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By e-mail and by courier

December 6, 2011

Ontario Energy Board Staff
P.O. Box 2319
2300 Yonge Street
27th floor
Toronto, ON M4P 1E4

Dear Sir/Madam,

Renewed Regulatory Framework for Electricity
Board File Nos.: EB-2010-0377, EB-2010-0378, EB-2010-0379, EB-2011-0043 and EB-2011-0004
Our File No.: 339583-000098

Further to our letter of December 5, 2011, we enclose an electronic version of a Brief containing copies of documents referenced in Schedule "A" to our December 2, 2011 letter. Hard copies are being sent to Board Staff by overnight courier.

Yours very truly,

Peter C.P. Thompson, Q.C.

PCT/slc
enclosure
c. All Interested Parties
Bruce Sharp (Aegent Energy Advisors)
Vince DeRose, Jack Hughes (BLG)
Paul Clipsham (CME)

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EB-2010-0377
EB-2010-0378
EB-2010-0379
EB-2011-0004
EB-2011-0043

Renewed Regulatory Framework for Electricity

BRIEF OF SCHEDULE "A" DOCUMENTS

Documents Informing CME's Approach to Renewed Regulatory Framework Consultative

TAB 1

Howard I. Wetston, Q.C.

Chair

Ontario Energy Board

SPEECH

Electricity Distributors Association
Annual General Meeting

Toronto, Ontario

March 29, 2010

Thank you, John (Loucks) for your kind introduction and I appreciate the invitation. John, whenever I feel that things have settled down in the sector, "I lie down until the feeling passes".

Last year I opened my remarks by noting "What a difference a year makes". This year I would like to comment on how we are organizing ourselves for the future. My point is, any attempt at energy reform, must include the wires not just generation. We have worked through a lot of issues in very challenging times in the electricity sector and I would like to congratulate John personally for the work he has done as Chair of the Electricity Distributors Association.

I am sure you have all noted John's expectation that 2010 will be a transformational year for distributors and that you are anticipating the issuance of regulations and directives that will provide you with a clearer path to engage in an array of new roles and responsibilities. He has written that you are keen to embrace new business opportunities, such that the local distribution company plays a vital role in building the robust and sustainable communities of tomorrow.

Indeed, the Green Energy Act (GEA) ushered in a new paradigm for Ontario's energy sector and for its network utilities in particular. Green energy is a key component of a strategy designed to achieve the broader environmental, industrial and social policy objectives of a green economy. The GEA presents a clear statement of new objectives to guide the Board: conservation, renewable energy and technological innovation through the smart grid.

Like you, the Board has had to roll up its sleeves and respond to the challenge created by the GEA of evolving how the Board regulates network utilities in the public interest. Even before the GEA was introduced, however, the Board recognized that our technical work of rate setting and service quality oversight was important but needed to be supplemented by innovative approaches to regulation. We recognized the need to be open to new ideas and new ways of doing our work, and that our approach had to be adaptive, developing new relationships and creating new opportunities for dialogue and facilitation. And while regulatory issues are increasingly complex and affect utilities in new and complex ways, we continue to recognize that regulation must establish a sense of order and stability and we believe that stability in the regulatory regime has won much for the public by fostering confidence.

We have therefore advanced the implementation of policy in a manner that protects the public interest by remaining true to our core principles: a long-term approach to issues; a transparent, open and inclusive process; timely, clear and decisive outcomes; and a focus on practical, workable and implementable solutions.

While the Green Energy Act added three new objectives to guide us when carrying out our responsibilities, our existing objectives relating to consumer protection, economic efficiency and cost effectiveness, and a financially viable electricity industry are unchanged. As such, from a regulatory perspective we are facing an immense increase in issue complexity.

Here is the challenge: we must pay greater attention to certain social and environmental factors that are intended by government policy, while at the same time facilitating the achievement of our economic goals. Those issues must be addressed in transparent and principled adjudicative and code development procedures that conform to the requirements of the law. The presence of socio-economic objectives does not mean we will not continue to encourage efficient outcomes in the distribution sector wherever possible.

Since we last met, the Board has undertaken many key initiatives to ensure that our regulatory instruments reflect the changes in our governing legislation and are well-aligned with the goals in the GEA. Most of these initiatives are now complete and can be divided into five broad categories.

In the first category, we have made the connection process for generators more rational and efficient. We have made it easier for generators up to 500 kilowatts to connect their local distribution system by exempting them from requiring a specific allocation of capacity. For larger generators, we have made a number of changes to ensure that those with capacity allocations have an incentive to move forward with their projects or risk having their allocation removed. And we have introduced a new simplified generation license for Feed-in Tariff (FIT) generators that will reduce the amount of time and paperwork required and avoids duplication with the Ontario Power Authority.

In the second category, we implemented new rules to standardize the billing and settlement processes for FIT and microFIT generators. There is now a single way of setting up generator accounts and settling them, regardless of whether they are connected in front of or behind the meter. We have also implemented a $5.25 monthly service charge that will apply to all microFIT generator accounts across the Province.

In the third category, we looked at the allocation of costs for renewable connections. The Board recognized that the FIT program was likely to lead to a large number of generators connecting to distribution systems and that substantial distribution system investment would be required. The Board decided that it would be best to shift much of the cost of this investment from individual generators to the utility's customers as a whole. The government also recognized this and the Board has been tasked to ensure that the cost burden of these additional investments is shared equitably among distribution connected ratepayers across the Province, less any benefits accruing to local ratepayers. We are in the midst of a consultation to determine the nature and quantification of those benefits.

The fourth category of work relates to the treatment of distributor-owned generation. The Board has issued guidelines that lay out the appropriate regulatory and accounting treatment of distributor owned generation as a non-regulated activity. We have also finalized code amendments that relax certain restrictions on how distributors can deal with generation affiliates, and create an obligation of equal treatment of a distributor's own facilities with that of third parties wishing to connect to the distributor's system. The Board's view is that a level playing field for all generators and generation proponents is consistent with the requirement to provide non-discriminatory access, will ensure the timely connection of all generation facilities, and will support the Board's new objective of promoting the connection of renewable generation.

Finally, the fifth category of our work relates to encouraging rational planning and investment. Network expansion is critical to sustaining investment in the green economy, and this means that the utilities are going to have to plan their investments even more thoroughly and carefully. The distribution planning guidelines issued last year allowed distributors to start by setting up deferral accounts for booking expenditures and a rate adder for additional funding. We also set out some guidelines as to what we expected to see in a distribution system plan. Just last week, we completed this phase of our work on distribution planning by issuing filing requirements for distribution system plans.

All this activity is occurring, yet we continue to have some transitional issues that have their origin in the pre-commercialization era of the sector, over 10 years ago. For example, we are continuing to delineate the demarcation point of the distribution system and to align it with the functional business lines that were established with restructuring. This was evident in the Board's recent Decision relating to Toronto Hydro's street lighting application.

My remarks thus far have focused on the green energy environment, highlighted some of the goals of the distribution community, and what we have done to meet the challenge of a new policy environment. Before I conclude my remarks however, I would like to share some of my thoughts on future directions which you might wish to consider as we organize the wires business for the 21st century.

First is the concept of regional planning and the issue of cost responsibility for regional planning. Regional planning was performed by utilities prior to commercialization, but is no longer generally being done. Are municipal boundaries the most economically efficient point for planning purposes or for allocating costs for system upgrades or system planning?

We have already established the ground rules to transition the distribution system into a low voltage transmission system that can accommodate green energy. We also need to integrate functional components like smart grid, reliability, changes in load, non-renewable generation, and conservation and demand management into the planning process to drive efficient outcomes. What would regional planning to accommodate these other imperatives look like? If we were to transition to a regional planning approach, would a regional, postage stamp distribution rate naturally evolve from it? Would regional planning produce further economic efficiency in the sector while achieving the policy objectives of government? Similarly, will regional shared services models and other approaches that have the potential of increasing the distributor's capability to fulfill its expanded role also evolve? For example, like Electricity Distributors Finance Corporation (EDFIN), that enables distributor access to debt capital markets and applying them over a regional planning area.

What is clear to me is that we need to think hard about whether we are doing things in the best way. The cost of transforming the functionality of the distribution system will be high and the benefits of doing so cannot be underestimated.

Finally, we are also thinking about the total bill and where it is going or, as Minister Duguid referred in his speech to the Ontario Energy Association on Wednesday last week, rate affordability. In an environment where all costs are increasing, we need to think about the various regulatory approaches to address the rate affordability issue.

These approaches might then inform how we regulate in the future and should move beyond simply thinking about rate mitigation. The benefits of the transformation of the electric system will not necessarily present themselves in lock step with spending that will occur. But early spending will be an investment for the future.

So let me close by saying that there is an ever increasing focus on Ontario's electricity grid on the wires business. All of us here recognize that electrons must flow over the wires, and that any attempt to reform the energy system must include the wires. The grid is being asked to do more in the future than it has in the past. It is being asked to have the capacity to handle significant amounts of new generation. Some of the new generation resources will be in more remote parts of the Province and others will be local, so that is a further challenge. You may also be called upon to make sure that electric cars, in increasing numbers, can be recharged at night without fail.

Obviously, this transformation in the grid will be critically important to the achievement of the government's goals. Our collective responsibility is to ensure that our regulatory and business frameworks allow that to happen.

In closing, I wish to extend my thanks to you for the important and hard work you do.

Thank you.

TAB 2

Ontario Energy Board

Commission de l'énergie de l'Ontario

EB-2009-0096

IN THE MATTER OF AN APPLICATION BY

HYDRO ONE NETWORKS INC.

2010 and 2011 DISTRIBUTION RATES

DECISION WITH REASONS

April 9, 2010

TABLE OF CONTENTS

<u>Appendices</u>

EB-2009-0096

IN THE MATTER OF the *Ontario Energy Board Act 1998*, S.O.1998, c.15, (Schedule B);

AND IN THE MATTER OF an application by Hydro One Networks Inc. for an order or orders approving or fixing just and reasonable distribution rates and other charges for 2010 and 2011.

BEFORE: Pamela Nowina
Presiding Member

Cynthia Chaplin
Vice Chair

Paul Sommerville
Member

DECISION WITH REASONS

April 9, 2010

3. OPERATIONS, MAINTENANCE AND ADMINISTRATION COSTS

The table below summarizes the Operations, Maintenance and Administration ("OM&A") costs proposed by Hydro One for the two test years and includes the percentage change from the prior year. The OM&A level approved in the last cost of service rate application for 2008 rates was $466 million. The 2010 test year amount requested by Hydro One is 20.2% higher than the approved 2008 level. Hydro One identified three key drivers for the increased spending: vegetation management, PCB regulations, and work related to the Green Energy Plan. The direct costs of the Green Energy Plan are not included in the table and are addressed separately in this decision. The table does include the indirect costs related to the Green Energy Plan, which Hydro One estimated to be $10 to $15 million.

OM&A Expenditures, 2008 – 2011
($ million, including % variance from prior year)

Category	2008 Actual	2009 Bridge	2010 Test	2011 Test
Sustaining	**284.5** 4.4%	**296.4** 4.2%	**318.5** 7.5%	**340.5** 6.9%
Development	**8.0** 90.4%	**14.5** 81.2%	**21.7** 49.6%	**21.9** 0.9%
Operations	**12.4** -0.2%	**12.5** 0.8%	**16.7** 33.6%	**17.6** 5.4%
Customer Care	**99.3** 2.3%	**106.7** 7.4%	**106.3** -0.4%	**102.4** -3.7%
Shared Services & Other	**62.9** -31.5%	**92.4** 46.9%	**92.1** -0.3%	**88.1** -4.3%
Tax other than Income Tax	**4.3**	**4.6**	**4.7**	**4.8**
Total	**471.3** -3.1%	**527.1** 11.8%	**560.0** 6.2%	**575.2** 2.7%

Hydro One maintained that year-over-year comparisons of OM&A costs should include the 2009 bridge year, because that was an Incentive Rate Mechanism ("IRM") rate adjustment year and any cost increases above the adjustment level were borne by the company. Hydro One submitted that many OM&A cost increases took place in 2009 and that this is evidence of the company's commitment to, and the necessity for, these programs.

Hydro One stressed the importance of the vegetation management program and explained the need to move to a shorter cycle to reduce unit costs and outages. It highlighted increased spending from $118 million in 2008 to $136 million in 2009, as an example of a bridge year increase that showed Hydro One's commitment to that program. Hydro One also highlighted lines and maintenance programs which are not discretionary and are a response to higher regulatory standards, principally for PCB regulations.

The following areas were addressed in the submissions:

- Overall OM&A Spending
- Compensation
- Vegetation Management

3.1 OVERALL OM&A SPENDING

PWU supported the proposed level of expenditures and cited the twin requirements of new government-mandated initiatives and the need to maintain an aging system. In PWU's view, reducing costs now would lead inevitably to even higher costs in the future.

Board staff and intervenors identified a number of factors which in their view showed that the OM&A cost increases are excessive: lower inflation and cost escalation factors; trend analysis; benchmark results; and specific spending items.

Board staff and most intervenors noted that updated evidence indicated lower overall inflation and lower distribution cost escalation than in the original application. VECC submitted that based on these updates OM&A is overstated by at least $9.4 million in 2010 and $7.0 million in 2011.

CME submitted that Hydro One's budget should be assessed through three trends or "indicators of reasonableness": total OM&A spending; OM&A cost per customer; and OM&A costs per circuit km. CME noted that OM&A costs have increased by 18.8% between 2008 and 2010 and by 44% between from 2006 and 2011. CME pointed to the

Board's decision in Hydro One's prior distribution rates case which specifically mentioned that past spending is a useful guide in assessing spending proposals. CME noted that OM&A cost per customer has grown by 16% between 2008 and 2010 and by 37% between 2006 and 2011, and that OM&A cost per circuit km has grown by 16% between 2008 and 2010 and by 35% between 2006 and 2011.

Hydro One agreed that historical spending levels are useful information for the Board but submitted that basing future expenditures only on historical norms ignores the reasons and evidence behind the changes. Hydro One argued that it had filed extensive evidence justifying the proposed spending increases and that arbitrary reductions without reference to the evidence should be rejected. With respect to the cost per customer and cost per circuit km trends, Hydro One responded that these measures were not meaningful because the cost increases are due to increased workload, not customer or wire additions. Hydro One cited the PCB regulations and increasing vegetation management spending as independent of either the customer numbers or circuit kilometres.

Board staff and intervenors also pointed to various benchmark results. Board staff submitted that the benchmarking results show that Hydro One has the highest distribution substation O&M expense per installed MVA, and was ranked in the middle-of-the-pack for substation O&M expense per asset. SEC also pointed to benchmarking results which show that Hydro One's OM&A cost per customer in 2010 is $459.50, which is more than double that of many large and complex Ontario utilities. In CCC's view, Hydro One has demonstrated very little in terms of productivity gains because work programs are increasing by 33% and total head is increasing by 37%.

Intervenors were also concerned that Hydro One was not exercising sufficient control over spending increases. SEC acknowledged some key cost drivers, such as PCB regulations, vegetation management needs and the Green Energy Plan spending, but submitted that when customers are being asked to absorb significant cost increases as a result of such key cost drivers, keeping cost increases in other areas to approximately the rate of inflation is a reasonable cost containment measure. SEC submitted that "...companies in a competitive environment facing key cost drivers in certain areas would work to ensure that other areas of spending are either held constant or held to minimal year over increases. Hydro One has done none of that."[3]

[3] SEC Final Argument, p. 17

CCC argued that in light of the pressure related to the Green Energy Plan and related projects, more discretionary projects should have been deferred or scaled back. CCC argued, for example, that the $3 million in 2010 and $4 million in 2011 associated with the head office and GTA space requirements should be viewed as discretionary and should be deferred.

CCC and CME both submitted that Hydro One should be held to a 3% inflationary increase relative to the 2008 Board approved level. CCC estimated this would result in a reduction of about $66 million in each of the test years. SEC recommended an overall OM&A reduction of $18.1 million in 2010.

Board staff recommended a reduction of $33 million in the overall OM&A budget for 2010. The reduction was defined as the half-way point between a 3% inflation scenario and the original OM&A budget. Board staff submitted it was inappropriate to micro-manage Hydro One's activities and recommended that Hydro One should reduce OM&A costs in areas it determines most appropriate. CME agreed with this approach.

Hydro One disagreed with the proposals by Board staff and intervenors to cut OM&A costs based on envelope or index-linked reductions. Hydro One maintained that there was no meaningful criticism or analysis of the underlying causes of the proposed increases and reiterated that the shareholder has borne significant cost increases during the IRM period as a result of the increased work programs, thereby demonstrating that the increased work is necessary. Hydro One maintained that if OM&A is reduced, less work will be accomplished and the performance of the distribution system will be affected.

BOARD FINDINGS

The Board finds that Hydro One's OM&A budget is excessive. Inflation and cost escalation factors are now lower than originally forecast and therefore the budgets are now over-stated on that measure. Second, and more importantly, the various trend measures demonstrate that Hydro One has had limited success in controlling expenditure increases. The Board agrees with Hydro One that these various trends are imperfect measures of reasonableness, but the measures are indicators. Hydro One emphasized that the expenditure increases are not driven by customer numbers or expansion in the circuit kilometres, but by increased workload particularly in the areas of vegetation management, PCB management, and Green Energy Plan related work.

However, if significant incremental work is required in particular areas, then it is the responsibility of the company to manage that in a way that ensures that growth in cost per customer is kept within reasonable levels to ensure ongoing customer affordability. The Board concludes that Hydro One has not been sufficiently successful in controlling the overall growth in spending. The benchmarking results also support the conclusion that Hydro One could and should do better in managing its growth in spending.

In the past, the Board has used different techniques to determine the allowed OM&A. In some cases a detailed line by line examination has resulted in an equally detailed funding prescription from the Board. In other cases the Board has provided the applicant with an overall envelope of funding. In such cases the Board does not stipulate an approved amount of spending for any particular category of spending, but rather leaves to the applicant the freedom to apply that spending according to its own prioritization.

In the Board's view, given Hydro One's capabilities and its complexity, it would not be appropriate to micromanage the utility's operations through a line by line authorization of spending; rather the Board should set an overall envelope and leave the specific allocation of the available funds to Hydro One's judgment and prioritization. In the following two sections of this decision, the Board will provide its observations and findings with respect to compensation and vegetation management. The company should take the Board's guidance on these subjects into account in arriving at its prioritization.

In arriving at the quantum of the envelope approved for OM&A the Board has taken a number of factors into account:

First is the totality of the evidence developed throughout the case. Through the detailed examination which takes place the Board achieves an understanding of the key drivers of utility operations and cost structures. This process also gives the Board the opportunity to assess the overall implications of the company's rate proposals for its customers and includes the opportunity for a variety of interests to express their particular concerns respecting the applicant's rate proposal and operational plans. This is a key element in arriving at a balanced and fair rate decision. The Board's consideration of the specific elements of the application as developed in the evidentiary portion is reflected in our observations and findings under compensation and vegetation management.

Second, the Board has considered the recent rate history of the distribution business. Over the last number of years Hydro One has applied for and received significant increases in the delivery portion of its electricity rates. Since 2004, Hydro One's delivery rates have increased significantly. Between 2004 and 2009 rates for the R1 Class have increased about 28%, whereas inflation has run at about 9%. The increase between 2007 and 2009 has also significantly outpaced inflation. As a result, Hydro One's revenues have exceeded inflation materially. That is not to say that the previous rate decisions have been inordinately generous. Over this period the company has been able to demonstrate a need to improve its customer information systems, maintain its physical plant, and generally manage its operations according to the revenue requirements approved. But the fact remains that customers have experienced increases in the delivery portion of their rates over this period that have significantly outstripped the general inflationary pressure within the economy.

Third, some of these rate increases combined with a recognized need to rationalize and harmonize the rate classes associated with acquired utilities have led to very significant increases in delivery charges for some customers. These increases have been of such a nature that they have been subject to rate mitigation measures, which are continuing.

Fourth, the Board must take into account the overall increase and prospect of further increases in the commodity portion of the bill. While these charges are outside of the control of the applicant, they are no less real for customers. In giving effect to the Board's objective to protect the interests of consumers the Board cannot ignore the overall impacts on customers.

The evidence also reveals another factor that has implications in determining the appropriate quantum of the conventional operations funding envelope. The Province, as part of a global phenomenon, has experienced a significant contraction in economic activity. The resulting demand reductions have two important implications. First, to the extent businesses have curtailed electricity demand or ceased operations, the per unit cost to be covered in delivery charges by the remaining customers will increase. This has an inherently inflationary effect on delivery charges. Second, both companies and individuals are experiencing material challenges in carrying added costs for the delivery of electricity.

Hydro One has maintained that the increases in 2009 borne by the shareholder demonstrate that the expenditures are necessary. In the Board's view, if a company spends more than the amount embedded in rates (whether for a test year or an IRM year), it is not determinative of whether the amounts are reasonable and prudent; nor does it establish the appropriate base for future levels. Management and shareholders make expenditure decisions for a variety of reasons, and the Board must still determine whether the test year forecasts are appropriate in light of all the evidence. Considering all the factors identified above, and in particular the conclusion that Hydro One has not sufficiently controlled its growth in spending, the Board finds that the appropriate quantum of the envelope to accommodate conventional operations should be derived from the year which was most recently examined and approved by the Board. In 2008, the approved level of expenditure was $466 million and the actual level of expenditure was $471 million. These figures are sufficiently close that the Board will derive the allowed level for 2010 and 2011 using the 2008 actual level.

To this initial 2008 level, the Board will apply an annual increase of 5% to derive an allowed OM&A for 2010 of $520 million. For 2011 the Board will apply an increase factor of 3% for an allowed OM&A of $535 million. The escalation factor for 2010 is higher than the rate of inflation. The Board adopts this approach in recognition that the company has statutory obligations, other than those associated with the *Green Energy and Green Economy Act, 2009* (GEA), which it must meet, and the fact that it is preparing itself for an operating environment that is turbulent and to some extent unknown. The escalation factor for 2011 is lower, although still higher than forecast inflation, to reflect that Hydro One itself proposed an even lower level of increase between 2010 and 2011. The Board notes that the approved spending levels are well in excess of the Minimum Level of spending (as explained in the capital expenditure section of this decision) of $476 million for 2010 and $483 million for 2011.

The Board recognizes that accommodating these levels of spending, which are significantly less than that applied for, will require the company to engage in a thoughtful reconsideration of its spending priorities. The Board concludes, however, that given the overall pressures operating within this environment, which are highlighted above, this is the right time for such a recalibration.

3.2 COMPENSATION

Hydro One's total compensation (for the distribution and transmission businesses) is forecast to grow from $566 million in 2008 to $849 million in 2010 and to $934 million by 2011. Headcount is forecast to increase from 6,547 in 2008 to 9,552 in 2010 and to 10,245 in 2011. Hydro One referred to the Mercer/Oliver Wyman Compensation Cost

Benchmarking study ("the Mercer study") filed in the last transmission case (EB-2008-0272). The Mercer study concluded that on a weighted average basis for the positions reviewed, Hydro One's compensation was approximately 17% above the market median. In the transmission proceeding, the Board disallowed $4 million in compensation costs. Hydro One estimated that the comparable reduction for the distribution business would be $9 million.

Hydro One noted that the Mercer study results were largely driven by the PWU represented employees. Hydro One submitted that because it is currently under a labour contract with the PWU it was not practical to expect it to negotiate a reduction in absolute wage levels and benefits through the collective bargaining process, at least not without a work stoppage. Hydro One maintained that it has demonstrated it is attempting to control labour costs while at the same time making a concerted effort to improve efficiency in the utilization of its labour resources.

Hydro One filed evidence comparing wages in 1999 and 2009 for the Ontario Hydro successor companies: Hydro One, Bruce Power and OPG. Hydro One also included the IESO in the comparisons showing the Society positions. Hydro One claimed that this comparative information demonstrated that it did have success in reducing compensation costs between 1999 and 2009 compared to the other companies.

Intervenors representing Hydro One's unionized staff supported the company's position. The Society cited the competitive pressures in attracting and retaining skilled staff, the efficiency benefits of a healthy collective bargaining relationship, and Hydro One's prudent use of internal staff and contractors. PWU submitted that the conclusions of the Board in the transmission case should not be applied in this case because the decision was flawed. PWU also highlighted the demographic challenges faced by Hydro One, the challenges faced by others in the industry, the increased volume of work, and the shortage of skilled labour. PWU maintained that the evidence showed that Hydro One has achieved smaller increases than other comparable companies and that Hydro One is maintaining wage escalation at competitive levels.

Board staff and intervenors representing ratepayers all argued that the compensation levels were excessive. Board staff, CCC, SEC and VECC each argued that the transmission decision remained applicable and that the compensation costs should be reduced by $9 million as a result. CCC and VECC took the position that Hydro One had not provided any significant new evidence which would justify a departure from the Board's decision in the transmission application. CME submitted that the Board should reduce compensation costs by at least $9 million but also indicated that the Board would be justified in reducing compensation by up to $29 million, CME's estimate of the impact of bringing costs to the market median determined in the Mercer study.

Board staff submitted that the tables that compare Hydro One to its related Ontario Hydro successor companies appeared to show that it has made some progress in controlling wages, but do not refute the conclusions made by the Board in the transmission case. Board staff maintained that the argument that high wages are required for attracting highly skilled staff does not explain why non-skilled wages were shown to be substantially higher as well. Board staff argued that more progress was required in those areas.

Energy Probe made similar submissions but rather than adopting the $9 million impact identified by Hydro One, Energy Probe estimated that the appropriate comparable reduction would be $16.5 million. Energy Probe also argued there should be two additional adjustments: a further 10% reduction for overtime on the basis that overtime represents about 10% of the total budget; and a reduction of $12 million in capitalized labour costs.

Energy Probe noted that the Management Compensation Plan (MCP) wage increases are in excess of inflation for 2006 to 2009 and submitted that the Board should set a zero percentage increase for MCP staff in 2010 and 2011. In Energy Probe's view, increases for MCP staff are not warranted in an economic slowdown and the evidence showed that turnover rates were not unusually high. Energy Probe estimated these reductions would reduce the compensation budget by $1.35 million in 2010 and $1.39 million in 2011.

A number of intervenors also took issue with the overall staffing level and the rate of increase. Board staff pointed out that staffing has continued to grow every year since 2006, that attrition is not a problem (besides retirements, very few employees leave of their own accord) and that witnesses acknowledged that hiring qualified workers is generally not an issue except for a few specific areas.

VECC submitted that the staff increase of 37% relative to the work program increase of 33% did not show any increases in productivity. SEC also noted the 47% increase in Head Office/GTA headcount between 2008 and 2011, and compared that with the increase in customer numbers of only 4%. SEC recommended that the Board deny increases in headcount that exceed the increases in customer count. Energy Probe questioned whether the staff increases were even achievable.

Hydro One maintained that in this proceeding it had attempted to provide additional and more meaningful evidence to demonstrate its bargaining achievements. Hydro One noted that in response to the Mercer study it had provided additional evidence comparing Hydro One to a more appropriate and relevant peer group: its successor companies, Bruce Power and OPG. Hydro One maintained that these are Hydro One's main competitors for labour resources and that Hydro One has achieved more success in controlling wage increases across virtually all wage classifications. In Hydro One's view, these achievements should be considered rather than simply focusing on current wage and benefit levels.

Hydro One acknowledged that it fully understands the Board's message in the earlier transmission decision but maintained that little can be done to address the issue in the short term because collective bargaining agreements are in place until 2011 for PWU and 2013 for the Society. Hydro One assured the Board that it would continue with its best efforts to address the Board's concerns through the means available to it.

BOARD FINDINGS

In the last transmission decision the Board stated:

> "The Board concludes that it is appropriate to disallow some compensation costs because these costs are substantially above those of other comparable companies and the company has failed to demonstrate that productivity levels offset this situation."[4]

The Board also stated:

> "Hydro One's evidence is that the revenue requirement would be $13 million less if it were based on the median compensation level from the Mercer Study...The Board has already indicated that while the full level of compensation has not been justified, Hydro One has made strides in controlling these costs. The Board will disallow $4 million in each of the test years; this level of adjustment goes some

[4] EB-2008-0272 Decision with Reasons, May 28, 2008, p. 30

> way toward aligning Hydro One's costs with other comparable companies."[5]

The Board concludes that a comparable reduction is warranted for the distribution business. Hydro One has shown (for the categories presented) that it has controlled wage escalation better than some of the other Ontario Hydro successor companies. However, compensation costs remain excessive in comparison to market indicators. The evidence indicates that Hydro One's main competition for labour comes from within Ontario and the Board regulates most of those other entities. It would be unacceptable for the Board to, in effect, fuel that wage competition by incorporating ever rising wage levels (over and above market related levels) into rates. Hydro One has indicated that a reduction of $9 million would be comparable to the Board's finding in the transmission decision. The Board has already established an overall OM&A envelope and will not order this as a specific reduction. However, the Board would observe that compensation costs, including growth in headcount, are one of the areas in which Hydro One must take further action to control expenditure increases.

3.3 VEGETATION MANAGEMENT

Hydro One's vegetation management program manages clearances to energized equipment to maintain reliability, manage safety hazards posed by trees, manage plant species to permit maintenance and restoration of power, and minimize environmental, ecological and social impacts. Vegetation management accounts for about 40% of the Sustaining budget in 2010. In 2008, actual spending was $118 million, increasing to $136 million in 2009, dropping slightly to $133 million in 2010 and growing to $145 million in 2011.

Hydro One's evidence indicated that the 2010 and 2011 spending requirements are based on continuing to reduce the vegetation management cycle so that a 7-year cycle can begin in 2011. Line clearing accomplishments in 2007 and 2008 were performed at about an 8-year cycle. Hydro One's evidence was that a reduction to a 7-year cycle would require a 14% increase in expenditures in 2010 and a 24% increase in 2011 in comparison to the 2007 and 2008 period.

PWU supported the proposal and submitted that the increased spending is required, will improve Hydro One's performance, and will control costs in the long-term.

[5] EB-2008-0272 Decision with Reasons, May 28, 2008, p. 31

AMPCO, VECC, CME, and SEC all argued that the vegetation management costs should be reduced by maintaining an 8-year cycle rather than moving to a 7-year cycle. Two primary reasons were cited: the need to control spending at this time and a lack of strong evidence supporting the benefits of moving to a 7-year cycle. Intervenors were also of the view that the activity was not being conducted as efficiently as possible.

AMPCO submitted that the evidence does not show improved reliability even though there have been increases in vegetation management spending since 2006. AMPCO accepted that there may be some benefits from moving to a 7-year cycle, but submitted that Hydro One had not provided sufficient evidence to support a decision to move beyond an 8-year cycle at this time. AMPCO urged the Board to direct Hydro One to continue on the 8-year cycle and provide evidence in its next application as to whether its projections of improved service quality are being realized. SEC also recommended staying with the 8-year cycle until evidence is provided that a shorter cycle is warranted and the benefits to ratepayers are determined.

VECC submitted that Hydro One is focusing too much on labour hours and not enough on overall cost efficiency and that an overall cost efficiency focus could lead to achieving more than an 8-year cycle for the same level of expenditure. In AMPCO's view, the Vegetation Management Study shows that the actual per unit cost for Hydro One to treat a tree was more than double that of other utilities. AMPCO submitted that the Board should direct Hydro One to undertake a study to determine whether it is prudent and cost effective to continue to execute their vegetation management program in-house.

Hydro One responded that its evidence, including the Vegetation Management Study, supported the move to a 7-year cycle. Hydro One maintained that the benefits of a shorter cycle do not seem to be in doubt and that reducing these costs in the short term would lead to increased costs in the longer term.

BOARD FINDINGS

The Board concludes that this is an area where spending deferrals or reductions may well be warranted. The analysis suggests that there are net benefits from moving to a 7-year cycle. However, the actual benefits of moving to an 8-year cycle have yet to be demonstrated on Hydro One's system. The Board understands the lag involved between increased spending levels for vegetation management and reduced future expenditures on trouble calls, but it would be appropriate to perform some analysis of actual results at the 8-year cycle before embarking on the significant expense associated with moving to the 7-year cycle.

The evidence also suggests that Hydro One's efficiency level for this activity could be enhanced whatever the cycle length. The significant expenditures associated with moving to the 7-year cycle should be supported by a thorough demonstration that Hydro One has investigated all potential efficiency improvements for this work, for example, greater outsourcing.

The evidence indicates that if Hydro One were to maintain spending at the 8-year cycle level, OM&A could be reduced by about $17 million in 2010 and $28 million in 2011. The Board has already established an overall OM&A envelope and will not order a specific incremental reduction for this item. However, vegetation management is one of the areas where expenditure reductions should be achievable.

TAB 3

Ontario

Cynthia Chaplin
Vice-Chair
Ontario Energy Board

8th Ontario Power Summit
St. Andrew's Club and Conference Centre
Toronto, Ontario

May 6, 2010

Check against delivery

First, I would like to thank the organizers for inviting me to speak to you today. An event such as this gives me the opportunity to talk about what we are doing at the Ontario Energy Board, but it also gives me an opportunity to get "out in the field" so to speak, to get feedback from industry participants and to hear directly from leaders in the area.

You have heard from Ben Chin about the work of the Ontario Power Authority (OPA) in implementing the GEA. I will describe the work of the Board in these same areas. I am going to cover four topics: the Board's role; the distribution system; the transmission system; and the impact on consumers.

I hope to demonstrate that the Board has a distinct role in the implementation of the GEA and that we are coordinating our work with the other agencies and ensuring the issues are addressed in a principled way.

First I will provide some context by describing the Board's role.

The Board's Role

Many of you, perhaps all of you, will be familiar with the role of the Board in setting rates for transmission and distribution, deciding applications for transmission projects, and establishing codes which govern conduct.

We do this work in accordance with a set of objectives which are set out in our legislation. We have two ways of doing this work: through consultation and through adjudication. In both approaches, the process is transparent and the conclusions are principled.

This ensures that the public interest is served in accordance with fundamental legal principles governing administrative tribunals. The disciplined framework and the transparent and principled approach also ensure that regulation continues to provide a sense of order and stability, which is important for investor and public confidence.

Within this disciplined legal framework we must continue to be flexible and adaptive in our approach: markets evolve and policies change. There is always room for innovation in regulation. We are open to new ideas and new ways of doing our work; we are developing new relationships and creating new opportunities for dialogue and facilitation.

The GEA will bring forward a new generation mix – and with it changes in the geography and operations of the electricity network.

The Board has gone about implementing the GEA in a manner that meets the public interest by remaining true to our core principles: a long-term approach to issues; a transparent, open and inclusive process; timely, clear and decisive outcomes; and a focus on practical, workable solutions.

I will now provide you with some of the detail about the work we have done in implementing the GEA on the distribution side of the sector.

The Distribution System
The Board has ensured that our regulatory instruments reflect the changes in our governing legislation and are well-aligned with the values in the GEA. Many of these initiatives are now complete and can be divided into five broad categories.

First, we made the connection process for generators more rational and efficient. It is now easier for generators up to 500 kilowatts to connect to their local distribution system because they are exempt from getting a specific capacity allocation. For larger generators, we established incentives to ensure that those with capacity allocations move forward with their projects or risk having their capacity allocation removed. And we introduced a new simplified generation licence for Feed-in Tariff (FIT) generators that will reduce the amount of time and paperwork required and avoids duplication with the OPA's processes.

Second, we standardized the billing and settlement processes for FIT and microFIT generators. There is now a single way of setting up generator accounts and settling them, whether they are connected in front of or behind the meter. We have also implemented a province-wide monthly service charge that will apply to all microFIT generator accounts.

Third, we changed how costs are allocated for renewable connections. The Board recognized that the FIT program was likely to lead to generators connecting to distribution systems and that additional distribution system investment would be required. The Board determined it would be appropriate for certain of the investment costs to be recovered from end use customers and not from individual generators. The government also recognized this and the Board has been tasked to ensure that the cost burden of these additional investments is shared equitably among distribution connected ratepayers across the Province. Any local benefits will be paid for by local ratepayers. We are coming to the end of our consultation to determine the nature and quantification of those local benefits.

Fourth, the Board's guidelines now lay out the appropriate regulatory and accounting treatment for distributor-owned generation as a non rate-regulated activity. Recent code amendments relax certain restrictions on how distributors deal with their generation affiliates. The amendments also create an obligation of equal treatment between a distributor's own facilities and those of third parties wishing to connect to the distributor's system. This approach is aligned with the Board's view that a level playing field for generators and generation proponents is consistent with the requirement to provide non-discriminatory access, will ensure the timely connection of generation facilities, and will support the Board's objective of promoting the connection of renewable generation.

The fifth category of work relates to encouraging rational planning and investment. Network expansion is necessary to sustaining investment in the green economy, and this means that network owners are going to be planning their investments. The Board issued distribution planning guidelines last year to allow distributors to get going and set up deferral accounts for booking expenditures, and a rate adder for additional funding. We also set out guidelines as to what we expected to see in a distribution system plan. Last month we completed this phase of our work on distribution planning by issuing filing requirements for distribution system plans. The Board recently issued its decision on Hydro One's Green Energy Plan, the first plan to be considered by the Board.

The other aspect of network planning and expansion is transmission – it is the next issue which must be tackled if the objectives of the GEA are to be achieved. The Board has been active in this area as well.

The Transmission System

As you know, the province is facing major infrastructure investments that will increase costs, potentially by a significant amount over a short period relative to historic patterns.

The Board recently released for comment a staff Discussion Paper on transmission project development plans. The paper sets out a proposed process to facilitate the timely and cost effective development portion of major transmission projects that may be required to connect renewable generation. Staff's work recognizes the OPA's role as transmission planner. It also anticipates that evaluative criteria such as economic efficiency, technical and financial capability, costs and project prioritization may be used by the Board in assessing project proposals and selecting proponents.

Evaluative criteria contribute to transparent, principled decision-making and to regulatory predictability. The development of evaluative criteria will become an important part of the Board's approach in this area.

The Board has developed evaluative criteria in a number of areas in the past – for example the principles or tests related to a prudence determination, or the criteria which are examined in a natural gas leave to construct application. For natural gas pipeline applications, for example, the Board considers need, economics, environmental impacts, landowner matters and rate impacts. These evaluative criteria have evolved over a series of applications over many years to the point where they form a stable framework in which to assess an application.

Many of the same evaluative criteria were considered by the Board in the Bruce to Milton transmission application. I expect these criteria will be further developed when the Board considers transmission development plans and facility applications.

It is important to bear in mind the approval of actual infrastructure build and the recovery of associated costs from ratepayers is through a transparent adjudicative process. The transparent and public process frames the debate in a particular way and places certain requirements on how the process is conducted. The public discourse on infrastructure construction may well be conducted within the leave to construct hearing.

The Board has specific factors which it must apply when assessing whether an application for transmission is in the public interest. These two factors are set down in the legislation. One factor or criteria is the "interests of consumers with respect to price, reliability and quality of electricity service". This ensures that a cost benefit analysis will be part of the Board's consideration when it determines whether or not to approve a project.

The consumer interest factor used to be the only factor the Board could consider. The scope of the Board's public interest consideration has been enlarged through the GEA with the addition of a second factor which is the promotion of the use of renewable energy sources, where applicable and in a manner consistent with the policies of the Government of Ontario. This new provision will inform how leave to construct applications are considered by the Board and will influence how interested parties approach a leave to construct hearing.

One of the key evaluative criteria for transmission projects is need – in other words whether the proponent has established that there is a genuine need for the project.

Going forward, it may be that the OPA's Economic Connection Test (ECT) will be used to support a project being built to incorporate renewables. As I understand it, the ECT will be used to look at FIT applications that cannot be accommodated on the existing system and assess what transmission would be required to connect these projects. Once the transmission expansions that would be needed to accommodate FIT applicants have been identified, the OPA will assess whether these expansions are economic by measuring the cost of each project with the amount of renewable generation enabled. I understand that projects whose metrics meet the thresholds set by the OPA will pass the ECT.

If a proponent relies in whole or in part on the ECT performed by the OPA to justify the project it may well be that the components of that test (the inputs, the assumptions, the methodology) will be tested in the leave to construct proceeding. There would of course be a variety of other considerations in a leave to construct proceeding as well.

I will now turn to my final topic: the impact on customers.

Customer Impact – Costs, Prices, Rates
The GEA sets out a comprehensive approach to acquiring new renewable generation and enhancing and expanding the transmission and distribution networks. The costs of new generation and network investments will find their way into electricity prices and transmission and distribution rates.

The Board is very aware of these impacts. We set the prices for electricity for customers under the Regulated Price Plan – and those prices are designed to recover the costs of generation. As many of you may be aware, the Global Adjustment Mechanism is a growing component of the electricity price. The Board also sets the rates for distribution and transmission, and those rates are designed to recover the costs of the investments which have been approved by the Board. The Board is aware of what this means for the customers' bills – and we are also concerned with the impact on customers – what Minister Duguid has referred to as rate affordability.

In an environment where costs are increasing, the Board may develop various approaches to address rate affordability. This is another area that demonstrates the importance of evaluative criteria. For example, one outcome of an approved distribution plan is the shifting of cost responsibility from generators to customers. Under the Distribution System Code, if a renewable generation facility requires system expansion to connect, then the generator is responsible for any costs which exceed $90,000 per megawatt. However, if an expansion is included in a distribution plan – and the plan is approved – then the generator will not bear any of the costs of expansion. In determining whether to approve a distribution system plan, the Board may consider how much more than $90,000 per megawatt is justifiable in terms of customer impacts; how certain is the need for the expansion; are there trade offs between these two considerations?

I think the Board may also consider other aspects of its regulatory mandate – for example the core distribution and transmission businesses – and Ontario Power Generation's payment levels – to determine whether there can be further innovations to drive efficiencies for the benefit of customers.

The Board has also recently received the Directive related to conservation and demand management (CDM) targets for distributors. CDM programs have the potential to help customers control their costs and bills. The Board is in the process of developing its CDM Code and that will be issued shortly for comment.

Consumers are becoming more interested and more engaged in these issues. We saw this in the Letters of Comment received during the Hydro One Distribution proceeding. There continues to be important work to be done in the area of customer education. Over time policy and regulation has an inherent tendency to become more complex. The GEA is driving changes within the core of our electricity system and addressing the resulting issues brings forth even greater complexity. This presents a challenge because complexity reduces accessibility. The Board therefore has a growing job to ensure that its work remains accessible and understandable to customers. This is necessary because the Board's credibility and legitimacy is predicated on its accessibility.

In conclusion, the Board has been successful to date in implementing the GEA, but there are important issues still be to be addressed if the benefits of the GEA are to be achieved and the public interest is served.

Thank you.

TAB 4

BORDEN
LADNER
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By electronic filing and by e-mail

August 26, 2010

Kirsten Walli
Board Secretary
Ontario Energy Board
P.O. Box 2319
27th floor
2300 Yonge Street
Toronto, ON M4P 1E4

Dear Ms Walli,

Hydro One Networks Inc. ("Hydro One")
2011-2012 Transmission Rates
Board File No.: EB-2010-0002
Our File No.: 339583-000057

Please find attached the evidence of Bruce Sharp from Aegent Energy Advisors Inc. ("Aegent"), which is being filed on behalf of Canadian Manufacturers & Exporters ("CME").

Yours very truly,

Vincent J. DeRose

VJD\slc
enclosures
c. Anne-Marie Reilly (Hydro One)
EB-2010-0002 Intervenors
Paul Clipsham

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Aegent
ENERGY ADVISORS INC.

Ontario Electricity Total Bill Impact Analysis
August 2011 to July 2015

About Aegent Energy Advisors

Aegent Energy Advisors Inc. ("Aegent") is a consulting company providing independent, objective advice to large energy buyers on all aspects of their electricity and natural gas procurement. Aegent specializes in helping buyers to reduce commodity cost, manage commodity price risk, and optimize utility contracts.

More on Aegent can be found at www.aegent.ca.

Background

With all of the changes the Ontario electricity industry is undergoing, it is clear there will be future cost increases and resulting customer impacts. Related to the Ontario Energy Board ("OEB") process for considering Hydro One's application for transmission rate increases for 2011 and 2012 (EB-2010-0002), Canadian Manufacturers and Exporters ("CME") commissioned Aegent to develop a total bill impact analysis of increases over the next five years. CME takes the position that the total bill impact of any specific utility rate application the OEB considers cannot be evaluated by simply considering utility-specific changes to line items in the electricity bill and holding everything else constant. Rather, there is a need to consider the total bill impact of what a particular utility is proposing in conjunction with everything else in the electricity bill that is simultaneously changing.

CME asked Aegent to provide this analysis because Aegent has experience in estimating total bill impacts of this nature. An example of this type of analysis was released by Aegent in March 2010 in a report. A copy of this is attached at Tab A.

This document provides a discussion of the method Aegent has applied and the results of the analysis. These materials have been prepared by Mr. Bruce Sharp of Aegent. Mr. Sharp, whose curriculum vitae is attached at Tab B, will testify to support this analysis.

The information upon which this analysis is based includes information published by the Ontario Power Authority ("OPA"), the Independent Electricity System Operator ("IESO"), Ontario electricity distributors, and rate case filings with the OEB made by Hydro One Networks Inc. ("Hydro One") and Ontario Power Generation Inc. ("OPG"). Almost all of these entities, except some of the electricity distributors, are owned by the Government of Ontario, and all are entities over which the OEB exercises regulatory authority.

Aegent does not have access to the five (5) year Business Plans of these entities. Accordingly, where necessary, this analysis provides Aegent's estimates, based on assumptions that it considers to be reasonable and conservative, of the electricity price implications of the five (5) year Business Plans of these entities that will have an influence on elements of the electricity bill. Aegent readily acknowledges that entities such as the OEB or the Ministry of Energy and Infrastructure ("MEI" or the Ministry of Energy), with an ability to access the five (5) year Business Plans of the OPA, IESO, Hydro One, OPG and other transmitters and distributors the OEB regulates, are in a position to provide any information that is needed to better align Aegent's estimates with the contents of those five (5) year Business Plans.

It is possible that the OEB and/or the MEI have already prepared total bill impact reports of the type presented in this analysis. If they are conducting total bill impact studies, then the results of those studies or reports should be made public. They are urgently needed by manufacturers and other consumers for business planning purposes.

Time Period Covered

This analysis assumes that there will be no lag in the bill impact of utility cost increases for a particular year for which the OEB sets prospective test period rates. Cost increases derived from information on file with the OEB are assumed to have an effect on the bill in each particular year for which those costs are either forecast or estimated to be incurred. For other cost increases, including those linked to procurements by the OPA, the analysis assumes that there will be a lag between the contracting commitments made by the OPA and the total bill impact of those procurement arrangements. The analysis assumes that commitments made between August of one year and July of the ensuing year will affect electricity bills in that ensuing year, so that costs reflected in OPA publications pertaining to the period August 2010 to July 2011 will be reflected in the analysis for the year 2011. Procurement commitments made by the OPA in the period between August 2011 and July 2012 will be reflected in the analysis for the year 2012. The same method is applied to estimate cost increases for 2013, 2014, and for early 2015.

Cost Increase Elements

The following cost increase elements, shown with the residential bill areas they fall under, were evaluated:

cost increase element	bill area	table
Feed-In-Tariff (FIT)	Electricity (Provincial Benefit)	1a, 1b, 1c
Renewable Energy Standard Offer Program (RESOP)	Electricity (Provincial Benefit)	2
Renewables (other)	Electricity (Provincial Benefit)	3
Bruce Power (existing)	Electricity (Provincial Benefit)	4
Bruce Power (new)	Electricity (Provincial Benefit)	5
OPG	Electricity (Provincial Benefit)	6
Natural Gas	Electricity (Provincial Benefit)	7
Non-Utility Generators (NUGs)	Electricity (Provincial Benefit)	8
Conservation and Demand Management (CDM)	Electricity (Provincial Benefit)	9
Transmission	Delivery or Regulatory	10a, 10b, 10c
Distribution (non-Green Energy Act)	Delivery	11
Distribution (Green Energy Act)	Delivery or Regulatory	12

Excluded Cost Increase Elements - Already in Effect

The following cost increase elements have already come into effect for residential consumers:

a) Two-tier RPP rate increase – This increase came into effect May 1, 2010. For consumers using 800 kWh per month, this increase amounted to $ 7.10/MWh (12 month impact).
b) TOU RPP increase – This has affected some residential consumers, with most to follow. The cost increase is in the order of $ 4/MWh.
c) Special Purpose Charge – Effective May 1, 2010 many or most local distribution companies began collecting this from customers. The rate/increase is $ 0.38/MWh.
d) HST – Introduction of the Harmonized Sales Tax on July 1, 2010 resulted in the sales tax on electricity increasing from 5 % to 13 % -- a residential bill impact. The additional 8 % adds about $ 9/MWh to an approximate, previous GST-exclusive residential unit rate of about $ 115/MWh.

The total of items a) to c) is about $ 11.50/MWh (no HST) or $ 13/MWh with HST. In combination with item d), the total bill impact of the items already in effect is about $ 22/MWh. This is an increase of about 18% from a previous GST- inclusive unit price of about $ 120/MWh. Increases included in this analysis are additive, though there is some overlap with these excluded items (in the order of $ 3/MWh).

Excluded Cost Increase Elements - Other

The following elements were not included in the analysis as they have non-uniform and/or uncertain impacts:

a) Industrial "time-of use" rates – This concerns the reallocation of Global Adjustment / Provincial Benefit costs, from a postage-stamp basis to one determined by coincident peak demands.
b) Coincident peak allocation of future transmission costs – Similar to the Global Adjustment/Provincial Benefit reallocation noted above, the same could occur with transmission. Even with transmission rates rising rapidly, there are less total dollars involved and so if this occurs the ultimate (into 2015) increase would likely be less than $ 0.50/MWh.
c) IESO Smart Grid investment – These costs may arise in the future but as of this date the IESO has not identified any significant related costs in its most recent Business Plan (2010 - 2012).
d) Ancillary services – The integration of a huge amount of new generation will most likely lead to significant operating challenges, which in turn will result in increased ancillary services (including operating reserve and regulation service) costs.

General Methodology

The following general methodology was used in analyzing each cost increase element:

a) Calculate cost in reference time period prior to first increase period, if applicable ($ million)
b) Calculate cumulative cost in forecast periods ($ million)
c) Cumulative increase for each forecast period is value or value less reference period value ($ million)
d) Use IESO total annual energy consumption forecast (and escalated) values (TWh)
e) Calculate cumulative unit cost increase values ($/MWh)
f) Increases will manifest themselves through increases to the Global Adjustment/Provincial Benefit, transmission distribution and possibly regulatory charges.

Methodology Details

The following methodologies were used in analyzing groups of or individual cost increase elements:

<u>FIT, RESOP, Renewables (other), Bruce Power (new)</u>

- For each period, subtract reference spot price from contract price to arrive at premium over spot price in $/MWh
- Estimate MW quantities added each period
- Calculate cumulative MW quantities to end of each period
- Use capacity factors and 8,760 hours in year to arrive at cumulative MWh to the end of each period
- Cumulative $, to end of period = cumulative MWh, to end of period x $/MWh
- Cumulative increase $ = cumulative $ (all "new" so no reference required to prior to Aug10)

<u>Bruce Power (existing)</u>

- For each period, subtract reference spot price from contract price to arrive at premium over spot price in $/MWh
- Use current, uniform MW quantity in each period
- Apply capacity factors and 8,760 hours in year to arrive at cumulative MWh in each period
- Cumulative $ to end of each period = cumulative MWh x $/MWh

- Cumulative increase $, to end of each period = cumulative $, in each period less cumulative $, prior to Aug10

OPG, NUGs

- Subtract reference spot price from contract price to arrive at premium over spot price in $/MWh
- Use annual TWh quantities for each period
- Calculate premium-over-spot $ in period = $/MWh x MWh
- Increase $ to end of period = premium-over-spot $ in period less same, prior to Aug10

Natural Gas

- Estimate MW quantities added each period
- Calculate cumulative MW quantities to end of each period
- Estimate contingent support payment rates ($/MW/year)
- Cumulative $ to end of each period = cumulative MW x $/MW/year
- Cumulative increase $ = cumulative $

CDM

- Estimate expenditures in each period
- Cumulative increase $, to end of each period = cumulative $, to end of period less cumulative $, prior to Aug10

Transmission

- Determine / estimate Rates Revenue Requirement in reference and each forecast period
- Cumulative increase $, to end of each period = cumulative $, to end of period less cumulative $, prior to Aug10

Distribution (non-GEA)

- Use 2009 total Ontario LDC distribution revenue (OEB's 2009 Yearbook of Electricity Distributors)
- Estimate annual increase percentages
- Calculate increased annual revenues
- Cumulative increase $, to end of each period = revenue, each period less revenue, 2010

Distribution (GEA)

- Use Hydro One Distribution Green Energy Act data to extrapolate total Green Energy Act investment by all Ontario LDCs
- Determine / estimate Rates Revenue Requirement in reference and each forecast period
- Cumulative increase $, to end of each period = cumulative $, to end of period less cumulative $, prior to Aug10

Commodity Price Assumptions

For this analysis we define the total commodity price for electricity as being comprised of the spot price of electricity and the Global Adjustment (the "GA"). By spot price we generally refer to the arithmetic average price of electricity, also referred to as the Hourly Ontario Energy Price ("HOEP"). The GA is also referred to as the Provincial Benefit on local distribution company ("LDC") – served customers' electricity bills).

HOEP-GA Interaction

There is a clear interaction between the spot price of electricity and the GA. When spot prices fall, the GA rises and vice versa. This occurs because the government and its agencies have entered into electricity supply arrangements that cover off a very large majority of Ontario electricity supply requirements. The majority of these contracts included fixed prices (some with escalators). With the huge amount of contracted generation coming in to service over the next five years, virtually no new supply will be un-contracted and so this interaction will become even stronger.

The dynamic is more complex than that but for the purposes of this analysis we assume that the combination of HOEP and the GA are generally fixed. This means that a lower spot price is offset by a correspondingly higher GA and vice versa.

Uniform Forecast of HOEP

We also assume that HOEP is fixed during the forecast period. This simplifies the analysis related to most of the generation-related elements, by taking away the need to forecast and incorporate HOEP and the GA for each year analyzed. Even if different HOEP forecast values were used for each period, HOEP-GA interaction assumption would have an offsetting impact, resulting in the same reference total commodity price and rendering varying annual HOEP values moot.

Reference Spot Market Prices

Based on the monthly behavior of HOEP and the GA over the last six to twelve months, we estimate the current, total commodity price to be approximately \$ 65/MWh, comprised of HOEP at \$ 38/MWh and the GA at \$ 27/MWh. For most of the new generation sources with fixed-price contracts, we assume they will be paid \$ 38/MWh from the spot market and then be "made whole" through payments funded through the GA. Solar and NUG projects are the exception – as they produce energy during higher-priced daylight and on-peak hours. We assume they will be paid \$ 48/MWh from the spot market, with the remainder funded through the GA.

Other Assumptions

This analysis includes a number of assumptions. Some relate to forecast years beyond test periods documented in OEB rate cases; in those cases we assumed similar and/or moderate increases in future years. In all cases we have tried to be reasonable and err on the side of being conservative, i.e. the low side.

One major assumption of note is the amount of FIT generation that will come into service during the forecast period. For our analysis, we assume a total of 10,500 MW of FIT generation will come online by July 2015. This is comprised of 8,000 MW of FIT applications received by the OPA as of April 2010 and 2,500 MW of Samsung wind and solar projects.

Incremental Surplus from New Generation

Using near-term IESO forecasts and similar escalation rates, we estimate that annual Ontario energy consumption will grow by 6.2 TWh between 2010 and 2015. By 2015, the new generation (FIT, remaining RESOP, other renewable, new Bruce Power) identified in this analysis will produce an approximate 41 TWh (25.9 + 1.4 + 1.5 + 12.0) of incremental annual energy.

Generation that will or could be retired or otherwise out of service in the next few years includes coal (10 TWh in 2009) and nuclear (OPG's Pickering B: 2,160 MW at a capacity factor of 85% ~ 16 TWh), for a total of about 26 TWh. Not included in this number is the inevitable contribution of energy from incremental natural gas generation, required for system operability and other purposes.

That leaves an incremental surplus of at least 15 TWh. Possible consequences of this surplus include:

a) Displacement of OPG's unregulated generation
b) Displacement of Bruce Power or renewable output, both with possible take-or-pay implications
c) Significantly increased surplus base load generation
d) Significantly increased (and subsidized) exports

Concerning the potential for renewable-related take-or-pay or curtailment events, if just 10% or 2.9 TWh of new renewable energy output by 2015 had to be dispatched off and still paid the above-market premium (an average of over $ 140/MWh), the impact would be $ 406 million. It should be noted however that in the context of this analysis this would not be additional as the above-market cost is already accounted for.

Results

Throughout the analysis we have used nominal (i.e. non-constant) dollars.

