors pay PILs over time, the total amount paid to the province is recorded. In the event of a sale of the distributor which changes its tax status, the cumulative PILs paid are credited against the transfer tax owing on the sale, as in the following example:

- Assume the same terms as the example above
- Assume also that since 1999, the distributor has paid approximately $100,000 in income taxes per year, and a total of $1 million in cumulative income taxes to date
- Transfer tax owing on a sale at book value would be $3.3 million less $1 million, or $2.3 million
- Proceeds for the shareholder would be $1.7 million

It should be noted that transactions do not normally occur at book value of assets; Rather a premium is typically applied. In North America over the past decade, the premium paid for regulated utilities has ranged between 1.1 and 1.5 times the value of the distributor's regulated rate base (rate base is a regulatory economics concept which usually consists of the book value of capital assets, plus an extra amount representing working capital). For the purposes of the simple example used in this paper, it may be useful to focus on a premium of 1.3 times the book value of distribution assets, and ignore the rate base issue. To continue the example above:

- Assume a sale price of 1.3 times book value of assets, or $13 million
- Transfer tax will be 33% of $13 million, or $4.3 million
- The credit against the transfer tax is $1 million, and debt continues to be $6 million
- Proceeds to the shareholder would be $13 – 6 – (4.3 - 1) = $3.7 million
- Since this is still less than the book value of the shareholder's equity, it is not likely that a transaction will be completed. However, between the transfer tax credit and the premium in the transaction, the economics are becoming closer to being favourable for the municipal shareholder.

If potential buyers are willing to pay even higher premiums, then a sale could become attractive to a municipal shareholder, even in the face of the transfer tax. To continue the example above:

- Assume a buyer willing to pay 1.4 times book value of assets, or $14 million
- Net transfer tax will be 14*.33 = 4.62 less $1 million in credits = $3.62 million
- Shareholder proceeds would be $14 less 6 in debt less 3.62 of transfer tax = $4.38
- The shareholder is paid a premium of $0.38 million above book value of equity, and may possibly begin to consider a sale

This system of credits against the transfer tax creates a dynamic policy environment over time. As credits against transfer tax build up through the payment of PILs, and depending on the willingness of buyers to pay premiums for desirable utility assets, transactions become more or less likely.

If the province were to either eliminate or reduce the Transfer Tax, the impact on distributor shareholders would be very significant.

If the Transfer Tax were eliminated in the 30% premium example above, then the shareholder would receive $7 million in sale proceeds, a 75% premium to book value of the equity. In the same example, if the Transfer Tax rate were just cut in half, to one sixth of the proceeds instead of one third, the shareholder would receive $5.85 million, which would be a 46% premium to the $4 million book value of equity.

Any change by the Province to Transfer Tax policy would be dramatic for the economics of transactions.

# Appendix 2

## Delivery Costs for Residential Customers of Selected Utilities

All data drawn from the OEB website in July 2012. Delivery costs consist of transmission plus distribution cost. As the transmission cost is flat across the province, with the exception of differences in local line losses, most of the variation in delivery costs between distributors is due to distribution rates. Customer counts are as reported to the OEB, measured at the end of 2010.

| Distributor | Delivery Cost 800 KWh to Residential Customer | Notes[28] |
|---|---|---|
| Algoma Power | $56.15 | • Owned by Fortis<br>• North of and surrounding Sault Ste. Marie<br>• Northern Ontario, rural and seasonal<br>• 11,612 customers |
| Eastern Ontario Power | $37.90 | • Owned by Fortis<br>• Gananoque, Eastern Ontario small town<br>• 3,561 customers |
| Canadian Niagara Power | $39.68 | • Owned by Fortis<br>• Fort Erie & Port Colborne, Southern Ontario towns<br>• 15,635 customers |
| PUC Distribution | $26.65 | • Sault Ste. Marie<br>• Northern Ontario city distributor, surrounded by Algoma which serves rural/seasonal areas<br>• 32,870 customers |
| Orillia Power Distribution | $31.57 | • Central Ontario town<br>• Owns its own waterpower generation<br>• 12,862 customers |
| Hydro 2000 | $26.96 | • Smallest remaining distributor in the province<br>• Towns of Alfred and Plantagenet in Eastern Ontario<br>• 1,196 customers |
| Erie Thames Powerlines | $40.56 | • Southern Ontario, collection of towns including Ingersoll, Tavistock, Norwich<br>• 14,373 customers |
| Wasaga Distribution | $30.96 | • Southern Ontario town, many seasonal customers<br>• 12,046 customers |

[28] Customer totals listed include all residential and business customers, with the exception of unmetered scattered load and street lighting.

| Distributor | Delivery Cost 800 KWh to Residential Customer | Notes[28] |
|---|---|---|
| Innisfil Hydro | $43.59 | • Southern Ontario town plus surrounding rural area<br>• 14,707 customers |
| Cambridge and North Dumfries Hydro | $31.71 | • Southern Ontario city plus surrounding rural area<br>• 50,890 customers |
| Burlington Hydro | $34.33 | • Greater Toronto Area suburban distributor<br>• 64,329 customers |
| Hydro Ottawa | $34.67 | • Urban distributor<br>• 300,664 customers |
| Toronto Hydro | $39.59 | • Urban distributor<br>• Second largest distributor after Hydro One<br>• 700,386 customers |
| Hydro One – Brampton | $30.67 | • Greater Toronto Area suburban<br>• 134,228 customers |
| Hydro One – Urban | $51.42 | • Group of 3000+ customers with density of 60+ per line km<br>• Sample areas: suburban Ottawa, suburban Hamilton, Caledon bordering on Brampton, etc.<br>• Hydro One total customers: 1,203,030<br>• Approximately 141,000 Urban Residential customers |
| Hydro One – Medium Density (R1) | $59.93 | • Group of 100+ customers with density of 15+ per line km<br>• Towns and villages in traditional Ontario Hydro service territory<br>• Approximately 413,000 Medium Density residential customers |
| Hydro One – Low Density (R2) | $97.81 (Less Rural and Remote Rate Protection subsidy of $28.50 results in customer charge of $69.31)[29] | • All other residential customers<br>• Most of rural Ontario<br>• Approximately 367,000 Low Density residential customers |
| Hydro One – Seasonal | $100.74 | • Seasonal customers are not eligible for Rural and Remote Rate Protection subsidy<br>• Approximately 157,000 seasonal customers |

[29] Rural and Remote Rate Protection is a program which applies a small charge on all customer bills across the province, and uses the revenue to reduce the cost of delivering electricity to certain rural and remote areas. Many such customers are in Hydro One territory, but certain other distributors have customers who qualify as well.

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