Cumulative Increase, Total Dollars ($ million)

The cumulative total dollar increase from 2011 to early 2015 is $ 7.739 billion. The cumulative dollar increase for each element and in total, on a year-by-year basis, is shown below:

element	2011	2012	2013	2014	early 2015
Feed-In-Tariff (FIT)	$ 481	$ 963	$ 1,444	$ 2,646	$ 3,848
Renewable Energy Standard Offer Program (RESOP)	$ -	$ 110	$ 220	$ 330	$ 330
Renewables (other)	$ -	$ 7	$ 36	$ 66	$ 96
Bruce Power (existing)	$ 14	$ 29	$ 43	$ 58	$ 74
Bruce Power (new)	$ -	$ 377	$ 404	$ 443	$ 461
OPG	$ 234	$ 304	$ 166	$ 166	$ 237
Natural Gas	$ 57	$ 86	$ 111	$ 111	$ 192
Non-Utility Generators (NUGs)	$ 94	$ 197	$ 158	$ 258	$ 170
Conservation and Demand Management (CDM)	$ 105	$ 187	$ 226	$ 265	$ 267
Transmission	$ 189	$ 299	$ 505	$ 704	$ 1,012
Distribution (non-Green Energy Act)	$ 80	$ 163	$ 206	$ 249	$ 293
Distribution (Green Energy Act)	$ 156	$ 310	$ 465	$ 615	$ 759
total	**$ 1,411**	**$ 3,032**	**$ 3,986**	**$ 5,911**	**$ 7,739**

Annual Energy

The following Ontario total annual energy consumption values were used. The 2011 value is the IESO's most recent weather-normalized forecast. We used the same energy quantity for 2012 – 2015 as we believe that increased conservation and demand management efforts will offset load growth that would otherwise take place.

for	2011	2012	2013	2014	2015
Ontario annual energy, TWh	142.9	142.9	142.9	142.9	142.9

Cumulative Increase, Unit Cost, ($/MWh)

The cumulative unit cost increase from 2011 to early 2015 is $ 54.15/MWh (no HST) and $ 61.19/MWh with HST. The GST/HST-exclusive cumulative increases for each element and in total, on a year-by-year basis, are shown below:

element	2011	2012	2013	2014	early 2015
Feed-In-Tariff (FIT)	$ 3.37	$ 6.74	$ 10.11	$ 18.52	$ 26.93
Renewable Energy Standard Offer Program (RESOP)	$ -	$ 0.77	$ 1.54	$ 2.31	$ 2.31
Renewables (other)	$ -	$ 0.05	$ 0.25	$ 0.46	$ 0.67
Bruce Power (existing)	$ 0.10	$ 0.20	$ 0.30	$ 0.41	$ 0.52
Bruce Power (new)	$ -	$ 2.64	$ 2.83	$ 3.10	$ 3.22
OPG	$ 1.63	$ 2.13	$ 1.16	$ 1.16	$ 1.66
Natural Gas	$ 0.40	$ 0.60	$ 0.78	$ 0.78	$ 1.35
Non-Utility Generators (NUGs)	$ 0.66	$ 1.38	$ 1.11	$ 1.80	$ 1.19
Conservation and Demand Management (CDM)	$ 0.73	$ 1.31	$ 1.58	$ 1.85	$ 1.87
Transmission	$ 1.32	$ 2.09	$ 3.53	$ 4.92	$ 7.08
Distribution (non-Green Energy Act)	$ 0.56	$ 1.14	$ 1.44	$ 1.74	$ 2.05
Distribution (Green Energy Act)	$ 1.09	$ 2.17	$ 3.26	$ 4.30	$ 5.31
total	**$ 9.87**	**$ 21.22**	**$ 27.90**	**$ 41.36**	**$ 54.15**

Unit Cost Impacts

Non-Residential

Unit costs can vary greatly, depending on load characteristics and LDC rates.

Based on the forecast total unit cost increase and depending on the reference unit cost, by early 2015, non-residential consumers would see their total unit cost rise by 47% - 64% (over the increase already experienced in 2010). This is equivalent to an average, annual, compounded increase of 8.0% – 10.4% (again, over the increase already experienced in 2010).

The table below shows the unit cost impacts for August 2010 reference unit costs ranging from $ 85/MWh to $ 115/MWh. This range has been selected as being representative of the total bill unit cost that small to large manufacturers currently pay. Note that all unit rates shown in the table below exclude GST/HST.

cumulative increase	$ 9.87	$ 21.22	$ 27.90	$ 41.36	$ 54.15	% increase, Aug10 - Jul15	
August 2010	2011	2012	2013	2014	early 2015	total	average annual (compounded)
$ 85.00	$ 94.87	$ 106.22	$ 112.90	$ 126.36	$ 139.15	63.7%	10.4%
$ 90.00	$ 99.87	$ 111.22	$ 117.90	$ 131.36	$ 144.15	60.2%	9.9%
$ 95.00	$ 104.87	$ 116.22	$ 122.90	$ 136.36	$ 149.15	57.0%	9.4%
$ 100.00	$ 109.87	$ 121.22	$ 127.90	$ 141.36	$ 154.15	54.2%	9.0%
$ 105.00	$ 114.87	$ 126.22	$ 132.90	$ 146.36	$ 159.15	51.6%	8.7%
$ 110.00	$ 119.87	$ 131.22	$ 137.90	$ 151.36	$ 164.15	49.2%	8.3%
$ 115.00	$ 124.87	$ 136.22	$ 142.90	$ 156.36	$ 169.15	47.1%	8.0%

Residential

This metric is included in this analysis as it is one the board is familiar with and regularly applies. Unit costs can vary greatly, depending on LDC rates.

Based on the forecast total unit cost increase and depending on the reference unit cost, by early 2015, residential consumers would see their total unit cost rise by 38% - 47% (over the significant increase already experienced in 2010). This is equivalent to an average, annual, compounded increase of 6.7 – 8.0% (again, over the significant increase already experienced in 2010).

The table below shows the unit cost impacts for August 2010, HST-inclusive reference unit costs ranging from $ 130/MWh to $ 160/MWh.

<table>
<tr><td rowspan="2">cumulative increase</td><td>no HST</td><td>$ 9.87</td><td>$ 21.22</td><td>$ 27.90</td><td>$ 41.36</td><td>$ 54.15</td><td colspan="2" rowspan="2">% increase, Aug10 - Jul15</td></tr>
<tr><td>with HST</td><td>$ 11.15</td><td>$ 23.97</td><td>$ 31.52</td><td>$ 46.74</td><td>$ 61.19</td></tr>
<tr><td colspan="7">with HST</td><td rowspan="2">total</td><td rowspan="2">average annual (compounded)</td></tr>
<tr><td colspan="2">August 2010</td><td>2011</td><td>2012</td><td>2013</td><td>2014</td><td>early 2015</td></tr>
<tr><td colspan="2">$130.00</td><td>$ 141.15</td><td>$ 153.97</td><td>$ 161.52</td><td>$ 176.74</td><td>$ 191.19</td><td>47.1%</td><td>8.0%</td></tr>
<tr><td colspan="2">$135.00</td><td>$ 146.15</td><td>$ 158.97</td><td>$ 166.52</td><td>$ 181.74</td><td>$ 196.19</td><td>45.3%</td><td>7.8%</td></tr>
<tr><td colspan="2">$140.00</td><td>$ 151.15</td><td>$ 163.97</td><td>$ 171.52</td><td>$ 186.74</td><td>$ 201.19</td><td>43.7%</td><td>7.5%</td></tr>
<tr><td colspan="2">$145.00</td><td>$ 156.15</td><td>$ 168.97</td><td>$ 176.52</td><td>$ 191.74</td><td>$ 206.19</td><td>42.2%</td><td>7.3%</td></tr>
<tr><td colspan="2">$150.00</td><td>$ 161.15</td><td>$ 173.97</td><td>$ 181.52</td><td>$ 196.74</td><td>$ 211.19</td><td>40.8%</td><td>7.1%</td></tr>
<tr><td colspan="2">$155.00</td><td>$ 166.15</td><td>$ 178.97</td><td>$ 186.52</td><td>$ 201.74</td><td>$ 216.19</td><td>39.5%</td><td>6.9%</td></tr>
<tr><td colspan="2">$160.00</td><td>$ 171.15</td><td>$ 183.97</td><td>$ 191.52</td><td>$ 206.74</td><td>$ 221.19</td><td>38.2%</td><td>6.7%</td></tr>
</table>

TAB A

Beware the Electricity Cost Iceberg

- *The Ontario Government's recently announced green levy or tax of $4/year for a typical residential consumer is only a small part of the total electricity bill increase that will occur by the end of 2011.*
- *By the end of 2011, green levy, smart meter, generation and HST-related increases will cause the typical residential bill to rise by 26% or $304.*
- *Residential consumers moving to the Smart Meter Regulated Price Plan will see their costs rise by $50/year.*
- *Pending generation cost increases will cause the typical residential bill to rise by $30/year, and future generation cost increases will cause a further increase of $122/year.*
- *Combined with near-term cost increases, the HST will add $98/year to the typical residential bill*

On March 20, the Ontario Government announced a green levy or tax on electricity that will take effect soon. The levy is intended to help cover the government's conservation and green energy program. The cost to a typical residential electricity consumer is only $4 per year and yet many are up in arms over it. The problem is this cost is only a small portion of what consumers will see over the next eighteen or so months - the tip of an approaching iceberg.

Above the Water Line

Although it has drawn a lot of attention in the press, the new $4 levy for a typical residential consumer with modest, annual consumption of 10,000 kWh is relatively minor. The charge is based on a total annual collection of about $54 million. Spread across all Ontario users, it works out to about 0.04 cents/kWh. This cost increase is insignificant compared to other, less-obvious increases, some pending and others expected in the future.

Ontario Power Generation (OPG) has announced an application for a 9.6% increase (about 0.5 cents/kWh) on the rates paid for its regulated generation, which represents about 47% of Ontario consumption. In the past, OPG has not received its full requested increase. If this time around they were to receive say 2/3 or about 0.3 cents/kWh of the increase, the residential bill impact would be 0.15 cents/kWh or $15/year.

Also pending is the Harmonized Sales Tax (HST) that will take effect July 1, 2010. It will add 8% or $92 to a current typical residential bill. The HST will also have the compound effect of adding 8% to all other cost increases that are incurred down the road. The HST is a fiscal policy, not an energy policy, but consumers will see that as a distinction without a difference when their energy bill arrives in August.

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Below the Water Line - Smart Meters

In May 2009, the Ontario Government set targets for the number of consumers on time-of-use rates under the Regulated Price Plan (RPP). This plan is also commonly referred to as the Smart Meter RPP. As of the end of 2009, Ontario utilities had installed about 3.4 million smart meters and about 350,000 residential consumers were on smart meter rates. By the summer of 2010, 1 million consumers are to pay these rates while by June 2011, the target is 3.6 million consumers.

Unfortunately, there are cost impacts with the Smart Meter RPP.

Typical residential consumers will see a cost increase when moving from the conventional RPP rates to the new Smart Meter RPP, because of a difference in how the rates allocate costs. The conventional RPP rate charges a lower energy cost to smaller volume users, something that tends to benefit residential consumers because they are subsidized by commercial or institutional users (whose use is greater). When they move to Smart Meter RPP rates, these customers will pay for energy based on time of use, and will no longer get a small volume discount rate. Residential consumers will see a cost increase of 0.38 cents/kWh or $38/year from the loss of this small volume discount that was imbedded in the conventional RPP rate.

The second Smart Meter cost impact is the assumed load profile used to set the Smart Meter RPP prices - currently 9.3, 8.0 and 4.4 cents/kWh for the on-, mid- and off-peak periods. Ostensibly, the OEB set these rates to recover the same average revenue used in setting the conventional meter rates. In so doing, the OEB identified two different load profiles - one for a typical Smart Meter RPP consumer and one for those with conventional or energy meters. If not on the RPP, the latter group would be charged for electricity based on an assumed load profile; namely, their utility's Net System Load Shape or NSLS. Close examination of Toronto Hydro's 2009 NSLS, however, indicates that if that collective group switched to Smart Meter RPP rates, they would pay 6.34 cents/kWh. The additional cost of 0.12 cents/kWh equates to $12/year for a typical residential consumer.

(Once all RPP consumers have moved to the Smart Meter RPP, revenues will reach an equilibrium state and the 0.12 cent/kWh or $12/year increase should disappear.)

Individual consumers who move to the Smart Meter RPP may in fact see an energy cost decrease based on their energy use profile. Our comments here address the overall impact on the average residential users.

The total impact of the Smart Meter increases is therefore 0.50 cents/kWh or $50/year for a typical residential consumer.

Below the Water Line - Pending Generation Cost Increases

A number of factors have caused the actual costs underlying the Regulated Price Plans to be higher than anticipated. General RPP rates will therefore rise to cover these higher actual costs and the unfavourable variance that has accumulated since November 2009. The new rates that take effect May 1 will be announced in mid-April. Aegent's current estimate for the RPP increase is 0.30 - 0.40 cents/kWh. Choosing the lower value, the increase for a typical residential consumer is $30/year.

It's worth noting that the RPP rate increases could be higher, depending on the extent to which the OEB anticipates future cost increases and includes them in the rates established for May 1.

Below the Water Line - Near-term, Future Generation Cost Increases

A number of generation plants are coming online, under a variety of Ontario Power Authority programs. All plants will be paid above-market rates or receive other supporting payments. The estimated cost impacts are shown in the table that follows.

generation type	estimated contract cost, ¢/kWh	increase, ¢/kWh per 1,000 MW added	MW added in 2010 and 2011	resulting cost increase, ¢/kWh	$/year for residential consumer
natural gas-fired	$75,000/MW/year	0.06	900	0.06	6
nuclear	7	0.16	1,500	0.24	24
RESOP - wind	14.1 (FIT pricing, as below)	0.22	300	0.07	7
RESOP - solar	44.3 (FIT)	0.38	500	0.19	19
FIT – solar	44.3	0.38	500	0.19	19
FIT – wind	14.1	0.22	1,500 (estimated)	0.33	33
total				**$1.07**	**$107**

Notes and Assumptions:

1. increases calculated relative to base spot price of 4.0 cents/kWh
2. costs spread across Ontario total annual consumption of 141 TWh
3. natural gas-fired: Clean Energy, Combined Heat and Power; cost is conservative Deemed Dispatch Payment
4. nuclear capacity factor of 85%
5. RESOP is Renewable Energy Standard Offer Program, precursor to Feed-In-Tariff program (FIT); majority of RESOP projects assumed to be paid FIT prices
6. wind assumed to be 90% onshore, 10% offshore with combined capacity factor of 31%
7. wind assumed to require natural gas fired back-up and enabling wires investments
8. solar assumed to be ground-mounted and less than 10 MW, capacity factor of 15%

As noted earlier, some of these cost increases could affect the new RPP rates that will take effect on May 1, 2010.

Summary of Cost Increases

Aegent's analysis indicates that by the end of 2011, a typical residential consumer could see a total cost increase of 3.04 cents/kWh or $304/year in their electricity bill. This represents a 26% increase over their current total cost of electricity. The components of the increase are:

source of increase	resulting cost increase, ¢/kWh	$/year for residential consumer
green levy/tax	0.04	4
Smart Meter RPP	0.5	50
pending generation cost increases	0.3	30
HST (based on new, imminent total cost of 12.3 ¢/kWh)	0.98	98
sub-total, increases in next 9 months	1.82	182
near-term, future OPG	0.15	15
near-term, other future generation cost increases	1.07	107
total increase to end of 2011	**3.04**	**$304**

Looking Ahead

In a future article, look for Aegent to discuss a cost increase wildcard: largely-fixed costs such as transmission and distribution and how Ontario's recent step-change drop in total consumption could cause associated unit cost increases. We'll also discuss how conservation may generate lower savings than expected and how non-conserving entities will see their total electricity costs rise as they shoulder more of the fixed-cost burden.

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TAB B

BRUCE SHARP, P. Eng.

SUMMARY

Bruce is Aegent Energy Advisor's senior resource in electricity consulting. Bruce holds a Bachelor of Applied Science degree in Mechanical Engineering from the University of Waterloo and has 23 years of experience in the energy business. Bruce is a professional engineer and a Chartered Industrial Gas Consultant.

Prior to joining Aegent, and as principal of his own company, Bruce provided independent advice to medium- and large-volume consumers of electricity and to small generators, on purchasing power and operating in the new Ontario market. As Manager, Power Products and Services with Engage Energy, he was actively involved in the design, sale, and delivery of client products and services targeted at the commodity segment of the electricity business. Bruce's professional experience also includes work at Ontario Hydro as an industrial energy advisor and at The Consumers' Gas Company Limited working with industrial and commercial customers.

Bruce has been a repeat speaker at industry conferences on the topic of practical power procurement strategies, and copies of these presentations are available on Aegent's web site. Bruce has been widely quoted in the press for his insightful analysis of the economic implications of government energy policy decisions.

PROFESSIONAL EXPERIENCE

2002 - Present	**Aegent Energy Advisors Inc.** Senior Consultant
2001 - 2002	**Sharp Energy Advice** Principal
1998 - 2001	**Engage Energy Canada, L.P. / Encore Energy Solutions, L.P.** Manager, Power Products & Services
1995 - 1997	**The Consumers' Gas Company Limited** Manager, Industrial Product Marketing Industrial Utilization Consultant
1987 - 1993	**Ontario Hydro** Industrial Energy Advisor Assistant Engineer, Hydraulic Generation Engineering Trainee, Hydraulic Generation

TAB C

T1a - element = FIT / bill area = Electricity (Provincial Benefit)

	contract price by year, $/MWh	reference spot market price, $/MWh	premium over spot market, $/MWh	comments
biomass < 10 MW	$ 138	$ 38	$ 100	contract prices as per OPA FIT schedule August 13, 2010; non-solar contract prices DO
biomass > 10 MW	$ 130	$ 38	$ 92	NOT INCLUDE 20%-of-CPI escalator
biogas, on-farm < 100 kW	$ 195	$ 38	$ 157	
biogas, on-farm 100 to 250 kW	$ 185	$ 38	$ 147	
biogas < 500 kW	$ 160	$ 38	$ 122	
biogas > 500 kW to 10 MW	$ 147	$ 38	$ 109	
biogas > 10 MW	$ 104	$ 38	$ 66	
water < 10 MW	$ 131	$ 38	$ 93	
water > 10 MW	$ 122	$ 38	$ 84	
landfill < 10 MW	$ 111	$ 38	$ 73	
landfill > 10 MW	$ 103	$ 38	$ 65	
solar, rooftop < 10 kW	$ 802	$ 48	$ 754	solar reference spot price at estimated premium to HOEP
solar, rooftop 10 to 250 kW	$ 713	$ 48	$ 665	
solar, rooftop 250 to 500 kW	$ 635	$ 48	$ 587	
solar, rooftop > 500 kW	$ 539	$ 48	$ 491	
solar, ground < 10 kW	$ 642	$ 48	$ 594	
solar, ground > 500 kW	$ 443	$ 48	$ 395	
wind,onshore	$ 135	$ 38	$ 97	
wind,offshore	$ 190	$ 38	$ 152	

T1b - element = FIT / bill area = Electricity (Provincial Benefit)

added during / to end of	Aug10 - Jul11	Aug11 - Jul12	Aug12 - Jul13	Aug13 - Jul14	Aug14 - Jul15	**comments**
quantity added during year, MW						
biomass < 10 MW	9.5	9.5	9.5	15.8	15.8	1st year quantities as per Mar10, Apr10 OPA backgrounders
biomass > 10 MW	-	-	-	-	-	subsequent year quantities in same proportions; exception is last two years, when 50% of
biogas, on-farm < 100 kW	-	-	-	-	-	each of Samsung project types is added
biogas, on-farm 100 to 250 kW	1.0	1.0	1.0	1.7	1.7	
biogas < 500 kW	2.0	2.0	2.0	3.3	3.3	
biogas > 500 kW to 10 MW	8.0	8.0	8.0	13.3	13.3	
biogas > 10 MW	-	-	-	-	-	
water < 10 MW	96.5	96.5	96.5	160.0	160.0	
water > 10 MW	-	-	-	-	-	
landfill < 10 MW	7.5	7.5	7.5	12.4	12.4	
landfill > 10 MW	-	-	-	-	-	
solar, rooftop < 10 kW	-	-	-	-	-	
solar, rooftop 10 to 250 kW	-	-	-	-	-	
solar, rooftop 250 to 500 kW	51.0	51.0	51.0	84.6	84.6	
solar, rooftop > 500 kW	-	-	-	-	-	
solar, ground < 10 kW	-	-	-	-	-	
solar, ground > 10 kW to 10 MW	326.0	326.0	326.0	790.6	790.6	
wind,onshore	615.0	615.0	615.0	2,019.9	2,019.9	
wind,offshore	150.0	150.0	150.0	248.7	248.7	
total	1,267	1,267	1,267	3,350	3,350	
quantity, end-year, MW						
biomass < 10 MW	9.5	19.0	28.5	44.3	60.0	
biomass > 10 MW	-	-	-	-	-	
biogas, on-farm < 100 kW	-	-	-	-	-	
biogas, on-farm 100 to 250 kW	1.0	2.0	3.0	4.7	6.3	
biogas < 500 kW	2.0	4.0	6.0	9.3	12.6	
biogas > 500 kW to 10 MW	8.0	16.0	24.0	37.3	50.5	
biogas > 10 MW	-	-	-	-	-	
water < 10 MW	96.5	193.0	289.5	449.5	609.6	
water > 10 MW	-	-	-	-	-	
landfill < 10 MW	7.5	15.0	22.5	34.9	47.4	
landfill > 10 MW	-	-	-	-	-	
solar, rooftop < 10 kW	-	-	-	-	-	
solar, rooftop 10 to 250 kW	-	-	-	-	-	
solar, rooftop 250 to 500 kW	51.0	102.0	153.0	237.6	322.1	
solar, rooftop > 500 kW	-	-	-	-	-	
solar, ground < 10 kW	-	-	-	-	-	
solar, ground > 10 kW to 10 MW	326.0	652.0	978.0	1,768.6	2,559.2	includes Samsung, 250 MW in each of 13/14, 14/15
wind,onshore	615.0	1,230.0	1,845.0	3,864.9	5,884.7	includes Samsung, 1000 MW in each of 13/14, 14/15
wind,offshore	150.0	300.0	450.0	698.7	947.5	
total	1,267	2,533	3,800	7,150	10,500	2,533 MW approved to April 2010; 8,000 MW of applications received to April 2010; includes additional 2,500 MW from Samsung

T1c - element = FIT / bill area = Electricity (Provincial Benefit)

	capacity factor	Aug10 - Jul11	Aug11 - Jul12	Aug12 - Jul13	Aug13 - Jul14	Aug14 - Jul15	comments
energy quantity, MWh							
biomass < 10 MW	85%	70,737	141,474	212,211	329,515	446,819	capacity factors as per OPA assumptions
biomass > 10 MW	85%	-	-	-	-	-	
biogas, on-farm < 100 kW	85%	-	-	-	-	-	
biogas, on-farm 100 to 250 kW	85%	7,446	14,892	22,338	34,686	47,034	
biogas < 500 kW	85%	14,892	29,784	44,676	69,372	94,067	
biogas > 500 kW to 10 MW	85%	59,568	119,136	178,704	277,486	376,268	
biogas > 10 MW	85%	-	-	-	-	-	
water < 10 MW	52%	439,577	879,154	1,318,730	2,047,685	2,776,640	
water > 10 MW	52%	-	-	-	-	-	
landfill < 10 MW	30%	19,710	39,420	59,130	91,815	124,501	
landfill > 10 MW	30%	-	-	-	-	-	
solar, rooftop < 10 kW	13%	-	-	-	-	-	
solar, rooftop 10 to 250 kW	13%	-	-	-	-	-	
solar, rooftop 250 to 500 kW	13%	58,079	116,158	174,236	270,549	366,862	
solar, rooftop > 500 kW	13%	-	-	-	-	-	
solar, ground < 10 kW	14%	-	-	-	-	-	
solar, ground > 10 kW to 10 MW	14%	399,806	799,613	1,199,419	2,169,022	3,138,625	
wind,onshore	30%	1,616,220	3,232,440	4,848,660	10,156,854	15,465,049	
wind,offshore	37%	486,180	972,360	1,458,540	2,264,777	3,071,015	
total		3,172,215	6,344,430	9,516,645	17,711,762	25,906,879	
premium over spot, $ million							
biomass < 10 MW		$ 7	$ 14	$ 21	$ 33	$ 45	
biomass > 10 MW		$ -	$ -	$ -	$ -	$ -	
biogas, on-farm < 100 kW		$ -	$ -	$ -	$ -	$ -	
biogas, on-farm 100 to 250 kW		$ 1	$ 2	$ 3	$ 5	$ 7	
biogas < 500 kW		$ 2	$ 4	$ 5	$ 8	$ 11	
biogas > 500 kW to 10 MW		$ 6	$ 13	$ 19	$ 30	$ 41	
biogas > 10 MW		$ -	$ -	$ -	$ -	$ -	
water < 10 MW		$ 41	$ 82	$ 123	$ 190	$ 258	
water > 10 MW		$ -	$ -	$ -	$ -	$ -	
landfill < 10 MW		$ 1	$ 3	$ 4	$ 7	$ 9	
landfill > 10 MW		$ -	$ -	$ -	$ -	$ -	
solar, rooftop < 10 kW		$ -	$ -	$ -	$ -	$ -	
solar, rooftop 10 to 250 kW		$ -	$ -	$ -	$ -	$ -	
solar, rooftop 250 to 500 kW		$ 34	$ 68	$ 102	$ 159	$ 215	
solar, rooftop > 500 kW		$ -	$ -	$ -	$ -	$ -	
solar, ground < 10 kW		$ -	$ -	$ -	$ -	$ -	
solar, ground > 10 kW to 10 MW		$ 158	$ 316	$ 474	$ 857	$ 1,240	
wind,onshore		$ 157	$ 314	$ 470	$ 985	$ 1,500	
wind,offshore		$ 74	$ 148	$ 222	$ 344	$ 467	
total		$ 481	$ 963	$ 1,444	$ 2,619	$ 3,793	
$/MWh		$ 152	$ 152	$ 152	$ 148	$ 146	
Samsung economic development adder, $ million					$ 28	$ 55	estimated, based on adder of $ 10 / MWh
total increase, $ million		$ 481	$ 963	$ 1,444	$ 2,646	$ 3,848	

T2 - element = RESOP (remaining) / bill area = Electricity (Provincial Benefit)

	contract price by year, $/MWh	reference spot market price, $/MWh	premium over spot market, $/MWh				comments
wind	$ 141	$ 38	$ 103				assumes FIT pricing
solar	$ 443	$ 38	$ 405				
added during / to end of	Aug10 - Jul11	Aug11 - Jul12	Aug12 - Jul13	Aug13 - Jul14	Aug14 - Jul15		
quantity added during year, MW							
wind		100	100	100			total quantities as per OPA's 2010 Q1 generation report
solar		167	167	166			total quantities as per OPA's 2010 Q1 generation report
total		267	267	266			
quantity, end-year, MW							
wind	-	100	200	300	300		
solar	-	167	334	500	500		
total	-	267	534	800	800		
						capacity factor	
energy quantity, MWh							
wind	-	262,800	525,600	788,400	788,400	30%	OPA assumption for on-shore wind CF
solar	-	204,809	409,618	613,200	613,200	14%	OPA assumption for ground-mount solar CF
total	-	467,609	935,218	1,401,600	1,401,600		
premium over spot, $ million							
wind	$ -	$ 27.07	$ 54.14	$ 81.21	$ 81.21		
solar	$ -	$ 82.95	$ 165.90	$ 248.35	$ 248.35		
total	$ -	$ 110	$ 220	$ 330	$ 330		
Increase, $ million							
	$ -	$ 110	$ 220	$ 330	$ 330		

T3 - element = Renewables (other) / bill area = Electricity (Provincial Benefit)

	contract price by year, $/MWh	reference spot market price, $/MWh	premium over spot market, $/MWh				comments
wind	$ 100	$ 38	$ 62				estimated pricing
water	$ 110	$ 38	$ 72				
added during / to end of	Aug10 - Jul11	Aug11 - Jul12	Aug12 - Jul13	Aug13 - Jul14	Aug14 - Jul15		
quantity added during year, MW							
wind			143	142	143		total quantities as per OPA's 2010 Q1 generation report
water		20	20	20	20		
total			163	162	163		
quantity, end-year, MW							
wind	-	-	143	285	428		
water	-	20	40	60	80		
total	-	20	183	345	508		
						capacity factor	
energy quantity, MWh							
wind	-	-	375,804	748,980	1,124,784	30%	OPA assumption for on-shore wind CF
water	-	91,104	182,208	273,312	364,416	52%	OPA assumption for water CF
total	-	91,104	558,012	1,022,292	1,489,200		
premium over spot, $ million							
wind	$ -	$ -	$ 23.30	$ 46.44	$ 69.74		
water	$ -	$ 6.56	$ 13.12	$ 19.68	$ 26.24		
total	$ -	$ 7	$ 36	$ 66	$ 96		
increase, $ million							
	$ -	$ 7	$ 36	$ 66	$ 96		

T4 - element = Bruce Power (existing) / bill area = Electricity (Provincial Benefit)

added during / to end of	capacity factor	previous	Aug10 - Jul11	Aug11 - Jul12	Aug12 - Jul13	Aug13 - Jul14	Aug14 - Jul15	comments
contract price by year, $/MWh								
nuclear		$ 69.00	$ 70.38	$ 71.79	$ 73.22	$ 74.69	$ 76.18	2010 pricing as per OEB RPP Price Report from Apr10; escalated at 2 %
reference spot market price, $/MWh								
nuclear		$ 38.00	$ 38.00	$ 38.00	$ 38.00	$ 38.00	$ 38.00	
contract price increase, $/MWh								
nuclear		$ 31.00	$ 32.38	$ 33.79	$ 35.22	$ 36.69	$ 38.18	
quantity, end-year, MW								
Bruce A U3		710	710	710	710	710	710	750 less current output
Bruce A U4		670	670	670	670	670	670	
total		1,380	1,380	1,380	1,380	1,380	1,380	
energy quantity, MWh	**capacity factor**							
Bruce A U3	85%	5,286,660	5,286,660	5,286,660	5,286,660	5,286,660	5,286,660	
Bruce A U4	85%	4,988,820	4,988,820	4,988,820	4,988,820	4,988,820	4,988,820	
total		10,275,480	10,275,480	10,275,480	10,275,480	10,275,480	10,275,480	
premium over spot, $ million								
Bruce A U3		$ 163.89	$ 171.18	$ 178.62	$ 186.21	$ 193.96	$ 201.85	
Bruce A U4		$ 154.65	$ 161.54	$ 168.56	$ 175.72	$ 183.03	$ 190.48	
total		$ 319	$ 333	$ 347	$ 362	$ 377	$ 392	
increase, $ million			$ 14	$ 29	$ 43	$ 58	$ 74	

T5 - element = Bruce Power (new) / bill area = Electricity (Provincial Benefit)

added during / to end of	previous	Aug10 - Jul11	Aug11 - Jul12	Aug12 - Jul13	Aug13 - Jul14	Aug14 - Jul15	comments
contract price by year, $/MWh							
nuclear	$ 69.00	$ 70.38	$ 71.79	$ 73.22	$ 74.69	$ 76.18	2010 pricing as per OEB RPP Price Report from Apr10; escalated at 2.5%
reference spot market price, $/MWh							
nuclear		$ 38.00	$ 38.00	$ 38.00	$ 38.00	$ 38.00	
premium over spot market price, $/MWh							
nuclear		$ 32.38	$ 33.79	$ 35.22	$ 36.69	$ 38.18	
quantity added during year, MW							
Bruce A U1, 2			1,500				quantities as per OPA's 2010 Q1 report
Bruce A U3				40			quantities as per OPA's 2010 Q1 report, current output
Bruce A U4					80		quantities as per OPA's 2010 Q1 report, current output
total		-	1,500	40	80	-	
quantity, end-year, MW							
Bruce A U1, 2		-	1,500	1,500	1,500	1,500	
Bruce A U3		-	-	40	40	40	
Bruce A U4		-	-	-	80	80	
total		-	1,500	1,540	1,620	1,620	
energy quantity, MWh	**capacity factor**						
Bruce A U1, 2	85%	-	11,169,000	11,169,000	11,169,000	11,169,000	estimated
Bruce A U3	85%	-	-	297,840	297,840	297,840	
Bruce A U4	85%	-	-	-	595,680	595,680	
total		-	11,169,000	11,466,840	12,062,520	12,062,520	
premium over spot, $ million							
Bruce A U1, 2		$ -	$ 377.37	$ 393.41	$ 409.77	$ 426.45	
Bruce A U3		$ -	$ -	$ 10.49	$ 10.93	$ 11.37	
Bruce A U4		$ -	$ -	$ -	$ 21.85	$ 22.74	
total		$ -	$ 377	$ 404	$ 443	$ 461	
increase, $ million							
		$ -	$ 377	$ 404	$ 443	$ 461	

T6 - element = OPG / bill area = Electricity (Provincial Benefit)

for year	2010	2011	2012	2013	2014	2015	comments
contract price by year, $/MWh							
hydro							
payment amount	$ 36.66	$ 37.38	$ 37.38	$ 38.13	$ 38.13	$ 38.89	2010: pricing as per EB-2009-0174; 2011/12 as EB-2010-0008, Ex I1, Tab 2, Sch 1; 13/14 = 11/12 esclated by 2 %; 15 = 13/14 esclated by 2%
payment rider		$ (2.46)	$ (2.46)				
total payment	$ 36.66	$ 34.92	$ 34.92	$ 38.13	$ 38.13	$ 38.89	
nuclear							
payment amount	$ 52.98	$ 55.34	$ 55.34	$ 56.45	$ 56.45	$ 57.58	2010: pricing as per EB-2009-0174; 2011/12 as EB-2010-0008, Ex I1, Tab 3, Sch 1; 13/14 = 11/12 esclated by 2 %; 15 = 13/14 esclated by 2%
payment rider	$ 2.00	$ 5.09	$ 5.09				
total payment	$ 54.98	$ 60.43	$ 60.43	$ 56.45	$ 56.45	$ 57.58	
reference spot market price, $/MWh							
hydro and nuclear	$ 38.00	$ 38.00	$ 38.00	$ 38.00	$ 38.00	$ 38.00	
premium over spot market, $/MWh							
hydro	$ (1.34)	$ (3.08)	$ (3.08)	$ 0.13	$ 0.13	$ 0.89	
nuclear	$ 16.98	$ 22.43	$ 22.43	$ 18.45	$ 18.45	$ 19.58	
energy quantity, TWh							
hydro	19.3	19.4	19.0	19.0	19.0	19.0	2010/1/2 Qs as per EB-2010-0008, Ex I1, Tab 1, Sch 1; 2013/4/5 = 2012
nuclear	46.2	46.9	50.0	50.0	50.0	50.0	
premium over spot, $ million							
hydro	$ (26)	$ (60)	$ (59)	$ 2	$ 2	$ 17	
nuclear	$ 784	$ 1,052	$ 1,122	$ 922	$ 922	$ 979	
total	$ 759	$ 992	$ 1,063	$ 925	$ 925	$ 996	
increase, $ million		$ 234	$ 304	$ 166	$ 166	$ 237	

T7 - element = Natural Gas / bill area = Electricity (Provincial Benefit)

added during / to end of	Aug10 - Jul11	Aug11 - Jul12	Aug12 - Jul13	Aug13 - Jul14	Aug14 - Jul15	comments
quantity added during year, MW						
Halton Hills	632					quantities as per OPA's 2010 Q1 generation report
York		408				
Greenfield South			280			
Oakville					900	
total	632	408	280	-	900	
quantity, end-year, MW						
Halton Hills	632	632	632	632	632	
York	-	408	408	408	408	
Greenfield South	-	-	280	280	280	
Oakville	-	-	-	-	900	
total	632	1,040	1,320	1,320	2,220	
contingent support payment, $/MW/year						
Halton Hills	$ 90,000					estimated
York	$ 72,000					
Greenfield South	$ 90,000					
Oakville	$ 90,000					
total						
premium, $ million						
Halton Hills	$ 56.88	$ 56.88	$ 56.88	$ 56.88	$ 56.88	
York	$ -	$ 29.38	$ 29.38	$ 29.38	$ 29.38	
Greenfield South	$ -	$ -	$ 25.20	$ 25.20	$ 25.20	
Oakville	$ -	$ -	$ -	$ -	$ 81.00	
total	$ 57	$ 86	$ 111	$ 111	$ 192	
increase, $ million						
	$ 57	$ 86	$ 111	$ 111	$ 192	

T8 - element = NUGs / bill area = Electricity (Provincial Benefit)							comments
during	2010	2011	2012	2013	2014	2015	
contract price by year, $/MWh							
NUGs	$ 95.00	$ 103.55	$ 112.87	$ 123.03	$ 134.10	$ 146.17	2010 pricing estimated; remainder escalated at estimated OEFC Total Market Cost escalation rate of 9%
reference spot market price, $/MWh							
NUGs	$ 48.00	$ 48.00	$ 48.00	$ 48.00	$ 48.00	$ 48.00	on-peak operation at premium to HOEP
premium over spot market price, $/MWh							
NUGs	$ 47.00	$ 55.55	$ 64.87	$ 75.03	$ 86.10	$ 98.17	
energy quantity, TWh							
NUGs	11	11	11	9	9	7	as per OPA 2007 IPSP
premium over spot, $ million							
NUGs	$ 517	$ 611	$ 714	$ 675	$ 775	$ 687	
increase over 2010, $ million							
		$ 94	$ 197	$ 158	$ 258	$ 170	

T9 - element = CDM / bill area = Electricity (Provincial Benefit)

	2009	2010	Aug10 - Jul11	Aug11 - Jul12	Aug12 - Jul13	Aug13 - Jul14	Aug14 - Jul15	**comments**
operating, OPA	$ 20	$ 25	$ 35	$ 36	$ 37	$ 38	$ 39	approx., from OPA 2009 annal report
operating, LDC			$ 20	$ 40	$ 41	$ 42	$ 43	estimated
program costs, excl. low-income	$ **224**	$ 287	$ 325	$ 350	$ 350	$ 350	$ 350	bolded value from OPA 2009 annal report
program costs, low-income			$ 37	$ 73	$ 110	$ 147	$ 147	50 % of LI households addressed by end-2014
total, current year	$ 244	$ 312	$ 417	$ 499	$ 538	$ 577	$ 579	
increase, $ million			$ 105	$ 187	$ 226	$ 265	$ 267	

low income households	733,000	OPA
basis	10%	
basis households	73,300	
expenditure/household	$ 1,000	
total basis expenditure	$ 73.30	

T10a - element = Transmission or Delivery / bill area = Delivery		12282.5	13503				comments
Rate Base	2010	2011	2012	2013	2014	2015	
Gross Plant incl. I-S CA	$ 11,478	$ 12,297	$ 13,510	$ 15,029	$ 16,594	$ 18,839	bolded values are mid-year and from EB-2010-0002, Ex D1, Tab 1, Sch 1
Accum Dep	$ 4,189	$ 4,429	$ 4,691	$ 5,011	$ 5,441	$ 5,923	
Net Plant in Service (NPiS)	$ 7,289	$ 7,868	$ 8,819	$ 10,018	$ 11,153	$ 12,916	
In-Service Capital Additions (ISCA) - Sustaining, Operations, Other				$ 500	$ 515	$ 530	estimated
ISCA - Development - Non-GEA				$ 100	$ 100	$ 100	estimated
ISCA - Development - GEA, major				$ 564	$ 947	$ 2,001	from TX, Green Energy Plan -- EB-2010-0002, Ex A, Tab 11, Sch 4; also T10b
ISCA - Development - GEA, sched B + Short Circuit				$ 300	$ 194	$ 193	from TX, Green Energy Plan -- EB-2010-0002, Ex A, Tab 11, Sch 4; also T10c
ISCA - total	798	$ 871	$ 1,619	$ 1,464	$ 1,756	$ 2,824	bolded values from EB-2010-0002, Ex D1, Tab 1, Sch 1
Retirements	$ 30	$ 39	$ 42				actual
				$ 45	$ 45	$ 45	estimated
Depreciaton, declining balance, existing	4.00%						estimated
	$ 260	$ 280	$ 288	$ 401	$ 446	$ 517	
Depreciation, declining balance, new assets	2.00%						estimated
	$ 16	$ 17	$ 32	$ 29	$ 35	$ 56	
Depreciation in year, total	$ 276	$ 297	$ 320	$ 430	$ 481	$ 573	
NPiS	$ 7,289	$ 7,868	$ 8,819	$ 10,018	$ 11,153	$ 12,916	
Total Revenue Requirement, actual	$ 1,257	$ 1,446	$ 1,547				bolded values are mid-year and from EB-2010-0002, Ex E1, Tab 1, Sch 1
TRR/NPiS, calculated		$ 0.1838	$ 0.1754				calculated metric
TRR/NPiS, estimated				$ 0.1750	$ 0.1750	$ 0.1750	estimated metric
Total Revenue Requirement, calculated				$ 1,753	$ 1,952	$ 2,260	
Total Revenue Requirement, forecast	$ 1,257	$ 1,446	$ 1,547	$ 1,753	$ 1,952	$ 2,260	
external revenues	-18	-31	-25				actual, from EB-2010-0002
				-25	-25	-25	estimated
other	-21	-8	-5				actual, from EB-2010-0002
				-5	-5	-5	estimated
reductions to RRR	-39	-39	-30	-30	-30	-30	
Rates Revenue Requirement	$ 1,218	$ 1,407	$ 1,517	$ 1,723	$ 1,922	$ 2,230	
added RRR from 2010		$ 189	$ 299	$ 505	$ 704	$ 1,012	

T10b - Transmission, supplemental information (GEA, schedule A / major projects)

Schedule A - Transmission Projects	dev't	capital	2013	2014	2015	2016	2017, after	comments
Network	dev't	capital						
1	$ 12	$ 511			$ 511			from TX, Green Energy Plan -- EB-2010-0002, Ex A, Tab 11, Sch 4
2, 3	$ 19	$ 884			$ 884			
4	$ 6	$ 432		$ 432				
5	$ 23	$ 706				$ 706		
6	$ 12	$ 167				$ 167		
	$ 72	$ 2,700						
	2.7%							
Connection	dev't	capital						
7, 9	$ 6	$ 164	$ 164					
8	$ 8	$ 169		$ 169				
10	$ 8	$ 137		$ 137				
11	$ 6	$ 121			$ 121			
12	$ 6	$ 84			$ 84			
13	$ 12	$ 112			$ 112			
	$ 46	$ 787						
	5.8%							
Regional	dev't	capital						
14	$ 22	$ 400	$ 400					
15	$ 1	$ 289			$ 289			
16	$ 1	$ 105		$ 105				
17	$ 1	$ 104		$ 104				
	$ 25	$ 898						
	2.8%							
Long-Term	dev't	capital						
18	$ 5	$ 1,234					$ 1,234	
19	$ 10	$ 306					$ 306	
20	$ 5	$ 1,006					$ 1,006	
	$ 20	$ 2,546						
	$ 0							
	$ 143	$ 4,385	$ 564	$ 947	$ 2,001	$ 873	$ 2,546	
	3.3%							

T10c - Transmission, supplemental information (GEA, schedule B and short circuit projects)

schedule B	2013	2014	2015
1	$ 76		
2	$ 83	$ 83	$ 83
3	$ 79	$ 79	$ 78
4	$ 32	$ 32	$ 32
5	$ -	$ -	$ -
	$ 270	$ 194	$ 193
short circuit, Manby	$ 30		
sched B + SC	$ 300	$ 194	$ 193

from TX, Green Energy Plan – EB-2010-0002, Ex A, Tab 11, Sch 4

T11 - element = Distribution, non-GEA / bill area = Delivery

	2009	2010	2011	2012	2013	2014	2015	comment
escalator, from previous year		3.0%	3.0%	3.0%	1.5%	1.5%	1.5%	estimated, reflects decreased throughput and inflation
annual revenue	$ 2,601	$ 2,679	$ 2,759	$ 2,842	$ 2,885	$ 2,928	$ 2,972	2009 annual revenue as per 2009 OEB Distributors' Yearbook
increase, $ million			$ 80	$ 163	$ 206	$ 249	$ 293	

T12 - element = Distribution, GEA / bill area = Delivery or Regulatory

Rate Base		2010	2011	2012	2013	2014	2015	comments
GEA DX additions, HONI								
Renewable Generation		168	296	310	310	310	310	from DX, Green Energy Plan – EB-2009-0096, Ex A, Tab 14, Sch 2
Smart Grid		30	62	83	83	83	83	
HONI DX, % of province								
customers		28%						as per HONI
Renewable Generation		50%						HONI proportion slightly higher
Smart Grid		35%						HONI proportion significantly higher
GEA DX additions, provincial								
Renewable Generation		$ 336	$ 592	$ 620	$ 620	$ 620	$ 620	provincial quantities scaled up from HONI quantities, by using percent estimates above
Smart Grid, HONI		$ 86	$ 177	$ 238	$ 238	$ 238	$ 238	
total GEA additions		$ 422	$ 769	$ 858	$ 858	$ 858	$ 858	
Gross Plant incl. I-S CA		$ -	$ 422	$ 1,191	$ 2,049	$ 2,907	$ 3,765	
Accum Dep	beginning	$ -	$ 8	$ 40	$ 104	$ 199	$ 324	
Net Plant in Service		$ -	$ 413	$ 1,151	$ 1,945	$ 2,709	$ 3,441	
Dep on existing NPiS	4.00%	$ -	$ 17	$ 46	$ 78	$ 108	$ 138	
Dep on Cap Adds	2.00%	$ 8	$ 15	$ 17	$ 17	$ 17	$ 17	
Dep, total		$ 8	$ 32	$ 63	$ 95	$ 126	$ 155	
Gross Plant incl. I-S CA		$ 422	$ 1,191	$ 2,049	$ 2,907	$ 3,765	$ 4,623	
Accum Dep	end	$ 8	$ 40	$ 104	$ 199	$ 324	$ 479	
Net Plant in Service		$ 413	$ 1,151	$ 1,945	$ 2,709	$ 3,441	$ 4,144	
Gross Plant incl. I-S CA		$ 211	$ 806	$ 1,620	$ 2,478	$ 3,336	$ 4,194	
Accum Dep	average	$ 4	$ 24	$ 72	$ 151	$ 261	$ 401	
Net Plant in Service		$ 207	$ 782	$ 1,548	$ 2,327	$ 3,075	$ 3,793	
TRR/NPiS		$ 0.200	$ 0.200	$ 0.200	$ 0.200	$ 0.200	$ 0.200	estimated metric
Total/Rate Revenue Requirement		$ 41	$ 156	$ 310	$ 465	$ 615	$ 759	
increase, $ million			$ 115	$ 268	$ 424	$ 574	$ 717	

TAB 5

Ontario

Howard I. Wetston, Q.C.

Chair & CEO

Ontario Energy Board

SPEECH

Ontario Energy Association

Annual Conference

Niagara Falls, Ontario

September 21, 2010

Check against delivery

Good morning. Thank you John (McGrath) for your introduction. Speaking today gives me an opportunity to recognize the success of the Ontario Energy Board (OEB or Board) on this, its fiftieth Anniversary. For 50 years, the OEB has been pursuing the public interest – that most elusive of goals. Our focus has always been on protecting the interests of consumers: through the introduction of competition in the natural gas industry; putting in place the regulatory instruments necessary to implement the restructuring of the electricity industry; and developing innovative ratemaking approaches.

But let me sharpen the focus of my remarks by highlighting the past two years. Since early 2009, the Board has completed a number of initiatives necessary to facilitate the advancement of the government's policy goals as expressed in the Green Energy and Green Economy Act (GEA). We are confident that we have put in place an appropriate regulatory framework that has five essential building blocks. They are:

1. Reforming the connection process for generators, making it more rational and efficient;

2. Standardizing billing and settlement processes for Feed-In Tariff (FIT) and microFIT generators;

3. Reforming our cost responsibility rules for renewable generation connections;

4. Providing guidelines on the accounting treatment of distributor-owned generation, as a non rate-regulated activity; and

5. Encouraging rational planning and investment to facilitate network expansion.

As such, while this framework promotes activities undertaken to fulfill the objectives contained in the GEA it might be considered as a separate policies. I prefer to look at them as more unified and encouraging a cost effective and efficient path from production to delivery to consumption.

The energy sector – not just in Ontario, but in jurisdictions around the globe – has undergone considerable change in the past 10 years. That change can be seen through the escalating importance of environmental and social goals that underpin sustainable development worldwide. In effect, "legacy" obligations remain unchanged while new policies add new layers. It is my opinion that the Board has an important responsibility to integrate these newer components into a coherent whole. Integration requires a recognition of the interdependence among the issues.

As a result of policy changes, new and significant demands are being placed on the sector's infrastructure. One of the results is a growing unease about the cost of electricity.

Obviously, the upward pressure on energy costs comes from a variety of sources:

- The need for new and upgraded infrastructure,
- Ongoing costs to maintain system operability and reliability,
- The cost of the infrastructure necessary to incorporate renewable generation,
- Smart meter deployment,
- Conservation initiatives.

Managing those pressures in a higher cost environment on behalf of the consumer is central to the Board's work, although the Board does not have direct oversight of some of these costs. However, the Board is aware that by facilitating network investment we enable some of these costs.

As we consider how best to address those pressures, we want to ensure that the Board itself, and the entities that we regulate, focus on outcomes. In my view, the Board should, in addition to applying its traditional cost of service analysis, begin to view the setting of rates from an additional perspective. This perspective should consider where we want to end up in terms of an outcome. We need to focus on the results achieved, measured against both the policy goals of the GEA and the ultimate costs to consumers. The Board is therefore seeking to better identify and articulate its own objectives in terms of the results that its various initiatives are in fact achieving.

This approach goes beyond measuring Board performance based solely on achievement of a particular goal through issuance of a policy paper or new Code, for example. We want to focus on long-term outcomes that clearly identify the desired impact on the consumer and the sector that we wish to achieve. We are pursuing this approach for our next business plan.

At the same time, the Board also intends to examine how well utilities consider long-term outcomes and impacts on customers as they plan their activities and come forward to the Board for cost recovery.

Performance is an important goal of economic regulation. As such, we need to focus on how well the utilities across the province achieve results and we need to improve our approaches to measuring results. After all, we want to encourage efficiency and discourage inefficiency.

So let me take a few minutes to discuss how we intend to ensure that our approach to this important work evolves along with the sector. We are at the beginning stage of this process and more detail will come shortly as each particular initiative takes shape.

Managing Cost Increases

The Board recognizes that the renewal and expansion of electricity infrastructure is one of the factors that will contribute to increased costs for Ontario consumers. On the other hand I do not wish to suggest that this renewal and expansion is not vital for Ontario consumers. It will be necessary to manage the impact of capital investments. In doing so, it will be important to acknowledge the contribution that utilities can make to ensuring that sustainable investments are made.

Given the magnitude of anticipated cost increases, the Board believes that, as we approach our next planning cycle, our regulatory work should properly focus on three key issues:

- Enhancing the cost effectiveness of networking system investment planning;
- An improved approach to determining appropriate cost levels in the Board's cost of service reviews, i.e. cost management; and, finally
- A review of the manner in which costs are recovered in rates.

Our goal is a framework which incents utilities to control costs as they plan, and reduces the need for rate mitigation measures later on.

Let me expand on the first challenge of enhanced network investment planning. Adding infrastructure to connect new renewable generation will affect customer bills in at least two ways: 1) higher network charges and 2) higher global adjustment.

The Board therefore intends to consider refinements to its policy regarding the assessment of distributors' infrastructure investment plans. The objective of this work is to ensure that the plans are economically efficient and cost effective. The Board will consider how best to ensure that investment proceeds at a pace and is prioritized on a basis that has regard both to demonstrated need and the cost implications for consumers. This approach may require an assessment of the combined cost impact of both the network investment and the generation that is connected by that investment.

The Board will also address the fact that an individual distributor's planning process may not, if considered in isolation, facilitate the lowest cost investment to meet the renewable energy and smart grid objectives under the GEA. Moreover, as I have suggested in the past, we may require greater regional coordination among distributors with respect to their planning.

The second related issue I mentioned was improved cost management. Given the likelihood of cost increases driven by the need to incorporate renewable energy sources, the Board will consider different approaches it might use to determine appropriate cost levels in the cost-of-service reviews for distributors. The purpose of this initiative is to ensure distributors manage their costs with regard to overall impact on rates paid by consumers. I believe we will need to focus on increasing efficiency not only to manage rate increases but to minimize the need for those increases.

It is my expectation that our work regarding distributor investment planning and the management of costs will inform the Board's review of how costs are recovered through rates. Our rate recovery focus may include a review of our current mitigation policy. The Board's rate mitigation policy was first established in 1999 under a different policy context than that of the Green Energy Act. The Board's 2006 Electricity Distribution Rate Handbook states, among other matters, that an "applicant must file a mitigation plan if total bill increases for any customer class or group exceed 10%". Back in 1999, however, the concern was rate impacts resulting from a change in rate design with rate unbundling. The objective of this review will be to examine ways to better promote gradualism in rates or bill increases. For example, over a utility's cost of service and incentive regulation mechanism (IRM) rate cycle, is there an optimal shape to the annual change in customer rates?

Existing Initiatives

A number of the Board's existing initiatives fit well with this refocus of the Board's priorities. For instance, work we are conducting on reliability standards, and the impact it will have on asset management decisions, will continue alongside the broader cost management initiative I have just outlined. The objective of the project is to establish appropriate reliability standards and performance targets for utilities. I expect we will go beyond simple measurements like current cost per customer metrics. The Board has already conducted an extensive survey of residential, commercial and industrial consumers on issues of system reliability, which it intends to make public shortly. We are holding a one-day stakeholder conference next month to solicit more in-depth feedback. The Board will use the information it gathers through its research to begin work on developing an effective reliability regime.

We are also evaluating the current methodology and structure of time-of-use (TOU) prices and considering the impact of changes in the supply mix and costs on those TOU prices. We are examining how we allocate different types of generation between periods and options for changing the periods' structure. As the Board moves toward the November Regulated Price Plan (RPP) reset we will consider whether additional changes need to be made in the short term for cost allocation that may increase incentives for load shifting.

Adjustments the Board has already made in the past 18 months include shifting the off-peak period to start an hour earlier at 9:00 p.m. and allocating the cost of peaking generation to the peak period. I fully expect the RPP and TOU methodology will continue to evolve going forward as we are committed to a program that effectively incents consumers to shift loads. But the principle of total cost recovery will remain central.

It is well known that consumer protection has been a core focus of the Board, whether it is through our compliance and enforcement work or through our work to inform consumers of their rights related to the energy sector. Scheduled to take effect January 1, 2011, the *Energy Consumer Protection Act, 2010* (ECPA) will enhance our role in a number of ways.

As you know, the ECPA focuses principally on three areas: retailers and marketers, disconnections and security deposits and suite metering. We are currently preparing extensive amendments to Board codes and rules related to retailers and marketers.

Some examples of work which will be undertaken in the next while include:

- Standard verification scripts to be used with potential customers; and
- Neutral, basic information in a disclosure statement that will help consumers make an informed choice before signing a contract.

We will also be conducting audits of the companies to ensure they are complying with the ECPA. To facilitate this important work we are creating a new Consumer Protection unit that consolidates within one department all our existing activities relating to retailers, marketers and energy consumers.

In July we adopted new province-wide customer service standards for electricity utilities. These new standards include very briefly, among others:

- 10-day notice before disconnection for non-payment;
- Arrears management programs; and
- Equal monthly payment plans

We welcome these new Consumer Protection responsibilities that build upon the work we already have underway.

Speaking more generally, the Board believes its overall approach to inform consumers is beneficial to the energy sector as a whole. Our new website dedicated to consumers provides information they need to know about the electricity and natural gas markets without all of the industry jargon. It is easier to understand and cuts straight to the information most pertinent to the consumer. The recent work we have done to explain the components of energy bills in a simpler way has been well received by consumer's. Our new, online calculators for gas and electricity bills quickly became the most popular pages on our site after they were launched in July.

I would be remiss if I did not also share some news on our gas work in the natural gas sector. As many of you will know already, the Board has initiated a review and examination of recent developments in North American natural gas supply markets. The purpose of the review is to assess how natural gas markets in Ontario are responding or adapting to changing market conditions, particularly due to increased shale gas production at Marcellus. The review will look at impacts over the next three to five years including the potential impact on prices, services and transportation infrastructure utilization. A specific objective of this initiative is to determine the need for regulatory changes, if necessary, in response to potential impacts identified. The Board will hold a stakeholder conference on October 7 and 8, 2010 to provide a forum for discussion of these recent developments in North American natural gas supply markets and the implications for the Ontario natural gas sector.

Conclusion

Let me close by promising that more detail on our cost management work will be shared in the coming months. We look forward to working with all of you as the Board develops these initiatives in a coordinated manner. We are in a transformational stage, and I believe the OEB has an important role to play. Effective regulation promotes smart transformation. It encourages the right amount of investment and new technologies while maintaining reliability, affordability and sustainability.

Thank you

TAB 6

See reference to
OEB 2010 Analysis
at page 95 of the
Auditor General's Report,
Chapter 3.03 at Tab 17
of this Brief.

TAB 7

The capital investments outlined are through both the private and public sector, and the majority will be paid for by electricity consumers spread over many years, depending on the cost recovery mechanism. (For example, electricity generators typically recover their investment over 20 years, whereas transmission investments may take up to 40 years to be fully repaid). This ensures that the annual costs to consumers, as reflected on electricity bills are spread over a longer period of time.

Conservation expenditures in this Plan include direct program costs and additional capital expenditures driven by higher appliance energy efficiency standards and higher building code efficiency standards.

Overall, renewables account for one third of total expenditures, nuclear just over one third, and natural gas, conservation and transmission the remainder. The breakdown is reflective of the Plan's objective to deliver a balanced and diverse supply mix that is cost effective, clean and helps create clean energy jobs.

7 electricity prices

Over the past 20 years, the price of water, fuel oil and cable TV have outpaced the price of electricity. Over the next 20 years, Ontario can expect stable prices that also reflect the true cost of electricity. The government will need to take a balanced and prudent approach to investment and pricing that ensures that Ontario's children and grandchildren have a clean, reliable system.

Ontarians now pay the true cost of electricity to ensure that essential investments are made in clean energy and modern transmission. About 40 per cent of Ontario's electricity generation is subject to price regulation, contributing significantly to predictable prices for Ontario consumers. Regulated Price Plan (RPP) rates (adjusted every six months) ensure pricing reflects the true cost of generating electricity. This helps to provide stable and predictable electricity prices for consumers.

Accomplishments

In 2003, the electricity system was in significant decline but Ontario families and businesses have invested in the creation of cleaner sources and the restoration of reliability. The cost of energy has increased in order to provide cleaner, more reliable energy for generations to come.

The government has also taken several steps to keep the cost of electricity down for Ontario families and businesses. Actions taken to prudently manage expenditures total over $1 billion, including:

- Freezing the compensation structures of all non-bargained public sector employees for two years – which include the five energy agencies.
- Limiting travel costs and other expenses for public sector workers.
- Requesting that Hydro One and Ontario Power Generation revise down their 2010 rate applications to find savings and efficiencies.
- The IESO has reduced costs by $23 million over the past seven years.
- For 2011, the OPA has reduced its overall operating budget by 4.1 per cent.
- Hydro One will reduce operations costs by $170 million in 2010 and 2011. Information technology upgrades will save $235 million over the next four years.
- OPG is reducing operations costs by more than $600M over the next four years.

Ontario has taken steps to lower the hydro debt left by the previous government. In 1999, the restructuring of Ontario Hydro and the attempt to sell-off Hydro left electricity consumers with a debt of $20.9 billion. Since 2003, Ontario has decreased that stranded debt by $5.7 billion. Payments toward the debt are made through Payments in Lieu of Taxes, dedicated income from government energy enterprises, and by ratepayers through the Debt Retirement Charge.

The government has also launched a number of initiatives to help Ontario families and businesses manage electricity bill increases. Some of these include:

- The Northern Ontario Energy Credit, a new, permanent annual credit to help families and individuals in the North who face high energy costs. The yearly credit of up to $130 for a single person and up to $200 for a family would be available to over half of all northern Ontario households.
- Ontario Energy and Property Tax Credit, starting with the 2010 tax year, to low-income Ontarians who own or rent a home would receive up to $900 in tax relief, with seniors able to claim up to $1,025 in tax relief to help with both their energy costs and property tax. Overall, the proposed Ontario Energy and Property Tax Credit would provide a total of about $1.3 billion annually to 2.8 million Ontarians.

Energy Consumer Protection Act, 2010:

On January 1, 2011, new rules will take effect under the Energy Consumer Protection Act, 2010 that will help protect electricity and natural gas consumers by putting an end to unfair practices by energy retailers. The rules will ensure that consumers receive accurate price disclosure from all energy retailers before they sign contracts, helping to protect Ontario families and seniors.

Ontario is helping low-income Ontarians with their energy costs through a province-wide strategy to help consumers better manage their energy consumption and costs, including:

- Establishing a new emergency energy financial assistance fund.
- Implementing enhanced customer service rules that will assist all customers, particularly low-income Ontarians.

Ontario is also developing a comprehensive electricity conservation program for low-income households in coordination with the natural gas utilities. Through the conservation measures, customers will be better able to manage their energy bills.

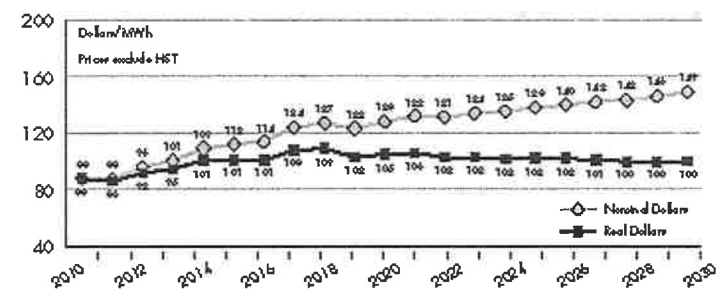
The Plan

Industrial Users

Due to investments to make the electricity system cleaner and more reliable for industry, the government projects that the industrial rate will increase by about 2.7 per cent annually over the next 20 years. The Ontario government has introduced initiatives to enhance the efficiency and competitiveness of large industrial consumers as well as protect jobs and local economies. These include:

- The Industrial Conservation Initiative will help the province's largest industrial and manufacturers to conserve energy, save on costs and increase their competitiveness. By changing the Global Adjustment Mechanism, large industrial users can shift their usage off peak times and save on electricity costs.
- The OPA's Industrial Accelerator Program has been launched to assist transmission-connected industrial electricity users to fast-track capital investment in major energy-efficiency projects.
- The Northern Industrial Energy Rate Program provides electricity price rebates for qualifying northern industrial consumers who commit to an energy efficiency and sustainability plan. On average, the program reduces prices by about 25 per cent for large facilities.

FIGURE 14: INDUSTRIAL PRICE PROJECTIONS (2010-2030)



Helping Ontario Small Businesses and Families

In order to ensure that Ontario has a clean, modern system that increases renewables, ensures reliability and creates jobs, continued investments in the electricity system are essential.

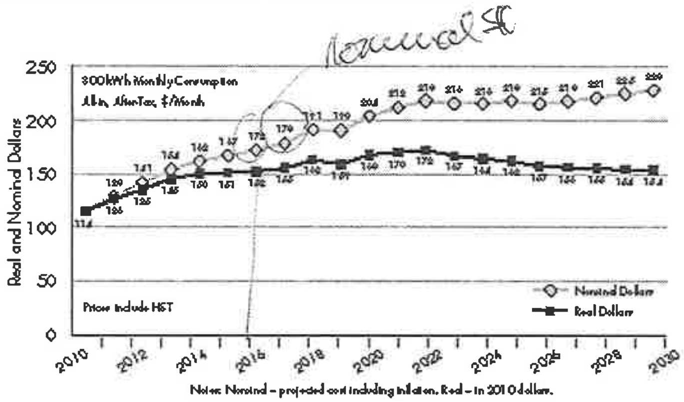
Based on the significant investments in clean, modern energy outlined in this plan, the government projects, based on current forecasts, that electricity prices will increase. Over the next 20 years, prices for Ontario families and small businesses will be relatively predictable. The consumer rate will increase by about 3.5 per cent annually over the length of the long-term plan.

Over the next five years, however, residential electricity prices are expected to rise by about 7.9 per cent annually (or 46 per cent over five years). This increase will help pay for critical improvements to the electricity capacity in nuclear and gas, transmission and distribution (accounting for about 44 per cent of the price increase) and investment in new, clean renewable energy generation (56 per cent of the increase).

Continued investments in transmission, conservation and supply are needed for a system that provides more efficient and reliable electricity to consumers whenever they need it and does not pollute Ontario's air or negatively affect the health of citizens and future generations.

After five years, Ontario will have largely completed the transition to a cleaner more reliable system due to the replacement of coal-fired generation and new renewable generation under the GEA. Once these investments have been made, price increases are expected to level off. The investments that the entire province is making in the future of electricity will help to ensure that Ontario never finds itself in the dire straits it was in just seven years ago.

FIGURE 15: RESIDENTIAL PRICE PROJECTIONS (2010-2030)



However, in the next five years, the government recognizes that the increases will have an impact on Ontario families and businesses.

The government's 2010 Ontario Economic Outlook and Fiscal Review took action to help Ontarians who are feeling the pinch of rising costs and electricity prices. The Ontario government proposed direct relief through a new Ontario Clean Energy Benefit (OCEB).

For eligible consumers, the proposed OCEB would provide a benefit equal to 10 per cent of the total cost of electricity on their bills including tax, effective January 1, 2011. Due to the length of time required to amend bills, the price adjustments would appear on electricity bills no later than May 2011, and would be retroactive to January 1, 2011.

Every little bit of assistance helps during lean times. The proposed OCEB together with the Northern Ontario Energy Credit and the Ontario Energy and Property Tax Credit will all help mitigate electricity costs for families.

Eligible consumers would include residential, farm, small business and other small users. The proposed OCEB would help over four million residential consumers and over 400,000 small businesses, farms and other consumers with the transition to an even more reliable and cleaner system.

Benefits for Eligible Consumers

Customer Monthly Consumption	Current Estimated Monthly Bill	Estimated Bill after Ontario Clean Energy Benefit	Monthly Benefit* (10%)	Yearly Benefit (10%)
Typical Residential 800kWh	$128	$115.20	$12.80	$153.60
Small Business 10,000kWh	$1,430	$1,287	$143	$1,716
Farm 12,000kWh	$1,710	$1,539	$171	$2,052

*Typical 2011 monthly benefit for a consumer. Benefit amount will vary based on actual price, consumption and location

Providing the 10 per cent OCEB to Ontarians is a responsible way of helping Ontario families and businesses through the transition to a cleaner electricity system. The OCEB would help residential and small business consumers over the next five years as the grid is modernized. The government has introduced legislation to implement the proposed OCEB.

Working together to reduce electricity use at peak times makes sound economic and environmental sense. Providing consumers with the benefit of up-to-date and accurate electricity consumption readings is also critical to the creation of a culture of conservation. The government is committed to moving forward with implementation of a Time-of-Use pricing structure that balances benefits for both the consumer and the electricity system as a whole.

To help families, Ontario will move the off-peak period for electricity users to 7 p.m. which will provide customers with an additional two hours in the lowest cost period. This change will be in effect for the May 2011 Regulated Price Plan update.

This plan has outlined a new clean, modern and reliable electricity system for the people of Ontario. Instead of a system that was polluting, unreliable and in decline with unstable pricing, Ontarians will have a North American-leading clean energy system that keeps the lights on for generations to come, creates jobs for Ontario families and ensures that the air they breathe is cleaner.

TAB 8

Ontario Energy Board

Commission de l'énergie de l'Ontario

Ontario

EB-2010-0002

IN THE MATTER OF AN APPLICATION BY

HYDRO ONE NETWORKS INC.

2011 and 2012 TRANSMISSION REVENUE REQUIREMENT AND RATES

DECISION WITH REASONS

December 23, 2010

TABLE OF CONTENTS

EB-2010-0002

IN THE MATTER OF the *Ontario Energy Board Act 1998*, S.O.1998, c.15, (Schedule B);

AND IN THE MATTER OF an application by Hydro One Networks Inc. for an order or orders approving a transmission revenue requirement and rates and other charges for the transmission of electricity for 2011 and 2012.

BEFORE: Paul Sommerville
Presiding Member

Ken Quesnelle
Member

Paula Conboy
Member

DECISION WITH REASONS

DECEMBER 23, 2010

BACKGROUND

On May 19, 2010 Hydro One Networks Inc. (Hydro One, the Applicant, or the Company) filed an application for 2011 and 2012 transmission revenue requirement and rates. The revenue requirement and charge determinants approved for Hydro One in this proceeding would be combined with other licensed Ontario transmitters to determine the Uniform Transmission Rates (UTRs) for 2011 and 2012. The Board assigned file number EB-2010-0002 to the application and issued an approved issues list on July 20, 2010.

Hydro One Networks Inc. is the largest electricity transmitter in Ontario with approximately 29,000 circuit kilometers of transmission line, 247 transformer stations and 33 switching stations. The network connects 91 generating stations, 51 Local Distribution Companies (LDC's) and 65 end-use transmission customers (89 connection points).

Hydro One sought approval of a transmission revenue requirement of $1,446 million for 2011 and $1,547 million for 2012, and approval of changes to the provincial UTRs that are charged for electricity transmission, to be effective January 1, 2011 and January 1, 2012.

The Board issued Procedural Order No.1 on June 28, 2010, establishing the procedural schedule for a number of early events and included a draft issues list.

The timing of the filing of the application was influenced by the receipt by the Company of a letter from the Minister of Energy, the sole shareholder of the Company on May 5, 2010. The Company's original proposal was held back in order to allow the Company to accommodate the Minister's instructions to re-focus the Company's proposals in the application to only those spending proposals necessary to ensure the safe and reliable operation of the system, and the implementation of capital programs specifically identified by the Ontario Power Authority as required immediately. The Company reviewed its application in light of the Minister's instruction and made consequential changes. The extent and adequacy of those changes was a matter of dispute among the parties in this case.

Intervenors

The following intervenors took an active role in this proceeding: Vulnerable Energy Consumers Coalition (VECC), Building Owners and Managers Association of the Greater Toronto Area and the London Property Management Association (BOMA/LPMA), School Energy Coalition (SEC), Canadian Manufacturers and Exporters (CME), Consumers Council of Canada (CCC), Energy Probe Research Foundation (Energy Probe), Association of Major Power Consumers in Ontario (AMPCO), Power Workers Union (PWU), Ontario Power Authority (OPA), Independent Electricity System

Operator (IESO), Association of Power Producers of Ontario (APPrO), Bruce Power, HQ Energy Marketing Inc., Pollution Probe and Toronto Hydro-Electric System Limited (THESL). A full list of all 27 intervenors in this case is attached in Appendix "A".

Hydro One Motion

Hydro One brought a motion before the Board on June 16, 2010 requesting an order severing the issue of the AMPCO proposal to alter the method of determining the transmission network charge, termed the "High 5 Proposal" (Issue 8.1), for review and assessment in a separate generic proceeding. The Board heard this motion on July 20, 2010 and denied the motion in an oral decision delivered on that day. The Board also issued its decision on the draft issues list in the same oral decision. That approved issues list was attached to Procedural Order No. 2, issued on July 21, 2010.

A copy of the decision on the motion is attached as Appendix B and the approved Issues List is attached as Appendix C.

Canadian Manufacturers and Exporters Motion

CME brought a motion before the Board on the first day of the oral hearing, September 20, 2010, requesting an order requiring Hydro One to produce certain materials provided to the Hydro One Board of Directors and requested in CME Interrogatories 1 and 2. The Board granted the motion in an oral decision on September 20, 2010.

A copy of the decision on the CME motion is attached as Appendix D.

Intervenor Evidence

Two intervenors filed evidence before the Board: AMPCO provided evidence on the High 5 charge determinant issue (Exhibit M-1), and CME provided evidence on Total Ontario Electricity Bill Impacts (Exhibit N-1).

Settlement Conference

A settlement conference for this proceeding was held on September 16, 2010, however no settlement was achieved.

The Hearing, Submissions and Evidence

The oral hearing for this proceeding took place in September and October 2010, concluding with Hydro One's oral argument-in-chief on October 7, 2010.

Board staff and intervenor submissions were filed on October 22, 2010 and November 2, 2010 respectively. The IESO filed its submissions on October 15, 2010. Hydro One submitted its reply argument on November 12, 2010.

Copies of the evidence, exhibits, submissions and transcripts of the proceeding are available for review at the Board's offices or on the Board website, www.oeb.gov.on.ca.

Further procedural details are found in Appendix A.

Confidentiality

During the proceeding, confidential treatment was requested for a number of documents. These documents are filed at the Board's offices.

The Board considered the full record of the proceeding but has summarized the record only to the extent necessary to provide context to its findings.

TOTAL BILL IMPACTS

One issue that was raised over the course of this proceeding was whether the Board should consider total bill impacts affecting Hydro One transmission customers and not just the bill impacts associated with this specific transmission rates application.

In support of the proposition that the Board should take the broader view, on August 26, 2010 CME filed evidence prepared by Bruce Sharp of Aegent Energy Advisors Inc. entitled Ontario Electricity Total Bill Impact Analysis, August 2011 to July 2015. This analysis included a forecast of the impacts of a number of factors other than transmission rates, including the price of the commodity, taxation effects, such as the Harmonized Sales Tax, anticipated increases in distribution rates, the advent of Time of Use (TOU) pricing, and expected government initiatives.

The analysis concluded that non-residential electricity costs would increase at an annual compound rate of 8.0 to 10.4 percent (depending on usage levels) from August 2010 to July 2015. For residential customers, electricity costs would increase at an annual compound rate of 6.7 to 8.0 percent (depending on usage levels) over the same time period. It is common ground that increases of this magnitude, if realized, would be quite significant for both residential and non-residential customers.

In response to a Board staff interrogatory, CME provided additional background to the evidence including how it proposed to use the evidence in this proceeding. CME stated that,

> "Having regard to the Board's obligation under the *Ontario Energy Board Act, 1998* (the *"OEB Act"*) to protect consumers with respect to electricity prices when carrying out its responsibilities under the *Act*, a consideration by the Board of evidence of the total bill impacts customers are experiencing and facing is mandatory."

In its argument-in-chief, Hydro One indicated that it did consider rate impacts in developing its rate proposals but did not expressly take into account extraneous cost pressures which are beyond its control. Hydro One stressed that it does not have any particular ability to take those costs into account, even if it were able to estimate them and even if it was thought appropriate to do so.

Hydro One argued that its paramount duty is to maintain and develop a safe, reliable transmission system, determining what investments are necessary to achieve the safest, most efficient and most reliable transmission system, now and in the future. Hydro One maintained that the current rate proposal, if approved, would enable Hydro One to achieve those objectives.

Hydro One submitted that it made no sense to reduce the needed funding to Hydro One for its transmission network because of the overall impact of a host of factors beyond its control. Hydro One's proposal in this case is an essential link in the chain of supply and delivery of electricity for the Province and it should not be curtailed or prevented from doing its job because of external cost pressures arising from other factors unrelated to the transmission of electricity.

CME took the lead on this issue in filing evidence as noted above. After reviewing the pricing pressures outlined in the Aegent evidence, CME submitted that the overall electricity price increases customers are likely to face over the course of Hydro One's five year planning cycle are a critical consideration when determining the overall reasonableness of the revenue requirement amounts Hydro One is asking the Board to approve.

CME also submitted that when exercising its rate-making jurisdiction under the OEB Act, the Board should give a particularly high priority to its statutory objective of protecting consumers with respect to electricity price increases. In its view, this is especially important during a period where significant overall price increases are anticipated.

CME acknowledged the Board's October 27, 2010 letter outlining three policy initiatives effecting its rate-making practice, designed to manage the pace or rate of bill increases for consumers. However, CME still emphasized that the Board's plan to proceed with these initiatives should not detract from its duty to discharge its statutory obligation in this case, and in every other rates case.

CME also argued that:

- Government policy does not override the Board's obligation to approve revenue requirements and resulting rates for Hydro One that are just and reasonable and in accordance with the Board's obligation to protect consumers with respect to electricity price increases.
- Government policy should not trump the Board's consideration of matters pertaining to economic feasibility. As an independent economic regulator, mandated by statute to carry out its responsibilities so as to protect the overall public interest, the Board should adopt a guarded approach when evaluating the utility spending implications of such policies.
- Government directives made to Hydro One in its capacity as the utility owner, stand on no higher footing than directives Enbridge Inc., the parent of Enbridge Gas Distribution Inc., might provide to its utility, or that Spectra Energy, the parent of Union Gas Limited, might provide to Union. The spending implications of such directives stand to be carefully scrutinized by the regulator for reasonableness. Formal or informal directives a utility receives from its

> Government owner do not preclude the Board from considering matters pertaining to the economic feasibility and prudence of the outcomes of such directives. The Board is not obliged to approve Hydro One's spending plans because they stem from directives it has received from its owner.

CME submitted that the applied-for revenue requirement should be reduced in one or more of the following areas:

(a) Approval of reduced Operation, Maintenance and Administration expense envelopes for 2011 and 2012;

(b) Approval of reduced Capital Expenditure envelopes for 2011 and 2012; and/or

(c) Approval of a reduction in Equity Return and related taxes in 2011 and 2012 to the extent that system safety and integrity is not compromised.

CME argued that if Hydro One's owner is sincerely concerned about the electricity price increases consumers are facing, then it should readily waive the amount of investment return that is not needed to support Hydro One's utility-related activities such as the dividends and related taxes Hydro One is planning to flow through to its owner in 2011 and 2012. CME maintained that the notion argued by Hydro One that temporarily reducing the equity return Hydro One realizes from its ratepayers requires taxpayers to subsidize ratepayers, lacks merit. CME submitted that by allowing Hydro One's owner to recover more than the actual costs of capital it incurs for utility purposes, ratepayers are subsidizing social programs.

Simply put, CME's submission is that in the significant electricity price increase environment that currently prevails, the appropriate regulatory response to Hydro One's application is for the Board to approve revenue requirement envelopes for 2011 and 2012 that reflect further reductions in the OM&A and Capital Expenditure envelopes of the types suggested by Board staff and other intervenors, along with a temporary disallowance of equity return and related taxes not needed to maintain system safety and integrity. CME provided a confidential schedule to their argument containing its estimates of these dividend and related tax amounts.

CCC focused its submissions on the Total Bill Impact on a decision of the Court of Appeal for Ontario in the case of *Toronto Hydro-Electric System Limited v. Ontario Energy Board.*

In that decision, the Court of Appeal made the following observation:

> The principles that govern a regulated utility that operates as a monopoly differ from those that apply to private sector companies, which operate in a competitive market. The directors and officers of

> unregulated companies have a fiduciary obligation to act in the best interests of the company (which is often interpreted to mean in the best interests of the shareholders) while a regulated utility must operate in a manner that balances the interests of the utility's shareholders against those of its ratepayers. If a utility fails to operate in this way, it is incumbent on the OEB to intervene in order to strike this balance and protect the interests of the ratepayers.[7]

CCC argued that Hydro One did not balance the interests of its shareholders and the interests of its ratepayers. With regard to the cost reductions undertaken by Hydro One in response to ministerial directions, CCC submitted that those reductions were due to the impacts of the EB-2009-0096 distribution decision and the deferral of Green Energy related projects, not made on the Company's own volition to protect the interests of consumers.

In its argument-in-chief, Hydro One stated:

> "The profits earned by the company through its allowed rate of return are, ultimately, paid to the province and are used to support a host of social programs, such as, for example, our school system. If we are to reduce the allowed return because of customer impacts, this implicitly means that the taxpayers of Ontario will be subsidizing the electricity users of Ontario." (Tr., Vol. 11, p. 16)

CCC submitted that the Board should draw three conclusions from this admission.

- Hydro One does not need its requested level of ROE for commercial reasons;
- Hydro One could reduce its ROE without compromising the safety or reliability of its system; and
- Hydro One has chosen to prefer the interests of its shareholder over than of its ratepayers.

In addition, CCC submitted that the projects for which the company does not offer evidence of prudence should not be approved for recovery in rates.

CCC submitted that imperatives for a Green Energy Plan were created by the government through legislation. The Minister, in his capacity as the representative of the shareholder, provided, in the September 21, 2009 letter, the direction to Hydro One to

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7 (*Toronto Hydro-Electric System Limited* v. *Ontario Energy Board*, 2010 ONCA 284, para 50)

begin development work on GE projects. The Minister's direction should be given no greater weight than should the direction of any other shareholder. The projects are to provide transmission links to Green Energy supply sources. The sources of supply have been approved by the OPA.

Hydro One has no role in the decision about whether the supply is required, whether the particular renewable energy source is a reasonable one, and, therefore, whether the overall transmission link is prudent. The overriding obligation of the Board is to approve just and reasonable rates, pursuant to section 78 of the OEB Act. The Board cannot, and should not do that in circumstances where Hydro One cannot provide evidence of the prudence of the overall project.

In summary, CCC submitted that:

1. the Board should find that Hydro One has failed to fulfill its obligation to balance the interests of its shareholder and that of its ratepayers;

2. given Hydro One's failure to balance the interests of its shareholder and its ratepayers, the Board is obligated to do so;

3. in order to strike the appropriate balance, the Board should further reduce Hydro One's revenue requirement to ensure that the Total Bill Impact is minimized to the extent possible;

4. the Board should not approve projects, and the cost consequences of projects, which Hydro One does not direct and for which it has not provided its own, independent evidence of prudence.

VECC supported the arguments of CCC on this issue.

In reply, Hydro One recognized and agreed that the impact upon consumers is an important factor to be considered by the Board. The Board is obligated, pursuant to its mandate in section 1(1) of the *Ontario Energy Board Act,* to protect the interests of consumers with respect to prices. However, the Board's function is also to balance the interests of the electricity system, the utility and the consumer. Hydro One's application must be assessed upon the evidentiary record, and not on matters external to Hydro One which are beyond its control and have no evidentiary basis in the proceeding.

Hydro One submitted it would be contrary to the principles of rate making to artificially suppress rates and curtail necessary capital projects and other programs because there may be other matters, external to Hydro One, which also may impact the overall rates charged to customers. The transmission rate is just one aspect of a customer's total bill.

Hydro One did not suggest that the impacts upon consumers ought to be ignored. Hydro One maintained that it had already adjusted its rate proposal in consideration of customer impact issues. Hydro One mentioned its proposed costing exception to IFRS requirements in order to avoid a $200M increase in revenue requirement and its voluntary absorption of additional pension costs in 2011 and 2012.

Hydro One supported the Board initiatives which will assess how total bill impacts ought to be considered by the Board and other stakeholders in cost of service rate applications. Hydro One indicated that it expects to participate fully in the consultation process and submitted that this generic process is the appropriate venue to address this generic issue, not a specific transmission rates application.

Hydro One concluded by urging the Board to consider the evidence in the case, the specific supporting evidence filed to explain the reasons for the variances and increases. Hydro One urged the Board not to make what it termed to be the arbitrary reductions suggested by Board staff and intervenors.

Board Findings

The Board does not accept the intervenors' arguments with respect to denying Hydro One recovery of its calculated ROE. The cost of capital is a cost element in the revenue requirement determination - not a floating discretionary surplus. What is being suggested here is a kind of collateral challenge which is unsupported by evidence going to the appropriateness of the application of the ROE formula to this utility. If it is the view of the intervenors that the cost of capital determination pursuant to the Board's Cost of Capital Report is inappropriate, they may challenge it, as recognized in the Cost of Capital Report itself. Otherwise there is a presumption that the rate arrived at by the Cost of Capital Report mechanism will be applied to every utility.

The Board recognizes that it must balance consumer impacts with the interests of shareholders and strike a balance between the interests of the electricity system, the utility and the consumer. It is important that in managing the quantum of rate increases and the pace of change, the Board not sacrifice the safety and reliability of the system. Any utility, but perhaps most notably this utility, must first and foremost ensure that its current system is appropriately robust and effective. Enhancements or expansions of the system cannot be undertaken at the expense of core reliability and safety. Elsewhere in this decision the Board has stated that expansions to the system ought to be undertaken only where it can be demonstrated that the projects at issue have been subjected to and emerged from a thoughtful, transparent and inclusive regional planning process. That planning process would necessarily include a detailed financial analysis.

The Board recognizes that Hydro One has suggested ways to reduce bill impacts with its proposals for MIFRS, absorbing the additional pension costs for the test years, reducing dividend payments and various efforts to increase productivity by its staff. However, Hydro One needs to be treated like all other regulated utilities in Ontario, and provided with an equal opportunity to achieve a rate of return on equity, regardless of the identity of its shareholder.

The Board has ordered some reductions in this Decision that will work to reduce the bill impact on customers, based on what the Board heard in evidence and arguments. The Board also notes the October 27, 2010 announcement of its three policy initiatives to review ways of exercising its rate-making jurisdiction to manage the pace or rate of bill increases for consumers. This is the kind of generic forum where this issue, which cuts across various sectors and areas of the electricity pricing equation in Ontario, can also be addressed.

TAB 9

ONTARIO

OPEN for Business

BUSINESS SECTOR STRATEGY:

MANUFACTURING

Created with:

Canadian Manufacturers & Exporters (CME)

January 2011

Ontario

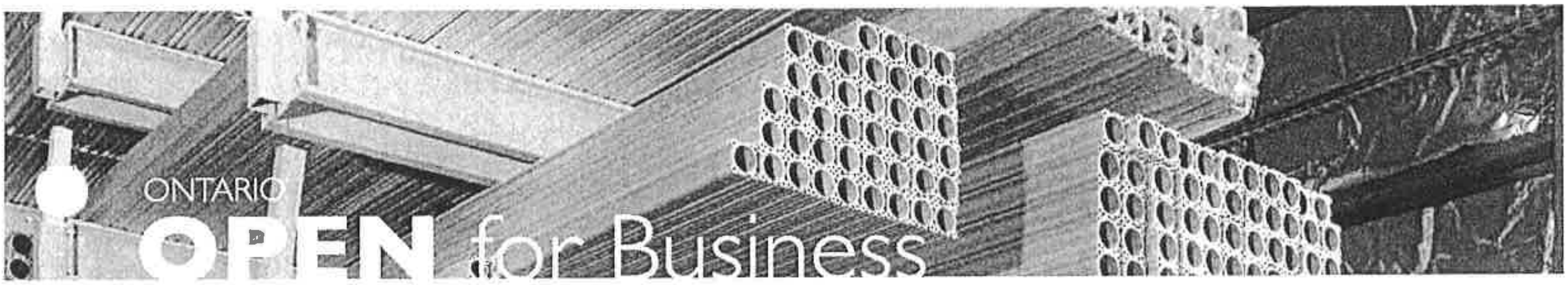
Open for Business is Ontario's initiative to create faster, smarter and streamlined government-to-business services and to establish a modern system of government by 2011. It's a key part of the Ontario government's commitment to make the Province more attractive to business while continuing to protect the public interest.

Open for Business has three key areas of focus:

Modern Government – create a streamlined and focused regulatory environment that delivers results for business, while protecting public interest

Modern Services – deliver better products, including service standards that support business needs

New Relationship with Business – create an open and responsive working relationship between business and government



Ontario's Business Sector Strategy

One of the ways Open for Business is implementing a new relationship with business is through the Ontario Business Sector Strategy which establishes an open dialogue and collaborative relationship between government and key business stakeholders.

Under the strategy, sector representatives are asked to identify five priorities under jurisdiction of the provincial government that would strengthen their sector's success. Ministries have two months to address these priorities, or explain why they cannot be addressed and deliver alternative solutions. This joint understanding of priorities allows government and the business sector to work together more effectively to generate economic growth, create jobs for Ontario families, and protect the public interest.

Open for Business is responsible for interfacing with ministries to ensure progress and resolution of each sector's issues within appropriate timelines.

Manufacturing Sector

Ontario's manufacturing industry generates $270 billion in annual sales and accounts for 18% of the province's GDP, employing over 12% of Ontario's total workforce.

Canadian Manufacturers & Exporters (CME) is Canada's largest industry and trade association, representing businesses in all sectors of manufacturing and exporting activity across Canada. Through their partnerships with other associations, CME's network extends to more than 100,000 companies from coast to coast, engaged in manufacturing, global business and service-related industries.

Manufacturing and Ontario's Business Sector Strategy

On August 18, 2010, Minister of Economic Development and Trade Sandra Pupatello held a roundtable with senior members of CME and other business leaders from the manufacturing sector. Joining the discussion were deputy ministers, and representatives from Cabinet Office, Open for Business, and the ministries identified in CME's priorities: Economic Development and Trade, Environment, Energy, and Labour.

Over a two-month period sector representatives and senior staff from the targeted ministries worked to arrive at mutually acceptable government responses to CME's priorities. Economic Development and Trade Minister Sandra Pupatello acknowledged that the process had been challenging. "This sector is made up of a broad, diversified group of industries, each with their own needs." Rob Hattin, Chair, CME Ontario Board of Directors and Vice Chair of the CME National Board of Directors agreed. "It has been hard work and frustrating for both sides. But Open for Business is a critical process and we appreciate the government's leadership in moving the process forward."

While much was accomplished during the Sector Strategy process, much still remains to be addressed. Plans are in place to move forward, and both the CME and government pledged their commitment to work together to achieve their mutually held goal to help Ontario grow and prosper.

Through the Ontario Business Sector Strategy, a foundation of collaboration and openness between government and business is being established that will continue to grow in the coming years.

Executive Summary
CME's Top Five Priorities

PRIORITY 1: Regulatory Impact on Manufacturers

CME recommended that the Ontario Regulatory Policy require an economic impact assessment be conducted each time a change in regulation or legislation is being considered by government, and that the Regulatory Policy be enshrined in regulation. The Association further requested that the assessment be transparent, allow for business participation and feature effective oversight to ensure adherence to the regulation. Lastly, CME requested a financial offset to help manufacturers manage an increase of compliance costs associated with regulatory change.

PRIORITY 2: Total Bill Impact Assessment for Energy

CME urged the Ministry of Energy to support CME's initiative to have the Ontario Energy Board establish a multi-year total bill impact analysis format for each electricity utility to complete and present when seeking approval for increases in its electricity rates. CME also asked that the ministry direct the Ontario Power Authority to adopt a total bill impact analysis for planning purposes.

PRIORITY 3: *Toxics Reduction Act*

CME recommended that the *Toxics Reduction Act* recognize and allow equivalency for existing environmental management programs to reduce the administrative burden for substance accounting. They also asked the ministry to reduce the administrative burden by grouping common substances together and require the creation of records for the group only.

PRIORITY 4: Air Standards (Reg. 419/05)

CME recommended that the government work towards a sustainable approach for developing standards and develop a policy to deal with the standards when obtaining a certificate of approval in order to maintain a timely approvals process.

PRIORITY 5: Ministry of Labour Inspectorate Challenges

CME suggested that a more formalized process be developed to address regulatory challenges and leverage solutions to manage the demands of increasing administrative issues. On a broader scale, CME suggested that the new process could help improve communications and the overall relationship between government and business.

Executive Summary
Government Response to CME's Top Five Priorities

PRIORITY 1: Regulatory Impact on Manufacturers

Ontario will introduce a mandatory regulatory economic impact assessment tool across all ministries, ensuring consistent and reliable analyses. To capture business input, consultation principles are in development with CME. Open for Business is considering enshrining the Regulatory Policy in regulation and a determination on this request is anticipated by early 2011. In regards to CME's request for a financial offset, the parameters of the Business Sector Strategy note that priorities with financial implications cannot be entertained.

PRIORITY 2: Total Bill Impact Assessment for Energy

The Ministry of Energy will work with the Ontario Energy Board to produce a report that outlines the total bill by cost component for all utilities based on a typical manufacturer's consumption. Furthermore, informal information sessions will be held between senior ministry staff and the CME to discuss pricing issues. The ministry has included CME in consultations on the development of the long-term energy plan and will ensure that the suggestion to use total bill impact analysis is considered for inclusion in the plan.

PRIORITY 3: *Toxics Reduction Act*

The Ministry of the Environment will ensure that guidance materials will be clear when existing prevention plans can be used and when supplemental information will be required. The ministry will work with CME on accounting and reporting requirements for specific substances and for substances in closed processes (January 31, 2011) and finalize accounting guidelines by January 31, 2011. The ministry met with CME (January 13, 2011) and other stakeholders (November 22, 2010) to discuss planner qualifications and requirements. On November 30, 2010, the Ministry of Environment posted a proposal to extend the timeline for toxic substance Phase I plans and plan summaries by one year. By Spring 2011, the ministry will establish a multi-stakeholder committee to assess and identify proposed updates to the prescribed lists of toxic substances and substances of concern.

PRIORITY 4: Air Standards (Reg. 419/05)

CME and the Ministry of the Environment agreed to meet in November 2010 and January 2011 to address air standards concerns and explore possible solutions. The ministry welcomes broad stakeholder involvement in the development of sustainable environmental regulations, and by February 3, 2010 the ministry will present a proposal to update the current terms of reference to the Multi-Stakeholder Group. The ministry, as well as other ministries, will use the new Regulatory Economic Assessment Tool (Priority #1) for new regulations, when it is rolled out by the government, and will work with MEDT and CME to develop a protocol to support the development of high quality regulatory impact assessments. The ministry will continue to consult with CME as well as other stakeholders on policy and regulatory initiatives.

Continued on next page...

PRIORITY 5: Ministry of Labour Inspectorate Challenges

The Ministry of Labour and CME have agreed to establish a Client Service Sub-committee and a Policy and Legislation Sub-committee to discuss key issues. The ministry will adopt a stronger client focus and work with CME to identify communication improvements and service enhancements to help employers, including small businesses, meet workplace health and safety obligations and achieve compliance with existing and new regulations.

Priority I

Regulatory Impact on Manufacturers

CME recommended that the Ontario Regulatory Policy include an economic impact assessment for each potential change in regulation or legislation, and that the Regulatory Policy be enshrined in regulation. The Association further requested that the assessment be transparent, allow for business participation and feature effective oversight to ensure adherence to the regulation. Lastly, CME asked for an offset to help manufacturers manage an increase of compliance costs associated with regulatory change.

Government Response

(Lead: Ministry of Economic Development & Trade/Open for Business; Associated Ministries: Cabinet Office)

Open for Business will implement a mandatory, regulatory economic impact assessment tool across government that will:

- Include a standard analytical framework and toolkit to estimate the direct compliance costs of proposed regulations on external stakeholders
- Utilize Statistics Canada data for consistent and reliable analyses
- Invite stakeholder engagement in advance of the decision-making process
- Apply to new and proposed amendments to regulations

The tool is based on a widely implemented, proven approach to economic impact assessment currently in use as part of regulatory development processes by the Government of Canada, several provinces, other jurisdictions around the world (e.g., European Union countries, the United States, etc.), and will calculate four types of direct compliance costs:

- Financial Costs (e.g., permits, fees and charges, etc.)
- Upfront Operating Costs (e.g., signage/notifications, training, new equipment, etc.)
- Ongoing Operating Costs (e.g., technology upgrades, equipment maintenance, etc.)
- Administrative costs (e.g., applications for permits, record keeping, etc.)

Consultation principles will be created to help strengthen the role of business in the regulatory decision-making process, ensuring that business is engaged early in the process and in a predictable manner. Initial principles have been developed:

Timely Consultation	Any engagement should begin when issues are identified allowing for careful consideration and commenting by consultation participants and when advice can be incorporated into any resulting action.
Clear Communication of Consultation Purpose	The issues at stake and reasons for consultation should be clearly communicated to business stakeholders. Where possible, participants should help to define outcomes.

Accessible Consultation	Tools and methods of consultation should be selected to maximize the opportunities for stakeholder participation.
Minimize the Burden of Consultation	Government to internally coordinate consultation activities to ensure a streamlined process and more meaningful engagement.
Acknowledge and Analyse Consultation Submissions	Government will provide stakeholders with an acknowledgement of their submission and analysis of the advice provided in the consultation within a defined timeframe.
Feedback Mechanism	Inviting business comment on the consultation process will allow for continuous improvement.

CME will provide principles describing the role that business can play in effective consultations and these will be included with those noted above.

The implementation strategy will ensure quality control and oversight by:

- Amending the Legislation and Regulations Committee templates and instructions to require the economic assessment analysis to be profiled in regulatory proposals
- Ensuring ministry accountability by continuing to require Ministers and Deputy Ministers to sign-off on all proposals
- Continuing to include Cabinet Office review of the quality of analysis presented in the proposals
- Driving analytical quality and ministry accountability through early and meaningful consultation with stakeholders
- Implementing an enterprise-wide process to track and report on Ontario Public Service compliance

The regulatory assessment tool will be implemented via a phased approach:

i. Open for Business will conduct internal education and training sessions

ii. Open for Business and Cabinet Office will finalize the business consultation guidelines (early 2011)

iii. Tool will initially be implemented with key regulatory ministries

iv. Full implementation of the tool across all ministries

Open for Business is exploring CME's request to enshrine Ontario's Regulatory Policy in regulation with legal counsel and is also conducting an analysis of approaches in other jurisdictions. The Minister of Economic Development and Trade is anticipated to make a determination on this request by early 2011.

In the meantime, Ontario will continue to implement and enforce the Ontario Regulatory Policy, a government policy that all ministries are required to follow per the legal requirements under the *Ontario-Quebec Trade and Cooperation Agreement*. Cabinet Office and Open for Business will oversee ministries' compliance with the requirements through internal tracking and reporting.

Due to the parameters of the Business Sector Strategy, CME's request for an offset (e.g. tax credit) where a regulatory change would increase the cost to business can not be entertained. It should be noted that regulatory changes are never proposed lightly and are often introduced to ensure a smooth, efficient and effective marketplace or to protect the health and safety of Ontarians.

Priority 2

Total Bill Impact Assessment for Energy

CME requested that the Ministry of Energy direct the Ontario Power Authority to adopt a total bill impact analysis for planning purposes.

Furthermore, CME urged the ministry to have the Ontario Energy Board establish a multi-year total bill impact analysis, or 'end of wire' cost, for each electricity distributor. This analysis would be presented when seeking Board approval for increases in electricity rates. This analysis would provide transparency and help manufacturers to make investment decisions and accommodate anticipated energy costs in their overall operating plans.

Government Response

(Lead: Ministry of Energy; Associated Ministries/Agencies: Ministry of Economic Development and Trade, Ontario Energy Board, Ontario Power Authority)

In their response, the Ministry of Energy explained the 'arms length' relationship between the ministry and the Ontario Energy Board and the independent rate-making process.

The ministry noted that an *Integrated Power System Plan*, a long-term energy plan for the province, was currently in development. The ministry committed to:

- Ensuring that consideration is given to directing the Ontario Power Authority to take total bill impacts on consumers into account
- Continuing to include CME in the development of the plan

During the Sector Strategy process, CME and the ministry agreed that greater transparency around electricity rates, including key cost drivers, and improved reporting that clearly breaks-out the overall costs would be useful. It was noted that the Board's independent rate-making process is guided by legislation that considers consumers' interests regarding price, adequacy and reliability of service, and it was agreed that this independent rate-setting process should remain untouched.

The ministry will work with the Ontario Energy Board to produce a report that sets out the total bill for each distributor by cost component for a typical manufacturer following distributor rate decisions made by the Ontario Energy Board. Furthermore, informal information sessions will be held between senior ministry staff and the CME to discuss pricing issues.

CME and the ministry declared their intent to maintain the dialogue to ensure that business input is reflected in the long-term *Integrated Power System Plan*.

Ontario Energy Board
The Board regulates the province's electricity and gas sectors in the public interest.

Ontario Power Authority
The Ontario Power Authority is responsible for ensuring a reliable, sustainable supply of electricity for Ontario. Licensed by the Ontario Energy Board, it reports to the Ontario Legislature through the Ministry of Energy.

Priority 3

Toxics Reduction Act

CME clearly supports meeting the intent of the *Toxics Reduction Act* in an efficient and effective manner. The following recommended solutions for delivering efficiencies are positive steps. However, it should be noted that these steps are unlikely to meet industry's primary concerns and as such, CME support for the recommendations is reserved.

Recognizing Existing Programs

For specific circumstances, to be further defined but includes examples such as copper used in copper cable manufacturing, reduce administrative burden for substance accounting by:

i. Defining subprocesses at a facility identical to the sub facility defined in the National Pollutant Release Inventory (NPRI).

ii. Utilizing the data reported to NPRI for substance accounting.

iii. Substituting relevant components of existing pollution prevention planning programs, such as ISO Plans, Environmental Management Systems (EMS) and Pollution Prevention (P2) Plans in place of detailed accounting and reduction plans.

iv. Grouping substances and creating records for the group only.

Toxic Planner Qualifications

CME supports the need for plans to be reviewed by competent persons, but believes that there are more effective approaches than licensing. Industry has provided substantive and relatively aligned feedback on the appropriate approach for planner function that will more effectively meet objectives.

Rethink Implementation Timing

Based on uncertainty associated with the lack of guidance and potential for more efficient accounting approaches, CME supports delaying the entire program.

Incorporation of Risk

CME noted that industry was not involved in the process to define the list of substances deemed 'toxic' under the Act. Furthermore, CME felt the list of substances was not risk based and, as a result, the administration for accounting and planning for a substance is the same regardless of its hazard or exposure.

Toxics Reduction Act

The *Toxics Reduction Act* is part of Ontario's strategy to reduce toxics in air, land, water and consumer products. Under the *Act*, regulations would require prescribed facilities to track and evaluate their current use, creation, and releases of toxics, develop plans to reduce the use and creation of toxics, and make reports and summaries of their plans available to the public.

Government Response

(Lead: Ministry of the Environment)

Recognize Equivalency of Existing Program

The *Toxics Reduction Act* is flexible and recognizes that industry has the greatest level of expertise to identify the appropriate number of stages and processes to satisfy this requirement. The Ministry of the Environment will work with CME on a priority basis on accounting and reporting requirements for copper, nickel and zinc and substances in closed processes by January 31, 2011, and will finalize the accounting guidelines by this date.

Recognize Existing Programs

Existing Environmental Management Systems (i.e., ISO 14001) could be used to meet requirements of the *Act*. Where necessary, facilities may need to provide supplemental information on substances or processes not included in International Organization for Standardization Standards (ISO) plans, Environmental Management Systems (EMS) or Pollution Prevention (P2) Plans. The Ministry of the Environment will ensure sector guidance materials, and planners' curriculum and compliance direction will be clear that existing ISO Plans, EMS and P2 plans can be used to meet requirements of the *Act*. The ministry will work with identified industrial sectors to develop sector specific guidance documents to show efficiencies in using existing documents and to identify when supplemental information will be required. By June 2011, the ministry will work with five sectors on sector specific guidance and continue on an on-going basis with other sectors. The ministry will work with CME and individual sectors to demonstrate, through guidance material, efficiencies in creating records for groups of substances.

Toxic Planner Qualifications

The *Act* requires certification of plans; the regulation will specify the qualifications required for planners. The Ministry of the Environment considers this important to ensure quality and that the required elements are included in the plans. This is especially important for those facilities that do not have existing ISO, EMS or Pollution Prevention Plans. By February 28, 2011 the ministry will meet with CME to discuss planner qualifications and requirements.

Rethink Implementation Timing

The Ministry of the Environment is proposing to recommend a regulatory amendment to delay the requirement for certified toxic substance reduction Phase I plans and plan summaries by one year to ensure sufficient time for industry to undertake thorough planning and to develop meaningful toxics substance reduction plans.

Incorporation of Risk

The Ministry of the Environment, in consultation with the Ministry of Health and Long-Term Care and Cancer Care Ontario and as advised by the Minister's Toxics Reduction Scientific Expert Panel, identified a list of 47 priority substances for Phase I. This list includes 23 carcinogens and 19 substances identified as toxic by the *Canadian Environmental Protection Act*.

The ministry will work with certain sectors to create sector specific guidance documents for plans, accounting, and reporting compliance policy to cover those substances for which there are no known substitutes in the production process (e.g. copper, nickel, zinc).

Priority 4

Air Standards (Reg. 419/05)

CME recommends that the government work towards a sustainable approach for developing standards and develop a policy to deal with the standards when obtaining a certificate of approval in order to maintain a timely approvals process.

CME recommended the use of the Regulatory Impact Assessment policy and tools include industry input covering business analysis and impacts, and this will be considered during the development of new or amended regulations.

CME proposed to meet with the Ministry of the Environment to review and discuss CME proposed solutions, and explore alternative approaches to address concerns related to:

- A balanced interpretation of science
- Short-term standards
- Expanded compliance assessment
- A draft Terms of Reference for an independent review of Combined Air Monitoring Model (CAMM)
- A distinction between planned and unplanned operations (Start-up Shut-down Malfunction) prior to the issues being tabled at the Multi-stakeholder Group.

Government Response

(Lead: Ministry of the Environment)

Regulatory Impact Assessment Tool (RIA)

The Ministry of the Environment will implement the RIA tool according to government direction on new regulations. For new regulations, the ministry will consult with CME and other stakeholders to receive input on the impacts of proposed regulations.

By spring 2011, the ministry will work with CME and other industry stakeholders to develop a protocol to support the development of high quality regulatory impact assessments. The protocol will address how to engage industry members of varying sizes (small, medium and large), evaluate their capacity to respond and provide guidelines for addressing the impact of the proposed regulation on the wide range of industries within the manufacturing sector.

Ontario Regulation 419/05

This is the primary regulatory tool used for the assessment and implementation of air standards to protect local air quality in our communities.

Air Standards Issues

CME is continuing to meet with the ministry to review and discuss CME proposed solutions, and explore alternative approaches to address concerns prior to issues being tabled at the Multi-stakeholder group.

On November 29, 2010, the ministry met with CME to discuss:

- **A 'balanced interpretation of the science:'** CME presented a written draft improvement proposal for discussion. A follow up meeting is scheduled for January 26, 2011.
- **Short-term standards:** CME presented a written draft improvement proposal for discussion and the ministry tabled a draft position for discussion. Follow-up discussions occurred on December 13, 2010, January 6 and January 13, 2011.
- **Expanded Compliance Assessment:** This meeting was combined with the discussion regarding short term standards. CME presented a written draft improvement proposal for discussion and the ministry also presented a draft framework for discussion. Follow-up discussions occurred on December 13, 2010, January 6 and January 13, 2011.

The ministry met with CME on November 28, 2010, December 17, 2010 and January 13, 2011 to refine a draft Terms of Reference for an independent review of Combined Air Monitoring Model (CAMM):

- The scope of the review will deal with specific technical issues, the components, outputs, and how the model can be improved in its application.
- The independent review is to be completed by September 2011.

The Ministry of the Environment met with CME on November 19, December 9, 2010 to develop a distinction between planned and unplanned operations (Start-up Shut-down Malfunction). The ministry tabled, for discussion, both a policy flow chart and operating scenarios for the refining and smelting sectors. CME presented information to support the understanding of the distinction.

Multi-stakeholder Consultation

The Ministry of the Environment and CME agree that success relies on stakeholders being involved in the development of solutions.

The ministry will work with CME and other stakeholders to set a framework and objectives for stakeholder involvement in developing solutions. By January 30, 2011, the Ministry of the Environment will work with CME and other stakeholders to update the terms of reference of the Multi-Stakeholder Group, including framework and objectives for stakeholder involvement and will update the Multi-Stakeholder Group on results of the discussions with CME.

Priority 5

Ministry of Labour Inspectorate Challenges

During the business sector strategy process held to address this priority, CME noted challenges with respect to the consistency of approach amongst Ministry of Labour inspectors. As a result, CME has recommended the following:

- Develop a more **formalized process** to deal with regulatory challenges and leverage solutions to deal with increasing administrative issues
- Provide **greater clarity** on how legislation and regulations apply in the workplace
- Address the **complexity of specific regulations** that compromise an employer's ability to both comply and operate their business (e.g. personal emergency leave, hours of work, overtime and vacation provisions)
- Explore issues of **inspectorate consistency** regarding the enforcement of legislation and regulations

Government Response

(Lead: Ministry of Labour)

Formalized Process

To create a more formalized process, the ministry and CME have agreed to establish a Client Service Sub-committee and a Policy and Legislation Sub-committee to discuss key issues, exchange ideas and information, and share concerns. By developing a mutual understanding of key sector concerns and public policy imperatives, members of these committees will explore opportunities for collaboration and resolution of key challenges. The ministry and CME have finalized the terms of reference for the committees which will meet at least twice per annum.

The ministry will strengthen its client focus and will work with CME to identify how overall communication can be improved and how service to employers can be enhanced to help employers, including small businesses, meet workplace health and safety obligations and achieve compliance with existing and new regulations.

Greater Clarity

The ministry will work with CME to help enhance a stronger client service focus. As a first step, inspectors will identify services offered by Health and Safety Associations that provide information to employers with the aim of assisting employers achieve compliance.

Further consultation between the CME, Health and Safety Associations, and the ministry will help to determine how to increase the capacity to serve these employers. In the meantime, the ministry has invited the CME to identify compliance tools that can be improved or suggest new tools that will help business increase their level of compliance. Furthermore, the ministry will respond to CME questions regarding the issue of 'consistency' which CME can distribute to their members. More 'question and answer' activities will follow, addressing other similar issues.

In advance of a conveyer guarding and lock out inspection blitz in November 2010, the ministry held an information session for CME members to identify measures and available resources to assist employers to achieve compliance and a successful inspection outcome.

The ministry has held an information session for CME members to address implementation concerns regarding the new workplace violence provisions of the *Occupational Health and Safety Act*. In addition, the CME has been invited to canvass their membership to determine other specific issues that could be addressed in future sessions. The ministry is prepared to offer additional information sessions if the CME has found these sessions beneficial.

Complexity of Specific Regulations

In addressing the complexity of regulations cited in the CME's priority, the ministry has outlined several next steps. In regards to regulations pertaining to Vacation Pay and Personal Emergency Leave provisions, the ministry will identify ways to better communicate Program Policies that can assist with interpretation and application of the *Employment Standards Act, 2000.*

To address the Hours of Work and Personal Emergency Leave provisions, the ministry will further analyze the impact of these provisions and identify non-regulatory solutions within the context of an Employment Standards Modernization Strategy. The ministry has invited the CME to participate in this exercise and would like to engage employers and labour stakeholders in discussion of this issue over the next 12 months.

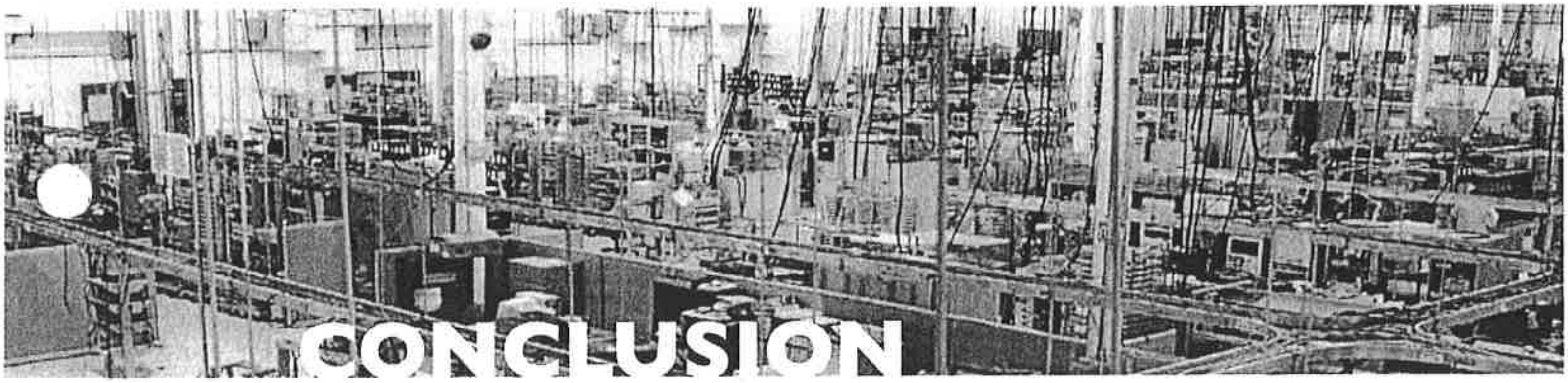
Inspectorate Consistency

The ministry welcomes CME's offer to participate in inspector training and has provided the Code of Professionalism that outlines the ministry's expectations of inspector conduct, a CD of the ministry's operational health and safety policy, and the procedures manual. The ministry has invited CME to participate in a managers' training session in early 2011.

To help small businesses meet workplace health and safety obligations, the ministry will work with CME and Health and Safety Associations to identify specific sectors that could benefit from customized information sessions and supports. This effort is targeted for completion by December 2011.

As part of an ongoing commitment to improve enforcement consistency, the ministry has taken the following steps:

- Development of Program Advisory Committees for the construction, industrial, health care and mining sectors. These committees are comprised of inspectors, regional program specialists and program managers from across the province and meet regularly to identify emerging enforcement issues and ensure they are addressed consistently
- Outreach to senior leaders at the Workplace Safety and Insurance Board and Health and Safety Associations to ensure that the appropriate system partner provides the appropriate support and avoids duplication of efforts
- Creation of a Total Quality Management and Quality Assurance Quality Control initiative (anticipated implementation 2011) to ensure consistent, high quality reports. CME input during the development of these initiatives is welcome and may be provided via the Client Service Sub-committee

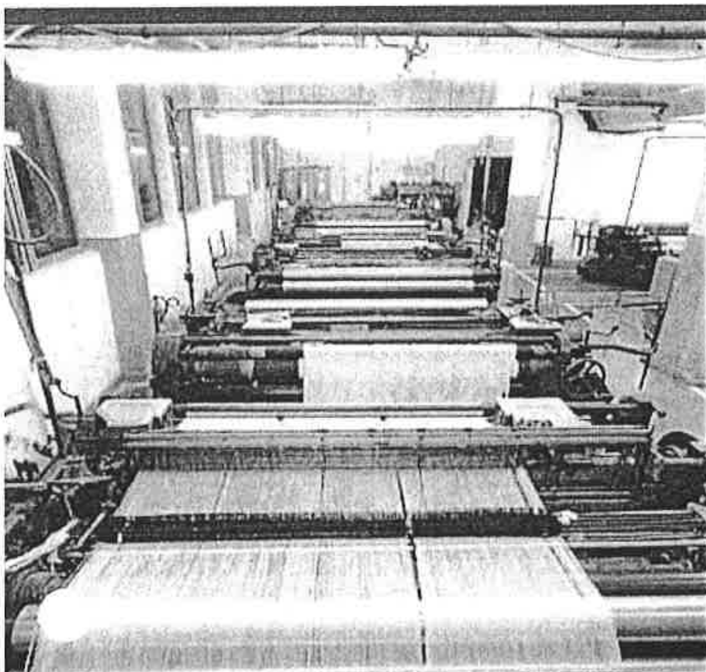


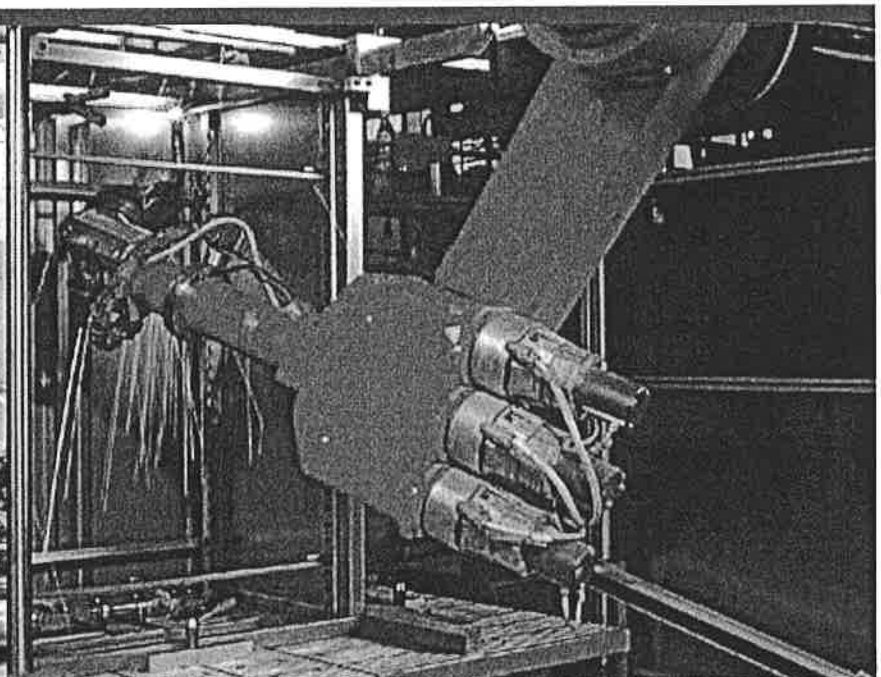
CONCLUSION

The need for and the potential of the Business Sector Strategy process was clearly demonstrated during the discussions between CME and the government. While the exercise was not without its challenges, over a period of two months, CME and other sector business leaders worked with the government to create a foundation for a more effective partnership. Over the coming weeks, months and years, this relationship will result in increased business consultation, a reduction of administrative burdens for business, enhanced transparency, and improvements in client service.

It is clear that the manufacturing sector and the government share common ground regarding generating economic growth, creating jobs for Ontario families and protecting the public interest. It is equally evident that where more understanding and cooperation is required is in the details – how these goals can be achieved while ensuring that business objectives and societal needs are both addressed.

Sandra Pupatello, Minister of Economic Development and Trade noted that, "Just because its complicated doesn't mean that we can't move the yardstick. It has been decades since this kind of interaction between business and government has taken place. We're not finished…there's more to be done, but we're committed to continuing the process."





For more information, please visit:
www.ontario.ca/openforbusiness
email: openforbusiness@ontario.ca
1-888-ONT-4-BIZ (1-888-668-4249)

Ontario

TAB 10

Ontario Energy Board | Commission de l'énergie de l'Ontario

Ontario

EB-2010-0008

IN THE MATTER OF AN APPLICATION BY

ONTARIO POWER GENERATION INC.

PAYMENT AMOUNTS FOR PRESCRIBED FACILITIES FOR 2011 AND 2012

DECISION WITH REASONS

March 10, 2011

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EB-2010-0008

IN THE MATTER OF the *Ontario Energy Board Act, 1998*, S.O.1998, c.15, (Schedule B);

AND IN THE MATTER OF an application by Ontario Power Generation Inc. pursuant to section 78.1 of the *Ontario Energy Board Act, 1998* for an Order or Orders determining payment amounts for the output of certain of its generating facilities.

BEFORE: Cynthia Chaplin
Presiding Member & Chair

Marika Hare
Member

Cathy Spoel
Member

DECISION WITH REASONS

MARCH 10, 2011

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Appendices:

1 INTRODUCTION

Ontario Power Generation Inc. ("OPG") filed an application with the Ontario Energy Board (the "Board") on May 26, 2010. The application was filed under section 78.1 of the *Ontario Energy Board Act, 1998*, S.O 1998, c. 15 (Schedule B) (the "Act"), seeking approval for payment amounts for OPG's prescribed generation facilities for the test period January 1, 2011 through December 31, 2012, to be effective March 1, 2011. The Board assigned the application file number EB-2010-0008.

OPG also requested that the Board issue an order declaring the current payment amounts interim if the new payment amounts are not implemented by March 1, 2011. By order dated February 17, 2011, the Board declared the current payment amounts interim effective March 1, 2011.

1.1 Legislative Requirements

Section 78.1(1) of the Act establishes the Board's authority to set the payment amounts for the prescribed generation facilities. Section 78.1 can be found at Appendix D of this Decision. Section 78.1(4) states:

> The Board shall make an order under this section in accordance with the rules prescribed by the regulations and may include in the order conditions, classifications or practices, including rules respecting the calculation of the amount of the payment.

Section 78.1(5) states:

> The Board may fix such other payment amounts as it finds to be just and reasonable,
> (a) on an application for an order under this section, if the Board is not satisfied that the amount applied for is just and reasonable; or
> (b) at any other time, if the Board is not satisfied that the current payment amount is just and reasonable.

Ontario Regulation 53/05, *Payments Under Section 78.1 of the Act,* ("O. Reg. 53/05") provides that the Board may establish the form, methodology, assumptions and calculations used in making an order that sets the payment amounts. O. Reg. 53/05 also includes detailed requirements that govern the determination of some components of the payment amounts.

O. Reg. 53/05 affects the setting of payment amounts for the prescribed generation facilities in three principal ways:

1. requiring that OPG establish certain variance and deferral accounts and that the Board ensure recovery of the balance in those accounts subject to certain conditions being met;
2. requiring that the Board ensure that certain costs, financial commitments or revenue requirement impacts be recovered by OPG; and
3. setting certain financial values that must be accepted by the Board when it makes its first order under section 78.1 of the Act.

The last item was addressed in the first payment amounts proceeding, EB-2007-0905.

O. Reg. 53/05 can be found at Appendix E.

1.2 The Prescribed Generation Facilities

OPG owns and operates both regulated and unregulated generation facilities. As set out in section 2 of O. Reg. 53/05, the regulated, or prescribed, facilities consist of three nuclear generating stations and six hydroelectric generating stations. These facilities produce approximately 48% of Ontario's electricity.

Table 1: Prescribed Generation Facilities

Hydroelectric		Nuclear	
Station	Capacity[1]	Station	Capacity[1]
Sir Adam Beck I	417 MW	Pickering A NGS	1,030 MW
Sir Adam Beck II	1,499 MW	Pickering B NGS	2,064 MW
Sir Adam Beck Pump Generating Station	174 MW	Darlington NGS	3,512 MW
DeCew Falls I	23 MW		
DeCew Falls II	144 MW		
R.H Saunders	1,045 MW		
Total	**3,302 MW**		**6,606 MW**

Note 1: Net in-service capacity
Source: Exh. A1-4-2, Chart 1 and Exh. A1-4-3, Chart 1

OPG also owns the Bruce A and B nuclear generating stations. These stations are leased on a long term basis to Bruce Power L.P. Under section 6(2)9 of O. Reg. 53/05, the Board must ensure that OPG recovers all the costs it incurs with respect to the Bruce nuclear generating stations. Under section 6(2)10 of O. Reg. 53/05, the revenues from the lease, net of costs, are to be used to reduce the payment amounts for the prescribed nuclear generating stations.

OPG has entered into a Memorandum of Agreement ("MOA") with its shareholder. This MOA sets out the shared expectations of the shareholder and the company regarding mandate, governance, performance and communications. Included in its provisions related to the nuclear mandate are expectations related to continuous improvement, benchmarking, and improved operations. The MOA is reproduced in Appendix G.

1.3 Previous Proceedings

The current application is OPG's second cost of service application. The first cost of service application, EB-2007-0905, was filed on November 30, 2007. The Board's decision on the 21 month test period, April 1, 2008 to December 31, 2009, was issued on November 3, 2008.

OPG filed two notices of motion for review and variance seeking to vary the portion of the EB-2007-0905 decision dealing with the treatment of tax losses. The first motion, EB-2008-0380, filed on November 24, 2008, was dismissed. The second motion, EB-2009-0380 was filed on January 28, 2009 and a decision granting the motion was issued on May 11, 2009. This decision is discussed further in Chapter 10.

On June 9, 2009, OPG filed an application for an accounting order regarding deferral and variance accounts approved in EB-2007-0905. As part of the application, OPG informed the Board that it had deferred the filing of its payment amounts application by one year. The decision, under file number EB-2009-0174, which addressed the treatment of deferral and variance accounts for the period after December 31, 2009, was issued on October 6, 2009.

The Board initiated a consultation on the filing guidelines for the current payment amounts application on September 24, 2009. The filing guidelines were issued under file number EB-2009-0331 on November 27, 2009.

1.4 The Application

In advance of its application, OPG held stakeholder information sessions on March 29, 2010 and April 1, 2010. At those sessions, OPG indicated that it would file the 2011-2012 payment amounts application in mid-April. However, on April 15, 2010, OPG advised that the application would be delayed to late May and that OPG was reviewing the application to identify ways to further lessen the impact of its request on ratepayers.

The application was filed on a Canadian GAAP basis on May 26, 2010. The proposed revenue requirement and recovery of deferral and variance accounts, as filed on May 26, 2010, is summarized in the following table.

Table 2: Proposed Revenue Requirement

$ million	Regulated Hydroelectric			Nuclear			Test Period Total
	2011	2012	Test Period	2011	2012	Test Period	
Expenses							
OM&A	$128.2	$125.9	$254.1	$2,021.2	$2,067.9	$4,089.1	$4,343.2
Gross Revenue Charge/Nuclear Fuel	257.1	252.2	509.3	235.6	261.7	497.3	1,006.6
Depreciation and Amortization	65.6	65.0	130.6	235.4	256.4	491.8	622.4
Property and Capital Taxes	-	-	-	16.0	16.6	32.6	32.6
Income Taxes	30.6	27.4	58.0	53.9	75.9	129.8	187.8
Cost of Capital							
Short-term Debt	4.6	6.1	10.7	3.0	4.3	7.3	18.0
Long-term Debt	106.9	105.8	212.7	70.8	74.4	145.2	357.9
Return on Equity	176.1	175.3	351.4	116.6	123.2	239.8	591.2
Adjustment for Lesser of UNL or ARC	-	-	-	85.0	83.1	168.1	168.1
Other Revenue							
Ancillary and Other	44.9	46.2	91.1	32.0	24.0	56.0	147.1
Bruce Revenue Net of Costs	-	-	-	128.1	143.0	271.1	271.1
Revenue Requirement	**$724.2**	**$711.5**	**$1,435.7**	**$2,677.4**	**$2,796.5**	**$5,473.9**	**$6,909.6**
Deferral and Variance Account Recovery	**(39.5)**	**(47.3)**	**(86.8)**	**227.1**	**232.8**	**459.9**	**373.1**

Source: Exh. I1-1-1, Table 1

With some exceptions, OPG proposed that the 2010 year end balances in the deferral and variance accounts be amortized over a 22 month period from March 1, 2011 to December 31, 2012. The major exception to that proposal is the tax loss variance account, which OPG proposed be amortized over a 46 month period, from March 1, 2011 to December 31, 2014, in order to lessen ratepayer impact. To achieve the revenue requirement and disposition of balances in the deferral and variance accounts, OPG requested the payment amounts and riders shown in the following table, which also provides the current payment amounts and riders.

Table 3: Payment Amounts and Rate Riders

($ per MWh)	Hydroelectric	Nuclear
Current		
Payment Amount	36.66	52.98
Rate Rider	—	2.00
Total	36.66	54.98
Proposed		
Payment Amount	37.38	55.34
Rate Rider	(2.46)	5.09
Total	34.92	60.43

Source: Exh. A1-2-2 (as filed May 26, 2010)

OPG estimated that if the application was approved as filed, the combined effect of the proposed payment amounts and rate riders would be an increase of 6.2% over the current payment amounts. This would be a 1.7% or $1.86 increase on the monthly total bill for a typical residential consumer consuming 800 kWh per month.

A summary of the approvals that OPG is seeking in the current application is found at Appendix B.

1.5 The Proceeding

Details of the procedural aspects of the proceeding are provided in Appendix A.

The Board issued Procedural Order No. 3 on July 21, 2010, establishing the final issues list for the proceeding. That list is found at Appendix F.

The Board received five letters of comment in response to the notice of application. The Board has reviewed each of these letters. The letters raise a variety of issues, many of which are dealt with in this Decision and others which are beyond the scope of this proceeding. Although the Board will not address each letter specifically, these comments have been taken into account in the Board's deliberations.

Two parties applied for, and were granted, observer status. Thirteen parties applied for and were granted intervenor status. The following intervenors took an active role in the proceeding: The Association of Major Power Consumers in Ontario ("AMPCO"), Canadian Manufacturers & Exporters ("CME"), Consumers Council of Canada ("CCC"), Energy Probe Research Foundation ("Energy Probe"), Green Energy Coalition ("GEC"), Pollution Probe Foundation ("Pollution Probe"), Power Workers' Union ("PWU"), School Energy Coalition ("SEC"), Society of Energy Professionals ("Society") and Vulnerable Energy Consumers Coalition ("VECC").

CME and CCC brought motions seeking production of certain materials. The Board denied the motions in an oral decision on October 4, 2010. A copy of the decision on the motions can be found at Appendix C.

During the proceeding, confidential treatment was granted for a large number of documents. These documents are filed at the Board's offices.

1.6 Board Observations

This Decision addresses a large number of issues. Most of these issues were material in nature; a number were not. Quite a number of very material issues were explored somewhat late in the process; in some cases the arguments themselves contained what could be characterized as evidence. The regulation of OPG is complex. It is imperative that the high priority issues be identified early and explored thoroughly and effectively during the proceeding.

The Board understands that many of the issues pursued by the parties were sizeable in the absolute sense, often involving millions of dollars. However, issues must be prioritized to ensure that the most significant issues, in terms of dollars and/or in terms of principle, are adequately investigated to ensure an appropriate outcome. The Board and the process are best served by the thorough investigation of the highest priority issues.

It is the Board's conclusion that a number of issues which parties pursued vigorously in cross-examination and argument were not of sufficiently high priority in terms of the dollars or the principle involved. The Board's concern is that an inordinate focus on lower priority issues diminishes the time and resources available to pursue the more substantive, higher priority issues. This is not intended as a criticism of any of the parties; nor is it an indication that there was insufficient evidence for the Board to render its decision. Rather, these comments are intended to guide the parties as to the Board's expectations for the next proceeding based on our observations of this proceeding.

The Board will explore with OPG and stakeholders how best to identify issues in the next proceeding to ensure that the highest priority issues are identified early.

The Board would also observe that at times the analysis was complicated by the fact that data was presented in ways which was not always comparable. The Board expects OPG to present data on a consistent basis so that comparisons are accurate.

1.7 Summary of Board Findings

The Board has adjusted OPG's requested revenue requirement in some areas and has increased the forecast of revenues in some areas. The following list summarizes those adjustments; the details of the findings are contained in the subsequent chapters of this Decision:

- An increase in forecast hydroelectric production, including a provision for increased Gross Revenue Charge and a variance account to capture the effects of Surplus Baseload Generation;
- An increase in forecast revenue from water transactions;
- An increase in forecast nuclear production, including a provision for increased nuclear fuel costs;
- A sharing of the revenues generated from sales of heavy water;
- A provision for increases in Canadian Nuclear Safety Commission costs;
- The removal of CWIP from rate base;
- A reduction in nuclear compensation costs in 2011 and 2012;
- An update for the return on equity, in accordance with the Board's policy; and
- An adjustment to the Hydroelectric Incentive Mechanism.

The following list identifies the studies and reports that the Board has directed OPG to complete in this Decision:

- Benchmarking of Nuclear Performance;
- Nuclear Staffing Benchmark Analysis;

- Review of Nuclear Fuel Procurement Program ;
- Compensation Benchmarking Study; and
- Depreciation Study.

OPG applied for a total revenue requirement of $6,909.6 million and deferral and variance account recovery of $373.1 million for the two-year test period, resulting in an average payment increase of 6.2%. The Board does not yet have all of the data necessary to establish the final revenue requirement because certain calculations remain to be completed by OPG. Based on the data the Board does have, the Board anticipates a small upward adjustment in the payment amounts that is in the range of less than 1%.

2 BUSINESS PLANNING AND BILL IMPACTS

2.1 Business Planning

The application is based on OPG's 2010-2014 business plan. OPG's business planning process is an annual decentralized process, although planning instructions originate from the finance department. The individual business units develop specific strategic and performance objectives and plan work to achieve the objectives. For the nuclear business, the 2010-2014 business plan incorporates "gap-based" and "top-down" business planning approaches. The gap-based business planning approach was introduced as part of the Phase 2 nuclear benchmarking initiative. There is further discussion of this approach later in this Decision.

In response to the financial and economic environment, OPG's business planning guidelines for 2010 required an $85 million reduction in OM&A compared with previously planned levels for that year. The 2010-2014 business plan was approved by the OPG Board of Directors in November 2009 and received shareholder concurrence.

At stakeholder information sessions held in late March and early April 2010, OPG indicated that it would file its application in mid-April. On April 15, 2010, OPG communicated to stakeholders that the timing for the application had been adjusted to late May and that OPG was reviewing its application to identify ways to further lessen the impact of its request on ratepayers. In May 2010, OPG decided to delay the requested implementation date for new payment amounts to March 1, 2011 and extended the proposed recovery period for the tax loss variance account. These changes were reviewed and approved by the OPG Board of Directors.

The PWU submitted that the assumptions in the 2010-2014 business plan are an appropriate basis on which to set payment amounts. The PWU is concerned, however, with the top-down business planning process used for the nuclear business, and the introduction of the gap-based approach using benchmarking results. The PWU stated that the benchmarking comparators were not peers and further stated that the top-down business planning approach is not appropriate given the capital intensive nature of the business, the technical complexity of the CANDU generators and the strict regulatory requirements of the nuclear business.

CME took issue with OPG's statements regarding the $85 million reduction, referring to the OPG press release dated March 29, 2010:

> We deferred our rate application once but we must go to the OEB this year to make a request for an increase in our regulated rates. We continue to look for internal savings on top of the $85 million we've saved to date.

CME argued that OPG did not reduce OM&A as suggested, but rather only reduced the original increase in OPG's 2009-2013 business plan by $85 million. CME described this and other examples (e.g. $260 million work-drive cost savings discussed later in this Decision at Chapter 4) as misleading characterizations of cost increases as cost reductions.

CME submitted that OPG's business planning process is deficient because it fails to consider total electricity price increases and other economic circumstances facing consumers in deriving the budgets and estimates that form the basis of the application. CME observed that, based on a plain reading of OPG's business planning instructions, the Board could conclude that OPG considers economic turmoil and the hardship consumers are facing in its planning process. CME submitted that, based on the testimony of OPG witnesses, one could conclude that OPG was of the view that the Board can only consider budgets, cost estimates and work programs when determining just and reasonable rates and that the economic hardship facing consumers merely set the context for OPG's planning.

CME submitted that the Board would be ignoring the statutory objectives set out in section 1(1)1 of the Act if it accepts OPG's business planning approach. The objective states:

> 1(1) The Board, in carrying out its responsibilities under this or any other Act in relation to electricity, shall be guided by the following objectives:
> 1. To protect the interests of consumers with respect to prices and the adequacy, reliability and quality of electricity service.

Further, CME referred to the Minister of Energy and Infrastructure's letter of May 5, 2010, to OPG regarding the impact of the recent recession:

> Bearing that in mind, I would request OPG carefully reassess the contents of its rate application prior to filing with the Ontario Energy Board. I would

> like OPG to demonstrate concerted efforts to identify cost saving opportunities and focus your forthcoming rate application on those items that are essential to the safe and reliable operation of your existing assets and projects already under development.

CME submitted that the evidence in the case reveals that neither the hydroelectric business nor the nuclear business was asked to reassess the contents of their respective business plans, or to identify ways to lessen costs. Based on the testimony of OPG witnesses, CME observed that the Business Planning group concluded that the business plan already addressed the Minister's concerns. CME submitted that OPG's response to the requests of the Minister should be of concern to the Board.

CCC observed that the "Renewed Regulatory Framework for Electricity" announced by the Board on October 27, 2010 is specifically tied to green energy investments. CCC submitted that neither the Board's policy initiative nor the Ontario Clean Energy Benefit, which provides residential consumers with a 10% rebate, absolve OPG from taking total bill impacts into consideration in its planning.

With respect to the obligation of utilities, CCC referred to the Ontario Court of Appeal decision in the Toronto Hydro-Electric System Ltd. ("Toronto Hydro") case. CCC submitted that the principles of the decision apply for all intents and purposes to OPG:

> The principles that govern a regulated utility that operates as a monopoly differ from those that apply to private sector companies, which operate in a competitive market. The directors and officers of unregulated companies have a fiduciary duty to act in the best interests of the company (which is often interpreted to mean in the best interests of the shareholders) while a regulated utility must operate in a manner that balances the interests of the utility shareholders against those of its ratepayers. If a utility fails to operate in this way, it is incumbent on the OEB to intervene in order to strike this balance and protect the interests of the ratepayers.[1]

Both CME and CCC submitted that OPG failed to respond appropriately to the Minister's letter of May 5, 2010. CCC submitted that OPG has added to the burden on ratepayers by unnecessarily requesting construction work in progress treatment for the Darlington Refurbishment Project and by not considering a reduction of its return on equity ("ROE"). CME argued that an unregulated market participant would likely make efforts to "hold the line on electricity price increases" in difficult economic

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[1] *Toronto Hydro-Electric System Ltd. v. Ontario Energy Board*, [2010] ONCA 284, para. 50 (Leave to Appeal to Supreme Court of Canada denied).

circumstances. CME submitted that the Board could approve a revenue requirement for OPG that reflects a lower ROE, arguing that a temporary reduction in ROE poses no threat to system safety or reliability. CME referred to the period prior to 2008 when the shareholder acknowledged that it did not need a full equity return to cover its actual costs of capital. At the time, the shareholder used a 5% return on equity to establish the revenue requirement for OPG.

OPG replied that the criticisms of the company's business planning process related to issues that, in OPG's view, have nothing to do with the company. OPG disagreed that it is obliged to consider costs over which it has no control.

With respect to the parties' reference to the Toronto Hydro case, OPG stated that the Board's decision, which was upheld by the Court, was related to concern about under-investment in physical plant and was hence a matter of prudence.

With respect to the Minister's letter of May 5, 2010, OPG replied that senior management had decided to delay the application to consider whether the application could be adjusted well before receiving the letter. OPG admitted that it did not change work plans or budgets in the 2010-2014 business plan, but maintained that this was not necessary "given the care OPG took in containing costs over which it has control during business planning."[2]

Board Findings

OPG has adopted a new planning process in the nuclear business, with an emphasis on top-down planning and a gap-based approach designed to drive significant improvement in OPG's operations. The Board does not share the concerns expressed by PWU in this area. The business planning process used by the nuclear division ("gap-based" and "top-down") has the potential to result in an important paradigm shift in how OPG operates. This shift is important if OPG is to improve operating and cost performance in its nuclear business. The Board sees no evidence to suggest that this change will bring about a reduction in safety or reliability. For reasons explained more fully in the benchmarking section of this Decision, the Board does not agree with PWU that OPG's business is not suitable for benchmarking. The Board notes that OPG's shareholder has called for benchmarking in its Memorandum of Agreement. As noted in several places in this Decision, the Board will assess the results of this change in the planning process and the emphasis on continual improvement in future applications.

[2] Reply Argument, p. 13.

With respect to the Minister's letter of May 5, 2010, the evidence is that OPG had already decided, before the letter was received, to forgo any rate increase for January and February 2011 and to delay the recovery of the tax loss variance account. The first adjustment represents a reduction in impact on ratepayers, but not necessarily a reduction in costs: OPG may choose to absorb the forgone revenues without reducing expenditures; it may defer costs to a later period; and for some of the largest projects (Niagara Tunnel, Pickering B Continued Operations and Darlington Refurbishment) the costs are captured through variance accounts in any event. The second adjustment is no reduction at all, merely a delay. OPG took no further or direct action in response to the Minister's May 5, 2010 letter. The business units were not even requested to consider the matter. The Board finds this response surprising. At a minimum, the Minister's letter indicates that the shareholder believed additional savings were possible. The Board would therefore have expected the company to look for further genuine savings. OPG has described what in its view are substantial reductions already included in the application, for example the plan over plan reduction of $85 million. The Board concludes that while this reduction does represent a genuine step towards cost control, it is an exaggeration to call it "savings". Most consumers would reasonably expect "savings" to mean a reduction over what is currently being paid. This is what the Minister requested and this is what OPG has largely failed to deliver.

The Board agrees that OPG has an obligation to consider the economic climate, including trends in electricity costs and consumers' ability to pay, in its business planning activities. A consideration of all aspects of the business climate is part of appropriate business planning. The Board does not agree, however, that OPG has an *obligation* to adjust its plan in response to the external environment. OPG is correct that it cannot control other aspects of consumers' electricity bills. This larger context is for the Board to consider in setting just and reasonable rates, and in particular, in considering whether OPG's forecast costs are reasonable. (This is discussed further below.) While OPG could certainly have proposed cost reductions in light of the economic climate (for example, a reduced return on equity), its *obligation* is to plan taking account of the requirements of its business and to propose payment amounts which represent recovery of an efficient and reasonable level of costs.

2.2 Bill Impacts

OPG estimated that the proposed payment amounts and riders result in an average increase of 6.2% from current payment amounts and riders. The increase represents an increase of approximately 1.7% or $1.86 on the typical residential customer's bill. OPG noted that the current payment amounts have been in place for almost three years by the time new payment amounts come into effect on March 1, 2011, and accordingly the increase OPG is seeking amounts to approximately 2% per year.

OPG argued, "To the extent other forces impact this bill, it would be both unfair and a legal error to reduce OPG's just and reasonable payment amounts to account for those external affects."[3] OPG further argued that it was entitled to recover all prudently incurred costs, which it described in the following way:

> Expenditures are deemed to be prudent in the absence of reasonable grounds to suggest the contrary. Only costs that are found to be dishonestly incurred, or which are negligent or wasteful losses, may be excluded from the legitimate operating costs of the utility in determining the rates that may be charged.[4]

OPG concluded that total bill impacts should be considered by the Board through the integrated policy framework announced on October 27, 2010 (the Renewed Regulatory Framework).

PWU supported OPG's position. PWU agreed that the Board's statutory objective is to protect the interests of consumers, but pointed out that the Board must also respect the adequacy, reliability and quality of electricity services, as noted in the second statutory objective:

> 2. To promote the economic efficiency and cost effectiveness in the generation, transmission, distribution, sale and demand management of electricity and to facilitate the maintenance of a financially viable electricity industry.

PWU submitted that the Board has no authority to consider factors beyond OPG's control, if it finds OPG's costs are just and reasonable. PWU argued that it is inappropriate to consider costs over which the Board has no jurisdiction, such as the Global Adjustment Mechanism and the Harmonized Sales Tax.

PWU also asserted that the cost of generation from the prescribed facilities is among the lowest cost generation available to Ontario consumers. PWU submitted that

[3] Argument in Chief, p. 5.
[4] Reply Argument, p. 9.

maximizing the value of OPG's prescribed facilities will help to mitigate bill increases related to higher priced supply that would replace production from the prescribed facilities. PWU also submitted that the Board needs to consider intergenerational equity and that there is an impact on future ratepayers if work is deferred to mitigate bill impacts for today's ratepayers.

SEC argued that the 6.2% increase masks the true extent of the increases OPG proposed. SEC submitted that the revenue requirement reductions related to the Darlington Refurbishment Project should not be implemented and that additional costs related to pension and other post employment benefits should not be deferred. When these factors and the impact of the tax loss variance account balance are taken into account, SEC concluded that the increase over current payment amounts is 13.1%, a decrease of 4.7% for hydroelectric and an increase of 23.0% for nuclear. OPG responded that SEC's analysis is not an "apples to apples" comparison and noted that even SEC admitted that not all the amounts are directly comparable. OPG argued that SEC had understated the current payment amounts by not accounting for the EB-2008-0038 decision (related to the tax loss variance account), and that SEC overstated the test period payment amounts by including post test period amounts.

CCC and CME submitted that the Board should consider total bill impact in its determination of payment amounts. CCC noted that the government's "2010 Ontario Economic Fiscal Review" stated that electricity prices are expected to rise by 46% over the next five years. CME referred to the evidence that it filed in the proceeding, an analysis by Aegent Energy Advisors, which concluded that total costs for non-residential customers would rise by 47% to 64% over the next five years and that the increase for residential customers would be 38% to 47%.

CME submitted that the Board's statutory objective in section 1(1)1 of the Act demands that total bill impact evidence be considered. CCC argued similarly that the Board is legally obligated to take total bill impact into consideration when determining the payment amounts. CCC referred to the decision of the Supreme Court of Canada in the Northwestern Utilities Ltd. case in which the court stated:

> The duty of the Board was to fix fair and reasonable rates; rates which, under the circumstances, would be fair to the consumer, on the one hand

> and which, on the other hand, would secure to the company a fair return for the capital invested.[5]

Both CCC and CME noted that the Board recognized the need to consider total bill impact when setting rates in the Board's decision in the Hydro One Networks Inc. ("Hydro One") distribution rates case, EB-2009-0096:

> ...the Board must take into account the overall increase and prospect of further increases in the commodity portion of the bill. While these charges are outside of the control of the applicant, they are no less real for customers. In giving effect to the Board's objective to protect the interests of consumers the Board cannot ignore the overall impacts on customers.[6]

CCC submitted that it does not take issue with allowing OPG a fair return on its capital, but stated that the Board must first determine the prudent and acceptable level of investment and then allow OPG a fair return.

CCC argued that the Board's policy initiative (Renewed Regulatory Framework) and the Ontario Clean Energy Benefit rebate do not relieve the Board of its obligation to consider total bill impact in its determination of payment amounts. Similarly, CME stated that the policy initiative does not relieve the Board from considering CME's evidence on bill impacts. CME reported that the majority of its members are either too large to quality for the Ontario Clean Energy Benefit or too small to qualify for benefits available to large consumers. CME stated that if care is not taken in managing increases in electricity prices, these manufacturers are likely to leave Ontario.

OPG responded that parties seeking reductions to OPG's application are doing so on the basis that aspects of the electricity bill over which OPG has no control are rising. OPG argued that the parties overstate the jurisdiction of the Board and that the arguments are really more in the nature of complaints relating to legislative and policy choices made by the Province.

OPG argued that the decision of the Supreme Court of Canada in the Northwestern Utilities case provided for a fair return to the company for the capital invested. OPG also noted that the Board's objectives include not only the protection of consumer interests but also facilitating a financially viable electricity industry. OPG argued that fair

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[5] *Northwestern Utilities Ltd. v. Edmonton (City)*, [1929] S.C.R. 186 at pp. 192-193. ("Northwestern Utilities")
[6] Decision with Reasons, EB-2009-0096, April 9, 2010, p. 13.

return to a utility is comprised of two legal entitlements: the right to recover all prudently incurred costs and the right to a fair return on invested capital.

With respect to prudently incurred costs, in OPG's view, only costs that are found to be dishonestly incurred, or which are negligent or wasteful losses may be excluded. OPG referred to the prudence standard in the Enbridge Gas Distribution Inc. decision, RP-2001-0032:

- Decisions made by the utility's management should generally be presumed to be prudent unless challenged on reasonable grounds.
- To be prudent, a decision must have been reasonable under the circumstances that were known or ought to have been known to the utility at the time the decision was made.
- Hindsight should not be used in determining prudence, although consideration of the outcome of the decision may legitimately be used to overcome the presumption of prudence.
- Prudence must be determined in a retrospective factual inquiry, in that the evidence must be concerned with the time the decision was made and must be based on facts about the elements that could or did enter into the decision at the time.[7]

OPG referred to the Board's decision on Hydro One transmission rates, EB-2008-0272, which was made near the bottom of the economic downturn, and noted that the Board stated that it would be inappropriate to "arbitrarily reduce spending in direct response to the economic downturn."[8]

With respect to the fair return standard, OPG referred to the decision of the Supreme Court of Canada in the Northwestern Utilities case:

> By a fair return is meant that the company will be allowed as a large return on the capital invested in its enterprise (which will be net to the company) as it would receive if it were investing the same amount in other securities possessing an attractiveness, stability and certainty equal to that of the company's enterprise.[9]

[7] Decision with Reasons, RP-2001-0032, December 13, 2002, p. 63.
[8] Decision with Reasons, EB-2008-0272, May 28, p. 4.
[9] *Northwestern Utilities*, pp. 192-193.

OPG also cited the Federal Court of Appeal's decision in *TransCanada Pipelines v. National Energy Board*, in which the court agreed that the approved rates will enable the company to earn a fair return and is not influenced by any resulting rate impact on customers.[10] OPG also noted that the *Report of the Board on the Cost of Capital for Ontario's Regulated Utilities*, EB-2009-0084, states that meeting the fair return standard is a legal requirement.

Board Findings

Throughout this Decision the Board has rendered findings on the reasonableness of OPG's forecast costs and revenues, and in some cases on the prudence of expenditures which were in excess of prior forecasts. The Board has made adjustments to OPG's proposals in a number of areas. The overall effect of this Decision is a reduction in the revenue requirement from that originally requested by OPG and lower payment amounts than requested and a reduced bill increase for customers. The detailed calculation of the payment amounts will be done by OPG as part of the process of completing the Payment Amounts Order, but the Board estimates that the increase will be in the order of 1%.

The Board has broad discretion to adopt the mechanisms it judges appropriate in setting just and reasonable rates. This is clearly established in O. Reg. 53/05 and the Act. O. Reg. 53/05 states "the Board may establish the form, methodology, assumptions and calculations used in making an order that determines payment amounts for the purpose of section 78.1 of the Act" subject to certain rules which are specified in O. Reg. 53/05. Section 78.1 states "the Board may fix such other payment amounts as it finds to be just and reasonable, (a) on application for an order under this section, if the Board is not satisfied that the amount applied for is just and reasonable..." With these authorities, the Board may take account of a broad suite of factors that affect the company and factors that affect consumers. Both considerations are relevant in determining just and reasonable payment amounts. For example, the Board may consider evidence on economic conditions and factors influencing other aspects of electricity rates. These sorts of factors may well be relevant in terms of deciding the appropriate pacing or level of expenditures. The Board must be satisfied that the rates are just and reasonable and it must consider all evidence that it finds relevant for that purpose. For the current proceeding, the Board finds that evidence regarding the economic situation and the trend in overall electricity costs is a relevant consideration,

[10] (2004), 319 N.R. 172 (FCA).

along with a variety of other factors (such as inflation rates, interest rates, legislation, business needs, benchmarking results).

OPG and PWU would have the Board constrain its consideration of the various spending proposals to a very narrow examination based on the presumption that all proposed expenditures are reasonable unless proved otherwise. In the words of OPG, "Only costs that are found to be dishonestly incurred, or which are negligent or wasteful losses, may be excluded from the legitimate operating costs of the utility in determining the rates that may be charged." The Board disagrees. When considering forecast costs, the onus is on the company to make its case and to support its claim that the forecast expenditures are reasonable. The company provides a wide spectrum of such evidence, including business cases, trend analysis, benchmarking data, etc. The test is not dishonesty, negligence, or wasteful loss; the test is reasonableness. And in assessing reasonableness, the Board is not constrained to consider only factors pertaining to OPG. The Board has the discretion to find forecast costs unreasonable based on the evidence – and that evidence may be related to the cost/benefit analysis, the impact on ratepayers, comparisons with other entities, or other considerations.

The benefit of a forward test period is that the company has the benefit of the Board's decision in advance regarding the recovery of forecast costs. To the extent costs are disallowed, for example, a forward test period provides the company with the opportunity to adjust its plans accordingly. In other words, there is not necessarily any cost borne by shareholders (unless the company decides to continue to spend at the higher level in any event). Somewhat different considerations will come into play when undertaking an after-the-fact prudence review. In the case of an after-the-fact prudence review, if the Board disallows a cost, it is necessarily borne by the shareholder. There is no opportunity for the company to take action to reduce the cost at that point. For this reason, the Board concludes there is a difference between the two types of examination, with the after-the-fact review being a prudence review conducted in the manner which includes a presumption of prudence.

The Board has considered the overall impact of the various adjustments it has made to the requested amounts and concludes that the resulting new payment amounts are just and reasonable in light of all relevant circumstances. The overall increase is approximately 1%.

TAB 11

Ontario

Rosemarie T. Leclair
Chair & CEO
Ontario Energy Board

SPEECH

Ontario Energy Association Breakfast Series

Toronto, Ontario
May 6, 2011

Thank you and good morning everyone!

First, let me say how delighted I am to be here this morning and to have the opportunity of delivering my first remarks as the new Chair of the Ontario Energy Board (OEB) at an Ontario Energy Association (OEA) event. I want to thank Elise and George, in particular for inviting me, and, more importantly, for providing such a welcoming venue with so many familiar faces.

Some of the familiar faces, I would like to acknowledge that are here today include our OEB staff and Board members. They have been working diligently, and patiently, over the last month or so, to bring me up to speed on both the operational side of the OEB, as well as the many policy initiatives and issues the Board is currently managing.

I would also like to take a moment to single out our Vice Chair, Cynthia Chaplin, who is well known to most of you, and to take this opportunity to publicly thank Cynthia. In addition to her responsibilities as Vice Chair, Cynthia also served as interim Chair of the OEB after Howard's departure in November. She, and indeed all of the OEB staff, have done an outstanding job in keeping the work of the Board moving forward and providing stability during this period of change. My thanks to all of them.

Now, as I mentioned, the OEA is a familiar venue for me, and the energy sector, or at least the electricity distribution side of it, is fairly well known to me. And to many of you in the room, I am, perhaps, an all too familiar face! But I also know that to many of you, I am very much an unknown quantity. So I thought I would take the opportunity this morning, to tell you a little bit about my background and how I think it fits in to my new role. Sharing a little bit of my history, I think, will provide the best insights into my vision and my priorities for the Ontario Energy Board.

For those of you in the room who know me, it is probably as the former Chief Executive Officer of Hydro Ottawa, one of Ontario's municipally-owned local distribution companies, a position I held until April 5th of this year, prior to my appointment to the OEB. But my time in the electricity sector marks only a small part of my professional career, the bulk of which has been spent in the municipal public sector.

In fact, my public service roots date way back, to the very beginning of my professional development, which started with an undergraduate degree in public administration from the University of Ottawa, followed by a law degree from this same university.

As a student of public administration, I learned the mechanics of government and the roles and responsibilities of the bureaucracy. But most importantly, I learned the importance of good public process in developing sound public policy.

As a student of law, I learned the rules of procedure and the basic tenets of law and how they are applied. But most importantly, I learned the importance of good process, fact based information, and objectivity in decision making. And throughout my career, I have had many opportunities to apply, refine and add to these important lessons.

As I said, prior to joining Hydro Ottawa, I spent twenty-three years working with the City of Ottawa, where I had the opportunity to oversee a number of portfolios – from my days as an articling student prosecuting municipal by-law violations, to my six years as Deputy City Manager of Public Works and Services, overseeing the provision of the most basic hard services in the City, services like drinking water treatment and distribution, wastewater treatment and collection, solid waste collection and disposal, public transit, road maintenance and construction, to name a few. Basic services that each of us, as residents, takes for granted, as we go about our daily routines. Services that we take for granted until they fail to live up to our expectations, or, fail us entirely.

In fact, in telling folks about my job, I used to say, if you can look out your window and complain about it, it's probably in my department. And you know, these days, that sounds remarkably like the energy sector, and my new job!

Now I say that, jokingly of course. But it does underscore what, in my mind, was the most important aspect of my position as Deputy City Manager of Public Works back then, and one of the most important aspects of my new role with the Ontario Energy Board today -- ensuring the seamless delivery of one of the most basic essential services/commodities that Ontario residents, businesses, and industries rely on, each and every day. An essential service, that has, for far too long, been taken for granted in this province, and in this country, because, quite simply, it has always been there when we need it.

As I mentioned, more recently, I have had the privilege of leading Hydro Ottawa, the third-largest municipally owned electricity distribution company in Ontario. During my tenure at Hydro Ottawa, I learned something about both the distribution and renewable generation sides of the energy business. And, I experienced first-hand some of the issues and the challenges facing the energy sector of our province - the need for *new* infrastructure to meet growing demand, the imperative of refurbishing *aging* infrastructure, and the importance of renewing a greying workforce.

And as the entity closest to the consumer, I also gained an appreciation of the importance of not only meeting customer expectations, but of understanding what those expectations really are – expectations that are very simple to articulate – responsiveness, affordability, and let me underline this one, *reliability*.

But achieving affordability, *and* ensuring reliability in the face of the many real challenges facing our industry is, as everyone in this room knows only too well, much easier said than done. But it is a mission that each of us in this room shares, and *must* be committed to delivering on.

In carrying out my various responsibilities over the years, I have learned that, serving the public and the public interest is, to say the least, a complex undertaking. It is about considering the big picture on behalf of consumers. It is about playing the long game, not about political expediency of the day. It is about having due regard to the longer term and the greater good. It is an undertaking that requires the ability to step back and objectively consider, and balance, the legitimate but competing interests and competing priorities among a variety of stakeholders. .

To be successful in finding the right balance, I have also come to appreciate the importance of reaching out, across traditional lines, across organizations, and to develop productive relationships that can help to foster common understanding, and to share knowledge, which will ultimately lead to better outcomes, and better serve the broader public interest. While each of us has our own unique roles and responsibilities, in my experience, objectives are quite often aligned.

And, I would suggest, that the energy sector is no different. The Ontario Energy Board, as you know, has a number of objectives, which are enshrined in legislation. Its primary objective is to protect the interests of consumers with respect to price, *and* reliability, *and* quality of service. I think everyone in the room will agree that that *is* job one!

I also think that everyone will agree that this mandate is not exclusive to the OEB, but very much a responsibility which we all share, whether you are a politician, a bureaucrat, a utility manager, or a regulator, whether your constituents are ratepayers, taxpayers, customers, or consumers. In the end, we are all engaging with the same person. And, we are all attempting to respond to their needs, expectations, and priorities, as *we* have defined them, each in our own way. The energy consumer is, for each of us, without question, at the forefront of everything that we do.

Another one of the OEB's objectives is to facilitate the maintenance of a financially viable industry for Ontario residents. Because without a financially viable sector, job one – ensuring an affordable and reliable supply for consumers – quite simply, will not be achieved. This, in my view, is another one of those responsibilities that is shared among all industry participants and stakeholders.

So therein lies the challenge -- balancing the competing priorities: needed investments in infrastructure, generation, transmission, and distribution to ensure reliable service; conservation programs to help reduce demand and capital investments and to help consumers reduce their energy costs; containing overall costs in the delivery of energy services to maintain affordability; and, ensuring economic viability.

In my view, these are challenges that can only be addressed if we look at the sector and its needs more holistically than we have in the past: what is needed and when; what *are* the most pressing requirements; and, how can we better plan and prioritize as a sector. How can we, working together, mitigate and smooth impacts on the consumer's bill, while providing for needed investments and a fair return? How can we better educate, inform, and engage the individual consumer, about the very real issues facing the sector? Because, in today's reality, one thing is certain: energy, the invisible essential service, is no longer quite so invisible to the average consumer. But it is still largely taken for granted.

We have acknowledged our shared responsibility, and our common objectives. Now, we must start actively working together, in a meaningful way, for a common good and toward a common purpose: a strong, sustainable and viable energy sector.

As I am learning more and more everyday, the role of the OEB is complex. And, as the sector continues to evolve, I expect that it will become even more complex. But the OEB's objectives are clear - to protect the public interest *and* to promote economic efficiency in the energy sector.

To achieve these objectives in the future, I believe, will require greater engagement with industry participants and industry associations so that we can better understand technical and operational challenges. It will mean finding better ways to engage, and hear *directly* from the consumer, not just through associations and intervenors. It will mean finding ways to exchange with our peers in government and across agencies to better define direction, roles and responsibilities.

While I of course acknowledge the importance of the independence of the regulator, I do believe that the Board can, while respecting its independence, play a lead role in facilitating better cooperation and collaboration right across the energy sector – from the ministry, to its agencies, to utilities, retailers and marketers, and the public.

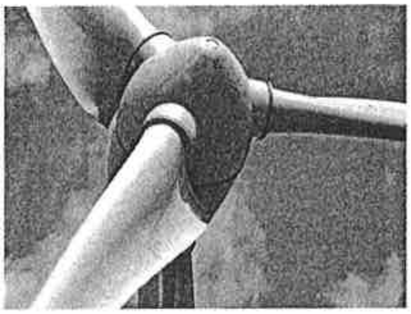
Stakeholders in this sector need to engage with each other in an open, constructive and ongoing dialogue, a dialogue that will result in a shared understanding of our individual and collective objectives, and our respective challenges in achieving them, a dialogue that will result in the sharing of knowledge, expertise and experience that will, I believe, facilitate the development of a strong, sustainable and viable energy sector that will meet the long-term needs of Ontarians.

Many years ago, American industrialist Henry Ford said something that has proven true time and again. He said, "If everyone is moving forward together, then success takes care of itself."

Having worked with so many of you in my previous capacity, I know how seriously you take your responsibility to consumers and how passionate you are about meeting, and exceeding the expectations of your customers. Like you, the Ontario Energy Board takes its responsibilities to consumers seriously. And I am committed to working with you, in the days, months, and years to come, to ensure that together we deliver on those expectations, and ensure that the energy consumer continues to come first.

Thank you once again for allowing me to share my thoughts with you this morning.

TAB 12



THE CASE FOR REFORM

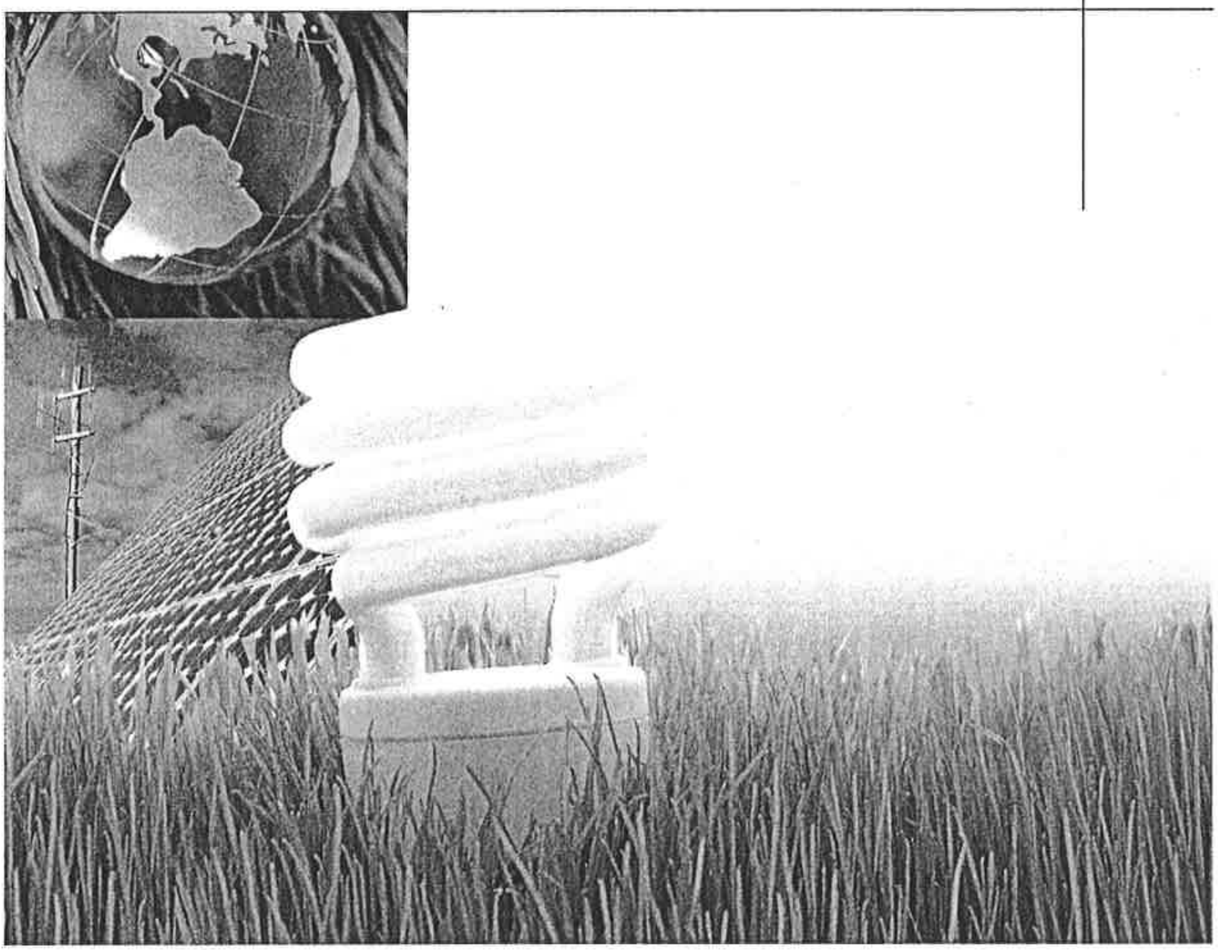
How regulatory streamlining could benefit Ontario's electricity consumers

JULY 2011

EDA

The Voice Of Ontario's Electricity Distributors

ELECTRICITY DISTRIBUTORS ASSOCIATION



Executive Summary

The Electricity Distributors Association (EDA) is the voice of Ontario's 78 electricity utilities who safely and reliably deliver electricity to 4.7 million residential, business and institutional customers. In 2010, the Association initiated a project to consult with members on how to streamline the current regulatory framework. This work has resulted in a number of specific recommendations supported by LDCs.

The key recommendations include:

- Revising the IRM Application Process
- Revising the Cost of Service Application Process
- Revising the Intervenor Process

Adopting these recommendations would improve regulatory oversight, reduce regulatory costs and ultimately benefit customers. The EDA continues to examine further opportunities to streamline regulation for the sector.

Background

The regulatory framework for Ontario's local electricity distribution companies (LDCs) has undergone significant changes over the past decade. More recently, LDCs have taken on new responsibilities and roles related to the Green Energy and Green Economy Act (GEA) which has had further impact on the regulatory framework.

In the midst of these changes, LDCs have found that the regulatory burden is consistently increasing. LDCs have gained substantial experience and insight working under OEB oversight in the existing regulatory framework. At the same time, there are increasing pressures to address the rising costs of electricity.

Ontario LDCs firmly believe that now is the time to carefully review the regulatory processes to identify areas that could be streamlined. The result will be a more efficient and cost-effective regulatory framework that achieves policy objectives and has the potential to make electricity more affordable for electricity consumers.

Guiding Principles for Regulatory Streamlining

In early 2011, the EDA Board of Directors developed the following Guiding Principles, to assist in developing recommendations for streamlining regulation of the sector:

- *There is a need to balance costs of regulation with the benefits to customers;*
- *The amount of regulation and reporting requirements should be proportionate to the policy objective/outcome;*
- *More emphasis should be placed on policy outcomes, not process;*
- *Duplication and overlap of reporting requirements should be eliminated*
- *Administrative burden to LDCs should be minimized, streamlined;*
- *Distributors should be provided flexibility to address their local circumstances*
- *Distributors should not be involved in addressing social problems;*
- *Distributors should be allowed to recover their costs to address aging infrastructure in a timely manner;*
- *Increased certainty and transparency should be provided for cost recovery by distributors;*
- *Decision-making by regulators needs to be timely.*

The EDA Board appointed a committee which developed and brought forward proposals to all LDCs for input. The members indicated strong support for the proposed recommendations.

In order to fully realize the business opportunities that will bring value to customers and shareholders alike, LDCs need a regulatory model that builds efficiencies for utilities. There is a need to review the regulatory system to produce favourable rate outcomes, bring more efficiency into the rate process and create value to the customer and shareholders in terms of addressing the costs associated with the regulatory system.

The Committee's recommendations focus primarily on three significant burdensome areas:

- Incentive Regulation Mechanism (IRM) application process
- Cost of Service (COS) application process
- Intervenor process

Distribution Rate Application Process

Every four years an LDC brings forward an application to the OEB for a full review of its costs and proposed rates. This is called a COS application.

In the years between these COS applications, rates are adjusted through an IRM application process whereby rates are updated annually by a formula which adjusts upward for inflation and downward for anticipated productivity improvements plus possible LDC-specific adjustments.

These possible adjustments in the IRM application include materially significant cost changes and significant increases in capital investments. During each application process, intervenors (stakeholders who participate in the hearing process) and OEB staff can ask questions and can file submissions to the OEB with respect to its decision on the LDC's application. Many intervenors are eligible to recover their costs from the Applicant (LDC) for participating in the hearing process.

This process was established as a replacement of the more traditional rate approval process where LDCs would file for a COS application each year. The IRM period between COS applications is designed to encourage LDCs to achieve efficiencies through cost savings and be rewarded with higher returns.

The Case for Reform

The EDA Board Committee identified the following challenges created under the current regulatory process, and offers recommendations for change that would benefit LDCs, their shareholders, the regulator and ultimately all electricity consumers in Ontario.

Challenge:
The OEB's capital module materiality threshold in the IRM period is too high. This encourages deferral of infrastructure renewal and often results in sharp rate increases for customers once every four years.

Capital investments taken separately on a year-by-year basis are often too small to meet the OEB's materiality threshold and/or other screening criteria to be included in rates during the IRM application period. As a result, LDCs will often defer these capital investments and include them at the time they submit their COS applications when the materiality threshold does not apply.

This approach of excluding all capital investments in the interim rate adjustments has three consequences:

1. LDCs are compelled to defer the much-needed capital investments for up to three years during a time when infrastructure is in need of renewal.
2. LDCs that do undertake capital investments that do not meet the materiality threshold have no certainty that they will be able to recover these costs. Moreover, LDCs must carry these costs until their full cost-of-service application, thereby penalizing their shareholders.
3. Customers may ultimately experience sharper rate increase at the time the full COS application is submitted, since all capital investments are included at that time.

Recommendation: Revise the Capital Module

Allow LDCs to obtain approval for multi-year capital investment plans in COS proceedings – and then scrutinize applications for the capital module during the IRM period based on the approved multi-year capital investment plans.

All capital investments made during the IRM period should be incorporated into rates during the same period.

Key benefits:
Enabling LDCs to submit and receive approval for multi-year capital investment plans would ensure much needed capital investments are undertaken in a timely manner. This would streamline the annual process to review capital module applications for both the OEB and LDCs making it more timely and cost effective.

Challenge:
Generic inflation and productivity factors used to adjust rates during IRM period don't reflect the current LDC-industry reality.

In the IRM period rates are adjusted annually for inflation and downward for anticipated productivity improvements. The current inflation factor used is the Canada Gross Domestic Product Implicit Price Index (Canada GDP-IPI), which is a generic indicator and it does not reflect the inflation pressures on distribution industry in Ontario. Inflation factors that are more specific to the LDC industry would better reflect the recent changing higher labour costs in the industry which are different from other sectors in the economy.

The productivity factor used for LDCs in Ontario is based on the long-term total factor productivity (TFP) trend from a representative set of U.S. electricity distributors over a long period beginning in the late 1980s.

This long-term US TFP data was selected because reliable long-term productivity data from Ontario LDCs was not available at that time. At the time the US TFP data was selected, none foresaw the degree of change that the Ontario electricity industry and LDCs would undergo as a result of overall industry restructuring. The additional mandates to install smart meters, deliver conservation programs, implement Time of Use pricing, connect renewable generation and develop the smart grid mean that the comparison of US Distributors to Ontario LDCs is no longer valid and as such, the long-term past trends in the US have not proven to be an accurate indicator of the actual productivity experience of Ontario LDCs.

As a result of their additional mandates, LDCs' focus has been centered on responding to the constantly changing requirements placed upon them. These increasing new responsibilities, coupled with constant changes in the industry, have offset or delayed the expected improvements to productivity. Using the current productivity factor results in rate decreases that are not sustainable as LDC businesses take on increasingly broader scope.

IRM rate adjustments that are based on factors not reflective of the current industry reality result in a "true-up" when LDCs bring forward their COS applications. The amount of the true-up can be substantial over the period between COS applications, and as such can create price instability and uncertainty for customers.

Recommendation: Revise the Productivity Factor and Inflation Factor

Use Industry-specific inflation factor to reflect changing labour costs in the industry rather than using Canada GDP – IPI in the IRM formula.

Lower the current productivity factor in the IRM formula to reflect existing productivity in the industry impacted by constant ongoing changes to regulatory requirements.

The current productivity factor in the IRM formula should be lowered to be more reflective of current productivity levels in the industry which has been and will continue to be affected by ongoing industry changes.

The EDA proposes adjusting the inflation factor so it is more reflective of industry inflation and setting the productivity factor at a level reflective of recent Ontario trends.

Key benefits:
More gradual rate changes will help avoid customer "sticker shock" which occurs under the current approach where rates increase sharply. The revised IRM process could also allow longer periods between filings of COS applications, reducing the amount of resources allocated by both the regulator and the LDC to this labour and time-intensive process. The new approach would also reduce the financial burden currently placed on LDCs.

Challenge:

Existing COS templates are extensive and open to interpretation, leading to an unnecessarily burdensome amount of administrative work.

The COS application process involves a full review of all the LDC's costs. The OEB notes that a COS application should provide sufficient detail to enable the OEB to determine whether the proposed rates are just and reasonable and the onus is on the LDC to provide sufficient evidence to prove the need for, justification and prudence of all its costs that are the basis for its proposed new rates.

The OEB has developed templates for filing COS applications that were designed to assist LDCs in organizing the information to be provided. LDCs are required to file an application which usually includes many volumes of information. However, the current existing COS templates are too extensive and open to interpretation which results in unnecessary administrative burden on LDCs to compile this information.

Recommendation: Revise the Cost of Service Application Process

Develop/revise the standardized templates for filing COS Applications to make the filing process as standardized as possible. Limit the textual component of the application to explaining cost increases or just variances in general, and reduce administrative paperwork by 30-50 per cent.

Develop metrics to evaluate an LDC's application provided in the standardized format.

OEB should provide updates or revisions to filing requirements well before the application deadline (i.e. in January but not in June – just two months before the application is due for filing).

Evaluate LDC's COS application based on the metrics developed:
- **If within a permissible range – limited review of application (Note: range should be based on defined variables/cost drivers such as urban/rural mix, geography, underground plant, etc.)**
- **If beyond the permissible range – review of the application**

LDCs request that the OEB develop new and revised templates for filing COS application to make the filing process more standardized and confine the textual component of the application to explaining cost increases or variances in general. Significant effort is required to provide the level of detail required by the current template, and current practice among OEB staff and intervenors indicates that they focus on only a small portion of the entire application. There is an opportunity to reduce the amount of administrative work by 30-50 per cent while still retaining all relevant information simply by revising the templates.

To further facilitate the review of a COS application, the OEB should develop metrics including permissible ranges to be used to evaluate an LDC's application. If the information contained in the LDC's application falls within the established permissible range, the application could be efficiently evaluated through a more limited review. This permissible range should be LDC-specific and be based on defined variables/cost drivers which take into account the specific situation of the LDC such as urban/rural mix, the extent of underground plant and local geography, and other factors which influence costs. Once established, using metrics will reduce the administrative cost and the regulatory burden on both the OEB and LDCs resulting in significant cost and time savings.

Notwithstanding the above recommendations, any updates or revisions to application filing requirements should be provided well before the application deadline (i.e., a minimum of eight months prior to filing deadlines) to enable LDCs sufficient time to compile their applications well before the due date for filing.

Key Benefits:

A revised template that focuses solely on relevant information, coupled with pre-established evaluation metrics will reduce administrative activity and costs for all parties and facilitate timely approvals.

Challenge:

Requests for information from intervenors and OEB staff are essentially duplicative in nature, however are worded such that they appear subtly different, necessitating a tailored response. This results in additional administrative burden with limited added value.

The situation is further aggravated by the fact that many intervenors serve common interests, with some representing a subset of a broader interest group. Since intervenors are allowed to recover their costs, the amount of work undertaken by intervenors, along with their growing numbers, has led to a sharp increase in cost awards payable which ultimately is borne by the customer.

Intervenors are expert consultants or counsels who participate in the review of applications on behalf of customer groups they represent. Intervenors are eligible for cost awards from the applicant for their time spent in reviewing the application, preparing questions on the application and participating in the process.

Some intervenors appear genuinely interested in addressing the concerns of their constituents as effectively as possible. However, due to lack of proper safeguards, the current process has become cumbersome and more costly than strictly necessary. For example, questions appear to be designed to elicit more material than necessary to effectively review the applications.

The OEB has established rules to prevent abuse of the cost award process. For example, intervenors must demonstrate that they do not unduly repeat questions asked by other parties, that they make effort to co-operate with other parties to reduce duplication, or that they don't act to unnecessarily lengthen the duration of the process. Nevertheless, the current process does often result in duplication as intervenors do not always follow a coordinated approach in filing questions.
Compounding the issue is that both intervenors and OEB staff have the same deadline for filing their questions on the application. As a result questions are often essentially duplicative, but only just different enough to require a tailored response.

Intervenors are eligible for cost awards if they primarily represent the direct interests of customers or primarily represent a public interest relevant to the OEB's mandate, such as an environmental group. However, some intervenors do not appear to represent a unique interest as they represent a subset of a larger group of customers already represented by another intervenor, often leading to duplication of questions in the regulatory process.

In all cases, intervenor costs are ultimately reflected in rates, so it is in the customer's interest to ensure these costs are reasonable and controlled.

Recommendation: Revise the Intervenor Process

Reduce the duplication of effort between OEB staff and intervenors in raising interrogatories.

- **OEB staff to take leadership role and issue the first round of interrogatories**
- **Intervenors to review OEB staff interrogatories and only then raise their own interrogatories without duplicating staff effort**
- **OEB staff should screen interrogatories from intervenors for duplication, relevance and materiality**

Intervenors should represent a clearly definable/distinct interest that is relevant to the issue being reviewed and OEB should be more strict in providing intervenor eligibility

Establish a cap on cost awards provided to intervenors so that costs and benefits of their review are balanced

Revise cost award eligibility rules so that parties with access to financial resources are not eligible for total cost recovery e.g. only 80 per cent of recovered through cost awards

Intervenors could act jointly in order to qualify for joint funding

There is opportunity to reduce duplication of requests for information by having OEB staff take on a greater leadership role in the entire application review process. OEB staff could develop the preliminary list of questions (i.e. interrogatories) on LDC applications. Intervenors would then be required to review the OEB staff interrogatories prior to submitting their own interrogatories with the requirement that these questions not be duplicative. OEB staff would screen the interrogatories for duplication, relevance and materiality before issuing them to the LDC applicant.

In order to encourage intervenors to make best use of resources, the EDA proposes that the OEB establish a cap on cost awards for each proceeding. The cap would be based on the anticipated effort required, as presently done for some OEB consultations. This would encourage intervenors to focus on issues that are material and help ensure the cost awards are better balanced with the benefits they provide.

To keep overall costs of the proceedings reasonable, the EDA proposes that cost award eligibility rules be revised so that parties with access to financial resources are not eligible for total cost recovery e.g. only 80% of expenses are recoverable through cost awards. This would encourage groups being represented by intervenors to undertake more active oversight of the work undertaken by the consultant/counsel working on their behalf. Presently, there is no cost driver to encourage groups to adequately oversee the intervenors working on their behalf and ensure their interests are being represented efficiently and effectively.

Intervenors should represent a clearly definable and distinct interest that is relevant to the issue being reviewed. There is an opportunity for the OEB to tighten rules around intervenor eligibility. This approach would reduce the overlap among intervenors and reduce the costs associated with funding two groups essentially representing the same interest.

Key benefits:
The proposed changes to the intervenor process will ultimately reduce costs associated with regulation and lead to more timely assessment of LDC applications. In addition, intervenors would be more focused on issues material and important to the groups they represent.

Ultimately, the customer would benefit from regulatory cost reductions in the form of more stable, affordable rates.

Additional Recommendations:

The OEB should conduct periodic review (every two to three years) of the reporting requirements to examine relevance and to avoid duplication.

The Social Agency Role for LDCs should be removed.

New requirements that involve significant implementation efforts should be coordinated between agencies and government to reduce overlapping implementation timelines that impact on LDC workload.

LDCs should not be compelled to take on the role of acting as a social agency. Recent examples include the requirement of LDCs to assist low income customers by adopting special customer service rules. The role of assisting low income customers should remain with social agencies that have the expertise and infrastructure to provide this assistance. LDCs should not be burdened with the administrative costs of implementing such social programs.

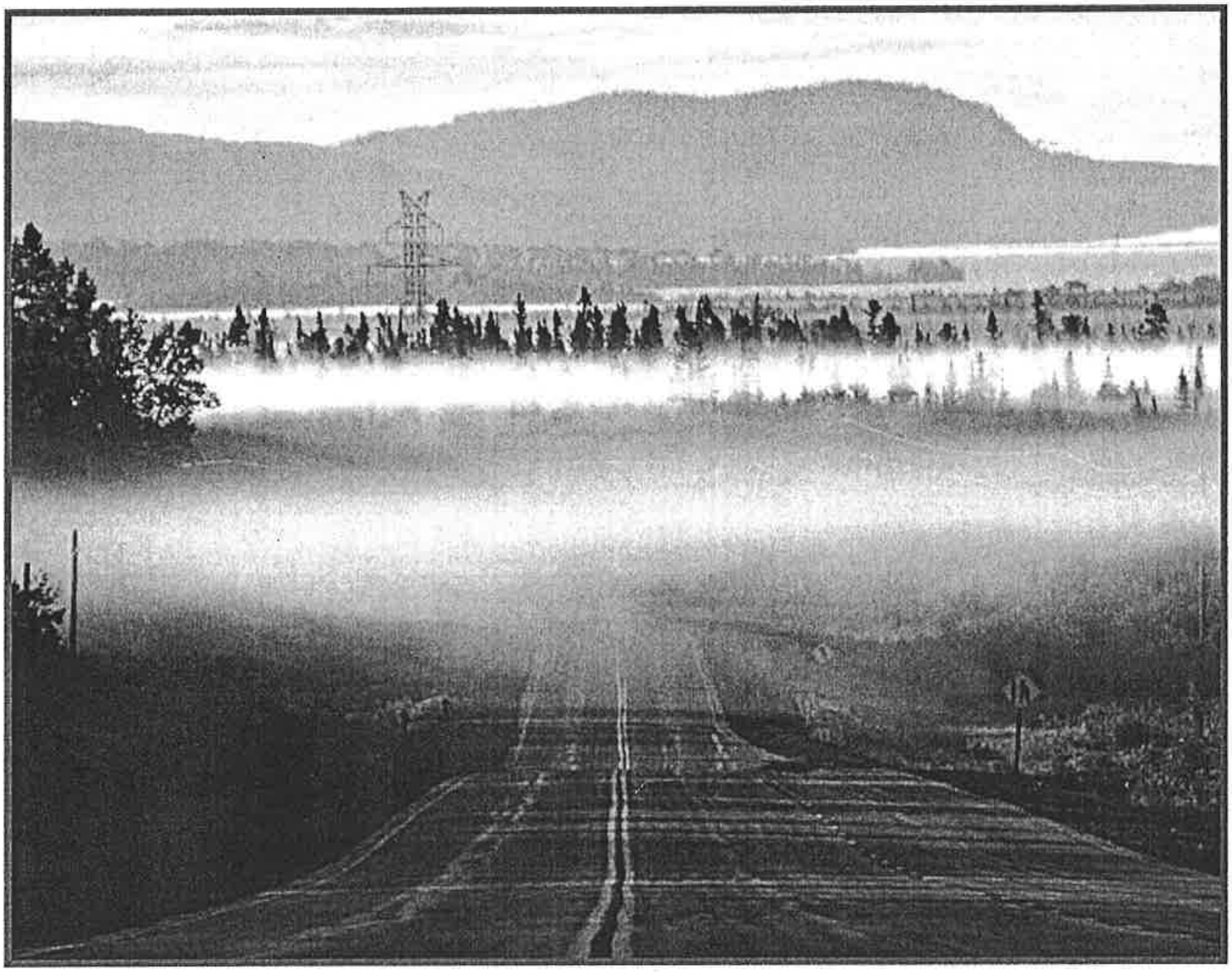
Conclusion

LDCs are experiencing increasing resource pressures associated with the steadily increasing regulatory burden year-over-year. The current regulatory process needs to be streamlined and simplified to reduce regulatory and administrative burdens in the interest of customers, LDCs and shareholders.

Implementation of the proposed recommendations will:

- Avoid sharp rate increases caused by the current regulatory approach and move to gradual rate changes.
- Reduce administrative/regulatory burden on both the regulator and LDCs.
- Reduce the undue financial burden on LDCs.

TAB 13



Electricity is the Answer

The EDA's Road Map for Delivering Ontario's Electric Future
November 1, 2011

EDA
The Voice Of Ontario's Electricity Distributors

Electricity Distributors Association

Chair's Message

The combined structure that is the generation, transmission, and distribution of electricity in Ontario is unique in the world. We are neither private nor public – we are both. While nuclear represents half of our power generation, the mix for the other half is changing at a rapid pace. And, as it relates specifically to local distribution companies, our mixture of large and small utilities, municipal, provincial, and private ownership means that there are few if any jurisdictions in the world that we can look to for advice.

That's just one of the insights you'll find in this important EDA document, **Electricity is the Answer** - *The EDA's Road Map for Delivering Ontario's Electric Future.* It was created under the leadership of the EDA's Board of Directors and leverages the expertise of renowned energy economist, Dr. Adonis Yatchew.

Electricity will power Ontario's future. Of that, there is no debate. From hand-held devices to electrically powered commuter trains and plug-in hybrid vehicles, electricity's share of Ontario's total energy mix will continue to grow. As it does, managing its generation, transmission, and distribution will become increasingly complex.

Today, we are at a crossroads. Whereas our transmission and distribution system was designed as a one-way street, this highway must now run in two directions. Once, only a few generators filled the system; now newly constructed on-ramps will enable the access of thousands. Tomorrow, millions may be added as plug-in vehicles provide mobile storage systems as well as emissions-free transportation. Infrastructure improvements take years to plan, decades to build and billions of dollars to finance. The crossroads at which we find ourselves requires no mere traffic light to manage. What's needed is a full-scale collaborative re-visioning involving all stakeholders.

For innovation to be successful, it cannot be centrally managed. Yet, for Ontario's dynamic electricity sector to be successful, innovation is required. Two groups of people are especially innovative – those on the shop floor and those with closest contact with customers. They both can be found at Ontario's local distribution companies. Our job at the EDA is to ensure their ideas and innovations are shared with all the stakeholders in the sector.

This paper represents our vision. The EDA calls on government decision-makers to seize the opportunity to make meaningful change in the sector, and invite them to use this vision as a starting point.

Jim Keech, EDA Chair

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Executive Summary

1. *Introduction and Background*

The purpose of this study is to identify the challenges that face the Ontario electricity distribution and transmission industry; to assess the structure of the industry and the roles of agencies and entities which regulate or otherwise interact with the wires segment; to evaluate strategies and policies which may be implemented to ensure that present and forthcoming challenges are met effectively; and to propose a vision and goals for the future.

The major trends affecting the industry have changed dramatically. A decade ago the emphasis was on unbundling, deregulation, competition and privatization. Today, major worldwide trends include decarbonisation, technologically based solutions such as smart-grids and smart meters, and evolving regulatory models. These trends have important implications for grid systems which we will examine in some detail.

2. *The Ontario Electricity Industry in Context*

Two primary forces drove electricity industry restructuring which took place in many parts of the world at the close of the last century: improved efficiency of smaller electricity generating units and increased emphasis on market forces.

The Ontario electricity industry underwent a period of restructuring and deregulation. The Ontario Hydro era ended when the iconic company was divided into multiple descendant entities. The Independent Market Operator (IMO)[1] was endowed with the responsibility of operating the competitive market which was launched in 2002. However, rising electricity prices led the government of the day to re-regulate the electricity market and a new body, the Ontario Power Authority (OPA) became the Provincial procurer of the majority of long-term supply.

During this period, the regulatory style of the Ontario Energy Board (OEB) changed as well, gradually moving, where it was possible to do so, from cost of service regulation to incentive regulation.

In 2009, the Provincial Government passed the Green Energy and Green Economy Act. The central purpose of the Act was to promote renewable electricity production and conservation, and demand management programs. The Act provided for more active and direct Government involvement in the management and decision-making within the electricity sector through Ministerial directives.

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[1] The IMO subsequently became the Independent Electricity System Operator (IESO).

Considerable resources have been expended on restructuring, resulting in a substantially more elaborate institutional structure. Concomitantly, the regulatory and administrative burden has increased dramatically for much of the industry. The broader objectives of decentralization and deregulation have, in many ways, fallen by the wayside.

3. *The Challenges Facing Transmission and Distribution*

The Ontario electricity industry has an exemplary record of providing the highest standards of service and reliability. It has done so in the face of major changes within the industry. The essentiality of electricity to the economy and to society mandates that this record continue to be upheld. However, the industry is now facing major challenges which we delineate below.

A. Infrastructure investment: Aging infrastructure needs to be refurbished or replaced on an ongoing basis and new investment is required to meet system growth and expansion.

B. New and emerging technologies: Smart meters have been installed in much of the Province. Smart grid and other innovative technologies will require ongoing resource commitments in order to ensure that they are incorporated in a cost effective manner. In time, electric vehicles will create new challenges for the industry.

C. Conservation and Demand Management: Utilities are required to meet conservation and demand management targets set by the Ontario Energy Board. For many utilities, this has resulted in an expansion of administrative tasks and responsibilities.

D. Distributed generation: The integration of distributed generation facilities will acquire ever increasing importance particularly where substantial changes are required to the operation and design of distribution systems. Variable energy resources such as wind and solar generation place new demands on distribution system operation. Ownership of distributed generation by distributors presents both a challenge and an opportunity.

E. Costs: Ontario electricity prices are projected to grow by 46% in the upcoming five years and 100% in the long term. A large portion of the increase is attributable to renewable energy programs. Though these rate increases are not principally attributable to traditional wires functions, they put pressure on cost structures throughout the industry and can affect regulated price increases and the internal decision-making at utilities.

F. Regulation and Government Policy: Recent legislative and policy initiatives have increased political and regulatory uncertainty. Regulatory burden has also increased substantially over the last decade.

G. Shareholders Objectives: Utilities need to ensure that they are meeting the objectives set by their shareholders, which may include private shareholders, municipalities, or in the case of Hydro One, the Province.

4. *Guiding Principles*

A. Service and reliability levels must meet customer expectations.

B. Mergers and acquisitions should be voluntary wherever possible, and should serve the interests of customers and shareholders.

C. The internal structure of distribution companies should be determined by individual utilities to the extent possible.

D. Wires utilities should be run on a commercial basis and accorded a full opportunity to earn commercial rates of return.

E. The implementation of technologically-based changes and innovations should be achieved through a consultative process and through incentive mechanisms to the extent possible.

F. Regulation that is free of political interference should be a commonly held objective.

G. Correct and transparent price signals should be implemented wherever possible.

5. *Regulatory and Legislative Objectives*

In order to achieve improved functioning of the sector as a whole, a number of legislative and regulatory options should be considered.

A. Reduced government involvement: Recent legislation has provided Government officials with additional authority to issue specific directives. Ideally, there should be an arms-length relationship between regulatory agencies and government. To achieve this objective, appropriate legislative changes would need to be enacted. It would be preferable if redistributive social welfare programs were provided by the Government rather than by utilities.

B. Rationalization and coordination of oversight agencies: The IESO was a creature of the deregulatory phase in the industry; the OPA a creature of the re-regulatory phase. Though both serve important purposes within the industry, a merger of the two entities, or further rationalization of their respective functions, could lead to more efficient decision-making within the industry.

C. Improving the regulatory process: A number of avenues exist for improving the regulatory process. These include the incorporation of multi-year capital reviews within the regulatory cycle; stricter constraints on the intervenor process; and, expedited reviews where appropriate. Increased coordination among regulatory entities may also serve to reduce regulatory burden. Consideration could be given to establishing a group, consisting of representatives from existing regulatory agencies, which coordinates overlapping or related activities of regulatory bodies and that has as its mandate the reduction of regulatory burden to industry participants.

D. Reduction in restrictions: Prior to industry restructuring, a number of distributors operated within public utility commissions which provided more than one service such as electricity and water. Such commissions exhibited, on average, materially lower costs. Consideration should be given to the reduction in regulatory restrictions on utility structure and relationships with utility affiliates.

E. Reallocation: In earlier years, distributors were responsible for the design of conservation and demand management (CDM) programs. That function now resides with the OPA. Consideration should be given to devolving many CDM responsibilities to utilities. A centralized agency would retain responsibility for administering the CDM program fund, research and possibly audit functions. Utilities could take on responsibility for design and development in addition to delivery of programs.

6. *Utility Objectives: Efficiency, Leadership and Excellence*

Among the important factors affecting the efficiency of distributing utilities are the scale of operation and the scope of activities. Ontario distributors display significant variation in unit costs for a variety of reasons, among them the density of the customer base, the age of the assets and historic investment and depreciation patterns.

Available empirical evidence suggests that scale efficiency can be achieved even by utilities of modest size; that contiguity and density of the customer base has important cost impacts; and that multi-utilities benefit from economies of scope.

Some have suggested that there are too many distributors in Ontario and that considerable customer savings can be achieved through major consolidations within the sector. Advantageous mergers among some distributors can produce cost savings, and innovative utilities will lead the way to new and more effective business models in a changing technological and operating environment. However, the empirical evidence generally suggests that most Ontario customers are served by utilities which have achieved scale efficiency so that consolidations would need to be evaluated on a case by case basis. Moreover, voluntary and incentive driven transactions, initiated by the utilities themselves, are far more likely to yield positive results than a directed approach.

The Ontario electricity industry has a long history of innovation beginning with the development of Niagara Falls in the early part of the 20th century, early and cost-effective electrification and the development of a unique nuclear technology. Today, Ontario continues to be at the forefront in smart and renewable technologies, many of which lie within the transmission and distribution segments of the industry.

The installation of smart meters throughout the Province is only the beginning of a process. A number of utilities have conducted their own time-of-use pricing experiments. However, much remains to be learned about the responsiveness of consumers to alternative rate designs and about the effectiveness of more advanced demand response regimes which rely upon real-time information and dynamic pricing. Technical sophistication is not synonymous with added value. Thus, reliable predictions of the likely effects of new programs would be very useful.

Government policies which promote renewable and distributed generation are a major driver of smart grid technology in the Province. As the share of renewables continues to grow, the need to accommodate variable energy resources at dispersed locations creates strong incentives for transmitters and distributors to seek solutions based on ever more intelligent technologies.

Ontario distributors enjoy an exemplary record of service and reliability. Maintaining this record should continue to be a central utility objective.

In most cases, distributors are the direct interface between the electricity supply chain and the end-user. In today's changing electricity environment, informing and educating customers has become an even more essential objective.

7. *Alternative Models*

We consider three scenarios or models for the wires segment of the Ontario electricity industry.

1. The 'status quo' assumes continuation of the present industry structure and regulatory and legislative framework.

2. The 'evolutionary model' builds on the existing structure, allowing it to evolve with suitable incentives.

3. The 'regionalization model' contemplates separation of distribution and transmission and the reorganization of distribution so that the Province is served by a reduced number of contiguous ('shoulder-to-shoulder') utilities.

Evaluation of Models

One would expect comparable levels of investment in regulated facilities under all three scenarios primarily because such investments are driven by the need for refurbishment and expansion. Regulatory approval is required for infrastructure investment and all parties recognize the importance of maintaining reliability levels.

One would expect a greater degree of innovation and assimilation of new technologies under the evolutionary and regionalization models than under the status quo.

Conservation and demand management programs would likely continue at comparable rates under all three scenarios as these programs are ultimately controlled by the regulatory authority. However, each scenario may result in differing approaches to achieving the targets. Under the evolutionary scenario, one might expect a greater degree of out-sourcing of program delivery through cooperative ventures.

Turning now to distributed generation, under all scenarios, the integration of variable energy resources constitutes a major challenge for distributors and for the transmission system. Some have argued that the regionalization scenario may have advantages in this regard.

Advantageous consolidations which lead to new efficiencies may be available, but they must be evaluated on a case.by case basis. They are most likely to occur under the evolutionary model. For the industry as a whole, the potential for gain through improved scale economies in wires operations, is modest.

Economies of scope, through increased flexibility in internal firm structure and operation can be realized under the evolutionary and regionalization models, as long as the regulator approves. New scope economies may arise as smart technologies and distributed generation expand. In time, this may create new potential for greater scale economies as well.

An important consideration on the cost side would appear to be the resources that would be required to implement alternative scenarios. The regionalization scenario would consume significant financial resources and there may be some losses in economies of scope by separating transmission and distribution.

There are, of course, numerous hybrids and other industry models that could be considered. In Ontario, the population is heavily concentrated in small geographic areas; there are also vast expanses of low population density, particularly in the north. This in turn may suggest a variant of the regionalization model where low density areas continue to be served by a combined transmission-distribution entity while more populated areas are served by regional distributors. To the extent that there are economies of scope in combined transmission and distribution operations in areas of low population density, these would continue to be retained. This variant would impose lesser transition costs and therefore may be an option worthy of more detailed consideration.

8. *Conclusions and Recommendations*

Ontario is at the forefront in a number of areas of electricity industry development and initiatives. This, combined with an industry structure that differs from those in most other jurisdictions, suggests that we cannot simply look elsewhere for formulaic solutions or templates.

There are multiple nuanced differences among the scenarios that were considered. Neither the evolutionary nor the regionalization model is uniformly better than the other. However, the regionalization model would likely consume significant resources and potentially face significant opposition. Given present circumstances and objectives, the evolutionary model is likely most appropriate at this time.

Key elements of the vision for transmission and distribution utilities include i) the pursuit of efficiencies through enhanced economies of scope, and possibly scale and contiguity; ii) leadership in innovation and cost-effective implementation of 'smart' technologies; and, iii) excellence in reliability and customer service.

From the political and regulatory standpoint, an arms-length relationship between the regulator and the government would improve decision making and reduce the uncertainty of the environment within which utilities operate. This in turn would likely enhance evolution of the sector and promote further advantageous consolidation. Streamlining, innovation and a more light-handed approach in regulatory processes would reduce regulatory burden and promote new efficiency gains through expanded economies of scope.

Summary of Recommendations

1. The relationship between the Provincial Government, the electricity industry and its regulatory agencies should be reviewed. This report proposes that an arms-length relationship is best suited to promoting the most effective decision-making within the industry, long-term efficiencies and a more predictable policy, regulatory and investment environment. If, this conclusion is supported by the review, appropriate modifications to legislation would need to be implemented.

2. Major restructuring of transmission and distribution is not warranted at this time. An evolutionary approach characterized by increased flexibility, well designed incentives, consensual change and low transition costs is the preferred model.

3. Regulatory restrictions which limit utilities from finding cost savings through expanded economies of scope should be relaxed to the extent possible.

4. Utilities should continue to seek improved efficiencies by taking advantage of possibilities for improved economies of scope and through mutually beneficial consolidations which may yield additional scale and contiguity economies.

5. A merger of the IESO and OPA or rationalization of their respective activities should be considered.

6. Regulation of the wires portion of the electricity industry should be reviewed. Utilities should have the option of seeking multi-year capital approvals. Consideration should also be given to streamlining the regulatory process where possible and providing utilities with broader regulatory options including expedited reviews.

7. Utilities should be given greater opportunities to design and develop their own CDM programs. Eventually, utilities may take on primary responsibility for these functions. Program fund administration and research should remain with a centralized agency such as the OPA or its successor.

8. An accurate understanding of customer response to increasingly sophisticated technology can be of great value. Further studies and analyses of advanced metering technologies and appropriate rate designs should be conducted.

9. Utilities should continue expanding their functional capabilities to accommodate new and emerging technologies such as smart-grid systems and distributed generation. Implementation of these technologies should be achieved on a cost-effective basis as determined by individual utilities and the regulator. Incentive based approaches should be implemented where possible.

10. The essentiality of electricity to the economy and to society mandates the continuation of the record of excellent service and reliability. This will require continuing investment in the wires networks.

1. Introduction and Background

A. Purpose

The purpose of this study is to identify the challenges that face the Ontario electricity distribution and transmission industry; to assess the structure of the industry and the roles of agencies and entities which regulate or otherwise interact with the wires segment; to evaluate strategies and policies which may be implemented to ensure that present and forthcoming challenges are met effectively; and to propose a vision and goals for the future.

The major trends affecting the industry have changed dramatically. A decade ago the emphasis was on unbundling, deregulation, competition and privatization. Today, electricity industries are engaging new trends including decarbonisation, technologically based solutions such as smart-grids and smart meters, and evolving regulatory regimes which, in some cases, have moved towards re-regulation.

In Ontario, the elimination of coal-based generation and the promotion of renewable technologies have been cornerstones of the decarbonisation agenda. Smart meters have been widely installed and the promotion of smart grid technologies is now enshrined in legislation. At the same time, the regulator is seeking new ways to regulate in a changing landscape.

Even a casual glance at the industry reveals a series of ongoing and upcoming challenges that need to be addressed. Prominent among these are the following.

The industry has provided high levels of service and reliability over the course of many decades. In order to maintain these levels, aging assets at many utilities require continued refurbishment or replacement.

As the Ontario population and economy grows, the electricity delivery system must continue to expand. Advanced societies worldwide are displaying a new electrification trend, driven by efforts to decarbonize their economies. Ontario is no different with the *share* of electricity in final energy consumption projected to grow. Increasing use of electricity in transport and other sectors places upward pressure on the entire electricity supply chain, not least on the delivery segment.

Provincial Government legislation and policy initiatives have markedly shifted the direction of the electricity industry with increased emphasis on renewable generation, smart meter and smart grid technologies, and conservation and demand management programs (CDM).

The very design of distribution networks is experiencing a paradigm shift. Previously, their main purpose was to repackage electrons to lower voltages and to deliver them to customers. Now, with the growth in distributed generation, they are required to collect electrons as well as to deliver them.

Increased regulatory burden, combined with functional, structural, legislative and policy changes over the last decade and into the coming years put considerable pressure on administrative resources within utilities. A fresh look at the regulatory approach should assist in relieving some of this pressure.

B. Themes

Certain interrelated themes will help to inform our review. They may be summarized using three terms: ***function***, ***structure*** and ***regulation***.

The first theme encompasses considerations such as current and nascent ***functions*** that the wires segment may need to fulfill as the electricity industry evolves. These include the integration of distributed generation, the incorporation of information technologies that facilitate such integration, the development of smart grid solutions which can improve the utilization of existing and new resources and lead to savings in capital expenditures, and the implementation of systems that ensure that smart meters are used to their best advantage.

The second theme embraces ***structural*** changes that may be considered. Among the drivers of structural change are the new and evolving ***functions*** just mentioned, the changing face of technology and government legislation, policies and directives. A perennial structural question is whether the number and geographical disposition of distributing utilities could be improved upon, and if so, by what mechanism. These relate to economies of scale and contiguity. Some have argued that there continue to be too many utilities and that some are too fragmented. But there are also important issues relating to intra-utility structure. For example, one needs to ask whether there are potential efficiency gains or scope economies which could flow from reducing barriers to functional integration of traditional wires company responsibilities with other activities. The structural changes that we consider are not restricted to the wires companies themselves. For example, we consider whether agencies which are directly involved with the wires segment, such as the Ontario Power Authority (OPA) and the Independent Electricity Systems Operator (IESO), should be restructured or whether functional reallocations should be considered.

The third theme involves the ***regulatory*** environment. Transmission and distribution in Ontario is regulated by a number of agencies, most importantly the Ontario Energy Board and the Electrical Safety Authority. Given the natural monopoly nature of the wires business, regulation is necessary. But the nature of regulation merits reconsideration, particularly in view of the changing and expanding functions utilities are being asked to perform and the associated regulatory burden. More importantly, the mechanisms by which political input influences decisions require attention.

2. The Ontario Electricity Industry in Context

A. The Forces That Drove Restructuring

A vision of the future requires an understanding of the past. For much of the 20th century, the broad structure of the Ontario electricity industry remained little changed. Ontario Hydro was the main provider of generation, transmission and rural distribution. Electricity distribution to urbanized areas was provided by a growing number of municipal utilities as municipalities exercised their right to establish hydroelectric or public utility commissions. These were regulated by Ontario Hydro which also bore primary responsibility for system planning and operation.

Two primary forces drove the electricity industry restructuring which took place in many parts of the world at the close of the last century. An understanding of these forces is important because it helps us to gain perspective on the present trends.

The first major driver was technological change which affected the scale economies of generating electricity. From the beginning of the 20th century to the 1970s, unit costs of generation fell as the size of generators increased and thermal efficiencies improved. Ever larger generating units were required to minimize costs, and by 1980, in order to achieve scale efficiency, generating units exceeding 1000 MW were being constructed.[2]

However, during the 1980`s, it became possible to construct smaller generating units that met the efficiency levels of large facilities. By 1990, gas turbine units ranging from 50 MW to 150 MW were economically viable.[3] This technological driver created the possibility of competition in the generation segment of the industry (see Figure 1).

The second primary force driving electricity restructuring was a worldwide shift towards increased emphasis on market forces. Beginning with the Great Depression, which had been seen as a profound market failure, the political pendulum had swung to the left, with an increasing role of government in the economy. However, the 1970s was a period of stagflation and slow economic growth. Regulatory failure and excesses were seen to be part of the problem. The elections of Margaret Thatcher and Ronald Reagan marked the end of an era and the pendulum swung to the right through the 1980s. That

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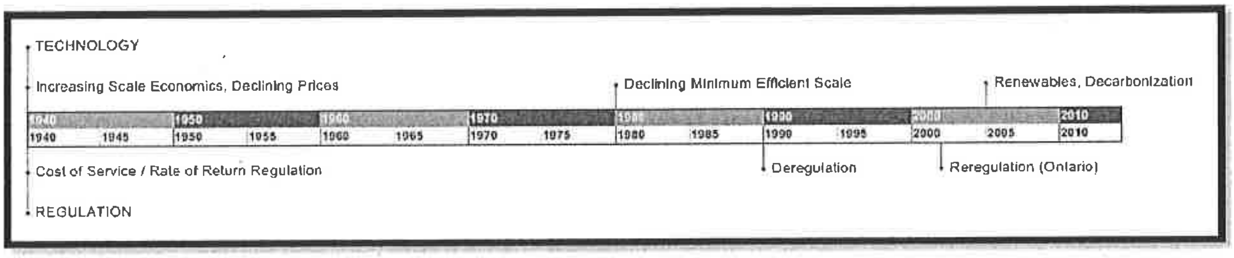
[2] See *Technology and Transformation in the American Electricity Industry*, by Richard Hirsch, Cambridge University Press, 1989, pages 1-11.

[3] See "Less is More: Why Gas Turbine Units Will Transform Electric Utilities", by Charles E. Bayless, *Public Utilities Fortnightly*, December 1, 1994, pages 21-25.

decade ended with the spectacular dissolution of the Soviet Union which was seen by many as a vindication of the market model vis-à-vis the central planning model.[4]

Figure 1: Technology and Regulation



Since deregulation had been successful in improving a number of other industries, among them airlines and natural gas, the general consensus was that competitive market forces could also improve the performance of the *generation* segment of the electricity industry and so a variety of 'deregulatory' experiments ensued.

The electricity industry restructurings that followed were founded upon the principle of separating competitive segments (generation and supply) from natural monopoly segments (transmission and distribution). In some jurisdictions, this was implemented through functional separation whereby competitive and non-competitive segments remained within an existing utility. In other jurisdictions, the industry was vertically unbundled through divestiture and the creation of new corporate entities.

In Ontario, the iconic Ontario Hydro gave birth to new entities, among them Ontario Power Generation which inherited the major portion of generation assets, Hydro One which incorporated transmission and mainly rural distribution, the Independent Market Operator (later the Independent Electricity System Operator) and the Electrical Safety Authority. Beginning in this time period, the number of distributors, of which there were over 300 prior to restructuring, fell sharply to about 80 today.

However, deregulation and marketization did not meet with uniform success. The difficulty in the California electricity market comprises one such example. The collapse of financial markets in 2008 has also been attributed at least in part to deregulation that took place in the 1990s. Despite these setbacks it is important not to overreact and undo many of the benefits that have accrued. Increased regulation may be warranted in certain cases, but excessive regulation and government intrusion in the decision-making of business is counterproductive.

[4] The shift towards marketization was also visible in China (and elsewhere) which began its liberalization programs in 1978. Since that time China has experienced prodigious economic growth and become an economic and political powerhouse.

For the electricity sector, two major policy trends are currently serving as important drivers. The first is decarbonisation which is being pursued through programs that promote renewables and through increased conservation and demand management. The second is reregulation or at least a cautious and selective approach to deregulation.

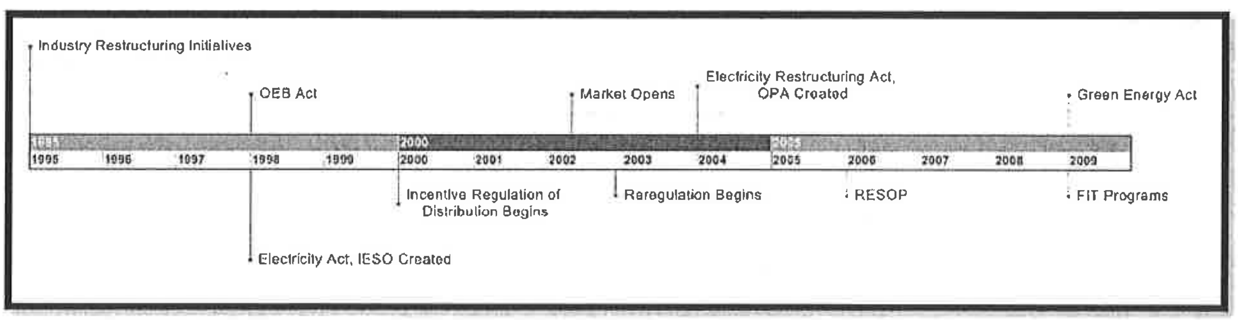
B. Formative Legislative Changes

In Ontario, a number of restructuring and deregulation models were proposed during the 1990s. By 1995, an active debate was taking place and formal mechanisms for changing the industry were being initiated.

Restructuring was enabled by a number of legislative initiatives, most importantly The Electricity Act (1998) which created the initial institutional structure, and the Ontario Energy Board Act (1998) which granted new regulatory powers to the Ontario Energy Board (OEB) over the various entities, among them distribution and transmission companies. (Previously, Ontario distributor rates were regulated by Ontario Hydro.)

In 2002, Ontario's short-lived foray into a fully competitive market structure for electricity began and ended. Shortly after the market opened, prices rose, after which the Provincial Government moved quickly to stabilize prices.

Figure 2: Ontario Electricity Industry Timeline



The Electricity Restructuring Act (2004) established a new entity, the Ontario Power Authority, which would be the Provincial procurer of the majority of long-term supply. A 'hybrid' market was now in the process of being established.

In 2009, the Provincial Government passed the Green Energy and Green Economy Act, the central purpose of which was to promote renewable electricity production and conservation and demand management programs. The Act established feed-in-tariff programs for renewable energy and required distribution and transmission entities to connect such facilities. Distributors were permitted to own small-scale renewable energy generating facilities.

The Act also introduced new objectives for the OEB, including the promotion of renewable energy, conservation and demand management, and a smart grid. It also required distributors to achieve conservation and demand management targets to be set by the OEB.

Notably, the Act provided for more active Government involvement in the management of renewable energy, conservation and smart grid initiatives through Ministerial directives. The approach marks a potentially substantial increase in government involvement in decision making and management of the electricity sector.

C. Regulatory Evolution

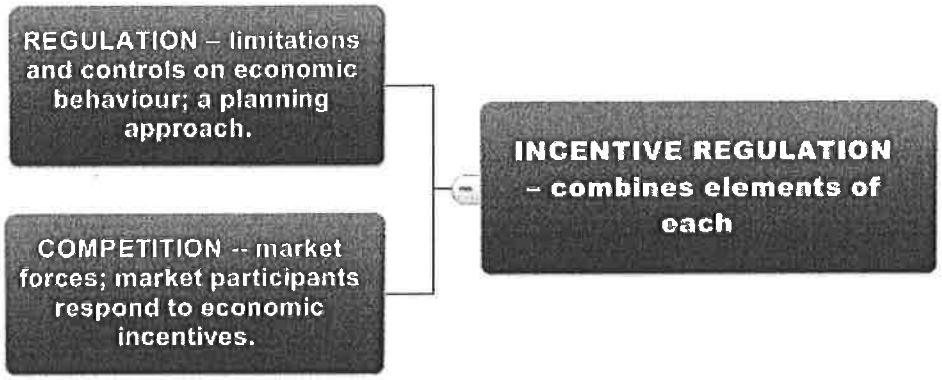
In the late 1990s, the regulatory style of the OEB began to change as well, gradually moving, where it was possible to do so from cost of service regulation towards incentive regulation. The latter is best understood as part of the sweeping intellectual, political and economic trends favouring market forces. The broad argument stated that just as governments should be less intrusive in the economy, the regulator should be less intrusive in its oversight duties. An important methodology underpinning incentive regulation involved mimicking market-type incentives where true markets could not be created.

Performance based or incentive regulation of Ontario distributing utilities began in the year 2000 (see Figure 2).[5] During the subsequent years, the approach was refined. In order to calibrate performance, detailed OM&A data were obtained for each distributor and the Board engaged consultants to model differences amongst utilities based on certain variables such as customer density, employee wage rates and the nature of the service territory.

This approach unfortunately failed to incorporate capital costs, which represents the dominant share of total costs. Subsequently the analysis set productivity factors in a price-cap formula based on those that had been observed in U.S. data and that incorporated detailed capital information.[6]

[5] Ontario Energy Board Decisions RP-1999-0034, January 18, 2000 and RP-2000-0069, September 29, 2000.
[6] EB-2007-0673, Supplemental Report of the Board on 3rd Generation Incentive Regulation for Ontario's Electricity Distributors, September 17, 2008.

Figure 3: Incentive Regulation



Regulation of rates continues to evolve and difficulties remain. The rapidly changing environment faced by utilities as well as new tasks that are being imposed complicates future evolution. On the one hand, new functions may require separate regulatory treatment and budget allocations as has been done in some instances in the past. But as the burden accumulates, one is inclined to consider other 'all-in' options where a utility may prefer to seek an uncomplicated but therefore light-handed and lenient approach rather than a multi-stage process where conventional activities are regulated by one mechanism and new functions are regulated on an individual basis.

3. The Challenges Facing Transmission and Distribution

The Ontario electricity industry has an exemplary record of providing the highest standards of service and reliability. It has done so in the face of major changes within the industry. The essentiality of electricity to our economy and society mandates that this record continue to be upheld. However, the industry is now facing major challenges.

A. Infrastructure Investment

a. **Refurbishment and replacement of existing assets.** Many of the assets within Ontario's distribution and transmission networks are aging and require refurbishment or replacement. It is essential that associated programs are conducted in a timely fashion to ensure service quality and to minimize longer term costs. Undue delay of such programs may result in greater overall costs to customers as well as rate shock if pent-up capital needs are subsequently met on an accelerated basis.

b. **System growth and expansion.** As Ontario's population and economy continues to grow, utilities must ensure that transmission and distribution facilities expand to meet this growth.

B. New and Emerging Technologies

a. **Smart meters.** The Government has mandated Province-wide installation of smart meters and many utilities have already done so. In order to fully realize the value inherent in this investment, which was mandated by the Province, utilities will need to continue to develop programs which make effective use of this technology.

b. **Smart grid.** Improved information technology is leading to innovations in grid management. In time, these developments can facilitate the incorporation of distributed generation, enhance load management and even provide for real-time customer response to system requirements. Proliferation of plug-in electric vehicles will create additional demands on electricity systems. At this time, many 'smart' technologies remain in a relatively early stage of development and their cost-effective implementation by utilities is a major challenge.[7]

C. Conservation and Demand Management

Utilities are required to meet conservation and demand management targets set by the Ontario Energy Board. The OPA has developed a series of Province-wide programs and utilities rely upon these programs to achieve their CDM objectives.[8] The OPA programs include:

- demand response programs under which end-use customers receive incentives to reduce consumption at certain peak times; these arrangements may be voluntary or contractual;
- small business programs designed to promote energy efficient lighting;
- building retrofit programs;
- support for energy audits;

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[7] The impacts on grid systems of smart technologies, demand response programs, renewables and distributed generation are receiving world-wide attention. For example, a team of researchers at the MIT Center for Energy and Environmental Policy Research is presently conducting a major study on the future of the U.S. electricity grid. The report is due in the fall of 2011. Preliminary presentations are available at http://web.mit.edu/ceepr/www/about/May2011/may%20handouts/schmalensee.pdf and http://web.mit.edu/ceepr/www/about/May2011/may%20handouts/rose.pdf.

[8] See https://www.saveonenergy.ca/.

- incentives for improvements in energy use by industrial and commercial enterprises;
- incentives for energy saving upgrades in new residential construction.

In a few cases, larger utilities have proposed additional programs that they are developing. The proponents of these programs must demonstrate that they are not duplicative of OPA programs. As part of the OEB review process, the OPA is asked to provide its opinion on the utility-specific programs and whether they are duplicative.

It would seem that the balance has not been struck properly. Centralization of the provision of some CDM programs is probably beneficial, particularly to the smaller utilities. On the other hand, it discourages innovation by distributors. Many of these development initiatives could be provided by single distributors or groups of distributors. With a multiplicity of utilities engaged in development, a competitive selection process will likely result in more rapid evolution and testing of programs. Centralization of this function also reduces the incentives for cooperative efforts by groups of utilities and for consolidation.

D. Distributed Generation

a. **Distributed generation facilities.** Current incentives for renewable energy projects have led to an abundance of applications, particularly for providers of small scale solar and wind generation. Some of these are located within municipal distributor boundaries. Distribution companies can no longer be thought of as simply distributing electricity, but also of collecting it.[9] Distribution systems originally conceived and engineered to deliver electricity must be modified to incorporate distributed generation.

b. **Integration of variable energy resources.** The overwhelming proportion of new renewable supply in Ontario is solar and wind based. Unlike conventional generation, the energy produced by such facilities fluctuates widely, sometimes over relatively short time intervals. Power quality can be deprecated and in some instances reverse power flows can occur. Technical integration within a distribution system presents new challenges, some of which may be resolved using emerging technologies.[10] However, a concentration of new supply of this type presents the host distributor with new engineering and design issues and can have upstream impacts which may not be paid for by the generator.

[9] If the latter is to occur on a large scale, the term "distribution company" becomes a misnomer.

[10] Cost effective deployment of battery-type storage or flywheel technologies may help to reduce the magnitude of the impacts on distribution systems in the future.

c. **Ownership of generation.** The Green Energy Act permits distributors to own small generation facilities. This presents both a challenge and an opportunity to some utilities.

E. Costs

a. **Cost pressures.** In past years, Ontario has enjoyed electricity prices that are relatively low by international standards and Ontario businesses have, to a greater or lesser degree, relied upon these prices in their locational and expansion decisions. Recent projections indicate that Ontario electricity prices will grow by close to 46% in the upcoming five years and 100% in the long term.[11] A large portion of the increase is attributable to renewables programs: cleaner energy implies more expensive energy, at least at the present time.[12] This in turn puts pressure on cost structures throughout the industry and can affect regulated price increases and subsequently the internal decision-making at utilities.

b. **Cost saving opportunities.** In some cases, mergers or amalgamations may lead to cost savings through improved economies of scale. In other cases, horizontal economies of scope, for example through the sharing of resources among multiple service types may also lead to reduced costs. Cooperative planning, development and marketing of programs, such as those related to conservation and demand management, can also lead to efficiency gains.

F. Regulation and Government Policy

a. **Government legislation and policy initiatives.** The Green Energy Act has created new obligations for wires companies, such as the requirement to connect renewable resources. The increased direct role of Government, through the issuance of directives,

[11] "Over the next 20 years, prices for Ontario families and small businesses will be relatively predictable. The consumer rate will increase by about 3.5 per cent annually over the length of the long-term plan. Over the next five years, however, residential electricity prices are expected to rise by about 7.9 per cent annually (or 46 per cent over five years)."Ontario's Long-Term Energy Plan, page 59, http://www.mei.gov.on.ca/en/pdf/MEI_LTEP_en.pdf.

[12] "This increase will help pay for critical improvements to the electricity capacity in nuclear and gas, transmission and distribution (accounting for about 44 per cent of the price increase) and investment in new, clean renewable energy generation (56 per cent of the increase)." Ibid., page 59. It is unclear whether a portion of the 44 per cent share attributable in part to transmission and distribution is itself caused by renewable energy related T&D expenditures. If so, then the clean energy program is accountable for a larger than 56 per cent share of rate increases.

is also likely to increase the uncertainty of the policy environment within which utilities operate.

b. **Regulatory burden and regulatory evolution.** Utilities have experienced a marked rise in regulatory burden over the last decade. Even rate applications have become much more complex than they were a decade ago. Meeting regulatory obligations, however, is only part of the picture. Utilities can and should help shape the regulatory model under which they operate so as to streamline it administratively and improve its effectiveness.

G. Shareholder Objectives

Utilities owned by municipalities, or in the case of Hydro One, by the Province, need to ensure that they are meeting the objectives set by their shareholders, including financial performance targets. Political and regulatory bodies should ensure that they are provided with a fair opportunity to do so.

4. Guiding Principles

In past industry reviews, guiding principles have been set out to assist in the formulation of possible paths. Below we list those that are fundamental in today's environment. Some of these principles fall squarely within one of the three themes – function, structure and regulation -- which serve to organize our reasoning. Others straddle boundaries and incorporate more than one theme.

A. **Service and reliability levels should meet customer expectations:** This principle has always been central to the mandates of distribution and transmission utilities, and Ontario utilities have provided excellent service. However, the requirement to connect and integrate distributed generation is transforming distribution companies into more sophisticated entities which harvest as well as distribute electrons. The supply of electricity from distributed generation can be less predictable than traditional generation. These factors, combined with infrastructure that, in many places, is aging, can lead to increased risks to service levels and reliability.

B. **Mergers and acquisitions should be voluntary wherever possible and serve the interests of customers and shareholders.** There has been a marked consolidation within the distribution segment of Ontario's electricity industry over the last fifteen years. Consolidations should be accomplished on a voluntary basis since this is most likely to lead to arrangements that serve the best interests of customers and shareholders. Merging utilities should be provided with a sufficient period of time to harvest the benefits of consolidation.

C. **The internal structure of distribution companies should be determined by individual utilities to the extent possible.** As part of the effort to create an unbundled and competitive electricity industry in Ontario, distribution utilities were required to restructure internally, separating wires, supply, energy service and other functions.[13] This likely resulted in some efficiency losses. Since that time there has been a fundamental shift in direction for the industry and distributors have been granted new rights of ownership of generating facilities. In this changing environment, distributors may be able to find new economies of scope through restructuring or reorganizing. To the extent possible, they should be permitted sufficient latitude to do so.

D. **Wires utilities should be run on a commercial basis. The regulatory and policy environment should be as predictable as possible and utilities should be accorded a full opportunity to earn commercial rates of return.** An important reference point of regulatory theory involves considering the industry structure and company behaviour that would occur if the industry were subject to market discipline. The regulator then attempts to achieve similar outcomes in the existing environment. Incentive regulation, for example, attempts to create incentives which induce firms to behave in ways similar to those that would be observed in competitive markets. To the extent possible, utilities should be provided with incentives to optimize their commercial performance. Among these incentives are a predictable regulatory and policy environment which is central to effective planning and investment, and a realistic opportunity to earn rates of return which are consistent with capital markets.

E. **The implementation of technologically-based changes and innovations should be achieved through a consultative process and through incentive mechanisms to the extent possible.** New technologies, particularly related to the smart-grid, have the potential of improving system operations, efficiency and reliability. Their implementation requires not only evaluation of the benefits to an individual utility's customers, but also consideration of wider network benefits. Thus a consultative process is especially important if optimal patterns of technology adoption are to occur. To the extent possible, incentive mechanisms should be used to promote technology adoption where greatest benefits can accrue.[14]

F. **Regulation that is free of political interference should be a commonly held objective.** Recent legislative changes have increased the potential for politically motivated directives

[13] The Affiliate Relationships Code formed part of the new rules governing distributor behaviour.
[14] See for example the Low Carbon Networks Fund put in place by OFGEM in the U.K. electricity industry. http://www.ofgem.gov.uk/NETWORKS/ELECDIST/LCNF/Pages/lcnf.aspx.

to the industry. Energy policy is a proper prerogative of government. However, the determination of mechanisms by which policy objectives are achieved is best left to the regulator and the industry. An arms-length relationship between government on the one hand, and the regulator and the industry on the other, is the preferred model. Just as over-regulation of the industry by the regulator is undesirable, excessive intrusiveness by the Government in the implementation of its broadly stated policies is unnecessary and often counter-productive.[15] Utilities have also been engaged to deliver certain social programs. It would be preferable if redistributive functions remained with the Government rather than being delivered by utilities.

G. **Correct and transparent price signals should be implemented wherever possible. To the extent that price-distorting cross-subsidies exist, they should be re-evaluated and eliminated to the extent possible.** The move to static, time-of-use pricing has improved the price signals received by retail customers. Efforts to further refine such rates and in the future, to consider dynamic time-of-use (TOU) pricing, should continue.

5. Regulatory and Legislative Objectives

In order to achieve improved functioning of the sector as a whole, certain regulatory and legislative options should be considered. We discuss each in turn. A summary is contained in Table 1.

A. Reduced Government Involvement

The processes of setting government energy and environmental policy, and that of regulating the economic entities that provide energy, are best separated through an arms-length relationship between the relevant regulatory agencies and the government. In present circumstances, and for various reasons, segments of the electricity industry require a relatively high degree of regulation and the purpose of regulatory agencies is to provide appropriate oversight within the confines of governing legislation and governmental policies. Regulatory agencies are expected to be a repository of institutional and industry-specific knowledge and should be in a position to make balanced decisions.

Recent legislation, however, has provided Government officials with additional authority to issue specific directives to industry participants. This authority permits the Government to leapfrog over the regulatory buffer, one that should be free of short-run considerations, and intervene directly in decisions that should be made by industry participants or by the regulator.

[15] In each case the simple objective should be "Tell us what you want us to achieve, but not how to achieve it."

Some may argue that this is merely a discretionary tool upon which the Government may rely. However, the very presence of this option may result in increased pressure from interest groups on the Provincial Government to exercise its prerogative under the current law.

Industrial policy arguments have also been raised in support of the existence of government directives such as those embodied in the Green Energy and Green Economy Act. However, the absence of this tool does not preclude the Government from using fiscal tools to promote industrial development and job creation. Furthermore, governments do not have, on balance, a favourable record of picking economic winners. In many cases where governments have had a direct hand in making business decisions, industries have thrived only as long as they have been supported by the government. [16]

Important lessons can be learned from the Ontario's lengthy efforts to restructure and liberalize the electricity market. After many years of discussion, a model was implemented in 2002, but then quickly overturned in response to public outcry. The model that was eventually implemented was arrived at by a highly circuitous route, which along the way consumed massive resources. [17,18]

The recent increased role for the Government, staked out through legislation, is in our view, detrimental to the long term interests of Ontarians. It increases the risk of politically motivated decisions, it reduces transparency and it has the potential of overriding the proper separations between the levels of decision-makers. This approach can also lead to reduced accountability and the Government adopting an ever increasing role in business decisions. It is inconsistent with light-handed or incentive regulation and it even creates the potential for circumventing meaningful and effective public input.

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[16] This point is relevant to concerns about the FIT programs. A recent report states "Many governments here in Canada and around the world are putting in place energy pricing regimes that encourage the rapid deployment of renewable energy generation. A typical element of this approach is a guaranteed feed-in-tariff (FIT) – a commitment by the public energy authority to pay much higher than prevailing market rates for energy created by favoured sources. FITs are necessary because the economics of sources like solar and wind have not yet delivered energy at a competitive cost. FIT proponents argue that these temporary subsidies are necessary to bring generating capacity on line and to stimulate the process of reducing costs as experience is gained. But there are few examples of such subsidies working to get costs down and of the subsidy being eliminated." See "Canada's Innovation Imperative", Institute for Competitiveness and Prosperity, May 2011, page 46.

[17] For a detailed account and analysis of the events and circumstances surrounding the process and decision-making see "Electricity Restructuring in Ontario", Michael Trebilcock and Roy Hrab, *The Energy Journal*, 2005, vol. 26, no. 1, pp. 123-146.

[18] There are other instances of decisions made within the Ontario electricity industry which had a substantial political component. Among them, the signing of long-term uranium supply contracts by Ontario Hydro that resulted in Ontario consumers paying for uranium at prices that far exceeded those prevailing in the market. Another example involves the continuation of construction of the Darlington generating facility during the 1980s despite serious concerns at the time about the need for it.

Table 1: Regulatory and Legislative Options	
Legislation	
Reduced Government Role	Consider modifications to legislation to ensure arms-length relationship between government, the industry and its regulatory agencies.
Rationalization / Coordination	Consider merger of the IESO and the OPA or rationalization of their respective activities. Increased coordination among regulatory entities may reduce regulatory burden.
Regulation	
Capital Programs	Review of multi-year capital programs by the regulator should be given serious consideration.
Streamlining	Consider innovative incentive-based approaches and a less onerous intervenor and hearing process.
Reduction in restrictions	Consider relaxing restrictions which limit utility ability to find cost savings through economies of scope.
Reallocation	Some functions, such as aspects of CDM program design may be reallocated to utilities.

In our view, policy decisions should reside with the Government. Regulatory decisions are best made by the regulators. And business decisions should be left to the companies themselves. This in turn would imply a reconsideration of certain portions of current legislation.

B. Rationalization and Coordination of Oversight Agencies

Prior to industry restructuring, most of the functions performed by the OPA and the IESO resided within Ontario Hydro. The IESO was a creature of the deregulatory phase in the industry; the OPA a creature of the re-regulatory phase. Indeed, the OPA was not created until efforts to create a fully competitive generation market in Ontario were abandoned.

In 2007, the Province appointed an Agency Review Panel to review the activities of a number of electricity sector entities, including the IESO and the OPA. Among the recommendations of the resulting report were a reallocation of CDM functions of the OPA and a merger of the OPA and the IESO. [19]

Since that time, only a limited degree of rationalization has taken place. Presently the Ministry of Energy is involved in the design and administration of some conservation functions and it plays an

[19] "The Report Of The Agency Review Panel On Phase II Of Its Review Of Ontario's Provincially-Owned Electricity Agencies", page 22, Queen's Printer for Ontario, November 2007.

important role in setting targets for the OPA. Much of the execution and design is performed by the OPA. That these functions reside directly within the Government increases the risk that decisions could be made on the basis of short-term considerations.

Both the IESO and OPA serve important purposes within the industry. However, it may be appropriate to revisit the possibility of merging these two entities or at least to consider further rationalization of functions between them.

Consideration could also be given to establishing a group, consisting of representatives from existing regulatory agencies, which coordinates overlapping or related activities of regulatory bodies and that has as its mandate the reduction of regulatory burden to industry participants.

Either of these approaches could lead to significant efficiency improvements within the industry, a reduction in overlap, more coordinated and timely decision-making and a reduction in regulatory burden.

C. Improving the Regulatory Process

Despite the move to incentive regulation, the regulatory and administrative burden borne by Ontario utilities has grown substantially over the last decade.

Incentive regulation can be particularly effective when certain conditions are present. Among these conditions are the following: i) an environment where utility responsibilities and technologies remain relatively stable, enhancing comparability of data on a year-to-year basis; ii) a dynamic technological environment where production costs are dropping, thus reducing political pressure on regulators as rates can be lowered without endangering necessary utility expenditures or profits; iii) private ownership which can reduce political temptation to tamper with utility incentives.

None of these conditions are present in Ontario. Utility responsibilities are changing dramatically. There is upward pressure on costs arising from a variety of factors such as renewable energy and CDM programs, distributed generation and aging infrastructure. Public ownership continually exposes utilities to increased risk of politically motivated micro-management in many dimensions, including with respect to earnings.

The Ontario Energy Board, to its credit, has attempted to meet these challenges using sophisticated tools specifically adapted to the Ontario environment. In order to manage the regulation of many disparate distributors, it has relied upon a variant of incentive regulation grounded in empirically based benchmarking.

However, the growing range of utility responsibilities and capital expenditure programs will make effective regulation ever more challenging and hamper its abilities to control regulatory burden for itself and for the industry as a whole. Furthermore, some utilities require major capital expenditures to refurbish and extend infrastructure. In this connection, multi-year capital program reviews could substantially improve the regulatory process by reducing the need for repeated cost-of-service applications and by smoothing capital expenditures.

The process of streamlining regulation will create additional challenges. Faced with new responsibilities with uncertain associated costs, many utilities may prefer cost-of-service regulation to reduce their risks. Separate regulation of each new activity is burdensome and may, in turn, lead to difficult cost allocation problems.

Fundamental to efficacious regulation is the continued focus on the creation, reinforcement and sustenance of incentives. Incentives might be strengthened by providing a menu of regulatory options to utilities whereby they could choose fast-tracked approvals with lesser information requirements and consolidated applications, or more detailed approval processes.

Further refinements of regulatory processes might also be considered. These include 'objective oriented regulation';[20] stricter constraints on regulatory review by the Ontario Energy Board and on the intervenor process; and, consolidation of the representation of consumer interests. Increased coordination among regulatory entities may also serve to reduce regulatory burden.

D. Reduction in Restrictions and Reallocation of Functions

Prior to industry restructuring, when Ontario municipal distributors were regulated by Ontario Hydro, a number of electricity distributors operated within public utility commissions which provided multiple services. Such commissions exhibited, on average, materially lower costs.[21]

As part of industry restructuring, electricity distribution was separated from other activities which could reside in related but separate entities. This restructuring and separation initiative was premised upon moving towards a competitive electricity market. It too was a product of the deregulatory period in the Ontario electricity industry. However, the deregulatory model has long been abandoned and new themes dominate the industry.

[20] 'Objective' or 'principle' based approaches have gained traction in financial regulation partly as a result of the financial collapse of 2008. Some of the ideas developed there may be relevant for regulating energy industries.

[21] Statistical estimates from data in the mid-1990s indicated that distributors that were part of public utility commissions exhibited lower average per-customer costs in the range of 6% to 10%. See "Scale Economies in Electricity Distribution: A Semiparametric Analysis", *Journal of Applied Econometrics*, volume 15, pages 187-210, Tables I(a) through II(c).

As the distribution segment of the industry evolves, incorporating increasing amounts of new technology and widening the types of services for which it is responsible, new possibilities for cross-hybridization and economies of scope are likely to emerge. It would be desirable for the regulator and the Government to take a forbearing approach in order that these new possibilities can thrive.

Recently distributors have been given the opportunity to own modest amounts of distributed generation and thus a certain degree of vertical re-integration is permitted. We note that, at present, most utilities[22] have chosen to situate this new generation within affiliates, rather than within the distribution company itself. This may be, in part, to avoid the possibility of regulatory claw-back and scrutiny. At the same time, it may be that economies of scope are being lost. It would be helpful to determine whether, in the absence of regulatory considerations, these utilities might have made their decisions differently.

In short, given that there is no longer a market-based need for separation of certain activities performed by distributors, it would be useful to consider reductions in regulatory restrictions on utility structure and relationships with utility affiliates in order to facilitate the pursuit of scope economies.

Distribution companies have a direct relationship with end-use customers and as such, are particularly well placed to assess the potential for programs that can reduce demand. In earlier years, distributors were responsible for the design of conservation programs. That function now resides with the OPA. Although some CDM activities are best performed in a centralized fashion, distributors can make important contributions not just to the delivery of such programs but also to their design and development. A significant portion of these responsibilities can be devolved to distributors. Utilities should have the option of acquiring their programs from those that are at the forefront of program development. Over time, there is likely be some degree of specialization amongst utilities and primary responsibility for these functions may be passed to the distributor segment of the industry. Administration of CDM program funds and certain research functions would remain with a centralized agency.

6. Utility Objectives: Efficiency, Leadership and Excellence

A. Efficiency: Economies of Scale, Scope and Contiguity

The efficiency of distributing utility and industry structure is affected by at least three important factors. The first is contiguity. The wires business requires a single utility to serve all customers within a contained area and for this reason service franchises have prevailed since the early years of electrification. (This does not imply that a utility must of necessity serve only one contiguous area – it

[22] We understand that PowerStream is an exception.

may serve several areas each of which is contiguous.) Highly fragmented service areas are inefficient and as a result, rarely observed.

A second factor affecting efficiency is the scale of operation. Generally, one would expect larger utilities to be more efficient, that is, until the utility has achieved sufficient size. An important empirical question is the size at which scale efficiency is achieved.

A third factor mentioned earlier, is the scope of operations. By efficiently combining activities from more than one type of service, such as billing, it may be possible to reduce overall costs.

In broad terms, the evidence on these factors is as follows.

- Contiguity economies are not estimated directly in statistical models of electricity distribution essentially because most utilities are either completely contiguous or serve a relatively small number of contiguous areas.[23] However, the importance of contiguity economies can be inferred indirectly by observing the effects of customer density. This variable is incorporated in most analyses of distributor costs and it almost invariably has a statistically significant and material impact. Ontario distributors typically serve contiguous areas, with a few exhibiting a modest degree of fragmentation.

- Scale economies are frequently incorporated in models of electricity distribution. Data are available from Ontario, Norway, New Zealand and a few other countries. These studies vary significantly in their estimates of scale efficiency. However, there is empirical support for the proposition that once a utility achieves sufficient size, unit costs remain relatively flat.

- Scope economies appear in a relatively small number of statistical analyses. However, where they are included, there is support for the proposition that broadening the range of offered services and the scope of activities can materially reduce unit costs.

There is an important caveat to this body of empirical work in that it is based on past data. Thus, judgement must be exercised when using these results in an environment where technology and utility responsibilities are changing, as these factors may influence future economies of scale, scope and contiguity.

The structure of the distribution segment continues to attract attention. The sentiment that there are too many utilities and that substantial efficiency gains could be achieved through consolidation has been expressed in certain quarters. Reflective consideration of this issue would take the following into account.

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[23] Some would argue that the very fact that we rarely observe highly discontiguous or overlapping service areas constitutes evidence of the need for contiguity.

First, competitive markets accommodate substantial variation in the sizes of firms, with small firms often prospering alongside large ones. Thus, consolidation, while it may in some respects be appealing, is neither a necessary nor sufficient condition for efficiency in the distribution sector.

Second, by analogy with competitive markets, consolidation within the sector should not be an end in itself, but should be driven by the benefits that would derive therefrom.

Third, a number of factors may increase the incentives for further consolidation. Integration of distributed generation, smart-grid development, increased ownership of generation facilities, and conservation and demand management programs may create previously unavailable scale and scope economies which would give larger utilities a cost advantage. If this is the case, mergers are more likely to occur spontaneously without any additional incentives.

Fourth, contiguity is likely to continue to play an important role in determining which utilities decide to amalgamate.

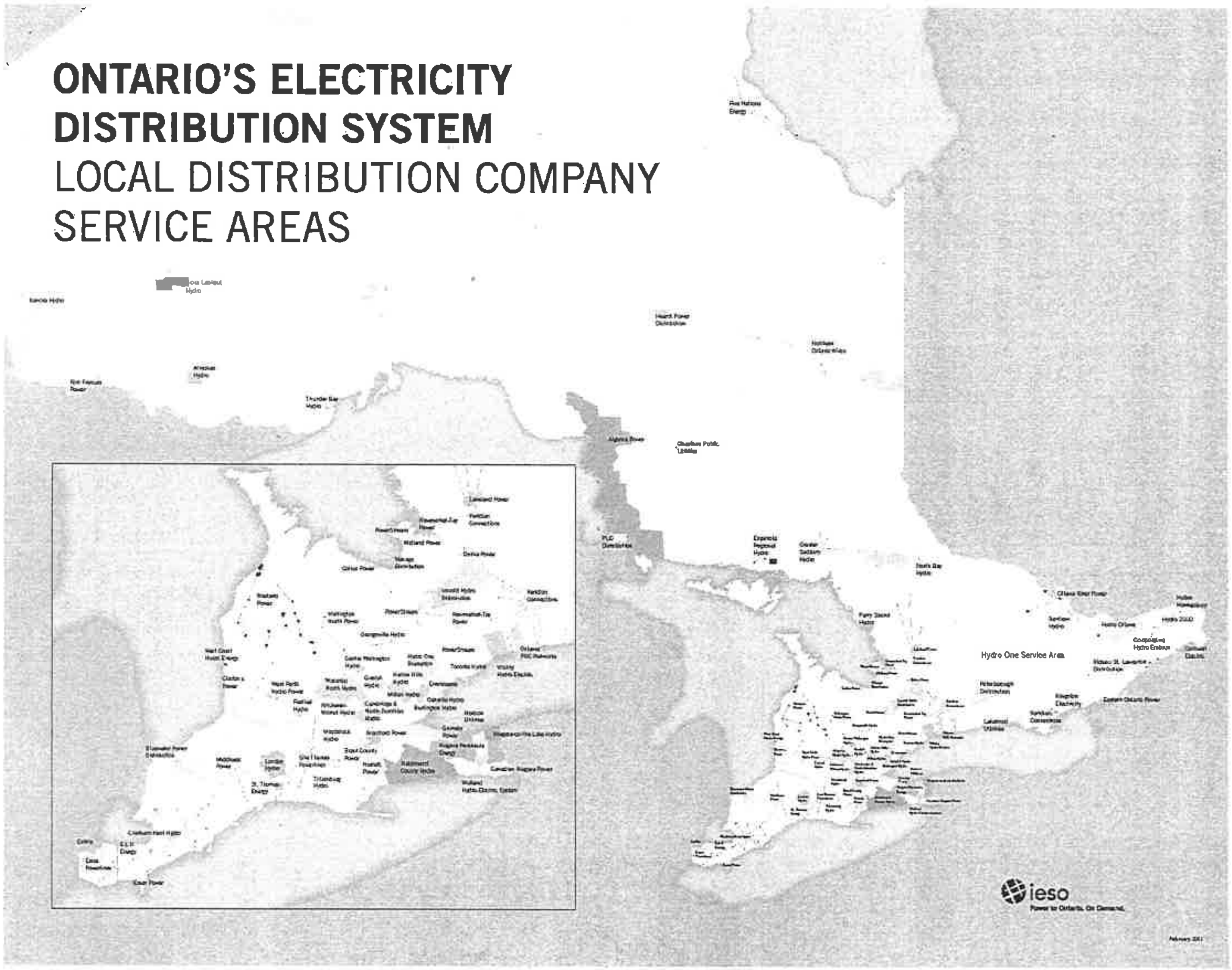
Fifth, as suggested earlier, the empirical evidence that is available does not support wholesale consolidation in the distribution sector. This does not imply that mutually advantageous consolidations are not available.

Where there are contiguity or scale gains to be made through consolidation, the natural question becomes how to achieve them. In subsequent sections we will discuss two possible approaches: an evolutionary approach whereby utility structure and consolidation continues to evolve; and, a regionalization approach under which distribution throughout the Province is restructured so that there are a relatively small number of regional distributors. In our view, additional scope economies can be realized under either approach, so long as regulatory authorities are willing to take a light-handed approach on this issue.

In some cases, mergers may, on balance, be unappealing because of rate or cost impacts. For example, labour costs at small utilities may be lower because living costs in the municipality are lower. Absorption into a larger utility may lead to a substantial increase in labour costs. In such cases, there may be alternative mechanisms by which certain economies may be captured, such as cooperative efforts amongst groups of utilities or through outsourcing.

In considering the efficiency of firms within an industry, it is also necessary to assess their dynamic efficiency; that is, their ability to respond and adapt to a changing environment. In competitive markets, firms that are unable to adapt sufficiently quickly fall by the wayside or are absorbed by other, more successful firms. Electricity transmission and distribution are natural monopolies. Nevertheless, Ontario transmission and distribution companies have been able to evolve and adapt to changing demands. Well-conceived incentive regulation can ensure that they continue to do so in the future.

Figure 1


ONTARIO'S ELECTRICITY
DISTRIBUTION SYSTEM
LOCAL DISTRIBUTION COMPANY
SERVICE AREAS
Hydro One Service Area
ieso

B. Leadership in Advanced Technologies

Smart-grid based innovation.

Advances in information and communication technologies have created an environment where various new technologies can now, or in the near future, be incorporated into electricity grids. These technologies have the potential of improving operations in multiple dimensions by:

- increasing the efficiency with which power is delivered,
- reducing costs through remote sensing and automated recovery,
- shortening response times in the event of malfunctions,
- facilitating the integration of distributed generation, renewable resources, storage and electric vehicle charging technologies, and
- improving overall system security.

Among the important enabling technologies are devices which permit simultaneous measurement of key characteristics at numerous points throughout the grid. Information of this type can provide system operators with earlier warnings of any system instabilities which may be emerging and require attention. [24]

Ontario is at the forefront of this technological frontier with legislators, regulators, utilities and other corporations and organizations taking a direct role. The Ontario Smart Grid Forum[25], under the auspices of the IESO, draws on representatives from various companies and organizations, including Ontario transmission and distribution utilities.

To ensure cost-effective investments in this area it is important to keep certain factors in mind. First, the overlay of these new technologies onto existing systems must not risk impairment of reliability of service. Second, there are disadvantages to the earliest adopters since this is when prices are usually the highest and the technology has not yet stabilized. Some utilities, for whom these innovations are presently less crucial, may delay their implementation until the technology reaches greater maturity.

Although one would expect that information technology will improve industry productivity, history suggests that this will not necessarily occur quickly. During the 1980s and 1990s, there was a general expectation that computers would have a dramatic impact on productivity of the overall economy. This

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[24] The information from these 'phasor measurement units' or PMUs can be synchronized using GPS information. See e.g., http://www.naspi.org/.

[25] See http://www.ieso.ca/imoweb/marketsandprograms/smart_grid.asp and "Enabling Tomorrow's Electricity System, Report of the Ontario Smart Grid Forum", February 2009 http://www.ieso.ca/imoweb/pubs/smart_grid/Smart_Grid_Forum-Report-May_2011.pdf.

was not to be the case. In fact, during the same period that computer technology was becoming ubiquitous, productivity was actually slowing. Acceleration in productivity did not occur until much later during the late 1990s.[26] The electricity industry has the added feature that assets are long-lived so that the capital stock changes slowly.

Longer pay-off periods are not an argument to avoid investment in these new technologies. The expected pay-off period should, however, be considered in regulatory settings where prices incorporate the expectation of productivity growth (e.g., through the "X-factor" in price cap regulation). To summarize, while some smart-grid investments could lead to immediate and observable improvements in productivity, others are likely to have a longer gestation period.

Smart-meters and time-of-use pricing

The nature of electricity systems is such that system operators must adjust supply to meet demand at any given moment. Although operator management of demand has been part of electricity operations for many years, for example through interruptible load, this component has comprised a relatively small proportion of the overall supply-demand balance. The inability to affect demand response over short intervals has generally increased the level and volatility of system costs.

Recent technological advances have created the possibility of greater responsiveness on the demand side. Major categories of technologies which are central to demand response include:

- Meters that record electricity consumption by time-of-day enable the implementation of *static* time-of-use rates which can be calibrated to approximate *expected* system costs averaged over time.
- Information systems that transmit current system costs to consumers enable the implementation of *dynamic* time-of-use rates which reflect *actual* system costs.
- Information and control systems can facilitate end-user response to real-time prices. These include 'apps' which permit integration of price and usage information in real time and smart appliances which can automate response to such information.

Ontario has engaged in Province-wide installation of smart meters. This has been a costly undertaking but the payoffs can be significant.

[26] See, for example, Brynjolfsson, Erik (1993). "The productivity paradox of information technology". Communications of the ACM 36 (12): 66–77.

Implementation of time-of-use rates has begun. Nevertheless, there are important and ongoing issues relating to their use. Time-of-use experiments have been conducted for many years and in many jurisdictions, but the results vary significantly and the determination of optimal TOU rates remains an ongoing project. Among the central issues are the elasticity of response and the importance of real-time information.

Studies conducted elsewhere suggest that the ratio of peak to off-peak prices is a critical determinant of customer response and that real-time pricing can lead to responsive participation by end-use customers.[27]

A number of Ontario utilities have conducted time of use pricing experiments and analyses. These include Ottawa Hydro, Veridian Connections, Oakville Hydro, Newmarket Hydro and Hydro One. The results have been generally supportive of a material customer response to time-of-use pricing. Future analyses that incorporate further refinements will no doubt help to inform better use of these technologies.[28] An accurate understanding of customer response to increasingly sophisticated technology can be of great value. For example, Ontarians are already, or will soon be, on time-of-use rates. The installation of the required metering technology is effectively a sunk cost. It would be extremely valuable to determine the *incremental* system and customer benefits arising from the implementation of the next level of technology which would permit real-time transmission of price information to customers.

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[27] For a recent review see "Rethinking Prices. The Changing Architecture of Demand Response in America", A. Faruqui, R. Hledik and S. Sergici, Public Utilities Fortnightly, January 2010, pages 30-39. Additional references are provided in an appendix to this report.

[28] Most analyses conducted are based on a sample of voluntary participants, even if the initial sample is randomly selected. Thus it is unclear whether the results are an accurate reflection of the general population as there may be a "self-selection problem". It is also often difficult to determine whether variations in consumption patterns are due to electricity rate design or to other factors such as weather and demographics. Statistical techniques such as regression modeling are typically used to estimate the impacts of these various factors. However, data often limit the accuracy with which they can be estimated.

Both of these problems can sometimes be remedied given suitable naturally occurring data (hence the term 'natural experiments'). For example, contemporaneous comparisons of households that are in close proximity, some of which are on compulsory TOU rates and others that are not, are especially informative because they automatically control for factors such as weather and location.

A recent study on neighbouring California communities facing different rate designs has yielded some important conclusions. See "Do Consumers Respond to Marginal or Average Price? Evidence from Nonlinear Electricity Pricing", Koichiro Ito, University of California, Berkeley. That study suggests that consumers respond to *average* electricity prices, not to the *actual* or *marginal* prices that they face. Such conclusions have important implications for rate design; http://ecnr.berkeley.edu/vfs/PPs/Ito-Koi/web/JMP_Koichiro_Ito_UC_Berkeley_2010_1122.pdf.

In Ontario, TOU prices are being implemented on a staggered basis and, as a result, there may be opportunities for valuable data of this type to emerge.

A realistic assessment of the response is further complicated by the difficulties in predicting the effectiveness of 'apps' which can be used by end-use customers to adapt consumption patterns to real-time information and penetration rates of smart appliances and control devices.

Keeping in mind that early implementation is not necessarily optimal in all cases, knowledge of the resulting benefits could inform both the timing and the type of systems that will ultimately be installed.

In all these areas, Ontario distributors can play an important continuing role in data collection and analysis, in rate design and in post-implementation assessment.

Renewable generation and distributed technologies

Policies and legislation passed by the Ontario Government have dramatically increased the role that renewable technologies will play in forthcoming years. The basis for negotiating renewable supply has changed fundamentally. Non-utility generation programs of the 1980s and 1990s were based on avoided costs. That is, contracts that were being negotiated with prospective generators were based upon the costs that Ontario Hydro could avoid. In contrast, rates for the FIT and microFIT programs were based upon estimates of the costs that wind and solar providers would need to recover in order to enter the market.[29]

The supply mix directive, issued by the Minister of Energy in February 2011, envisions over 10,000 MW of non-hydraulic renewable energy capacity in the Province by the year 2018.[30] This will represent about 10 to 15 per cent of total Ontario generation. Most of this capacity will be comprised of wind and solar generation.

Despite the high current costs of non-hydraulic generation, particularly solar and wind energy, pressures to further increase their share are likely to intensify. First, Ontario's use of coal in the generation of electricity is to end in 2014, increasing the need for 'clean generation'. Second, whatever the objective risks associated with nuclear generation, the events in Japan in March 2011 are likely to have negative implications for nuclear generation through increased costs, greater regulatory hurdles and adverse public opinion.[31,32]

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[29] For a recent review see "Ontario Feed-In Tariff Programs", A. Yatchew, A. and A. Baziliauskas, *Energy Policy*, 39 (2011), pages 3885–3893.

[30] Letter from the Minister of Energy, Brad Duguid to the CEO of the OPA, Colin Andersen, February 17, 2011.

[31] On May 29, 2011 in the wake of the events at Fukushima and consequent impacts on public opinion, the German Environment Minister announced that nuclear generation of electricity would end no later than 2022. Wall Street Journal, May 31, 2011, "Germany to Forsake Its Nuclear Reactors".

[32] Natural gas electricity generation may also receive a boost from the events in Japan. Shale gas which is extracted using 'fracking' technologies has produced a paradigm shift in natural gas markets. Though there are

As the share of variable energy resources increases, the challenges of balancing the system also increase mainly because of the variability and difficulty in predicting supply from these sources. To accommodate them, increased transmission and reserve capacity may be required.

A significant portion of renewable supply will consist of small-scale distributed generation projects. In order to successfully integrate this supply without compromising reliability, smart distribution system technologies will be required. In due course, energy storage technologies may reduce the variability and unpredictability of wind and solar energy. However, such enabling technologies are not yet available at cost-effective prices.

C. Excellence in Reliability and Customer Service

In recent years, investment in transmission has been driven by four major factors: the Ontario Government policy to eliminate coal-fired generation; the need to improve grid reliability; the connection of renewable generation; and, the need for improved interconnection with neighbouring jurisdictions.

In the near-term, further transmission investments are required to accommodate renewable generation, and to ensure supply capacity and reliability. In future years, further investments may be required as the share of renewable capacity grows. The construction of renewable facilities in more remote locations and the integration of energy storage could also increase transmission requirements.

On the distribution side, investment is being driven by the need for replacement, expansion and upgrades. The Ontario electricity distribution industry collectively holds a portfolio of assets of widely ranging ages. Engineering as well as statistical analyses suggest a trade-off between replacement, refurbishment and maintenance costs. These processes must be undertaken on a continuous basis if long-term costs are to be minimized and reliability is to be ensured.

Distribution utilities need to be able to upgrade infrastructure to accommodate distributed generation and to take advantage of evolving technologies. In this connection, regional cooperation in transmission and distribution planning is essential.[33]

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environmental issues associated with this technology, the dramatic impact on price and supply of natural gas is likely to enhance its appeal.

[33] The Ontario Energy Board is presently "holding a consultation aimed at promoting the cost-effective development of electricity infrastructure through coordinated planning on a regional basis between licensed distributors and transmitters". http://www.ontarioenergyboard.ca/OEB/Industry/Regulatory+Proceedings/Policy+Initiatives+and+Consultations/Regional+Planning

Growth in demand for electricity, albeit at a reduced rate, is also an important investment driver. Current forecasts suggest that on average, demand will grow at less than 1% per year over the next two decades.[34] The growth will not be distributed evenly across distribution utilities; for example, utilities that serve expanding suburban areas are likely to experience faster demand growth.

Current long-term demand forecasts may be low if penetration rates of electric vehicles or other electricity intensive technologies are higher. As suggested earlier, the *share* of electricity in total energy consumed has been growing and is projected to continue to grow. On the other hand, if the price of electricity increases more quickly than currently forecast, there will be a dampening effect on demand.

Finally, distributors are the direct interface between the electricity supply chain and the end-user. In today's changing electricity environment, informing and educating customers is even more essential. Some utilities have already put in place on-line systems which allow customers to view their recent consumption patterns and the prices that they pay.

7. Alternative Models

A. Models and Scenarios

We consider three stylized scenarios or models for the wires segment of the Ontario electricity industry. The 'status quo' which assumes continuation of the present industry structure and regulatory and legislative framework; an 'evolutionary model' which builds on the existing structure, allowing it to evolve; and, a 'regionalization model' under which distribution and transmission are separated and distribution is reorganized so that the Province is served by a reduced number of contiguous ('shoulder-to-shoulder') utilities.

Each model is evaluated using criteria which are based on the challenges that the wires industry faces now and in the future and the relevant guiding principles that have been set forth earlier.

B. Evolutionary Model

Under this scenario, the present industry structure would be permitted to evolve over time, with suitable incentives.

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[34] "Demand is expected to grow moderately (about 15 percent) between 2010 and 2030." ISPS Planning and Consultation Review, May 2011, page 1-3.

It has been suggested by some that Ontario has too many distributors and that there are substantial scale economies that could be realized through consolidation within this sector. Presently, Ontario is served by approximately 80 distributors of widely varying size. This is far fewer than was the case in the 1990s when there were over 300 distributors. To determine whether there are unrealized scale economies requires an estimate of the size at which scale efficiency is achieved. If we take the threshold to be say 50,000 customers,[35] then there are 17 distributors exceeding this level and together they serve over 80% of Ontario customers. The 9 distributors with 100,000 or more customers serve 70% of Ontario customers. On this basis, wide-ranging consolidations are not likely to result in major savings in distribution costs, particularly not in major metropolitan areas.

A separate issue is whether, going forward, there will be new scale economies to be realized as distributors become progressively more involved in implementing smart technologies and ownership of distributed generation. This is an open question, the answer to which cannot be preordained from existing data. An evolutionary approach whereby utilities find efficiencies on a mutually consensual basis through voluntary consolidations or cooperative ventures would therefore seem to be preferred.

C. Regionalization Model

This scenario contemplates restructuring of the wires industry in Ontario in two steps. In the first step, transmission would be separated from distribution. In the second step, distribution would be restructured into a reduced number of contiguous, 'shoulder-to-shoulder' utilities which would cover the Province in its entirety.

One of the principles which underlies this model is the potential for gains arising out of economies of contiguity. The technology of electricity distribution is such that it is more efficient to serve customers that populate a contiguous self-contained area. A single utility may serve multiple areas, but it is preferable if each of its service areas is of sufficient size so that economies of scale are also realized.

It is worthwhile to consider the extent to which the geographic pattern of Ontario distribution meets the contiguity criterion.

- The largest concentration of population is in the Golden Horseshoe which is served by a series of contiguous utilities. Collectively these represent approximately 45% of customers in Ontario.

- Hydro One Networks serves approximately 25% of Ontario customers.

- Several utilities provide service to multiple non-contiguous areas. An expansion of their service territories to create contiguous zones to the extent possible may be worthy of consideration.

[35] Past estimates based on Ontario data find that even utilities with 20,000 – 30,000 customers appear to be scale efficient.

- There are a number of utilities which are surrounded by vast expanses of land with very low population density.

Thus, while there would seem to be potential for some contiguity benefits through restructuring, the magnitude of the gain, viewed in terms of its impact on average provincial electricity rates, is unlikely to be large.

This scenario also involves the separation of transmission and distribution. This may in turn lead to some loss in economies of scope arising from this separation.

D. Comparative Assessment of Scenarios

We now turn to a comparative assessment of the alternative scenarios, a summary of which is contained in Table 2. We remind the reader that many variations could be considered. Our intent is to provide an overall guide to three paths that could be undertaken.

One would expect comparable levels of investment in regulated facilities under all three scenarios mainly because investment is driven by the need for refurbishment, expansion and modernization. This type of investment requires regulatory approval and all parties recognize the importance of maintaining reliability levels. Under all three scenarios, the industry will be under continued cost pressures and restraints due to rising electricity prices and these will influence the timing and perhaps the levels of regulated investments that flow into rates.

Ontario's publicly owned electricity companies have a long tradition of innovation, beginning with the development of Niagara Falls in the early part of the 20th century, early and cost-effective electrification of habited areas of Ontario, and the development of a unique nuclear technology. Most recently the electricity industry in Ontario, both private and public, is involved in multiple research initiatives in renewable and smart technologies.

One can expect conservation and demand management programs to continue at comparable rates under all three scenarios as these programs are ultimately controlled by the regulatory authorities. Each scenario may result in differing approaches to achieving the targets. Under the evolutionary scenario, one might expect a greater degree of out-sourcing or program delivery through cooperative ventures. On the other hand, under the regionalization model one might expect a larger in-house component to program design and delivery.

Under all scenarios, the integration of variable energy resources constitutes a major challenge for distributors and for the transmission system. At present, it would not appear that any of the three scenarios is particularly better suited to addressing these issues.

There is some potential for gains from consolidations, though these would need to be evaluated on a case-by-case basis. Widespread enforced consolidations are unlikely to result in major scale gains, as most customers are served by utilities which have evidently achieved scale efficiency. There is potential for gain in contiguity economies as there is some fragmentation within the industry (see Figure 1). The evolutionary scenario, endowed with proper incentives, is well suited for identifying and monetizing these benefits. If optimal boundaries could be identified, the regionalization scenario, could realize contiguity gains on an accelerated basis.

Economies of scope, through increased flexibility in internal firm structure and operation can be realized under all scenarios, as long as the regulator approves.

A major consideration on the cost side would appear to be the resources that would be required to implement alternative scenarios. Continuation of the status quo incurs, by definition, no restructuring costs, but losses suffered through the failure to incorporate efficiencies in a timely fashion, could be significant. Transition costs under the evolutionary model are likely to be modest. More importantly, they would be 'self-justifying' so long as the changes were voluntary and therefore undertaken only if the net benefit were positive. The regionalization model would consume significant financial resources. Moreover, it is likely to be opposed by a number of utilities.

The consequences for regulation differ moderately for each scenario. Under the regionalization scenario, there would likely be some reduction in regulatory burden borne by the regulator as the number of utilities would decline. However, regulatory convenience should not be a major driver of industry structure.

The responsiveness of utilities to Provincial government policy and directives is likely to be comparable under all three scenarios. However, if under the restructuring scenario, small municipal utilities are merged into large utilities, responsiveness to local communities may decline.

There are of course numerous hybrids and other industry models that could be considered. In Ontario, the population is heavily concentrated in small geographic areas with vast expanses of low population density, particularly in the north. This in turn may suggest a variant of the regionalization model where low density areas continue to be served by a combined transmission-distribution entity while more populated areas are served by regional distributors. To the extent that there are economies of scope in combined transmission and distribution operations in areas of low population density, these would continue to be retained.

Table 2: Summary Evaluation of Alternative Models

	Status Quo	Evolutionary Model	Regionalization Model
A. Infrastructure Investment	Levels of regulated investment are expected to be comparable in all three models.		
B. New and Emerging Technologies	Implementation of new technologies will continue, but probably not at a pace that would occur under the other models.	These models facilitate adaptive and innovative responses to a changing technological environment.	
C. Conservation and Demand Management	Implementation of CDM will continue to achieve targets.	Likely greater reliance on cooperative ventures and out-sourcing.	Larger in-house component to program design and delivery.
D. Distributed Generation	Integration of variable energy resources is challenging under all models.		
E. Costs			
Economies of scale	Consolidations seem to be in a holding pattern at this time.	Incentives which lead to further consolidations may yield additional scale economies.	Judiciously assembled regional utilities may improve scale economies.
Economies of contiguity	Some fragmentation likely to continue to exist.	Incentives which lead to consolidations of neighbouring utilities may yield additional contiguity economies.	Restructuring of distribution into 'shoulder-to-shoulder' utilities could optimize contiguity economies.
Economies of scope	Unexploited scope economies result in costs higher than necessary.	Potential gains in horizontal economies of scope if regulator agrees. Separation of transmission and distribution may lead to some losses in scope economies.	
Transition costs	No transition costs.	Modest transition costs incurred on an as-needed basis.	Significant restructuring costs. Potential resistance from some utilities.
F. Regulation and Government Policy			
Regulatory burden	Increasing regulatory requirements constitute a major burden for utilities.	Streamlining regulation, multi-year capital plans and improved intervenor processes may reduce overall burden.	
Regulatory efficacy	Expanded role of government	Proper division of responsibilities and decision-making as between	

	increases regulatory uncertainty and may lead to sub-optimal decisions.	Government, regulators and utilities should improve efficacy of regulation.

8. Conclusions and Recommendations

Ontario is at the forefront in a number of areas of electricity industry development. This, combined with an industry structure that differs from those in most jurisdictions, suggests that one cannot simply look for formulaic solutions or templates elsewhere.

We have evaluated three alternative scenarios for the wires segment of the industry – the status quo, an evolutionary model and a regionalization model. There are multiple nuanced differences among these models: no scenario is uniformly better than the others. However, the benefits of radical change at this time do not seem to be justified given the costs and potential loss of focus on key objectives.

The Ontario electricity industry underwent major changes during the last decade and a half, at very considerable cost. In hindsight, given where the industry is today, the necessary changes could have been achieved at much lower overall costs. The regionalization model also involves considerable transition costs. In our view, the evolutionary model represents the preferred approach.

Earlier we suggested three themes which can help to organize our thinking. We now use these to organize our additional conclusions.

Function:

Transmission and distribution functions are changing and emerging information-based technologies require the development of new functional capabilities. Foremost among these are the incorporation of distributed generation and the integration and expanded utilization of smart-meter and smart-grid systems.

Structure:

The internal structure of wires companies should be permitted to evolve in order to exploit potential economies of scope. The separation of wires functions from other activities, that is unbundling, was sensible at a time when the main objective was to open the industry to maximum competition. That model has long since been abandoned and combining some activities, to the extent that it reduces costs, may be appropriate.

The best available empirical evidence indicates that the most promising path for evolving the structure of the distribution segment of the industry is to proceed on a voluntary basis. Strategic and advantageous mergers will occur so long as there are sufficient incentives to do so. Utilities that are at the forefront of developing new and better business models will lead the way.

The structure of agencies that affect the wires segment bears further consideration. The IESO was a creature of the deregulatory phase in the industry; the OPA a creature of the re-regulatory phase. Both serve important purposes within the industry. However, a merger of the two entities, or further rationalization of functions between them to reduce overlap, could lead to more efficient decision-making within the industry.

Regulation:

Regulatory burden has grown steadily over the last decade and on its present path is likely to grow further. The intervenor process, although it is an important part of the review process, has become increasingly burdensome. Capital expenditures to replenish depleted capital stock, new conservation programs, investment in systems which can accommodate distributed generation and emerging information technologies will increase demands on regulators and wires companies.

Improving and streamlining the regulatory process will be essential, but this responsibility does not reside with the regulator alone. Utilities may need to accept more risk and responsibility in order to save regulatory resources. At the same time, they should be provided with a clear opportunity to operate their businesses with as little regulatory and political intervention as possible. One useful step that can be immediately undertaken is the development of a unified position, shared by wires companies, on the means for implementing smart-grid solutions and the appropriate regulatory treatment.

There has been considerable attention focussed on smart-grid technologies and Ontario is one of the jurisdictions at the forefront in this area. It should be recognized that these technologies alter the risk profile of distributing utilities which, when these risks achieve materiality, should be reflected in the returns that utilities are permitted to earn.

It is natural to ask whether, after a decade of structural and legislative changes, we are in a better place. Considerable resources have been expended on restructuring resulting in a substantially more elaborate institutional structure. Concomitantly, the regulatory and administrative burden has increased dramatically for much of the industry. The broader objectives of decentralization and deregulation have, in many ways, fallen by the wayside.

Perhaps the most important lesson from the past is not to jump on the next trend too vigorously without careful reflection. Ratepayers have limited capacity for costly changes that prove to be lacking in efficiency or effectiveness. This, in turn, can endanger legitimate long-term objectives. In short, political capital must be expended wisely. The previous government embarked on a costly marketization experiment. The present government has embarked on a path fundamentally driven by the decarbonisation of the electricity sector. Both are laudable objectives. However, an arms-length relationship between the political masters that set policy and the regulators who have deep institutional knowledge of the industry is the preferred approach.

Summary of Recommendations

1. The relationship between the Provincial Government, the electricity industry and its regulatory agencies should be reviewed. This report proposes that an arms-length relationship is best suited to promoting the most effective decision-making within the industry, long-term efficiencies and a more predictable policy, regulatory and investment environment. If, this conclusion is supported by the review, appropriate modifications to legislation would need to be implemented.

2. Major restructuring of transmission and distribution is not warranted at this time. An evolutionary approach characterized by increased flexibility, well designed incentives, consensual change and low transition costs is the preferred model.

3. Regulatory restrictions which limit utilities from finding cost savings through expanded economies of scope should be relaxed to the extent possible.

4. Utilities should continue to seek improved efficiencies by taking advantage of possibilities for improved economies of scope and through mutually beneficial consolidations which may yield additional scale and contiguity economies.

5. A merger of the IESO and OPA or rationalization of their respective activities should be considered.

6. Regulation of the wires portion of the electricity industry should be reviewed. Utilities should have the option of seeking multi-year capital approvals. Consideration should also be given to streamlining the regulatory process where possible and providing utilities with broader regulatory options including expedited reviews.

7. Utilities should be given greater opportunities to design and develop their own CDM programs. Eventually, utilities may take on primary responsibility for these functions. Program fund administration and research should remain with a centralized agency such as the OPA or its successor.

8. An accurate understanding of customer response to increasingly sophisticated technology can be of great value. Further studies and analyses of advanced metering technologies and appropriate rate designs should be conducted.

9. Utilities should continue expanding their functional capabilities to accommodate new and emerging technologies such as smart-grid systems and distributed generation. Implementation of these technologies should be achieved on a cost-effective basis as determined by individual utilities and the regulator. Incentive based approaches should be implemented where possible.

10. The essentiality of electricity to the economy and to society mandates the continuation of the record of excellent service and reliability. This will require continuing investment in the wires networks.

Appendices

A. References and Information Sources

A Selection of Useful Websites

1. Ontario websites:
    a. Ontario Energy Board http://www.ontarioenergyboard.ca/OEB/Industry
    b. Independent Electricity System Operator http://www.ieso.ca/
    c. Ontario Power Authority http://www.powerauthority.on.ca/

2. Sites associated with academic institutions:
    a. MIT Center for Energy and Environmental Policy Research
    http://web.mit.edu/ceepr/www/
    b. MIT Grid Study – forthcoming, fall 2011; preliminary presentations available at
    http://web.mit.edu/ceepr/www/about/May2011/may%20handouts/schmalensee.pdf
    and http://web.mit.edu/ceepr/www/about/May2011/may%20handouts/rose.pdf
    c. Electricity Policy Research Group, University of Cambridge
    http://www.eprg.group.cam.ac.uk/
    d. Harvard Electricity Policy Research Group,
    http://www.hks.harvard.edu/hepg/index.html
    e. Energy Institute at Haas, University of California, Berkeley,
    http://ei.haas.berkeley.edu/leadership.html

3. Other sites:
    a. International Energy Agency, http://www.iea.org/
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B. Private Equity and Privatization Considerations

In this section we briefly consider some of the issues and consequences relating to privatization in the wires segment of the industry. Changes to legislation and regulatory policy would be required if widespread privatization were to occur. It may be also necessary or desirable to first complete certain restructuring initiatives. For example, it may be appropriate to first separate transmission and distribution and to restructure the distribution segment into a system of contiguous 'shoulder-to-shoulder' utilities.

One of the arguments favouring privatization is the access to equity markets that descendant private utilities would possess. Municipalities (or in the case of Hydro One, the Province) that decide to sell their utilities would benefit from an immediate influx of funds which can be used for other purposes. Partial privatization options, whereby the government owner sells an interest, (but not necessarily a controlling interest), could also be considered and would, if implemented, would provide new funds.

There are regulatory arguments that tend to support the privatization scenario. First, private companies are more responsive to financial incentives. This in turn provides a firmer basis for incentive creation and consequently incentive regulation. Second, private companies have a greater potential for resisting government efforts to control rates by reducing profits.[36] Even a moderate increase in the degree of private ownership of distribution companies in Ontario could have beneficial spin-off effects in providing a bulwark against political interference. This might in turn provide a measure of protection for utilities remaining in public hands as fairness would seem to require that all distributors be treated equally.

Under the privatization scenario, investment in unregulated activities by utilities or their affiliates could be higher as a result of augmented access to funding. For example, one would expect a greater degree of utility ownership of distributed generation under the privatization scenario. Whether privatization would lead to an overall increase in aggregate distributed generation within the Province is unclear as under present programs (in particular, the FIT and microFIT programs) there is an excess supply of applications for facility approval and connection.

There are, however, arguments which would tend to make it less likely that privatization would receive sufficient popular and political support.

First, privatization, and any associated restructuring is likely to be costly. The restructuring that took place in the Ontario electricity industry in preparation for competition in generation was very costly and no doubt contributed to upward pressure on rates. One must ask whether another round of radical changes would benefit the ratepayer and whether the perceived benefits would justify incurring such costs.

[36] For years, Ontario Hydro operated at debt ratios and levels of net income that would be difficult or impossible to sustain in the private sector. More recently, Ontario distributors have been operating in an environment where it has been difficult, for some utilities, to attain reasonable rates of return.

Second, while the empirical evidence is overwhelming that privatization in competitive markets leads to greater efficiencies, the evidence is far less convincing when one focuses attention on natural monopolies. Thus one cannot be assured that substantial cost savings would arise if a substantial portion of distribution were to be privatized. Indeed, electricity prices in the U.S., where most of the electricity industry is privately owned, are generally higher than in Canada.[37]

Third, once private property rights are created, they are difficult to reverse. Thus, privatization might constrain future restructuring of the industry, should it be desirable.[38]

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[37] One of the few analyses of the efficiency consequences of privatization for distribution networks is contained in "The Restructuring and Privatization of Distribution and Electricity Supply Businesses in England and Wales: A Social Cost-Benefit Analysis", Preetum Domah and Michael Pollitt, *Fiscal Studies*, 2001, 22(1), 107-146. That study concludes that there were only minor benefits to customers during the first decade following privatization.

[38] This is sometimes referred to as the "option value of state ownership". See, e.g., "Issues and Options for Restructuring Electricity Supply Industries", David Newbery, University of Cambridge, June 2004.

C. Author Qualifications

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Since receiving his Ph.D. from Harvard University in 1980, Adonis Yatchew has been a member of the Economics Department at the University of Toronto. He has also taught at the University of Chicago. He has held visiting research appointments at Harvard University, Cambridge University, Australian National University, University of Melbourne and the National Bureau of Economic Research, among others. He has been a recipient of the Social Science Undergraduate Teaching Award at the University of Toronto.

His principal areas of research are econometrics, energy and regulatory economics. Since 1995 he has held various editorial positions at *The Energy Journal*. He is presently Editor-in-Chief of that publication, a position he has held since 2006.

He has also served on the editorial boards of *Economics Letters* and *Foundations* and *Trends in Econometrics.* In 1997 he jointly edited a special issue of *The Energy Journal* entitled *Distributed Generation*.

Professor Yatchew has prepared numerous analyses and studies of the electricity industry. He has prepared short term market assessments and forecasts of the cellular telephone industry; coauthored studies on oil pipeline cost allocation; and has been involved in major analyses of the natural gas, gasoline and airline industries, among others. He has also prepared testimony on a range of subjects concerning the electricity industry, incentive regulation and in various contractual disputes and litigations.

His book, entitled *Semiparametric Regression for the Applied Econometrician*, 2003, 213 pages, Cambridge University Press, contains many examples from energy economics.

A selection of his publications follows.

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EDA
The Voice Of Ontario's Electricity Distributors
ELECTRICITY DISTRIBUTORS ASSOCIATION

Electricity is the Answer - The EDA's Road Map for Delivering Ontario's Electric Future

This important EDA document, **Electricity is the Answer** - *The EDA's Road Map for Delivering Ontario's Electric Future*, was created under the leadership of the EDA's Board of Directors and leverages the expertise of renowned energy economist, Dr. Adonis Yatchew.

This paper represents the EDA's vision. We are calling on government decision-makers to seize the opportunity to make meaningful change in the sector, and invite them to use this road map as a starting point.

Sector Review final

Sector Review_final.pdf

TAB 14

Ontario

Rosemarie T. Leclair
Chair & CEO
Ontario Energy Board

Moving Forward

Remarks for the Ontario Energy Network
Toronto, Ontario

November 21, 2011
CHECK AGAINST DELIVERY

Thanks Charlie (Macaluso), for that kind introduction.

First let me say how delighted I am to be here today, and to have the opportunity to share some thoughts with such a distinguished group from the energy sector.

The last time I had such an opportunity was back in May of this year when I addressed the OEA, shortly after my appointment as the new Chair of the Ontario Energy Board.

Well, a few months have passed since then, and over those months I have had several more opportunities to engage with many of you in the room, in smaller venues or one on one, to hear your concerns, your priorities, and your suggestions.

You have been generous in sharing your expertise, your experience, and your thoughts on how the regulator can better address the needs of the energy sector today and in the years ahead.

And, as a newly appointed Chair, I have truly enjoyed and benefited from each and every one of these exchanges.

One of the things that has struck me from these various exchanges is that, as a sector, we are spending a lot of time talking about the technical aspects…the mechanics of our businesses…things like infrastructure renewal, conservation programs, regulatory process…and while these are clearly important…we also need to spend more time talking ***about***… and talking ***to***…the beneficiary of the service we are providing…the consumer…

And this is even more important as considerable investments are made on their behalf over the coming years…

In his introductory remarks, Charlie spoke a little bit about my background. I have spent some 23 years working in the public service at the municipal level as Deputy City Manager of Public Works and 6 years as CEO of Hydro Ottawa – ensuring the seamless delivery of some of the most basic essential services that residents, businesses and industries rely on each and every day.

And in carrying out my various responsibilities over the years, I have learned that serving the public and the public interest is, to say the least, a complex undertaking.

I've also learned that in our efforts to respond to the competing but legitimate interests of various stakeholders, we can risk losing sight of the interests of those most affected by our decisions.

This is a risk we must guard against in the electricity sector.

While each of us…legislators, regulators, utilities…is genuinely attempting to respond to their needs, expectations, and priorities…as **we** have defined them…we must also consider the broader realities of the average consumer.

So the question for me is: how do we, as the regulator, align and achieve all of the objectives with which we are tasked in a way that continues to put the consumer at the forefront?

It's a question that is not unique to the OEB. It's a question that is being asked by regulators far and wide.

And…it's the question that is, very much, at the core of the OEB's initiative to develop a Renewed Regulatory Framework for Electricity.

In a recent speech, the president of the Council of European Energy Regulation, Lord Mogg, told his audience that this is a critical time for consumers.

Prices are rising at a time when a difficult financial climate is impacting consumers' living standards. As such, he said there is a need to inject a consumer focus into the technical work being undertaken on their behalf, whether it's network codes, energy efficiency, energy infrastructure regulation or other issues.

This speech was delivered in London, England, but it could just as well have been delivered in London, Ontario.

Our customers…your customers...are also trying to manage life in uncertain times.

We all know the challenges that we are facing in the coming years.

The Long-Term Energy Plan has forecasted capital investments at $87 billion over the next 20 years as we provide for renewal of our generation assets, needed expansion of the transmission network, and greening of supply…

In addition, distributors are currently spending about $1.4 billion per year on their capital requirements, and this pace is also likely to continue.

The reality is that these industry challenges to continue to supply safe and reliable electricity are also the consumer's challenge as funding for these investments make their way onto the consumer's bill.

As a result…aligning the interests of legislators, utilities, and the consumer…is…I believe…the most significant challenge facing the OEB today.

The Renewed Regulatory Framework is about addressing that challenge by taking a new approach…an approach that takes a more holistic view of our energy system, and that recognizes that it all comes together on the customer's bill.

In my first public speech at the OEA, I talked about the need to engage with industry more holistically…because we all have a common interest.

More recently, I have talked with many of you about the important issues facing the sector and your utilities.

Now, it's time to talk about how, and how fast, we move forward to meet industry and public policy objectives…and how to do that in a way that reflects the economic realities of Ontario consumers in today's environment.

It is my hope that the discussion papers released a week or so ago, as part of the Renewed Regulatory Framework will be the start of that very important discussion...

....a discussion that will ultimately result in a more efficient and effective regulatory framework that will serve industry well and benefit consumers.

While it is still very early in the consultation process, let's take a look at what a renewed framework might look like and how it will benefit customers.

As I noted earlier, one of the major challenges facing the sector today and the most significant driver of costs is the scale of capital spending expected over the next few years from most utilities...

– generators, transmitters, and distributors alike – to renew and modernize the system, and provide for new demand. That spending will ultimately find its way into rate applications and onto the customer's bill.

So we need to start looking at how we can better plan, and pace, these capital investments.

We need a framework that will allow us to start looking at capital spending on the system in a holistic way, not solely in individual applications, so that investments are prioritized, optimized and provide the best value to consumers.

We need a framework that will recognize that many capital projects are not linear, and take months and years to complete. We need a framework that will recognize that much of the capital investment for distributors to serve individual customers is based on a fixed cost that varies little with consumption.

We need a framework that will define performance expectations in terms of quality and reliability of supply, and factor that performance into proposed capital plans.

We need a framework that will allow us to engage with consumers in a meaningful way, so that they can understand the choices and the consequences of the Board's decisions… the important balance between reliability and price…

We all know that we can achieve 99.99% reliability, but are consumers willing to cover the costs of what it would take to get our system to that level? Likewise, we could spend less on renewing and modernizing the system, but are consumers willing to pay the price in less reliable supply at home and at their businesses?

According to our research, what consumers expect is that reliability is maintained at current levels. But as the system becomes more and more complex, we need to find a way to continue to meet consumer's expectations for reliability, in a way that they can afford.

The first discussion papers of the Renewed Regulatory Framework are very much focused on how best to approach capital investments and...

...how to mitigate rate impacts for consumers – from regional planning, to network investment, to modernization through smart grid technology...

But a renewed framework, in my view, needs to go further. While accommodating significant capital investments, we cannot lose our focus on encouraging greater utility efficiency in day to day operations.

The fifth paper in the framework – Defining and Measuring Performance of Transmitters and Distributors…is intended to initiate a discussion on how best to measure utility performance.

In my view, this discussion must go well beyond measuring – it is about recognizing that 10 years after electricity restructuring in Ontario, we need to start treating utilities, big and small, like mature businesses, all the while recognizing our shared responsibility to the consumer.

For me, that means developing a regulatory framework for electricity that is less prescriptive, and much more focused on outcomes – those outcomes that are valued by consumers...

A regulatory framework that establishes performance expectations, with annual reporting and monitoring and industry benchmarks to assess achievement…A framework that provides incentives for those who exceed performance expectations and consequences for those who do not.

We need a regulatory framework that considers utilities risks and allocates them appropriately, allows a reasonable and predictable return on investment, encourages utilities to look at their own cost structure to improve on those returns…and to deal with unforeseen circumstances.

Perhaps it is now time that we considered a model for utility regulation that establishes objectives...and provides the supporting tools that encourages utilities to bring an even more competitive service to the customer...

As you can tell, I'm looking well into the crystal ball…

And, as I have said, it is still very early in the process, and we expect to hear from many interested stakeholders over the coming months. But this is the depth of the discussion that I would like to encourage.

Our current approach to regulating the industry has served the consumer well since its inception. But much has changed in the last ten years. It is time, and it is appropriate, to take stock of where we are at, and ensure that our regulatory regime continues to be well suited to the challenges of the future.

The regulation of the sector has to evolve in lock step with the sector itself. We can't get too far ahead, but we cannot lag behind. And, as the regulator, we must continue to provide a healthy push for the sector's continued development.

In doing that, I believe that we must be forward looking and proactive. We must have a sense of where the sector is heading, and where it should be heading, and we must chart a course to facilitate its achievement.
And it's important that we get this right...because utilities AND consumers have a lot riding on it.

The Renewed Regulatory Framework is an opportunity for all of us to take a step back and look at how we keep moving forward.

If we are going to succeed, we all need to work toward helping the consumer better understand the challenges and opportunities before us ...so that they can also understand the action we need to take ... and how ultimately, it benefits them.

That will require the participation of all parties – the regulator, utilities, consumer groups and others.

And I encourage all of you to participate as we consider the evolution of our regulatory framework.

The OEB's mandate has evolved over the years, as have the mandates and structures of utilities. I expect that that evolution will continue, and as it does, we will respond accordingly.

But our basic responsibility as a sector has remained the same over time: to serve the needs of Ontario energy users as efficiently and effectively as possible.

It is both an exciting and a challenging time to be engaged in that effort.

We have the opportunity to reshape our electricity system and the service experience of the customer like few before us….and the responsibility to do so while keeping electricity rates fair and reasonable.

Many years ago, American industrialist Henry Ford said something that has proven true time and time again. He said, "If everyone is moving forward together, then success takes care of itself."

Having talked with so many of you over the last few months, I know how seriously you take your responsibility to consumers, and how passionate you are about meeting and exceeding their expectations.

I am confident that together we can develop a renewed regulatory approach that will ensure that the energy consumer continues to come first.

Thank you.

TAB 15

Delivering Value in Today's Electricity Market

Tom Mitchell

President and CEO
Ontario Power Generation

To the Toronto Board of Trade

November 30, 2011
Toronto, Ontario

Subject to change upon delivery

Tom Mitchell
President and CEO
Ontario Power Generation
to the
Toronto Board of Trade

November 30, 2011
Toronto, Ontario

DELIVERING VALUE IN TODAY'S ELECTRICITY MARKET

I would like to thank the Toronto Board of Trade for inviting me here.

My predecessor, Jim Hankinson, spoke at the Toronto Board of Trade in 2006. That was over five years ago. And of course a lot can happen in five years – as all of us know.

So this is a good opportunity for me to bring you up to speed on some of our initiatives and their *value* to Ontario.

If there is one word that I would like you to remember from my remarks today it's this word "value."

Because delivering value to Ontarians – in the broadest sense of the term – is what we're striving to achieve at OPG.

Jim Hankinson transformed OPG into a performance-driven organization. Building on that legacy, we are equally focussed on being an organization that provides value --especially in today's challenging economic climate.

For those who may not know a lot about OPG, we are Ontario's largest electricity generator. We supply about 60 per cent of the electricity Ontario uses. We own and operate over 70 generating stations across Ontario.

And we are owned by you, the people of Ontario.

We're also a major presence in Toronto and its surrounding regions.

- Our head office is here – on the corner of College and University.
- We have a facility in Etobicoke – on Kipling Ave.
- We partnered with TransCanada Energy to build the combined cycle, gas-fired Portlands Energy Centre – an important addition to ensure the reliability of Toronto's electricity supply.
- And in nearby Durham Region, we operate two nuclear generating stations supported by two major office facilities.

Altogether, about 9,000 of our approximately 12,000 employees work in the Greater Toronto Area, including Durham.

OPG is also connected to Toronto by virtue of our history.

- Our predecessor company, Ontario Hydro, owned three buildings at College and University and used them as its headquarters.
- One of Hydro's greatest chairmen, Robert Saunders, was four-times elected mayor of Toronto in the 1940s.
- The founder of Ontario Hydro in 1906, Sir Adam Beck, has a magnificent statue in his honour on University Ave. near Queen Street. And whenever I see it, I'm reminded of the great legacy of "service to the people" that OPG has inherited.
- Hydro also built and operated two thermal plants in the GTA – the Hearn plant in the Portlands; and the Lakeview Generating Station in Mississauga. Both plants have ceased to operate.

So OPG is very much a part of this great city.

Going forward, we want to contribute to its success – and Ontario's success.

And the way we try to do that is – as I said -- by providing you – our shareholders – with VALUE.

That is our vision -- to deliver *value* by producing safe, sustainable, reliable, low-cost electricity. This is our *key role.*

The other part of our vision entails making the right business decisions -- so that we remain a viable company. This helps ensure that the value we provide and the assets we operate – on behalf of all Ontarians -- continue to be there for present and future generations

I believe this vision is relevant to Toronto.

I look out from my office on University Avenue and I see at least a dozen construction cranes – part of major boom in the residential and office high-rises that is re-drawing the skyline of this city.

To sustain this growth, attract investment and operate its residences, schools, hospitals and businesses, Toronto – like any city in Ontario – needs affordable, reliable, sustainable electricity. And there must be a sufficient supply – for 10, 20, 50, 100 years down the road.

That's what I mean by value.

We have a number of areas we're focusing on that I believe help us deliver value.

Strategic Investments

One area …is strategic investments.

This province has a wealth of diverse generating assets of which we – OPG -- are the stewards.

It's in all our interests to get the most out of these assets, either through renewal, or expansion or proactive maintenance.

One of our most important asset-groups is hydroelectric power – the power that built Ontario.

To preserve and enhance the contribution hydropower makes, OPG is engaged in some of the largest hydroelectric development projects ever undertaken in the province.

These initiatives represent hundreds of MWs of additional clean, renewable energy.

They include the Niagara Tunnel in southern Ontario.

They also include major projects in northern Ontario, like:

- the redevelopment of our hydro stations on the Upper Mattagami River, and
- the massive Lower Mattagami project – the largest hydro construction project the North has seen in 40 years.

These – and our other hydro projects being planned – represent billions of dollars of infrastructure investment by OPG and hundreds of good jobs for Ontarians.

- The Tunnel is a $1.6 billion project – with a workforce of 450 people.
- Lower Mattagami represents $2.6 billion – with a peak workforce of over 800.
- Upper Mattagami and Hound Chute was a $300 million project that employed 500 workers at peak including skilled trades, labourers, and engineers.

This is in addition to the millions of dollars we invest every year to maintain the performance of our existing hydroelectric assets through maintenance, repairs and the purchase of new equipment.

You know, many people view hydroelectric as the "Rodney Dangerfield" of generation sources. "It gets no respect." And yet it's one of the cleanest, most affordable and most historically important energy sources Ontario has.

Before there was coal…Before there was nuclear…Before oil or natural gas was used to generate electricity…There was hydro.

And it's still going strong.

OPG has hydroelectric plants which are 50-70 years old, and even 100 years old. And they operate as well today as the day they were built – and in many cases, even better.

The Niagara Tunnel we are building will last *for 100 years and more.*

Few manufacturing facilities can claim that kind of longevity.

That's an amazing legacy to leave for our children, their children and generations to come.

I'm really proud of what we've achieved with the Tunnel.

It's tracking well to being completed on time and on budget in 2013.

When it's finished, it will deliver exceptional value to the people of Ontario -- an additional 1.6 billion kilowatt hours of clean affordable hydropower – enough to power 160,000 homes every year.

Not only that…it's an engineering marvel in its own right.

The machine we used to dig the Tunnel weighed 4,000 tonnes, was 150 metres long and excavated enough rock to fill 100,000 dump trucks. It was the largest machine of its kind in the world.

As for the tunnel itself, picture 18 CN Towers lying end to end. That's how long it is -- 10.2 kilometres….over 14 metres high…and 140 metres underground. The water it will carry travels so fast and in such high volume that it can fill an Olympic swimming pool in just five seconds.

We've had delegations from around the world come to visit the project – that's how famous it is.

Even Rick Mercer paid us a visit.

And it's right here on our doorstep…a tribute to Ontario's technological prowess.

Another big strategic area in which we're investing is nuclear energy.

For example, we're moving forward with plans to refurbish our four-unit Darlington nuclear plant.

Darlington is one of Ontario's most valuable assets.

- It supplies almost 20 per cent of the electricity used in the province.
- Its employees have an exceptional workplace safety record – with over 11.7 million hours worked without a lost time injury.
- And currently, two of its four units are performing in the top quartile against US nuclear reactors and all CANDU reactors worldwide.

Refurbishment will ensure this valuable facility will serve the Province for many years to come.

As part of our refurbishment project, we're constructing a major energy complex in Durham Region.

It will house a full-scale mock-up of a Darlington reactor.

We broke ground for this facility in July and expect it to be completed in 2013. Already, about 60 people are working on site – with a total of 120 expected during peak construction.

Simultaneous with our refurbishment activities, we are also continuing with the federal approvals process for the construction of two new nuclear units. These proposed units will be based at the Darlington site in Durham Region Ontario.

Both refurbishment and nuclear new build are multi-billion dollar projects -- with the potential to create thousands of construction, engineering and technical jobs and hundreds of new operational jobs. Not to mention spin off benefits to the local community and to our many industrial suppliers and partners throughout Ontario.

Darlington refurbishment alone is expected to create 3,000 jobs.

Another 3,500 people could be employed in constructing the proposed two new nuclear units at Darlington, according to the Government's Long Term Energy Plan.

This is good for Ontario. And it's good for the GTA.

Before I leave the topic of nuclear I want to say a few words about the Fukushima nuclear crisis resulting from tsunami that struck Japan last March.

I was recently in China attending the Biennial General Meeting of the World Association of Nuclear Operators (WANO).

WANO is the international nuclear industry's foremost safety organization.

Its entire meeting, which lasted three days and attracted over 600 delegates, was devoted exclusively to Fukushima.

I was there to present the recommendations of the WANO Post-Fukushima Commission, of which I was chair.

This was an honour for me -- and for Canada – and I had an opportunity to work with some of the most experienced and respected nuclear professionals in the business.

And let me assure you, not only is Canada highly regarded in the nuclear industry. But everyone – and I mean everyone -- in the nuclear industry is taking Fukushima extremely seriously.

We have identified a number of issues relating to the disaster.

We are taking learnings from the event, and we are beginning as in industry to apply those learnings.

And we will continue to do so.

No industry puts safety at such a premium as the nuclear industry.

In this regard, I was pleased that the recommendations of the Commission were unanimously endorsed by the WANO delegates.

Our focus was on the importance of both accident prevention and the mitigation of accidents like the extraordinary one that struck Fukushima.

The industry recognizes this importance.

And I am convinced that as a result of Fukushima the nuclear industry will emerge safer and better than ever before.

Going back to the topic of strategic investments, I want to mention the significant contribution that our thermal plants make.

OPG's thermal plants just celebrated their 60^{th} anniversary of serving Ontario.

If hydropower reminds some people of Rodney Dangerfield, then our thermal plants remind me of Robin Williams – because they're flexible, adaptable and able to improvise on short notice.

They are proving their versatility as we transition away from coal toward burning cleaner fuels.

One of the great strengths of our thermal plants is their ability to quickly provide dispatchable power – especially during periods of high demand.

Thanks to our dedicated staff, they are still in excellent condition.

As many of you know, the Ontario government has directed OPG to stop burning coal by the end of 2014.

We have put together a plan and developed a schedule to make this happen.

When 2014 comes to a close, I can assure you, no OPG generating unit will be burning coal.

But we are doing it right. We are doing it in a way that allows us to *preserve* the flexibility and value our thermal units provide to Ontario.

Rather than just shutting all of them down forever, we are exploring the possibility of repowering some of them with cleaner biomass and natural gas fuels.

If successful, our biomass initiative – which burns fuels such as wood chips -- has the potential to help develop a whole new industry in Ontario.

As for natural gas, OPG has a good track record in developing gas generation – especially in partnership with others, as the Portlands Energy Centre demonstrates.

We are ready and willing to expand our role if requested.

Strategic Partnerships

In addition to making strategic investments, we're also focusing on strategic partnerships.

We welcome and want partnerships with a wide range of players so that we can maximize the value we deliver.

In Durham region, for example, OPG has joined forces with approximately 70 other organizations under the Durham Strategic Energy Alliance.

With our DSEA partners, we are helping to transform Durham into Ontario's energy centre and a leading-edge technology "cluster."

Businesses, municipalities and post-secondary institutions like Durham College and UOIT are all working together to provide timely, sustainable and reliable energy solutions.

I know the Toronto Board of Trade sees economic clusters as a major tool in helping Toronto become a globally competitive city.

The DSEA fits right into that function.

We're also developing innovative partnerships with First Nations, contractors, suppliers, biodiversity groups, -- and even the electric vehicle sector.

Transportation is one of the last major areas of society not powered by electricity.

Our involvement here could help encourage a major shift to a future of significantly cleaner air and lower greenhouse gas emissions.

Not to mention providing a vast new source to be served by our own low cost, low emission hydro and nuclear baseload generation.

We also have numerous community partnerships.

OPG delivers value to the communities where we operate through:

- the goods and services we purchase;
- the taxes we pay;
- the local causes we help support, and what I am most proud of….
- the volunteerism and involvement of our employees.

Add this up, and it represents billions of dollars.

Looking at just one of these categories -- goods and services bought in Ontario -- OPG purchases added up to over $3.3 billion in 2010.

Innovation

Another area where we strive to deliver value is through innovation.

As the largest operator of CANDU reactors in the world, we have either developed or implemented a number of innovative processes that we can market internationally – adding to Ontario's prestige as a high-tech jurisdiction.

We are one of the first companies to use Body Wave technology -- which enables technicians to remotely execute commands using only their brain waves.

This technology was recently profiled in *Time Magazine* and the *Globe and Mail*.

We're also at the cutting edge of initiatives in technology, in biodiversity, in procurement and partnerships….and in finance.

Our Finance department just won a major international award for developing an innovative new way to finance our Lower Mattagami Project. The bottom line is that it's allowed us to save Ontarians more than $50 million in project costs – a great example of how being innovative creates value.

And when I'm talking about value, I'm also talking about delivering specific value to the electricity consumers of Ontario.

Cost Control

Hence our focus on cost-control.

In 2009, we deliberately deferred seeking a rate increase from the OEB due to the recession and its impact on Ontarians.

Over a two year period in 2009/10, we cut costs by $87 million following a review of our support functions.

In 2010, we achieved another $100 million in internal costs savings.

We also identified reductions totalling $600 million in our 2010-2014 business plan – many of which have been achieved.

Our focus on being strategic and innovative and cost-effective has helped us deliver value in another area.

We are Ontario's low cost producer.

Ontario consumers pay less for power from OPG than they do for power from any other generator in the province.

What's more, we're the only generator whose rates are set through an open, transparent and very public process before the Ontario Energy Board. Under this process, the people of Ontario can – and do – hold us accountable.

And every penny of net income that we earn – every penny – stays right here in Ontario. It's being reinvested in our energy infrastructure and contributing to our society's well-being and growth.

I'm proud that as a public power company, OPG has the opportunity to provide value in today's demanding economic climate. That's what a public power company should do.

Challenges

Our task going forward is to make sure we continue to deliver value.

It won't be easy.

OPG is generating less electricity than in the past, which has impacted our revenues.

At the same time our costs are rising as we undertake to invest the billions of dollars in new generation development and asset modernization that Ontario needs.

There's also the hard reality of Ontario's economic situation. Finance Minister Duncan and premier McGuinty have made it very clear.

Growth is slowing and fiscal restraint must be the order of the day.

The recent Speech from the Throne revealed that major agencies such as Hydro One and OPG will be expected to find a combined $200 million in savings by 2014.

And...there's the whole issue of rising electricity prices. Pricing are rising – due in part to the need to modernize Ontario's aging electricity infrastructure. This will be a huge undertaking, the cost of which the Government's Long Term Energy Plan estimates at $87 billion.

The Chair and CEO of the Ontario Energy Board, Rosemarie Leclair, raised a legitimate question in a speech she gave last week at the Ontario Energy Network

How can we help keep increases under control for the consumer while investing the billions required in infrastructure improvement?

I agree with the OEB Chair.

A balance needs to be struck between these two imperatives.

OPG will work on this issue to help achieve this balance

At the same time, we will continue to play a moderating role with respect to price. Overall, we receive a lower price for the electricity we generate than other generators receive. Without this moderating effect, prices would be higher.

We are also focusing on keeping our own financial house strong.

Our options include exploring new revenue opportunities – such as expanding our role in natural gas generation.

We will also continue our laser-like focus on costs and efficiency.

To this end, we have launched a major transformation of our business organization.

It includes a leaner senior management structure and a more simplified corporate framework – one example being the merger of our hydro and thermal businesses.

Our new structure is going to help keep OPG on track in delivering value to Ontarians.

It's going to help make us more cost-efficient, nimble and responsive to the economic and market realities.

And it's going to show the people of Ontario – our shareholders – that we understand the pressures they are under in today's economy and are doing our part to make Ontario better and stronger.

So that the next time we go to the OEB and ask them to review our operations and consider a rate increase, people will know – and we will know – that we are taking meaningful action to keep our costs low.

Conclusion

In this way, we believe we can continue to deliver value to the people of Ontario.

Value has a lot of meaning at OPG. It means:

"Value" as a responsible steward of Ontario's generating assets;

"Value" as a job catalyst and job creator;
"Value" as a trusted partner and engaged community member;

"Value" as an innovator....and

"Value" as the low cost producer of safe, reliable power

We are going to do whatever it takes to continue delivering value.

Thank you very much.

TAB 16

Chapter 3
Section
3.02

Ontario Energy Board

Electricity Sector—Regulatory Oversight

Background

Electricity is an essential commodity required for the well-being of Ontario's economy and the day-to-day activities of its citizens. That, along with the electricity sector's status as a near-monopoly, necessitated a system of oversight and regulation to ensure sustainability and cost-effectiveness in the generation and delivery of electricity to meet the needs of consumers, business, and industry. Ontario's electricity sector serves 4.7 million customers and is composed of several key entities, as illustrated in Figure 1.

The Ontario Energy Board (Board) was originally established in 1960 to set rates for the sale and storage of natural gas and to approve pipeline construction projects. Over time, its powers and responsibilities evolved through legislation. In 1973, it became responsible for reviewing and reporting to the Minister of Energy on electricity rates charged by the old Ontario Hydro, a function that it performed until the late 1990s, when Ontario Hydro was split into several successor companies.

Today, the Board still regulates the province's natural-gas sector, but devotes most of its time to oversight of the electricity sector in Ontario. The Board is required to oversee the sector through effective, fair, and transparent processes, in accordance with the *Electricity Act, 1998* and the *Ontario Energy Board Act, 1998*. The objectives of the Board include protecting the interests of consumers, facilitating the maintenance of a financially viable electricity sector, and promoting efficiency and cost-effectiveness in the sector. The Board's key functions with respect to fulfilling these objectives include:

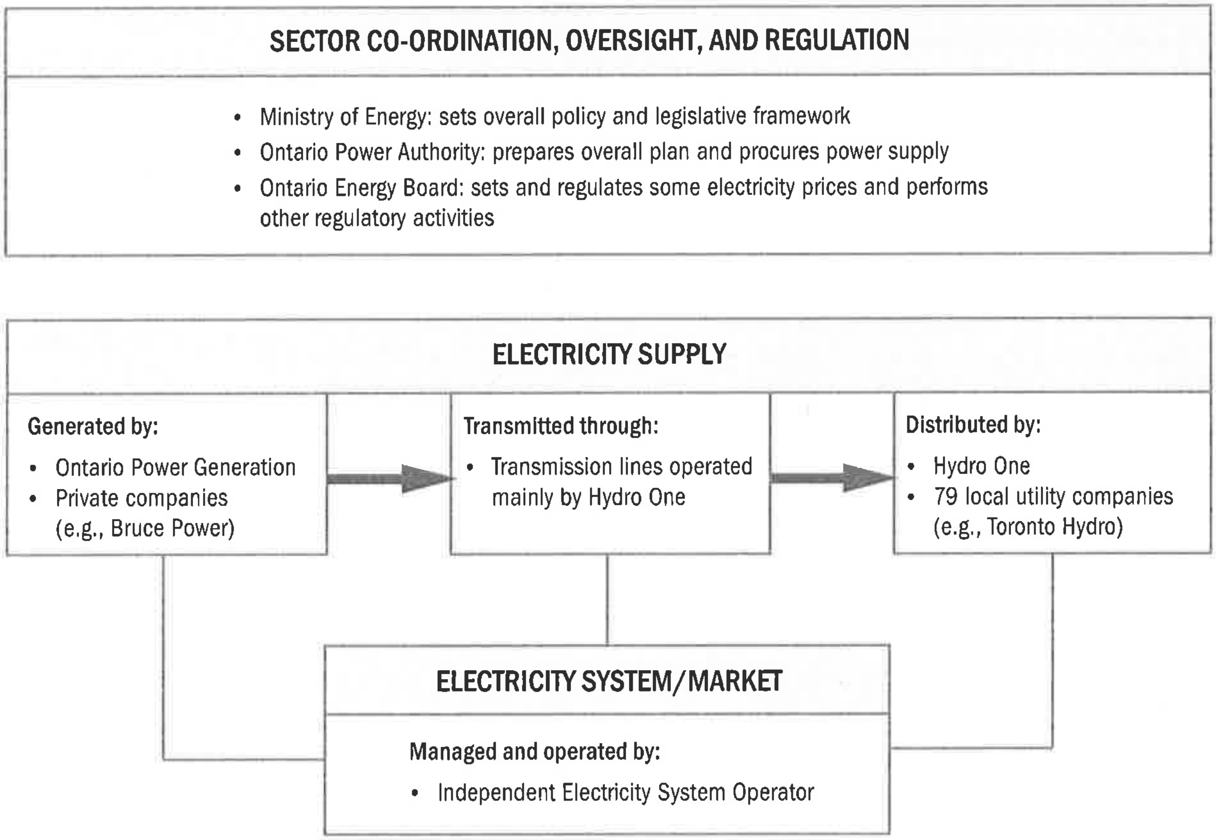
- setting prices for electricity and its delivery;
- monitoring electricity markets and licensing participants;
- approving the annual expenditure and revenue requirements of the Ontario Power Authority and the Independent Electricity System Operator; and
- reviewing and setting regulatory policies.

The Lieutenant Governor-in-Council appoints members to the Board. At the time of our fieldwork, the Board had eight members—seven full-time and one part-time—supported by a staff of about 170. Board operating costs were $34.8 million in the 2010/11 fiscal year, with 80% of that paid by regulated electricity entities and 20% by the natural-gas sector.

Audit Objective and Scope

The objective of our audit was to assess whether the Ontario Energy Board (Board) had adequate

Figure 1: Selected Key Roles of Entities in Ontario's Electricity Sector
Prepared by the Office of the Auditor General of Ontario



systems and procedures in place to protect the interests of electricity consumers and ensure that the electricity sector provides reliable and sustainable energy at a reasonable cost.

A secondary and equally important objective of our report was to look at the regulatory context of the charges on Ontario electricity bills and explain what these charges relate to. In keeping with our aim to inform readers in the simplest terms possible, we use the terms "ratepayer," "customer," and "consumer" interchangeably in this audit report.

The scope of our work included a review and analysis of rate applications and filing guidelines and interviews with members and appropriate staff at the Board. We also met with staff from other provincial agencies, including the Ministry of Energy, the Ontario Power Authority, the Independent Electricity System Operator, Ontario Power Generation, and Hydro One.

We also spoke with various participants and stakeholders in the electricity market, including local distribution companies and intervenors, to get their perspective on their interactions with the Board as well as its regulatory processes. Intervenors are individuals or groups representing consumers or other interested parties who actively advocate on their behalf in the hearing processes. In addition, we researched the operations of electricity regulators in other Canadian jurisdictions and engaged an independent consultant with expert knowledge of electricity regulation across Canada to assist us on an advisory basis. The Board follows a quasi-judicial process to make its rate-setting decisions. These decisions and the judgment of the Board panels were not a subject of this audit.

Before beginning our work, we developed audit criteria that we used to achieve our audit objective. These were discussed with and agreed to by the Board's senior management.

Summary

A key role of the Ontario Energy Board (Board) as regulator of the electricity sector is to protect consumers while providing a reasonable rate of return for the industry by setting just and reasonable prices. This role is especially important given that electricity prices for the average consumer have increased 65% since the restructuring of the electricity sector in 1999, and prices are expected to rise another 46% in the next five years.

We observed that Board staff undertook to provide Board members with useful analyses and other information to assist them in their deliberations. As well, the Board has undertaken a number of initiatives to educate consumers about the charges on their electricity bills, including an on-line bill calculator that has garnered industry recognition. However, we identified certain factors that could limit the Board's ability to perform its regulatory duties to the extent that consumers and the electricity sector might reasonably expect. Among our observations:

- The Board is not responsible for ensuring that electricity bills as a whole are just and reasonable, insofar as its jurisdiction extends to only about half of the total charges on a typical bill. The Board's role is largely limited to setting rates for the nuclear power and some of the hydro power produced by Ontario Power Generation (OPG), along with transmission, distribution, and certain other charges. The other half of power bills is based on government policy decisions over which the Board has no say. For example:
  - About 50% of the electricity sold to residential customers comes from suppliers who signed long-term contracts with the government or the Ontario Power Authority, and the price of this power accounts for 65% of the cost of the electricity component on the typical bill. However, the Board has no regulatory oversight role with respect to this portion of the electricity charge. Rather, it regulates only electricity from certain OPG nuclear and hydro plants, which constitutes about one-third of the electricity charges on a typical bill.
  - The debt retirement charge that consumers pay each month was originally created by the government in 1999 to help pay off the estimated "residual stranded debt" of $7.8 billion that remained after the old Ontario Hydro was broken up. The Board has no oversight role with respect to this charge or how long it is to be applied to consumers' electricity bills.
  - The Board has regulatory oversight over only about $190 million of the close to $900 million collected from ratepayers to administer and operate the electricity market and to meet other legislated requirements.
- In areas where it does have jurisdiction, the Board sets rates using a quasi-judicial process that requires utilities and other regulated entities, such as OPG and Hydro One, to justify any proposed rate increases in a public hearing. Many small and mid-sized utilities said that this process costs ratepayers an average of between $100,000 and $250,000 per application—or as much as half the revenue increase sought in the first place by these utilities. These costs are generally incurred once every four years and are recovered from consumers over the next four-year period.
- Individuals or organizations wishing to participate in the hearings on behalf of consumers can obtain intervenor status, and can qualify for reimbursement of their expenses by utilities and other regulated entities. However,

many of these utilities and other regulated entities cited the high cost of providing the large quantities of detailed information requested by intervenors and called for better co-ordination by the Board to manage these requests.

- In monitoring utilities for compliance with its guidelines and reporting requirements, the Board identified a number of significant deficiencies in the utilities' record-keeping and reporting practices. This could be an indication of inaccuracies in the information the Board uses to make decisions. However, the Board does not consistently follow up to ensure that the noted deficiencies were corrected by the utilities.
- Consumers can purchase their electricity either through their utility at the Regulated Price Plan prices set by the Board or through an electricity retailer at a price set by the retailer. Some 15% of residential customers, looking for price protection and stability on their power bills, signed fixed-price contracts with electricity retailers. However, we found that these consumers could be paying anywhere from 35% to 65% more for their electricity than they would pay had they not signed those contracts. In the last five years, the Board has received more than 17,000 complaints from the public; the overwhelming majority of them have been against electricity retailers. Issues included misrepresentation by sales agents and even forgery of signatures on the contracts. Although the Board follows up on complaints, the number of enforcement actions taken against retailers has been very limited.
- The Board has a well-structured performance-reporting process, but its performance measures need to be more results-based rather than process-oriented.

Detailed Audit Observations

OVERVIEW OF THE ONTARIO ENERGY BOARD AND THE ELECTRICITY SECTOR

The Ontario Energy Board (Board) was founded in 1960 to regulate the natural-gas sector in Ontario. In 1973, its role was expanded to include the electricity sector. A significant shift in the Board's mandate came when the government enacted the *Energy Competition Act, 1998* (Act), which broke up the old Ontario Hydro into several successor companies and sought to introduce competition to the electricity sector.

The Act mandated the Board to protect the interests of consumers while simultaneously ensuring a financially viable electricity industry. More detail about legislative and policy changes since 1999, and the impact of these changes on the electricity sector and the Board, is shown in Figure 2.

IMPACT ON CONSUMERS

Ontario consumers have experienced significant electricity-cost increases over the past decade as a result of major changes to the province's electricity sector. Since 1999, the average residential consumer using 800 kilowatt hours (kWh) per month has seen a 65% increase in his or her power bill. The Ministry of Energy predicted in its 2010 Long-term Energy Plan that residential electricity bills will rise another 46% over the next five years to help pay for upgrades to Ontario's existing nuclear and natural-gas generation capacity and its transmission and distribution facilities, and to help finance new and cleaner renewable-energy generation.

A summary of the impact on energy bills of the major policy changes since 1999 is shown in Figure 3.

UNDERSTANDING ELECTRICITY BILLS

In 2004, the government passed a regulation requiring electricity bills for low-volume consumers

Figure 2: Government Legislation and Policy Changes in the Electricity Sector, 1998–2011
Prepared by the Office of the Auditor General of Ontario

Legislation/Policy and Year	Impact
Energy Competition Act, 1998	• Breaks up Ontario Hydro into several companies • Ontario Energy Board (Board) assumes responsibility for regulating three Ontario Hydro successor companies and local distribution companies
Electricity Pricing, Conservation and Supply Act, 2002	• Caps electricity price at 4.3¢/kWh, for two years, effective May 1, 2002 • Freezes transmission and distribution rates until at least May 1, 2006
Ontario Energy Board Consumer Protection and Governance Act, 2003	• Creates a management committee to oversee Board activities • Strengthens Board powers to protect and educate consumers
Ontario Energy Board Amendment Act (Electricity Pricing), 2003	• Replaces 4.3¢/kWh price cap as of April 1, 2004, with 4.7¢/kWh for the first 750 kWh/month, and 5.5¢/kWh beyond 750 kWh/month • Allows local distribution companies to recoup costs by lifting freeze imposed by *Electricity Pricing, Conservation and Supply Act, 2002*
Electricity Restructuring Act, 2004	• Amends *Ontario Energy Board Act, 1998* and *Electricity Act, 1998* • Board assumes responsibility for Market Surveillance Panel • Establishes Ontario Power Authority (OPA) to ensure adequate, reliable, and secure electricity supply in Ontario
Minister's Directive to Board (2004)	• Develops smart-meter implementation plan
Minister's Directive to OPA (2006)	• Develops plan to replace coal-fired generation with cleaner sources as soon as possible
Green Energy and Green Economy Act, 2009	• Establishes responsibility for Board and other entities to achieve objectives of conservation, promotion of renewable energy, and technological innovation
Harmonized Sales Tax (2010)	• Adds 8% to total electricity bill effective July 1, 2010
Energy Consumer Protection Act, 2010	• Requires that Ontarians be provided with the information they need about electricity contracts and prices and that consumers be protected by fair business practices effective January 1, 2011
Ontario Clean Energy Benefit (2011)	• 10% discount on electricity bill for five years from January 1, 2011

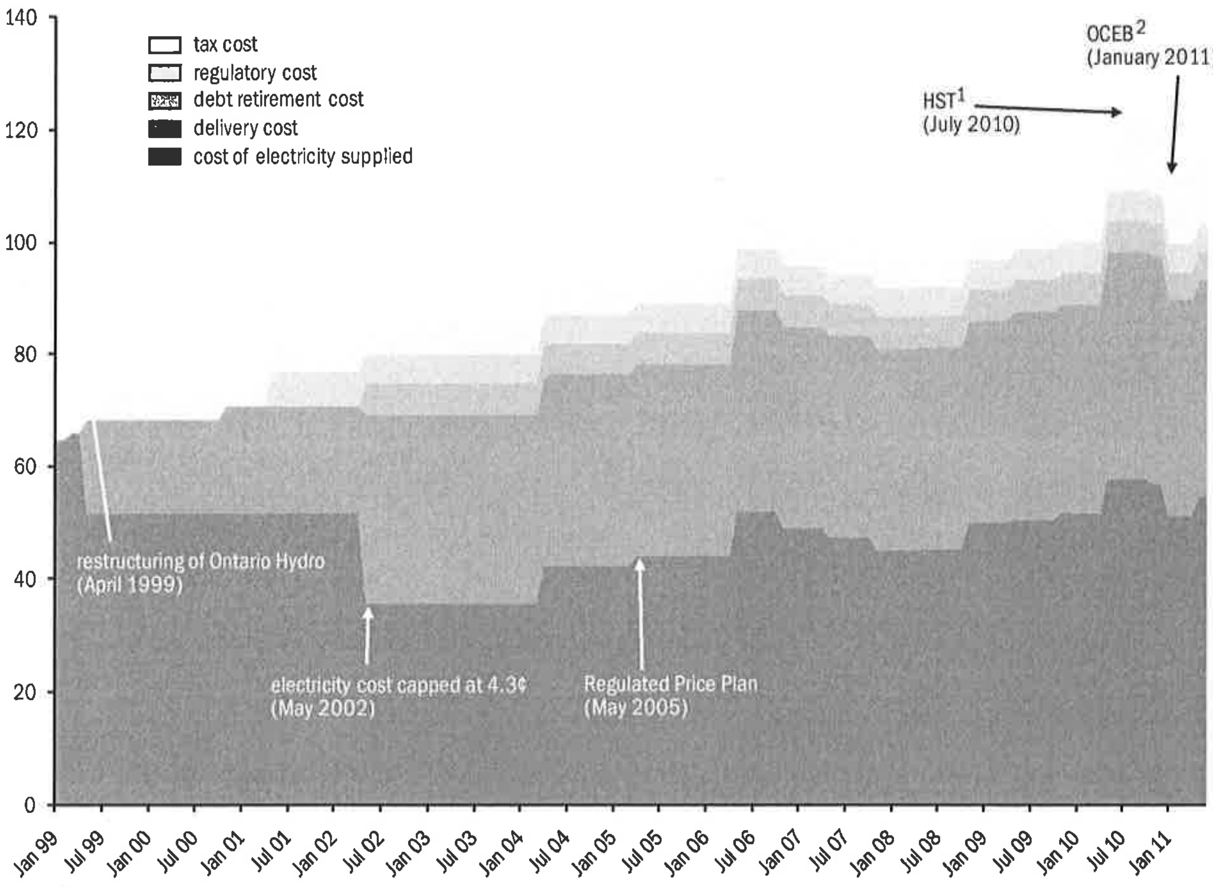
(residential and small-business consumers) to show four categories of charges: Electricity, Delivery, Regulatory, and Debt Retirement. The regulation also specifies how these categories of charges are to be explained on or with the bill. A sample bill for an average Toronto Hydro residential consumer with an 800 kWh monthly consumption (or about 830 kWh when adjustment due to loss in the distribution system is included) is shown in Figure 4.

The various charges break down as follows:

- "Electricity" is the cost of the actual power consumed, which the province obtains primarily from Ontario Power Generation (OPG) and from suppliers who have signed contracts with the government or the Ontario Power Authority (OPA). The presentation of this charge on bills varies, depending on whether the consumer buys from a utility or has signed a contract with a retailer. In Ontario, 85% of residential consumers purchase their electricity from local utilities and pay what is known as Regulated Price Plan (RPP) prices, while the remaining 15% purchase their electricity from electricity retailers.

RPP prices are set by the Board. Time-of-use RPP prices—where the price of electricity varies depending on when during the day the consumer uses power—apply if the consumer's utility has migrated to time-of-use billing. Otherwise, two-tiered RPP pricing—where the price of electricity varies depending

Figure 3: Electricity Costs for Average Toronto Consumer Using 800 kWh of Electricity a Month, 1999–2011 ($)
Prepared by the Office of the Auditor General of Ontario



1. Harmonized Sales Tax: additional 8%
2. Ontario Clean Energy Benefit: 10% discount over the next five years

on how much power the consumer uses per month—applies.

Consumers with retail contracts pay the price stipulated in their contracts plus a Global Adjustment—mostly consisting of the difference between the market price and the price paid to generators as set by the Board for OPG or under contract with the government or the OPA. The Global Adjustment has been rising steadily over the last few years and is expected to continue to rise as a result of investments in existing generation capacity and renewable power generation. The RPP prices calculated by the Board include a forecast of the Global Adjustment. RPP consumers therefore do not see a separate Global Adjustment charge on their electricity bills.

- "Delivery" is the cost of transmitting and distributing electricity from the generator to the consumer. Transmission is handled primarily by Hydro One over high-voltage wires connecting generators across the province to local utilities, which handle distribution to homes and businesses. Delivery rates vary across the province, with rural and remote locations generally paying higher rates.
- "Regulatory" is the cost to operate the electricity system and maintain the reliability of the provincial grid. This includes the operational costs of the Independent Electricity System

Figure 4: Monthly Electricity Bill Comparison (Regulated Price Plan vs. Retail Contract Consumer)
Source of data: Ontario Energy Board website, August 2011

Monthly Bill Statement Toronto Hydro-Electric System Limited - Main	
Account Number: 000 000 000 000 0000	
Meter Number: 00000000	
Your Electricity Charges	
Electricity (what is this charge?)	
Off-Peak @ 5.900 ¢/kWh	31.34
Mid-Peak @ 8.900 ¢/kWh	13.30
On-Peak @ 10.700 ¢/kWh	15.99
Delivery (what is this charge?)	40.50
Regulatory Charges (what is this charge?)	5.95
Debt Retirement Charge (what is this charge?)	5.60
Total Electricity Charges	**$112.68**
HST	14.65
Subtotal	**$127.33**
Ontario Clean Energy Benefit (-10%) (what is this?)	(-12.73)
Total Amount	**$114.60**

Monthly Bill Statement Electricity Retail Contract	
Account Number: 000 000 000 000 0000	
Meter Number: 00000000	
Your Electricity Charges	
Electricity (what is this charge?)	
Supplied By: your selected retail company Phone No.: 000.000.0000	
Global Adjustment (what is this charge?)	30.80
800 kWh @ 8 ¢/kWh	66.41
Delivery (what is this charge?)	40.50
Regulatory Charges (what is this charge?)	5.70
Debt Retirement Charge (what is this charge?)	5.60
Total Electricity Charges	**$149.01**
HST	19.37
Subtotal	**$168.38**
Ontario Clean Energy Benefit (-10%) (what is this?)	(-16.84)
Total Amount	**$151.54**

Operator (IESO) and the OPA, charges to partly offset the higher cost of providing electricity to rural and/or remote areas, and a charge to cover administrative costs of local utilities.

- "Debt Retirement Charge" is mandated by the government to help pay off the residual stranded debt of the old Ontario Hydro that could not be funded by other revenues. This charge will be collected from consumers until, in the opinion of the Minister of Finance, the debt has been eliminated.
- "Ontario Clean Energy Benefit" is a 10% discount on the total electricity bill that applies for five years starting January 1, 2011, to help offset price increases. The annual cost of this rebate is estimated at $1.1 billion and is funded by taxpayers through the Ministry of Energy's annual appropriation.

REGULATORY OVERSIGHT OF ELECTRICITY

The Ontario Energy Board (Board) is mandated to regulate the electricity sector in Ontario. However, its authority to review and regulate is limited to only about half the charges on the average residential or small-business bill, as illustrated in Figure 5.

What the Board Does—and Does Not—Regulate

For the electricity component of a bill, the Board regulates the cost of power from certain OPG assets such as nuclear and large hydro generating plants; however, the costs of power from OPG's other generation assets, as well as the costs of electricity supplied under contracts negotiated by the OPA and under power agreements with non-utility suppliers, are not subject to Board regulation. Every six months, the Board reviews the RPP electricity prices being paid by residential and small-business consumers and, if necessary, adjusts them to ensure that they reflect the cost of supplying electricity to those consumers.

The Board regulates the entire delivery component (that is, all of the transmission and distribution charges).

For the regulatory component, the Board regulates the operational costs of the IESO and the OPA, but there are other regulatory costs that it does not regulate.

The debt retirement charge is not subject to Board regulation.

CHARGES SUBJECT TO REGULATORY OVERSIGHT

The old Ontario Hydro followed a relatively straightforward rate-setting process, calculating rates on a cost-recovery basis. It was not required to consider whether the costs incurred were reasonable or whether all costs were being billed to consumers over an appropriate time period. The current system is more complicated. It requires that the Board set just and reasonable rates, with the result that the Board's information needs are more complex than those during the time of the old Ontario Hydro. Such rate-setting oversight involves assessing projected operating costs as well as recovering the cost of capital investments.

In the case of such infrastructure investments, the Board must determine whether these capital costs are fairly distributed between current and future consumers. It must also examine the costs of building or acquiring different types of electricity assets, and how long they will last. Regulated entities investing in such assets are entitled to a reasonable rate of return on their investment, and their returns are largely guaranteed once the Board approves their rates. For proposed capital investments, the Board must satisfy itself that the investments are needed. For example, is more investment required to maintain or enhance the system's reliability, when should new electricity generators be connected to the transmission system given forecasted future demand, and how should new initiatives such as the smart grid be implemented?

In fulfilling its rate-setting role, the Board follows a quasi-judicial process that is open to public participation. The Board advised us that it takes seriously the need for its adjudication decisions to

Figure 5: Percentage of Electricity Bill Regulated by the Board, 2010 (average utility customer consuming 800 kWh a month at a cost of $116) (%)
Prepared by the Office of the Auditor General of Ontario

Bill Component	Costs Included	Regulated by Board	Not Regulated by Board	Portion of Bill
electricity	OPG generation assets, Non-Utility Generators (NUGs), OPA Renewable and other contracts	19	37	56
delivery	distribution and transmission	33	–	33
regulatory	wholesale market service charge, rural remote rate protection, IESO and OPA operating costs, and other charges	3	3	6
DRC	debt retirement charge	–	5	5
Electricity cost before tax and benefit		**55**	**45**	**100**
HST	Harmonized Sales Tax (13%) effective July 2010			
OCEB	Ontario Clean Energy Benefit (-10%) reduction on bill effective January 2011			

be made—and to be seen to be made—independently and impartially. The hearing process must comply with statutory requirements and principles of administrative law.

The regulatory process the Board follows is summarized in Figure 6.

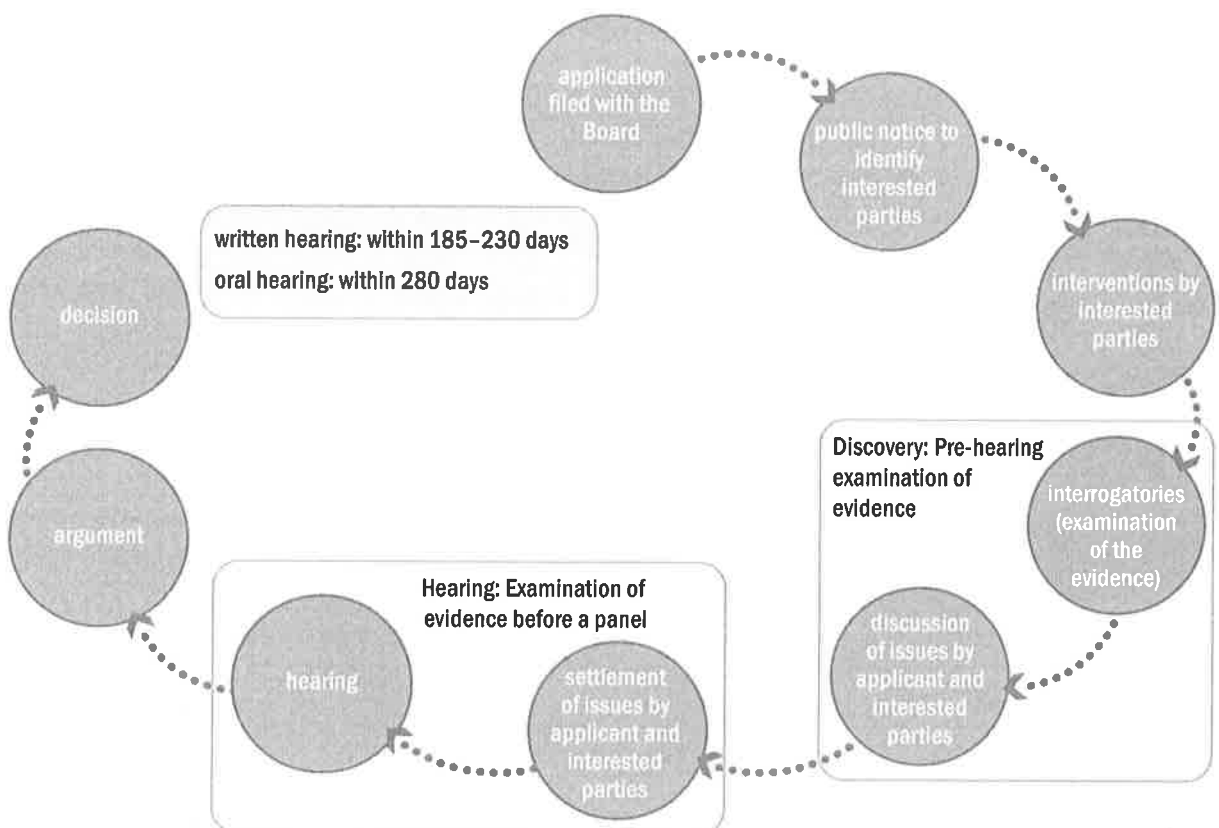
Applicants, including utilities, OPG, and Hydro One, are expected to provide sufficient detail about proposed rate increases to enable the Board to determine whether the proposed rates are just and reasonable, although the onus is on applicants to prove that the proposed increases are justified. In considering such applications, the Board examines the applicant's forecasts, along with financial and operational details, in a public forum. Applicants must provide documentation to cover current operations and historical data going back three years. The Board aims to set rates that allow applicants to recover their ongoing operating costs and the cost of capital expenditures over an appropriate time period and earn a reasonable rate of return. The rate of return set by the Board for 2011 was 9.58%.

Rates and fees subject to regulation include the rate charged for power supplied by OPG's nuclear and large hydro generating assets, IESO and OPA operating costs, and transmission and distribution charges.

Rates for distribution costs are set using a combination of two mechanisms, as follows:

- The Cost of Service (COS) review sets rates for each distributor every four years or whenever the Board deems necessary (the Board has also allowed distributors to apply for more frequent COS reviews). COS applications are detailed and require documentation and calculations supporting the applicant's electricity demand forecasts, estimates of the cost to service this demand, and past operating revenue

Figure 6: Rate-setting Adjudication Process at the Board
Source of data: Ontario Energy Board



and costs. A typical COS application runs to between 800 and 1,200 pages for a small to mid-sized local utility.

- The Incentive Regulation Mechanism (IRM) is an annual process that, between COS reviews, adjusts rates. It does so by applying a formula that considers inflation and productivity. Other factors may also be considered in the annual rate adjustment on a case-by-case basis. A typical IRM application for a small to mid-sized utility would require 80 to 100 pages of documents, including a summary with all requested rate adjustments, the models used to calculate the new rates, and a list of all current rates and charges.

On average, the Board adjudicates 20 COS applications and 60 IRM applications each year for Ontario's 80 distribution utilities.

The rates for transmission (primarily through Hydro One) and OPG payments for its regulated assets are set using the COS mechanism, and the IESO and OPA operating costs are subject to annual reviews by the Board.

As mentioned in our Audit Objective and Scope section, the individual Board decisions were not a focus of this audit, but we did observe that Board staff undertook to provide Board members with useful analyses and input to assist them with their deliberations.

Complexity and Cost of Regulatory Oversight

Regardless of their size, all utilities are expected to meet the same filing guidelines. We found that this "one-size-fits-all" approach to rate-setting is a costly exercise that seems to focus as much on getting complete records into the public forum as on ensuring that the process has the information it needs to set just and reasonable rates. In addition, all costs of the regulatory process must be recovered from consumers through rate increases.

The Board cited customer-service-quality statistics for utilities that had gone through COS reviews in 2008 or 2009 as evidence that utilities can cope with these requirements. However, staff of distribution utilities told us that meeting filing requirements required significant overtime. In addition, small and mid-sized utilities often had to engage costly external consultants to help complete their applications. Meeting the documentation requirements has been particularly challenging for the smaller utilities, some of which have fewer than 2,000 consumers and only five or fewer administrative staff. We further noted that the Board used to provide utilities with rate-application templates but no longer does so, providing them instead with models, suggested data formats, and filing guidelines, which, we were advised, were more complicated to use than the templates.

The average cost of filing a COS rate application is approximately $100,000 for a small utility and $250,000 for a mid-sized one, representing between 15% and 55% of the revenue increase these utilities are seeking in the first place. Most of these costs relate to consulting and legal services to assist with preparation of evidence to meet Board filing requirements, to answer questions from intervenors, and to pay intervenor billings. The cost of a rate application for the biggest utilities can run to $1 million or more. The impact of this cost ranges from about $1 per consumer for the largest utilities to as much as $40 per consumer for the smaller ones. These amounts are recovered from ratepayers over a four-year period.

The Board had not analyzed the cost/benefit impact of its current regulatory requirements in protecting consumers. The Board did acknowledge the problems faced by smaller utilities in dealing with filing requirements but said that every consumer in Ontario deserved the same level of protection.

Intervenors

Intervenors are individuals or groups of individuals who actively participate in the regulatory processes. Intervenors may include consumers, consumer and trade associations, environmental groups, public interest groups, and affected individuals. The costs of their participation in the regulatory process are borne by the regulated entities and, eventually, consumers. Intervenor costs can range from $10,000 for a small utility with one intervenor to over $1 million for a larger applicant with more intervenors.

Prior to the start of proceedings, intervenors may apply to the Board to have their costs paid by the rate applicants. A Board panel rules on a case-by-case basis whether intervenors are eligible for an award of reasonably incurred costs, which include time spent reviewing evidence and participating in hearings, and travel and accommodation expenses. Because the focus of our audit was not on individual Board decisions or judgment, our observations relate only to concerns we noted regarding the administrative processes—not to individual panel decisions or intervenor costs the Board had agreed to have applicants reimburse.

The intervenor community is composed of a small number of specialists, primarily lawyers, and we recognize that their knowledge and experience can add value to the process. However, it is also important that intervenors be integrated efficiently and effectively into the hearing process to ensure that the value they provide is not outweighed by the additional costs they impose on consumers, who ultimately pay for their services.

The rate applicants with which we met indicated that better co-ordination between Board staff and intervenors was needed to manage the heavy volume of questions and requests for information stemming from intervenors. The applicants also noted that there is significant overlap between the questions and requests from the intervenors and the Board staff; intervenors are recycling questions or requests for information from other rate cases and, in some instances, the name of the previous applicant had not even been removed from the questions; and the intervenor questions and requests were not always relevant or of significant importance to the current case. This last point was echoed by the Board in its 2011 OPG decision, which raised the concern that an inordinate focus on lower-priority issues diminishes the time and resources available to pursue the more substantive, higher-priority issues. As well, intervenors bill for the time that their external consultants and legal advisors spend, and all such billings are eventually paid by electricity consumers.

Total intervenor costs over the last three years were $16 million for the electricity sector. The reasonableness of intervenor cost claims can be challenged either by the Board or by the rate applicant, and there have been 17 claim reductions totalling about $750,000 against intervenors over the last three years. However, utilities and other applicants advised us that they felt this did not reflect the full extent of questionable cost claims. They also said that they were generally unwilling to challenge intervenor billings because they did not want to incur the additional costs of such challenges.

RECOMMENDATION 1

To enhance the cost-effectiveness of its rate-setting process, the Ontario Energy Board should:

- work with the regulated entities to address their concerns about the cost and complexity of the current rate-setting filing requirements and the impact on their operations; and
- better co-ordinate and evaluate intervenor participation in the rate-setting process in an effort to reduce duplication and time spent on lower-priority issues.

BOARD RESPONSE

The Board is committed to improving the efficiency of its processes, which the Auditor General has recognized as being transparent and as benefiting from the work of staff and the contribution of intervenors. The rate-setting process requires appropriate information on the public record to support sound and responsible decision-making. We annually update our filing requirements for rate applications to ensure that only appropriate information is being requested.

We will continue to consult with the industry and other stakeholders to ensure that our rate-setting processes are as efficient as possible.

CHARGES NOT SUBJECT TO REGULATORY OVERSIGHT

Non-regulated Electricity Charges

In recent years, rates for the electricity component of the average bill that is supplied by unregulated sources have been significantly higher than rates for that supplied by regulated sources, which must be approved by the Board. As a result, although unregulated electricity accounts for only 50% of the total electricity supplied, the price of the unregulated electricity accounts for about 65% of the price paid by the average consumer. Accordingly, only about $35 of every $100 in the cost-of-electricity component on a typical bill is subject to rate regulation by the Board.

The unregulated sources are primarily suppliers under power contracts that have been signed by the OPA under the government's direction, because the province's long-term power-system plan has not been approved by the Board. On August 29, 2007, the Board received the OPA's application for review and approval of the Integrated Power System Plan (IPSP), the blueprint for electricity in Ontario. The IPSP must be approved by the Board before the plan can be implemented. However, the hearing was adjourned on October 2, 2008, pending new government targets requiring a revised IPSP, and the Board was directed by the Minister of Energy on February 17, 2011, to complete its review of the OPA's revised IPSP within 12 months of its submission. As of August 2011, the revised IPSP had not been submitted to the Board for review.

Over the last four years, the government has directed the OPA to enter into new long-term electricity-supply contracts in the absence of an approved IPSP, which would have set out guidelines for such transactions. According to the Board, these contracts are outside the scope of its statutory mandate and regulatory powers, so any eventual approved IPSP would have no impact on procurement commitments already made by the OPA.

Non-regulated Regulatory Charges

There are a number of components in the regulatory charge, including service charges to cover the cost of administering the wholesale electricity market and maintaining the reliability of the overall electricity grid. These charges account for about half of the total regulatory charges collected. Other components include the operating costs of the IESO and OPA; the cost associated with funding government conservation and renewable-energy programs; a charge to subsidize consumers living in rural and/or remote areas; and a charge to help recover utility administration costs.

Most regulatory charges are not subject to any form of Board oversight. The exceptions are the costs to operate the IESO and OPA, which account for about $190 million of the close to $900 million in regulatory charges collected annually. The other charges either are prescribed by government regulation or consist of other costs not subject to Board oversight.

Market Surveillance Panel

As noted earlier, the only regulatory charges in an electricity bill whose rates the Board regulates are the fees that the IESO and OPA charge to cover their operating costs. The Board does not regulate any of the other costs of operating the wholesale market. The Market Surveillance Panel (Panel), which was transferred from the IESO to the Board in 2005, monitors wholesale market activities and reports on them to the Board twice a year. The Panel has consistently recommended that the IESO explore structural changes to the electricity market to reduce or eliminate what are known as "congestion management settlement credit (CMSC) payments" where they do not contribute to market efficiency. These payments are a result of the current electricity market structure, which compensates generators or traders when, for example, transmission constraints curtail their ability to participate in the market.

From 2006 to 2010, the IESO paid more than $420 million in constrained-off CMSC payments to generators and traders whose power cannot be fed into the grid because of the transmission system's capacity constraints. In its May–October 2010 report, the Panel reported that it had two ongoing investigations into these market activities. One was at the request of a market participant, and the other a formal investigation of potential "gaming" of the system to obtain increased CMSC payments.

The Board advised us that, although the Panel reports to the Board, it is up to the IESO to implement Panel recommendations. However, given that the Panel is required to report to the Board, we questioned why the Board would not be more proactive in ensuring that the IESO gives adequate priority to Panel recommendations. In March 2011 we noted that, for the first time since assuming responsibility for monitoring the market in 2005, the interim Chair of the Board asked the IESO to report back on its proposed response to certain Panel recommendations.

Non-regulated Debt Retirement Charge

When Ontario Hydro was broken up in 1999, the government created the Ontario Electricity Financial Corporation (OEFC) to assume its $38.1-billion debt and other liabilities and provided it with $18.5 billion in financial assets. The difference between the assets and debt, $19.4 billion, came to be known as the "stranded debt." The government established a long-term plan to repay most of it using future electricity revenues, including the profits of OPG and Hydro One in excess of the government's financing cost for its investment in the two entities.

However, the government also said at the time that these anticipated repayment streams would be insufficient for an estimated $7.8-billion portion of the stranded debt known as the "residual stranded debt." In order to repay this amount, the government imposed a new debt retirement charge to be included on electricity bills and used to service the residual stranded debt.

The original 1999 plan estimated that the stranded debt would likely be retired by 2010. However, since then, the OEFC has faced a number of challenges in managing the stranded debt, which have included the impact of interest charges on the $38.1 billion in assumed liabilities, volatility in OPG and Hydro One profits, and other government-mandated electricity expenditures. As a result, OEFC currently estimates that the stranded debt will be eliminated between 2015 and 2018. For additional information on the stranded debt and the debt retirement charge, see Section 3.04, Electricity Sector—Stranded Debt.

The Board has had no role in setting or otherwise regulating the debt retirement charge. However, given that the Board regulates the industry, consumers could reasonably assume that it is responsible for overseeing all facets of their electricity bill. To prevent this misconception, the Board should clearly spell out charges over which it has no power and identify which entities do have control over these charges.

RECOMMENDATION 2

To help ensure that the interests of consumers are protected with respect to those charges not subject to Ontario Energy Board (Board) oversight and regulation, the Board should:

- encourage the Ministry of Energy (Ministry) and the Ontario Power Authority (OPA) to consult with it on a more timely basis with respect to the interests of consumers in all energy-supply and pricing undertakings by the Ministry and the OPA;
- work more proactively with the Independent Electricity System Operator to address the high-priority recommendations from the Market Surveillance Panel; and

- clearly explain the reason for each charge on consumer power bills, identify the entity receiving the proceeds from each charge, and disclose whether the Board has any oversight role relating to the charge.

BOARD RESPONSE

The Board supports the objective of enhanced co-ordination among energy-sector agencies, while at the same time respecting both its own mandate and the authority and responsibilities of other agencies. The Board will work with the Independent Electricity System Operator to ensure that high-priority recommendations made by the Market Surveillance Panel are appropriately addressed in a timely manner. The Board has already developed several innovative consumer education tools (such as the on-line bill calculator) and will examine how to assist consumers further.

CONSUMER PROTECTION

Consumer Education

As noted previously, the government enacted a regulation in 2004 that required electricity bills issued to residential and small-business consumers to be broken down by electricity, delivery, regulatory, and debt retirement charges. However, these components typically have to be further divided into sub-components to be fully explained.

Given the increased complexity on residential electricity bills, consumers need additional sources of information to help them understand just what they are being asked to pay for. Such education is crucial as the sector continues to evolve and consumers are given more choices in how to manage their power costs. For example, they need to understand the risks and potential benefits of signing retail fixed-price contracts. They also need to understand the time-of-use system and how they may save money by adjusting their power-usage patterns.

Although the Board has indicated that consumer education is a responsibility it shares with other entities in the electricity sector, the Board has established a number of educational programs and communication tools, including consumer outreach programs, advertising campaigns, and on-line resource materials. The Board has also included a bill calculator function on its website that enables consumers to calculate a monthly estimated bill with their local utility or to compare how their charges would differ on a retail contract. This is a beneficial tool for consumers who want to understand the price differences between a retail contract and the Regulated Price Plan (RPP) before committing to a long-term fixed-price contract. A sample from the bill calculator is given in Figure 4.

Although we acknowledge that some of these programs have garnered recognition from industry associations, there is still room for improvement. For instance, in a focus group conducted in 2010, many participants said that they still did not understand the meaning of the charges on their electricity bills and were unaware of the Board's role in protecting them. In a 2010 stakeholder survey, respondents rated the Board poorly on its consumer and public education efforts, and similar results were noted in focus groups from previous years. A continuing lack of understanding of the nature of electricity charges by the general public clearly poses challenges for the Board in providing assurance to the public that the interests of electricity consumers are being protected.

We agree that consumer education is a responsibility that is shared with other entities in the electricity sector; however, the Board could use its authority over these entities to better influence them to meet their responsibilities.

Monitoring for Compliance

Regulated entities are required to adhere to the accounting, reporting, regulatory, and record-keeping requirements specified in the terms and conditions of their licences. Regulatory requirements cover a wide range of activities, including conduct toward consumers by the regulated entities, billing practices and calculations, and related-party transactions.

The Board conducts compliance activities to ensure that regulated entities are adhering to their statutory and regulatory obligations, and it works to ensure that entities understand their obligations. It also investigates allegations of non-compliance, and undertakes enforcement action where it deems appropriate.

Three Board groups are responsible for compliance. The Regulatory Audit and Accounting Department focuses on ensuring that utilities use appropriate accounting policies and practices to generate reliable data for regulatory decision-making, and conducts audits to ensure that data collected from regulated entities is reliable to use in decision-making. The Regulatory Policy Group and the Consumer Protection Unit assess for compliance by monitoring the complaint process and identifying issues from other sources. They also conduct follow-up work, where warranted, on issues they have identified.

Compliance with Reporting Requirements

The Regulatory Audit and Accounting Department (Department) audits selected accounts and service-quality information reported by regulated entities. In the last three years, the Department has identified consistent deficiencies in utility record-keeping and reporting practices and persistent difficulties in meeting regulatory accounting and reporting requirements. Over the last two years, the Department has attempted to address some of these weaknesses by organizing three on-line training seminars for regulated entities.

In addition, local utility companies advised us that they had concerns about some of the reporting requirements. For example, they are not clear why some of the requirements even exist, or whether the Board uses the information it gets. They also noted issues with the required frequency of reporting, including a Board requirement that utilities report certain information on a quarterly basis, including the number of consumers by rate class, the energy sales in kilowatt hours for each rate class, and the energy sales by electricity retailer. The utilities said that there is no need to report this information on a quarterly basis, because the industry does not change materially within such a short period of time. Instead, they said, it would be more cost-effective to report on an annual basis. Our review of the information collected by the Board also shows that the Board did not use this and other reported information on a quarterly basis.

The Board also collects, reviews, and analyzes information submitted by utilities to assess the reliability and quality of their service and to monitor their financial health. However, it has not clearly communicated to them why it needs the information and how the information is used. Such communication would help regulated entities understand the reporting requirements and ensure that they report correctly, which in turn could also enable the Board to identify systemic concerns that warrant its attention.

Compliance with Regulatory Requirements

In July 2009, the Board's compliance functions became the responsibility of its Regulatory Policy Group, which has not since conducted any proactive reviews of whether electricity utilities are complying with specific regulatory requirements. We noted that the current monitoring for compliance with codes and guidelines relies primarily on outside feedback, mostly customer complaints, and issues noted in the review of rate applications.

The last proactive reviews for conditions of service and affiliated relations (that is, related-party transactions) were conducted in 2007. These reviews noted a number of non-compliance issues. Among them:

- Some local utilities unduly transferred financial benefits to their affiliates. Examples included a $1-million interest-free loan and inappropriate sharing of employees between the utility and the affiliate.

- The *Ontario Energy Board Act, 1998* (Act) bars distributors from carrying on certain activities. Some utilities' provision of municipal street lighting was in contravention of the Act.

Because the Board had not done any recent work relating to affiliate transactions, we conducted an analysis of affiliated loans currently reported by local utilities and selected 10 for follow-up. We noted three errors in the information provided to the Board regarding these loans, including mistakes in reported interest income, loan-related expenses, and loan balances. Although the Board agreed that these were indeed reporting errors, it also indicated that they were identified in the rate-setting applications and were therefore taken into consideration in the rate-setting process. However, because we looked at only one narrow area, it is possible that there are errors in other information reported to the Board. Without more proactive surveillance, such errors could be difficult to detect.

Consumer Complaints

The Board's responsibilities include responding to inquiries from electricity consumers about the Board and dealing with consumer complaints about regulated entities. Consumers can contact the Board by telephone, on-line, or in person. The number of complaints against regulated entities in the electricity sector grew from 1,400 in 2006 to 4,300 in 2010, and totalled 17,000 over the last five years. Complaints against electricity retailers account for between 70% and 90% of the total, with the remainder primarily about local utilities.

Common complaints include customers being switched to retail pricing without a contract, which can happen when a retailer obtains a customer's electricity account number; misrepresentation of identity by retailer agents claiming to work for the Board or the local utility; refusal to cancel contracts; misrepresentation about retail-contract pricing; and even forgery of signatures on the contracts.

The Board's Consumer Relations Group resolves most complaints by contacting the regulated entity and by encouraging consumers to try to resolve the complaints directly with the company. Complaints that cannot be resolved in this way are escalated for review and follow-up by the Retail Markets and Compliance Management Group. The Board was unable to provide data from before 2006, but it said that in the last four years, 1,442 cases, representing about 11% of complaints against electricity retailers, were escalated for follow-up. In the last three years, 658 electricity retail contracts were cancelled through the complaint process and consumers received refunds worth more than $700,000.

Given the continuing high number of complaints against electricity retailers, along with the costs involved in pursuing enforcement actions, it would be helpful for the Board to determine the underlying causes of these complaints and to determine whether appropriate mitigation measures can be implemented.

In 2010, the province passed the *Energy Consumer Protection Act* to ensure that Ontarians have the information they need about electricity contracts and electricity pricing, and that they can count on fair business practices. The new rules came into effect in January 2011, and the Board has contracted an external accounting firm to perform compliance audits on retailers with respect to the new requirements. The related costs of these audits (together with most of the costs of operating the Board's Consumer Protection Unit) are being allocated and charged back to retailers and marketers through the Board's cost-assessment process. This new allocation is effective as of April 1, 2011, in accordance with amendments to the Board's cost-assessment regulation.

Retail Contracts

In the current electricity market, consumers can purchase their supply of electricity for consumption either through their utility at the Regulated Price Plan (RPP) rates set by the Board or through an electricity retailer at a price set by the retailer. There are currently nine active retailers in Ontario, and approximately 630,000 residential consumers (representing 15% of the total) have entered into contracts with them.

The Board licenses all retailers who sell electricity contracts in Ontario but does not set the prices they charge. The Board indicated that the existence of the retail sector and its ability to conduct door-to-door sales are matters for the government. The Board also indicated that there are inherent difficulties in taking enforcement action against door-to-door salespeople, given that there is always a question of "who said what." However, because the Board licenses these entities, we believe that the public could reasonably expect it to play a more proactive role in protecting consumers from unfair business practices.

Consumer Desire for Price Protection

Consumers generally enter into retail contracts because they want price protection and stability in their electricity bills. However, such contracts do not actually offer protection against price increases. The potential protection they offer is applicable only to the "market price" portion of the electricity charge on the bill. They provide no protection against increases either in the Global Adjustment component of the electricity charge or in other costs. As noted earlier, the Global Adjustment has been rising steadily over the last few years with the cost of acquiring the electricity supply, even though the overall market price has been declining because of oversupply. Most consumers do not follow these developments, something that some retailers appear to have exploited to encourage consumers to sign a contract with them.

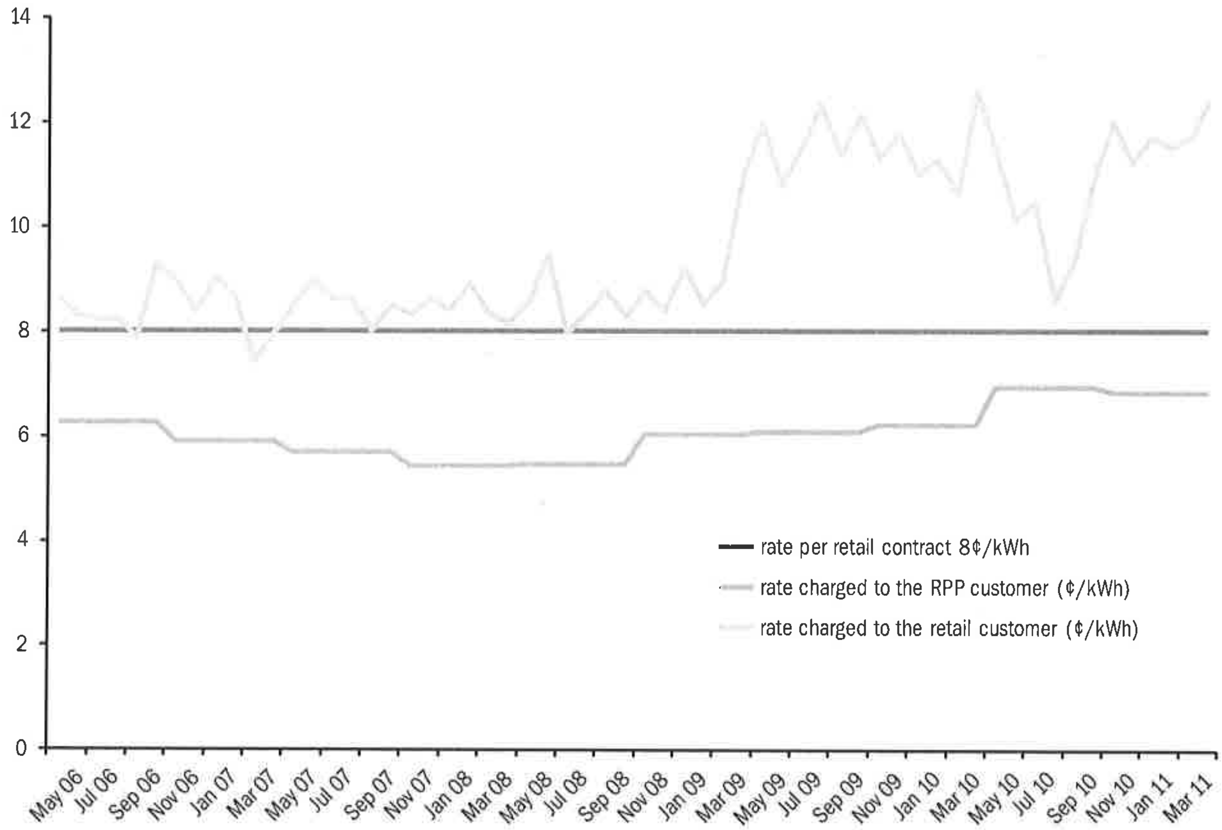
As the government moves forward with its long-term energy plan, Ontarians can expect continued increases in the cost of electricity. Most of these increases will be the result of upgrades to existing generating and transmission capacity, and commitments to purchase renewable energy through long-term contracts. As long as there is surplus capacity, the price increases associated with many of these investments will likely be reflected in the Global Adjustment and not the market price. Accordingly, consumers with fixed-price contracts will have no protection from these increases even though such "fixed-price" protection was undoubtedly why consumers signed these contracts in the first place. In fact, the OPA is projecting electricity surpluses in the future that will put further downward pressure on the market price. Fixed-price contract holders will obtain no benefit from any such decreases because they will continue to pay their contracted price.

Effectiveness of Price Protection

We sampled customer bills from 2006 to 2009 from various retailers, and noted that retailers offered fixed electricity rates in the range of 8.49¢/kWh to 10.53¢/kWh. During this same period, the average market electricity rate ranged from 3.2¢/kWh to 5.2¢/kWh. The Board set the average RPP price, including both the market and Global Adjustment rates, at between 5.4¢/kWh and 6.3¢/kWh. Accordingly, our sample of retail-contract customers paid anywhere from 35% to 65% more for their electricity, before tax and other charges, than the highest RPP rate over the term of their contract.

For example, a consumer who committed to a five-year fixed-price electricity retail contract at 8¢/kWh would have actually seen more dramatic electricity price increases and price fluctuations on his or her electricity bill than a customer who stayed on the Board's Regulated Price Plan, as shown in Figure 7. This effectively negates the main reason—price stability—that leads people to enter into such contracts in the first place. Over the term of a five-year contract, we estimate that under this scenario a customer using 1,000 kWh per month could pay about $2,000 more for electricity than one on the RPP plan. As well, retailers have profited without facing some of the usual business risks because the utilities that supply electricity to the retailers' customers are required to pay the retailers first and then attempt to collect from consumers.

Figure 7: Electricity Price Comparison (RPP vs. Retail-contract Price), 2006–2011
Prepared by the Office of the Auditor General of Ontario



As noted earlier, approximately 70% to 90% of all customer complaints in the electricity sector to the Board over the last five years were against retailers. The Board advised us that dealing with retailers choosing to conduct door-to-door sales is not within its authority; however, because it is responsible for licensing retailers, we believe that it has at least some responsibility to protect consumers from unfair practices by the retailers it licenses. To the extent that the Board's responsibility is shared with others, such as the Ministry of Consumer Services, it would be prudent to ensure that a co-ordinated and effective process is in place for resolving consumer complaints about these retailers.

Enforcement

In its compliance work, the Board has continually observed non-compliance with its regulatory and reporting requirements by the regulated entities. Some of these instances of non-compliance might be addressed through better communication, such as the on-line training sessions put on by the Board's auditing group and the information bulletins it puts out. Adequate follow-up reviews are also required, to ensure that these and other remedial actions have been effective in ensuring compliance.

In addition, since assuming the increased responsibilities for regulating the electricity sector in 1999, the Board indicated that it made a deliberate and principled decision in the earlier stages of its activities to focus on voluntary compliance, recognizing that regulated entities required some time to understand and adapt to the legal and regulatory requirements and to correct their practices. We acknowledge that time is required for regulated entities to adapt to new regulatory requirements and that the Board needed to work with these regulated entities to ensure that they understand and build up their capacity to meet these new requirements. However, a voluntary system is effective only if it leads to eventual compliance; if non-compliance is persistent, other remedial actions are required.

The Board clearly recognizes the importance of enforcement in effectively regulating the near-monopoly that is the electricity sector, because its business plans and annual reports acknowledge the importance of enforcement as a key part of an effective compliance function. That said, despite the high number of public complaints against electricity retailers, we noted little enforcement action against retailers with repeat offences. Since July 2003, the Board has issued only four enforcement orders in 2009 and just one in 2010. In total, three retailers were fined about $500,000 and had special licence conditions imposed on them. The Board indicated that enforcement actions are a costly and resource-intensive process.

RECOMMENDATION 3

To ensure that consumers are protected and that they have the information they need to understand their electricity bills, the Ontario Energy Board should:

- review its current educational and communication programs and make the appropriate adjustments to meet consumer information needs;
- consider initiating limited proactive compliance reviews focusing on high-risk areas;
- work with utilities to streamline reporting requirements, including the timing and frequency of reporting; and
- determine whether appropriate deterrent actions in those areas that have generated frequent legitimate consumer complaints can be implemented.

BOARD RESPONSE

The Board appreciates the Auditor General's recognition of its consumer education materials, and it commits to enhancing them to meet changing consumer needs.

The Board agrees that proactive compliance is an important part of a robust monitoring and compliance program. The Board has included a commitment to this in each of its business plans since 2004 and has undertaken focused proactive compliance reviews based on a risk assessment that includes reviewing consumer complaints. The Board's compliance philosophy focuses on bringing industry players into compliance through a multi-faceted process that includes enforcement action where appropriate. With the passage of the *Energy Consumer Protection Act, 2010* (Act), the Board has established a Consumer Protection Business Unit that is focused on ensuring that industry licensees are adhering to consumer protection requirements. The Board has conducted detailed compliance inspections of all active retailers and has recently initiated enforcement actions relating to allegations of failure by retailers to meet the requirements of the Act and related regulatory requirements.

The Board has worked to streamline its reporting requirements and will further review them in consultation with the industry and other stakeholders. In the past two years, the Board has taken steps to assist distributors by enhancing its electronic filing system to facilitate reporting, as well as by providing definitions and guidance that promote a common understanding of the reporting requirements.

PERFORMANCE MEASURES

Performance indicators can be defined as measurable outcomes that are within an entity's control and clearly linked to its objectives. Since the 2004/05 fiscal year, the Board has developed and published an annual business plan with associated performance measures. The business plan identifies the Board's strategic objectives and the management initiatives to support them. It also sets out the activities that the Board intends to undertake over the next three years to achieve its objectives, and how it will measure its success. The Board's actual performance vis-à-vis these performance measures is independently reviewed by an external auditor.

We concluded that this process was well structured and offered the potential to be an excellent performance-reporting mechanism. However, to take full advantage of this process, the Board's performance measures need to be more results- or outcome-based, rather than process-oriented or output-based. For example, the Board's measures looked at whether "Regulated Price Plan prices have been adjusted as required" and whether "filing guidelines for cost-of-service applications will be updated." The challenge with process-oriented or output-based measures is that they often provide little evidence as to the actual achievement of the Board's strategic objectives. We acknowledge that in its 2011–2014 Business Plan, the Board recognized the value of moving toward outcome-based performance measures. However, no such measures had been developed at the time of our audit.

One of the Board's performance measures is its own internal costs, which have been increasing over the last 10 years although they have remained more stable over the last three years. In addition to the Board's operating expenses, the cost of regulation also includes such other expenses as the cost of intervenors and costs incurred by applicants seeking approval for price increases. However, neither cost has been included in its cost calculations. Because all regulatory costs are ultimately passed on to the same electricity consumers that the Board is mandated to protect, we believe that these costs should also be reflected.

RECOMMENDATION 4

To improve the reporting of the effectiveness and costs of its regulatory activities, the Ontario Energy Board (Board) should develop more results-based or outcome-based performance measures that are aligned with its strategic objectives and mandate, and summarize and report all of the costs associated with the Board's regulatory processes.

BOARD RESPONSE

In its most recent business plan, the Board expressed its commitment to moving to outcome-based performance measures. The Board is working toward the establishment of a robust performance-assessment framework that will include the collection and assessment of indicators and data relating to the impact of its decisions and policy initiatives over time. The Board appreciates the Auditor General's conclusion that its current performance-measurement process is well structured and will continue to use that process in the interim to confirm achievement of its business-plan initiatives.

The Board will, in addition to reporting on its own costs, report on cost awards paid to intervenors. The Board will explore whether information on utility regulatory costs can be readily provided by the utilities at a cost that is commensurate with the benefits of enhanced reporting.

TAB 17

Ministry of Energy

Electricity Sector—Renewable Energy Initiatives

Background

The government is responsible for setting the legislative and policy framework over the production, transmission, and sale of electricity in Ontario. The three key factors that impact its electricity policy-setting role are price, reliability, and sustainability.

The Ministry of Energy (Ministry) is responsible for providing the regulatory framework and implementing the government's electricity policies, and does this in part through its oversight of several government entities, including:

- the Ontario Power Authority (OPA), which plans and procures electricity supply to meet the province's power needs;
- the Ontario Energy Board (OEB), which regulates Ontario's electricity and natural-gas sectors;
- the Independent Electricity System Operator (IESO), which is responsible for the day-to-day operation of Ontario's electrical system;
- Ontario Power Generation (OPG), which generates electricity through its nuclear, thermal, and hydroelectric stations; and
- Hydro One, which distributes electricity across the province.

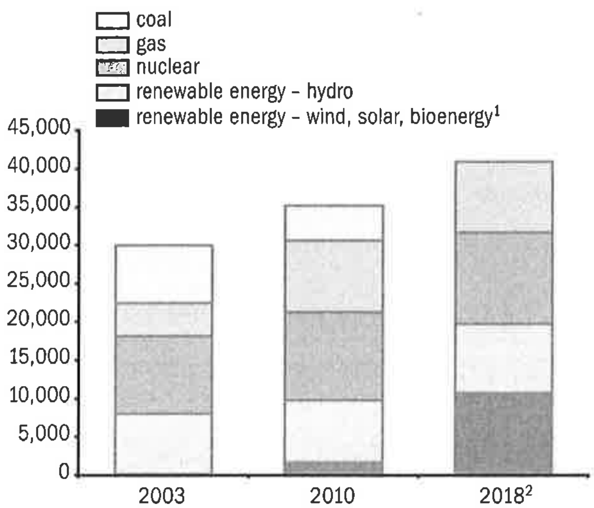
One cornerstone of the current government's energy policy is the development of a significantly greater role for renewable energy in Ontario's electricity-supply mix. Renewable electricity refers to those sources of energy generated by natural processes. The four major forms of renewable energy are:

- hydro, generated from the movement of water;
- wind, generated by turbines from air currents;
- solar, generated by photovoltaic cells that capture energy from the sun; and
- bioenergy, generated by burning organic forestry residues and agricultural wastes.

The Ontario government has proposed an increased reliance on renewable energy sources, especially wind, solar, and bioenergy, partly to replace coal-fired generating plants by the end of 2014. The installed capacity from different energy sources between 2003 and 2018, as projected in the Ministry's Long-Term Energy Plan of November 2010, is shown in Figure 1.

In keeping with this priority, the government enacted the *Green Energy and Green Economy Act* (Act) in May 2009. The intent of the Act, which included new legislation and amendments to existing laws, was to attract investment in renewable energy, promote a culture of energy conservation, create a competitive business environment, increase job opportunities, and reduce greenhouse gas emissions.

Figure 1: Installed Capacity of Electricity Supply from Different Energy Sources (MW), 2003–2018
Source of data: Ministry of Energy



1. The expected electricity outputs from wind and solar are much lower than their installed capacity (see Figure 10).
2. Projected.

Both the Ministry and the OPA have played an active role in implementing the government's renewable energy policies. The Ministry's responsibilities have focused on the development of programs and policies to advance implementation of the Act, while the OPA has played a key role in planning and procuring renewable energy by contracting to buy power from developers of renewable energy projects.

Audit Objective and Scope

The objective of our audit was to assess whether the Ministry of Energy (Ministry) and the Ontario Power Authority (OPA) had adequate systems and procedures in place to:

- ensure that renewable energy resources are obtained in a cost-effective manner and within the context of applicable legislation and government policy; and
- implement a balanced and responsible plan with respect to renewable energy that provides Ontarians with a clean, reliable, affordable, and sustainable electricity system.

Senior management at the Ministry and the OPA reviewed and agreed to our audit objective and associated audit criteria.

We conducted our audit work at the Ministry and the OPA. We also visited the system control centre of the Independent Electricity System Operator (IESO) to help us better understand the operation of Ontario's electricity market.

In conducting our audit work, we reviewed relevant legislation, regulations, policies, and procedures; analyzed historical and projected electricity-related data collected by the OPA and the IESO; reviewed analyses conducted by the Ministry and the OPA; interviewed ministry and OPA staff; met with representatives from the IESO, the Ontario Energy Board, and Hydro One; and reviewed relevant literature and best practices in other jurisdictions. In addition, we engaged independent consultants with expert knowledge of Ontario's energy sector on an advisory basis.

We did not rely on the Ministry's internal audit service team to reduce the extent of our audit work because it had not recently conducted any audit work on renewable energy initiatives.

Summary

Historically in Ontario, electricity generation and transmission to residential and commercial users was largely the responsibility of Ontario Hydro, a Crown corporation, and after 1999, its successor companies. The responsibility for ensuring that these entities provided consumers with electricity that was both sustainable over the long term and reasonably priced fell to the Ministry of Energy (Ministry) and the Ontario Energy Board, an independent regulator. The *Green Energy and Green Economy Act, 2009* delegated a certain part of the responsibility for dramatically increasing the province's renewable energy supply directly to the Minister of Energy. Under this legislation, the government created a new process to expedite the development of renewable energy by providing the Minister with the authority to supersede many of the government's usual planning and regulatory oversight processes.

As a result, the government has been able to further its renewable energy policy agenda without the delays that these processes can sometimes cause. This agenda has included generating significantly more energy from renewable sources to replace coal-sourced energy, given its environmental and health risks. It has also included creating jobs in a new "green" energy sector.

The government's renewable energy initiatives have been successful in rapidly increasing the amount of renewable power available over the next few years. At the same time, however, wind and solar renewable power will add significant additional costs to ratepayers' electricity bills. Renewable energy sources such as wind and solar are also not as reliable and require backup from alternative energy-supply methods such as gas-fired generation. The government was well aware that its renewable energy initiatives meant higher costs but felt that this was a more-than-acceptable trade-off given the environmental and health benefits, as well as the anticipated job-creation benefits.

Some of our observations relating to the implementation of the government's renewable energy policy were as follows:

- Ontario is on track to shut down its more than 7,500 megawatts (MW)—the capacity as of 2003—of coal-fired generation by the end of 2014. Coal-generated power is being replaced by nuclear power from refurbished plants and by an increase of about 5,000 MW of gas-fired generation, with the remainder resulting largely from bringing more renewable energy online. More significantly, actions taken by the OPA and the Ministry to implement the Minister's Directives are projected to increase renewable energy, mainly wind and solar power, to 10,700 MW by 2018.
- Because the ministerial directions were quite specific about what was to be done, both the Ministry and the OPA directed their energies to implementing the Minister's requested actions as quickly as possible. As a result, no comprehensive business-case evaluation was done to objectively evaluate the impacts of the billion-dollar commitment. Such an evaluation would typically include assessing the prospective economic and environmental effects of such a massive investment in renewable energy on future electricity prices, direct and indirect job creation or losses, greenhouse gas emissions, and other variables.
- In May 2009, when the *Green Energy and Green Economy Act* (Act) was passed, the Ministry said the Act would lead to modest incremental increases in electricity bills of about 1% annually—the result of adding 1,500 MW of renewable energy under a renewable procurement program called the Feed-in Tariff program and implementing conservation initiatives. In November 2010, the Ministry forecast that a typical residential electricity bill would rise about 7.9% annually over the next five years, with 56% of the increase due to investments in renewable energy that would increase the supply to 10,700 MW by 2018, as well as the associated capital investments to connect all the renewable power sources to the electricity transmission grid.
- The OPA was designated as the province's energy planner, responsible for submitting long-term plans to the Ontario Energy Board (OEB) for approval. However, the first long-term energy plan put forward by the OPA since its creation in December 2004 has not been approved by the OEB. Although the OPA did spend $10.7 million to develop its first energy plan, which it submitted to the OEB for review in 2007, the government suspended the OEB's review of the plan in 2008. In 2010,

the Ministry released its own Long-Term Energy Plan to provide the OPA with sufficient context on the government's policy priorities and targets to guide it in its planning. From the public's perspective, this could lead to some ambiguity as to which entity is responsible for electricity planning in Ontario.

- Earlier procurement programs for renewable energy included competitive bidding and the Renewable Energy Standard Offer Program (RESOP), which were both very successful and achieved renewable generation targets in record time. In particular, RESOP received overwhelming responses. It was expected to develop 1,000 MW over 10 years, but it exceeded this target in a little more than one year. Although continuing the successful RESOP initiative was one option, the Minister directed the OPA to replace RESOP with a new Feed-in Tariff (FIT) program that was wider in scope, required made-in-Ontario components, and provided renewable energy generators with significantly more attractive contract prices than RESOP. These higher prices added about $4.4 billion in costs over the 20-year contract terms as compared to what would have been incurred had RESOP prices for wind and solar power been maintained. The Ministry indicated that replacing RESOP with FIT successfully expedited its renewable energy program and promoted Ontario's domestic industry.
- Many other jurisdictions set lower FIT prices than Ontario and have mechanisms to limit the total costs arising from FIT programs. The OPA made a number of recommendations to lower Ontario's pricing structure. We were advised that the government opted for price stability to maintain the investor confidence required to attract capital investment to Ontario until the planned two-year review of the FIT program could be undertaken. Examples of proposed changes included the following:
  - In March 2009, before the passage of the *Green Energy and Green Economy Act,* the OPA proposed a reduction of 9% to FIT prices for electricity generated from ground-mounted solar projects, in line with similar practices in some other jurisdictions. This could have reduced the cost of the program by about $2.6 billion over the 20-year contract terms. The government did not apply this reduction. The Ministry informed us that such a predetermined price reduction ran counter to the government's goals of maintaining policy and price stability for the initial two-year period.
  - In February 2010, the OPA recommended cutting the FIT price paid for power from microFIT ground-mounted solar projects after the unexpected popularity of these projects at the price of 80.2¢ per kilowatt hour (kWh), the same price as was being paid for rooftop solar projects, became apparent. This price would provide these ground-mounted solar project developers with a 23% to 24% after-tax return on equity instead of the 11% intended by the OPA. The recommended price cut was not implemented until August 2010. In the five months from the time the OPA recommended the price cut in February 2010 to the actual announcement in July 2010, the OPA received more than 11,000 applications from developers. Because the government decided to grandfather the price in order to maintain investor confidence, all of these applications, if approved, would qualify for the higher price rather than the reduced one. We estimated that, had the revised price been implemented when first recommended by the OPA, the cost of the program could have been reduced by about $950 million over the 20-year contract terms.
- The Ministry negotiated a contract with a consortium of Korean companies to build renewable energy projects. The consortium

will receive two additional incentives over the life of the contract if it meets its job-creation targets: a payment of $437 million (reduced to $110 million, as announced by the Ministry in July 2011 after the completion of our audit fieldwork) in addition to the already attractive FIT prices; and priority access to Ontario's electricity transmission system, whose capacity to connect renewable energy projects is already limited. However, no economic analysis or business case was done to determine whether the agreement with the consortium was economically prudent and cost-effective, and neither the OEB nor the OPA was consulted about the agreement. On September 29, 2009, the ongoing negotiations with the consortium were publicly announced, and Cabinet was briefed on the details of the negotiations and the prospective agreement in October 2009. The formal agreement was signed in January 2010.

- Surplus generating capacity is necessary to meet periods of peak demand, which, in Ontario, occur in the summer. Therefore, to ensure system reliability, all jurisdictions will have surplus power from time to time. Ontario deals with surplus-power situations mainly by exporting electricity to other jurisdictions at a price that is lower than the cost of generating that power. Given that demand growth for electricity is expected to remain modest at the same time as more renewable energy is being added to the system, electricity ratepayers may have to pay renewable energy generators under the FIT program between $150 million and $225 million a year not to generate electricity.
- Ontario's electricity transmission and distribution systems already operate at or near capacity. A higher-than-anticipated number of renewable energy projects under the FIT program are awaiting connection to the distribution grid. As of April 1, 2011, about 10,400 MW, representing more than 3,000 FIT applications, cannot be accommodated into the existing power grid.
- Recent public announcements stated that the *Green Energy and Green Economy Act, 2009* was expected to support over 50,000 jobs, about 40,000 of which would be related to renewable energy. However, about 30,000, or 75%, of these jobs were expected to be construction jobs lasting only from one to three years. We also noted that studies in other jurisdictions have shown that for each job created through renewable energy programs, about two to four jobs are often lost in other sectors of the economy because of higher electricity prices.
- Renewable energy sources such as wind and solar provide intermittent energy and require backup power from coal- or gas-fired generators to maintain a steady, reliable output. According to the study used by the Ministry and the OPA, 10,000 MW of electricity from wind would require an additional 47% of non-wind power, typically produced by natural-gas-fired generation plants, to ensure continuous supply.

OVERALL MINISTRY RESPONSE

The Ministry of Energy (Ministry) welcomes the Auditor General's recommendations and remains committed to providing quality policy advice and implementing the government's decisions in a manner that is cost-effective and promotes system reliability and sustainability.

The *Green Energy and Green Economy Act, 2009*, enacted by the Ontario Legislature and authorizing the creation of a Feed-in Tariff (FIT) program, represents a fundamental shift in Ontario's electricity policy direction. This directional shift is consistent with some 88 jurisdictions worldwide that have also implemented FIT programs.

Ontario's FIT program was designed to meet three key policy objectives:

- Reduce our environmental footprint (greenhouse gas emissions) by bringing more renewable energy online and supporting the phase-out of coal by 2014.
- Better protect the health of Ontarians by eliminating the harmful emissions from burning coal. In fact, an Ontario independent study in 2005 found that coal-fired generation costs $4.4 billion annually when health and environmental costs are taken into consideration.
- Create green energy jobs and attract scarce investment capital to Ontario amidst a global recession.

The uptake of Ontario's FIT program has been successful largely due to the government's decision to set attractive FIT prices and instill investor confidence by not reducing prices or making major policy or program changes prior to the mandatory two-year review.

Planning for a stable supply of electricity is a complex exercise requiring compliance with North American standards. Prudent planning requires providing significantly more generating capacity than peak demand. By 2016, energy supply and demand are projected to match closely as nuclear units are taken offline for refurbishment.

The Ministry will continue to work closely with the Ontario Power Authority to balance energy supply and demand in the next Integrated Power System Plan and make adjustments as necessary to ensure reliability.

OVERALL OPA RESPONSE

The OPA supports the Auditor General's recommendations with respect to the ongoing development and administration of renewable energy programs in the province. The Ontario FIT program—the first of its kind in North America in scope, comprehensiveness, and magnitude—was designed and launched in 2009 in a particular set of economic and policy circumstances. The OPA worked to diligently and effectively implement the program within short timelines. Consistent with the OPA's own internal audit, the Auditor General did not find any significant issues with the administration of the FIT program. From the outset, a mandatory review was built in, at the two-year mark, to provide a period of program stability as well as to recognize that the program would need to evolve as both technology and markets matured over time. This review, under way in fall 2011, provides an opportunity to consider many of the issues raised in the audit.

The Auditor General also identifies the importance of sector-wide collaboration and coordination for renewable energy development. The OPA works closely with the Ministry of Energy, Hydro One, the Independent Electricity System Operator, local distribution companies, and the Ontario Energy Board on renewable energy development—for example, through the Renewable Energy Supply Integration Team—and will continue to do so. This includes finding ways to more effectively communicate with the public on the costs of renewable energy and other types of electricity generation. Finally, the OPA is encouraged that the Auditor General recognizes the contribution that renewable energy is making to support the reduction of greenhouse gases in Ontario's electricity system.

Detailed Audit Observations

SIGNIFICANT RENEWABLE ENERGY COMING ON-LINE

Building clean, affordable, reliable, and sustainable sources of electricity is a top priority for the Ontario government. As part of its goals of protecting the environment and the health of Ontarians, the government has committed to closing all coal-fired plants by the end of 2014. Ontario is on track to meet this commitment. Of the 19 units operated at five coal-fired plants across Ontario in 2003, the Ministry indicated that eight units had been closed since that year and two more were to be shut down later in 2011. As a result of these closures, the installed capacity of coal-fired generation in Ontario has been decreasing. It is anticipated that more than 7,500 MW of coal-fired installed capacity in 2003 will be replaced by nuclear power from refurbished plants and an increase of about 5,000 MW of gas-fired generation, with the balance coming from new renewable energy sources (see Figure 1).

Specifically, with the passage of the *Green Energy and Green Economy Act, 2009*, Ontario has made progress in bringing more renewable energy on-line. According to the Ministry, the installed capacity of cleaner renewable energy such as wind, solar, and bioenergy has increased from about 160 MW in 2003 to about 1,700 MW in 2010, and is expected to increase further to 10,700 MW by 2018 (see Figure 1).

COST IMPACT OF RENEWABLE ENERGY ON CONSUMERS

Rising electricity costs have in the last few years been a concern for Ontarians, who saw their power bills rise an average of 26% between 2008 and 2010, mainly as a result of capital investments, refurbishment of generating infrastructure, and the imposition of the Harmonized Sale Tax (HST). The government responded with a 10% reduction, called the Ontario Clean Energy Benefit, on the monthly electricity bills of households and small businesses that took effect on January 1, 2011, and that is to last for five years.

At the same time, mounting concerns about the impact of conventional power generation on the environment and public health have led many to give serious consideration to environmentally friendly renewable energy as an alternative. On the other hand, renewable energy sources, particularly wind and solar, cost much more than conventional energy sources. Accordingly, electricity bills are projected to rise even further as more renewable energy projects start commercial operations in the next few years. The following section deals with some of the key factors affecting the cost of electricity in Ontario.

Hourly Ontario Electricity Price (HOEP) and Global Adjustment (GA)

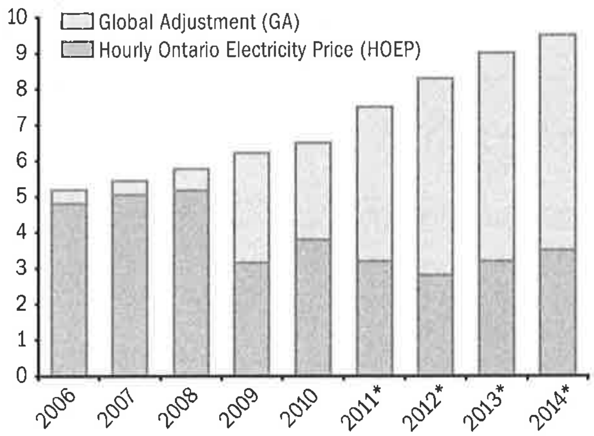
There are five parts to the typical electricity bill: electricity charge, delivery charge, regulatory charge, debt retirement charge, and HST. The electricity charge accounts for the biggest single portion of the bill, and it consists of two key components:

- The Hourly Ontario Energy Price (HOEP) is an hourly market price based on supply and demand for electricity as determined by a competitive process in which generators bid to supply electricity into the market.
- The Global Adjustment (GA) is the difference between the market price (HOEP) and the guaranteed prices paid to regulated and contracted generators. It also accounts for the cost of the OPA's conservation programs. Guaranteed prices are paid to generators, including, but not limited to, nuclear and hydroelectric generators administered by the Ontario Power Generation (OPG), non-utility generators administered by the Ontario Electricity Financial Corporation, and gas-fired and renewable energy generators contracted by the OPA.

The OPA has entered into a number of fixed-price contracts, resulting in higher-than-market electricity prices. Following passage of the *Green Energy and Green Economy Act* in 2009, the OPA was directed to significantly expand renewable energy by offering very attractive contract prices to developers of renewable energy projects. These contracts are expected to lead to significantly higher electricity charges through the GA portion of the electricity bill. Figure 2 shows that:

- The sum of the HOEP and the GA, representing the biggest part of electricity bills,

Figure 2: Electricity Charge, 2006–2014 (¢/kWh)
Source of data: OPA and IESO



* Projected.

increased by 25% between 2006 and 2010, and is expected to rise another 43% by 2014 due to rapid growth in the GA.

- By 2014, the GA is expected to be 6¢ per kilowatt hour (kWh)—almost two-thirds of the electricity charge—and will be almost two times more than that year's projected HOEP.

Based on our analysis of OPA data, renewable energy contracts will contribute significantly to increases to the Global Adjustment. As illustrated in Figure 3, the total GA is expected to increase tenfold province-wide, from about $700 million in 2006 to $8.1 billion in 2014, when the last coal-fired plants are phased out. Almost one-third of this $8.1 billion is attributable to renewable energy contracts.

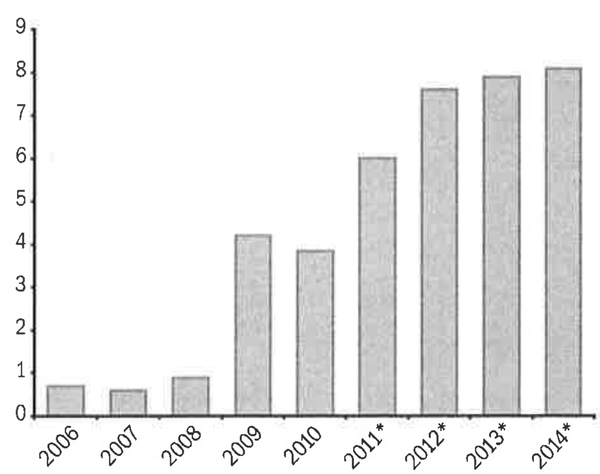
Public Awareness of the Cost Impact of Renewable Energy

The OPA indicated that consumers have to be advised, through appropriate channels, of the expected electricity-price increases arising from a large number of contracts to buy green energy at fixed rates that are significantly higher than market prices. However, a number of consumer surveys conducted by the government in spring and fall 2010 indicated that although consumers generally supported renewable energy, they were for the most part unaware of its impact on prices. Specifically:

- An OPA survey showed that only 14% of respondents thought renewable energy would lead to electricity price increases, while 60% disagreed that "green energy sources like wind and solar are too expensive and unreliable."
- Ministry surveys found that only a minority of respondents linked recent price increases to the cost of renewable energy, although many respondents did say that they were prepared to pay "modest" increases for renewable electricity.
- Hydro One surveys found that consumers supported spending to connect renewable energy to the power grid, but were less inclined to support electricity bill increases associated with these investments. About half said they were willing to pay for such investments, but only 27% would agree to an increase in their electricity bills of more than 5%.

In May 2009, when the *Green Energy and Green Economy Act* was passed, the Ministry said it would lead to modest incremental increases in electricity bills of about 1% annually as a result of adding 1,500 MW of renewable energy under a renewable energy program called Feed-in Tariff (FIT) and implementing conservation initiatives. In November

Figure 3: Total Global Adjustment, 2006–2014 ($ billion)
Source of data: OPA and IESO



* Projected.

2010, the Ministry's Long-Term Energy Plan (LTEP) included electricity-price forecasts based on the effects of all investments in Ontario's electricity system. According to the LTEP, a typical residential electricity bill would rise about 7.9% annually over the next five years, with 56% of the increase due to investment in new, cleaner renewable energy that would increase the supply to 10,700 MW by 2018 as well as the associated capital investments to connect renewable power sources to the transmission grids.

Because the forecasts in the LTEP were not specific to renewable energy, we asked the Ministry for a detailed breakdown and analysis showing the impact of all renewable energy initiatives on various components of residential, industrial, and commercial electricity bills. As Figure 4 illustrates, the impact of renewable energy on monthly electricity charges is expected to increase for all sectors between 2010 and 2018, especially the large commercial and industrial sectors. However, the Ministry did not have a similar breakdown for the impact of renewable energy on monthly delivery and regulatory charges. We also noted that although the LTEP and the related pamphlet did inform the public that renewable energy would increase their electricity bills, the cost impact of renewable energy by sector was not disclosed in detail. The Ministry informed us that the forecasts in the LTEP were based on all-in total costs, which are more important to the public than cost data relating to the different sources of energy, such as renewable energy.

In addition to the forecasts in the Ministry's LTEP and contained in Figure 4, in April 2010, the OEB completed an analysis predicting that a typical household's annual electricity bill will increase by about $570, or 46%, from about $1,250 in 2009 to more than $1,820 by 2014. More than half of this increase would be because of renewable energy contracts.

RECOMMENDATION 1

To ensure that electricity ratepayers understand why their electricity bills are rising at a much higher rate than inflation, the Ministry of Energy (Ministry) and the Ontario Power Authority (OPA) should work together to increase consumer awareness of the concept of the Global Adjustment and make more information available on the cost impact of its major components.

MINISTRY RESPONSE

The Ministry agrees that consumer awareness of electricity costs, and the factors that affect those costs, is vital.

The Ministry will seek to build on its extensive public education and awareness actions to

Figure 4: Monthly Electricity Charge Related to Renewable Energy in Different Sectors
Source of data: Ministry of Energy

Economic Sector	Examples	Assumed Electricity Consumption (kWh/month)	Renewable Energy-related Electricity Charge ($) 2010 (Actual)	2018 (Projected)
residential	n/a	800	2	31
small commercial	convenience store, small dry cleaner, restaurant, small retail store	12,000	38	500
large commercial	supermarket, shopping mall, large office building, hotel	130,000	385	5,000
industrial	paper and pulp, automobile, mining, cement, iron and steel manufacturing, chemical products, petroleum (i.e., refineries)	61,200,000	200,000	2,400,000

date. In 2011, these actions included providing the following focused information about changes to electricity prices to all of Ontario's electricity consumers:

- the "Electricity Prices Are Changing" pamphlet, sent to all Ontario households; and
- a quarterly electricity bill insert titled "Ontario Clean Energy Benefit," detailing changes to electricity bills.

The Ministry will continue to work with the Ontario Energy Board, local distribution companies, the OPA, and its other partners to seek opportunities to further increase public awareness about energy prices. The Ministry will also explore options for an integrated media campaign, which could include web postings and fact sheets and other opportunities.

OPA RESPONSE

The OPA agrees with this recommendation. Information about the Global Adjustment (GA) and the relationship between the OPA's contracts and the GA is currently available on the OPA website. The OPA has started work to simplify this information and co-ordinate with other electricity organizations to provide comprehensive, consistent information about the total cost of electricity. The OPA maintains updated cost forecasts and has substantially completed an update of the Integrated Power System Plan, which will contain a detailed cost and bill-impact analysis. As the province's electricity planner, the OPA could be the logical source of independent and credible information on costs.

DEVELOPMENT OF ENERGY PLAN AND RENEWABLE ENERGY POLICY

The OPA was created in December 2004 by the *Electricity Restructuring Act*. One of its key objectives is to ensure the adequacy and reliability of Ontario's electricity supply through planning and procurement. Under the legislation, the Ministry and the OPA would continue to provide the government with advice on the development of renewable energy, but the Minister essentially had the authority to direct the OPA, which minimized the need for an analysis of different policy options and an assessment of the cost-effectiveness of alternative approaches.

Integrated Power System Plan (IPSP)

The OPA has since its inception had the statutory responsibility to develop an Integrated Power System Plan (IPSP) and procurement processes for electricity. The IPSP is to represent Ontario's 20-year plan to achieve the province's energy goals. The OPA is required to submit the IPSP and the related procurement processes every three years to the Ontario Energy Board (OEB), which then must review the proposed IPSP to ensure that it is economically prudent and cost-effective. However, the OEB has never approved the first IPSP put forward by the OPA after the OPA's creation in December 2004 because of frequent changes to government policy and planning requirements, as illustrated in Figure 5.

The OEB's review and approval process of the OPA's first IPSP, submitted in August 2007, was suspended the following year at the direction of the Minister, who asked the OPA to revise the IPSP. The suspension of the independent regulator's review meant that there would be no independent assessment to ensure that decisions were made in an economically prudent and cost-effective manner.

In November 2010, the Ministry released a document called the Long-Term Energy Plan (LTEP) that specified Ontario's energy goals and supply-mix to 2030. The Ministry indicated that the LTEP, along with a February 2011 supply-mix directive, provided sufficient context to guide the OPA in planning and developing a revised IPSP. However, OPA staff acknowledged that the existence of two plans—the Ministry's and its own—could lead some

Figure 5: Key Developments in Ontario's Long-term Energy Planning, 2006–2011
Source of data: Ministry of Energy and OPA

Date	Events
June 2006	Minister issues first supply-mix directive, which calls for renewable energy capacity of 15,700 MW by 2025, and instructs OPA to develop Integrated Power System Plan (IPSP) and maximize the contribution from renewable energy sources.
Aug. 2007	OPA submits first IPSP, designed to help achieve goals set in the June 2006 supply-mix directive, to OEB for review and approval.
Sept. 2008	Minister issues a new supply-mix directive, suspending OEB review and approval process of current IPSP and requiring OPA to submit a revised IPSP to OEB within six months.
Mar. 2009	OPA does not revise IPSP as per the September 2008 supply-mix directive, saying in a letter to OEB that it would wait before issuing revised IPSP due to "significant evolution" in the policy environment.
May 2009	*Green Energy and Green Economy Act, 2009* is passed to accelerate significant additions of renewable energy through creation of a Feed-in Tariff (FIT) program to promote renewable energy, in particular wind and solar power.
Sept. 2009	Minister issues a directive requiring OPA to develop the FIT program.
May 2010	OPA Board of Directors notes that a new IPSP is likely needed due to significant changes that have occurred since original IPSP was filed in 2007.
Nov. 2010	Ministry releases Long-Term Energy Plan (LTEP), a high-level document highlighting Ontario's energy goals and supply-mix to 2030.
Feb. 2011	Minister issues a new supply-mix directive, which calls for renewable energy capacity of 19,700 MW by 2018, and instructs OPA to develop a new IPSP based on the Ministry's LTEP.

to conclude that the OPA has only limited authority as an energy planner and that the Ministry's LTEP is Ontario's "true" plan for the future.

Renewable Energy Initiatives

In June 2006, the Minister issued the first supply-mix directive to increase the province's renewable energy capacity to 15,700 megawatts (MW) by 2025, representing an increase of about 90% over the actual installed capacity of 8,200 MW in 2006. In February 2011, the Minister issued a new supply-mix directive that further increased the renewable energy target to 19,700 MW, but stipulated that it be achieved seven years earlier than the date set in the 2006 directive. In order to achieve these aggressive new targets, both the Ministry and the OPA expeditiously implemented the actions the Minister requested in his ministerial directives. Several renewable energy initiatives were introduced, as illustrated in Figure 6.

Although the Ministry consulted with stakeholders in developing the supply-mix directives, the LTEP, and the *Green Energy and Green Economy Act*, billions of dollars were committed to renewable energy without fully evaluating the impact, the trade-offs, and the alternatives through a comprehensive business-case analysis. Specifically, the OPA, the OEB, and the IESO acknowledged that:

- no independent, objective, expert investigation had been done to examine the potential effects of renewable-energy policies on prices, job creation, and greenhouse gas emissions; and
- no thorough and professional cost/benefit analysis had been conducted to identify potentially cleaner, more economically productive, and cost-effective alternatives to renewable energy, such as energy imports and increased conservation.

Figure 6: Summary of Renewable Energy Initiatives in Ontario
Source of data: Ministry of Energy and OPA

Launch Date	Program/ Initiative	Acquisition Method	Description	Capacity as of April 1, 2011 (MW) Committed [1]	Non-committed [2]	Total Capacity
OPA-contracted Renewable Energy Sources						
June 2004 June 2005 Aug. 2008	Renewable Energy Supply (RES I, II, and III)	request for proposals (competitive)	based on confidential pricing proposals from bidders	1,570	–	1,570
Nov. 2006	Renewable Energy Standard Offer Program (RESOP)	standard offer (pre-set price)	initiated by ministerial direction to remove obstacles for small renewable projects by setting fixed contract prices and simplifying contract rules and processes	916	–	916
Dec. 2007 May 2009	Hydroelectric Energy Supply Agreement (HESA) Hydroelectric Contract Initiative (HCI)	negotiation (non-competitive)	initiated by ministerial directions that required OPA to enter into hydroelectric contracts	2,062	–	2,062
Oct. 2009	Feed-in Tariff (FIT) and microFIT	standard offer (pre-set price)	initiated by ministerial direction to replace RESOP by setting higher contract prices, with a focus on creating jobs and green economy	3,675	10,408	14,083
Jan. 2010	Korean consortium [3]	negotiation (investment arrangement)	privately negotiated contract between the Ministry and the Korean consortium	2,500	–	2,500
Uncontracted Renewable Energy Sources						
	uncontracted hydroelectric facilities [4]	n/a	managed by private developers and/or OPG	5,938	–	5,938
Total				**16,661**	**10,408**	**27,069**

1. Includes all projects that were offered contracts or have executed contracts, either under construction or in commercial operation.
2. Includes all projects that have submitted applications, either under review or waiting for review. Does not include projects that have been rejected or withdrawn.
3. Considered as committed since the Green Energy Investment Agreement was signed in January 2010.
4. Estimated by subtracting 2,062 MW (HESA and HCI) from approximately 8,000 MW (total hydroelectric capacity) because no complete listing exists of uncontracted hydroelectric facilities.

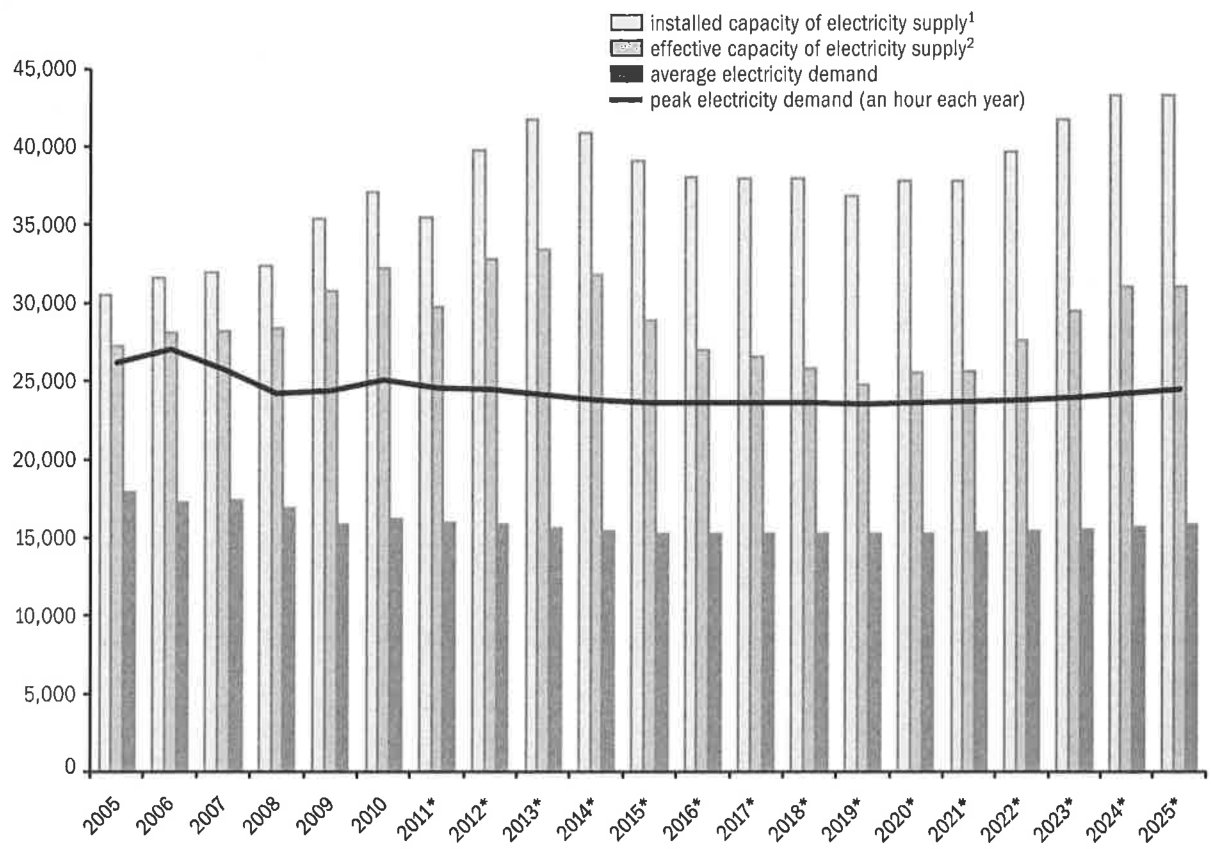
Electricity Supply and Demand in Ontario

According to the OPA, Ontario's electricity generation capacity has been much higher than demand in recent years. Electricity demand has declined since 2005 due to the economic downturn, conservation, and declines in the auto, pulp, and paper industries, while supply increased mainly because of the addition of renewable energy and gas-fired resources. The OPA noted that demand is expected to remain flat or decline due to continued conservation efforts and uncertain or slow economic recovery, while supply is expected to increase as a result of significantly more renewable energy coming on-line.

Our analysis of actual and projected data from the IESO and the OPA shows that from 2005 to 2025, installed and effective capacity will continue to exceed both average demand and peak demand. The OPA did advise us that Ontario will face significant energy uncertainty beyond 2015 as a result of the increasing supply of renewable energy, the phasing out of coal by the end of 2014, and the refurbishment of nuclear units. Figure 7 shows that Ontario will experience a temporary supply reduction from 2016 to 2020, when all coal-fired plants will be closed and some nuclear units will be taken out of service for refurbishment. The expected increase in renewable energy sources such as wind and solar will not effectively address the temporary supply reduction. According to the OPA, renewable energy sources are not always available during peak demand periods due to their intermittency and low effective capacity.

As illustrated in Figure 7, average demand is expected to drop from about 18,000 MW to 16,000 MW and peak demand from about 26,000 MW to 24,000 MW. In the same period, installed capacity (the maximum amount of electricity that can be produced by generators) is expected to rise from about 30,000 MW to 43,000 MW, and effective capacity (the portion of installed capacity that can be depended upon to produce electricity) is expected to grow from about 27,000 MW to 31,000 MW. An OEB analysis completed in April 2010 also concluded that, by 2016, electricity supply will far exceed demand. Despite these anticipated

Figure 7: Ontario's Installed and Effective Capacity, and Average and Peak Electricity Demand, 2005–2025 (MW)
Source of data: OPA and IESO



* Projected. Significant uncertainty is expected beyond 2015.

1. Installed capacity is the maximum amount of electricity that can be produced by generators.
2. Effective capacity is the portion of installed capacity that can be depended on to produce electricity.

surpluses, renewable energy generators who have contracts with the OPA will get paid even though Ontario does not need their electricity.

It is critically important that peak demand (the highest demand, generally occurring once a year for about one hour in July or August) is met reliably. Otherwise, the OPA said, the shortfall between available supply and peak demand could lead to blackouts. Although Ontario has sufficient generation capacity to meet even peak summer demand, the OPA indicated that it is required to plan for a 17% reserve margin in excess of peak demand to ensure system safety and reliability and to offset unexpected events such as changes in demand and equipment failure. The North American Electric Reliability Corporation monitors whether this requirement is being met.

We noted that the August 14, 2003, blackout in Ontario and the U.S. Northeast—the biggest ever in North American history—was not caused by any electricity shortfall in Ontario. According to a joint Canada–U.S. task force, it was actually triggered by an unexpected electricity shutdown in Ohio that led to a cascade of shutdowns.

Figure 7 shows that Ontario's effective capacity is expected to grow from about 27,000 MW to 31,000 MW between 2005 and 2025. However, we noted that Ontario rarely needs that much effective capacity to meet peak demand throughout the year. For example, the last time that demand in Ontario reached 27,000 MW was in August 2006—and then only for two hours in a single day. Since 2007, Ontario has not experienced a single day in which demand exceeded 26,000 MW, and it experienced only two days of demand greater than 25,000 MW in 2010. Even on July 21, 2011, one of the hottest days on record in the Greater Toronto Area and many other Ontario cities, demand was about 25,000 MW—well below the all-time high of 27,000 MW reached in August 2006.

Roles of the OPA and the OEB

Even after the breakup of the former Ontario Hydro, Ontario's electricity sector continued to have a system of checks and balances in place with two expert agencies playing key roles—the OPA as energy planner and the OEB as regulator. This arrangement was intended to ensure that decisions are made transparently and objectively; that consumers get reliable, affordable, and sustainable power; and that any energy plan is economically prudent and cost-effective. With the *Green Energy and Green Economy Act, 2009* (Act) giving the Minister the authority to direct certain aspects of planning and procurement of electricity supply through ministerial "directives" and "directions," the frequent exercise of this authority has created some ambiguity regarding the original mandates of the OPA and the OEB from the planning and oversight perspective.

The OPA: Planning and Procurement

The OPA is designated as Ontario's energy planner, with the authority to procure electricity supply. However, the Minister has the authority to issue "directives" (which require Cabinet approval) to the OPA regarding the supply mix. The Minister can also issue "directions" (which do not require Cabinet approval) on specific electricity-related initiatives, such as renewable energy projects. Since the creation of the OPA in December 2004, 22 of the 48 directives and directions issued to it by the Minister were partly or fully related to renewable energy.

The introduction of the Act has affected the OPA's role as Ontario's energy planner. Specifically:

- Before the Act was passed, the Minister had the authority to issue directions without Cabinet approval to the OPA to procure electricity supply. However, this direction-making authority was to expire once the OEB approved the OPA's first long-term plan, or IPSP, which would have specified the procurement processes that the OPA would use. In essence, the OPA currently has no independent authority to procure electricity supply until the OEB approves its IPSP, except pursuant to the authority given to the OPA through ministerial directions. However, as noted earlier, the first IPSP developed by the OPA has never been approved by the OEB.

- Under the Act, the Minister has the authority to issue directions related to renewable energy without Cabinet approval, and this direction-making authority will not expire after an IPSP has been approved. Under this authority, the Minister can direct certain aspects of the OPA's procurement of renewable energy, including price and whether to use competitive or non-competitive procurement.

The OPA did acknowledge that, as Ontario's energy planner, it requires some level of independence to allow it to objectively and proactively develop alternative options and ideas instead of relying exclusively on ministerial directions.

The OEB: Regulatory and Oversight

The OEB is an independent regulatory agency mandated to protect the interests of consumers with respect to the price, adequacy, reliability, and quality of electricity service. It is also responsible for promoting economic efficiency and cost-effectiveness in the generation, transmission, and distribution of electricity. Under the *Green Energy and Green Economy Act, 2009* (Act), the OEB was also given a new objective: the promotion of renewable energy, including the timely connection of renewable energy projects to transmission and distribution systems.

The ministerial direction-making authority has limited the OEB's ability to carry out its regulatory and oversight role on behalf of consumers with respect to renewable energy. The OEB advised us that other than the review of the IPSP, it has no oversight responsibility over any procurement of renewable energy, which has become an increasingly important part of Ontario's electricity-supply mix. Because the OEB has not yet approved any IPSP, it has had no oversight role with respect to renewable energy since the creation of the OPA in 2004. Had the OEB's review and approval responsibilities with respect to the OPA's first IPSP not been suspended, the impact of any ministerial directions would have been analyzed as part of the OEB's review of the IPSP. Many directions related to the procurement and pricing of renewable energy have been issued since 2008 in the absence of an approved IPSP, and the OEB has had no oversight role whatsoever. A report in 2009 by the Environmental Commissioner of Ontario raised concerns that the OEB will not be able to examine the economic prudence and cost-effectiveness of any electricity-related initiatives introduced through ministerial directions in the absence of an approved IPSP.

Although the OEB has played an oversight role in the connection of renewable energy to the grid by evaluating construction, expansion, and reinforcement projects of transmission and distribution systems, its limited involvement in reviewing the procurement and pricing of renewable energy has limited the effectiveness of its normal role in protecting the interests of consumers with respect to prices and overall cost-effectiveness in the electricity sector. For example, in December 2007 the Minister directed the OPA to enter into contracts for certain hydro projects that would have the "potential to add a new supply of clean, renewable power at an acceptable price to Ontario ratepayers." In January 2010, the OPA was advised that the estimated cost for one of these projects had increased substantially, from $1.5 billion to $2.6 billion, and there was no guarantee that the cost would not continue to rise. Given the estimated $1.1-billion cost increase, the OPA expressed concerns about whether the project would provide value for ratepayers. In February 2010, at the OPA's request, a direction was issued by the Minister, who acknowledged the cost overrun but instructed the OPA to proceed anyway. The direction noted that the Minister was satisfied that the project remained consistent with government priorities. The Ministry informed us that under the existing regulatory and legislative framework, the

OEB would not have had any oversight role with respect to this particular project.

RECOMMENDATION 2

To ensure that senior policy decision-makers are provided with sound information on which to base their decisions on renewable energy policy, the Ministry of Energy and the Ontario Power Authority should work collaboratively to conduct adequate analyses of the various renewable energy implementation alternatives so that decision-makers are able to give due consideration to cost, reliability, and sustainability.

MINISTRY RESPONSE

The Ministry will continue to build on its effective collaborative working relationship with the OPA to provide decision-makers with the best advice, giving due consideration to cost, reliability, and sustainability. In developing the Feed-in Tariff (FIT) program, the Ministry worked closely with technical experts in the electricity sector to harness the best policy and technical advice. The expert group met regularly from fall 2008 to summer 2009 to design the implementation of FIT.

The Ministry will continue to build upon its existing policy advisory practices, including seeking advice and working in co-operation with the OPA, as well as the Independent Electricity System Operator, Hydro One, and Ontario Power Generation; developing policy options and costs; and considering international practice, experience, and the perspectives brought by non-governmental organizations.

OPA RESPONSE

The OPA agrees with this recommendation and will continue to provide the Ministry with expert professional advice on the development of renewable energy as well as other types of generation. The OPA has substantially completed an update of the Integrated Power System Plan (IPSP) and plans to file the document with the Ontario Energy Board in fall 2011. Cost, reliability, and sustainability of renewable energy and other sources of generation are assessed in the updated IPSP.

PROCUREMENT OF RENEWABLE ENERGY

Procurement Methods

There have been three forms of procurement processes for renewable energy: competitive (request for proposals), non-competitive (negotiations), and standard offer (pre-set price), as illustrated in Figure 6. Initially, Ontario solicited renewable energy projects mainly through competitive requests for proposals from private developers. In recent years, renewable energy has often been procured through standard-offer and non-competitive processes in response to ministerial directions. Prices for renewable energy, especially under the FIT program, have been between two and 10 times higher than those of conventional energy sources, such as nuclear, natural gas, and coal. Generators of renewable energy will be paid guaranteed prices over the contract terms, which range from 20 years for electricity from wind, solar, and bioenergy, to 40 years for hydroelectricity.

Request for Proposals and Standard-Offer Program

The first competitive procurement initiative adopted by the government to acquire renewable energy was several requests for proposals (RFPs) inviting potential developers to bid on renewable energy projects. The OPA indicated that the competitive process usually provides the best value and is the preferred option, barring other policy priorities, to ensure that contracted prices are cost-effective and reflect current market costs. Three RFPs for Renewable Energy Supply (RES)

Figure 8: Prices of Renewable Energy Sources under Different Procurement Methods, as of April 2011 (¢/kWh)

Source of data: Ministry of Energy and OPA

	Renewable Energy Supply (RES I, II, III)[1]	Renewable Energy Standard Offer Program (RESOP)	Feed-in Tariff (FIT) and microFIT[2]	Korean Consortium[3]
	June 2004, June 2005, Aug. 2008	Nov. 2006	Oct. 2009	Jan. 2010
solar (rooftop)		42.00	53.90–80.20	
solar (ground-mounted)		42.00	44.30–64.20	44.30 + 2.60
wind (offshore)		11.00	19.00	
wind (onshore)	9.51	11.00	13.50	13.50 + 0.50
hydroelectric	7.85	11.00	12.20–13.10	
bioenergy	8.23	11.00	10.30–19.50	

1. Weighted averages of all projects.
2. Prices vary depending on project size, with smaller projects typically qualifying for higher prices.
3. Standard FIT prices apply to phase 1 and phase 2 projects, plus additional payment called Economic Development Adder (EDA) as stated in the original Green Energy Investment Agreement (GEIA). Subsequent to our audit fieldwork, the GEIA was amended in July 2011, and the EDA was reduced to 1.43¢/kWh for solar power and 0.27¢/kWh for wind power.

programs were issued: RES I in June 2004, RES II in June 2005, and RES III in August 2008.

However, the complexity and cost of developing competitive RFPs was seen as favouring larger projects at the expense of smaller ones. To remove these barriers to small projects, the Minister issued a direction in 2006 to the OPA to develop a Renewable Energy Standard Offer Program (RESOP) that would offer smaller renewable energy projects a standard pricing regime while providing for simplified regulations, including eligibility and contracting.

Prices under RESOP were about 16% to 40% higher than the competitive prices under the RFPs, as illustrated in Figure 8. The OPA indicated that RESOP would not be successful if the standard prices were not set high enough to attract investment in renewable energy projects. On the other hand, the OPA did acknowledge that the standard-offer process might have had some unintended consequences arising from an absence of the competitive tension that encourages innovative solutions, and it did ultimately result in high prices and oversubscription.

The Ministry and the OPA indicated that both RES and RESOP were successful. For example, RES I substantially increased the number of wind turbines, from 10 in 2003 to more than 200 in 2006, an increase in capacity of about 300 MW. RES II, which had been intended to attract 1,000 MW of renewable energy, had twice as many applications as expected because of developers' interest in the guaranteed high prices.

Feed-in Tariff (FIT) Program

Both RES and RESOP proved to be immediate successes, with high response rates and generation targets being met in record time. In particular, RESOP, which offered very attractive contract prices to renewable energy generators, received overwhelming responses. When RESOP was launched in November 2006, it was expected to develop 1,000 MW over 10 years. In May 2008, the OPA indicated that RESOP had exceeded all expectations and achieved more than 1,000 MW of contracted projects in a little more than a year. Although continuing the successful RESOP initiative was one option, the Minister directed the OPA in September 2009 to replace RESOP with a new standard-offer program called Feed-in Tariff (FIT), which was wider in scope, required made-in-Ontario components, and provided renewable energy generators with significantly more attractive contract prices than RESOP, as illustrated in Figure 8. These higher prices added about $4.4 billion in costs over the 20-year contract terms as compared to what would have been incurred had RESOP prices for wind and solar power been maintained. The Ministry indicated that replacing RESOP with FIT successfully expedited its renewable energy program and promoted Ontario's domestic industry.

According to the Ministry, RES and RESOP were replaced with FIT following a government policy decision to expand more rapidly the procurement of renewable energy in order to create jobs and protect the environment.

Determination of FIT Prices

The FIT program aims to encourage development of renewable energy projects by a diverse range of developers, including homeowners, farmers, small businesses, and community groups, by offering long-term, fixed prices for the electricity they generate. Launched in October 2009, FIT garnered an overwhelming response, receiving applications for a total capacity of about 14,000 MW at the end of the first quarter of 2011. The FIT program has two streams: the comprehensive FIT stream for projects over 10 kW and the simplified microFIT stream for those under 10 kW. Both offer prices that vary depending on energy sources (wind, solar, hydro, and bioenergy), project sizes (microFIT projects below 10 kW qualify for higher prices), and deployment methods (rooftop or ground-mounted solar, onshore or offshore wind), as illustrated in Figure 8.

FIT prices were based on several factors, including prior experience in Ontario and other jurisdictions, feedback from stakeholders, and cost assumptions for capital, operations and maintenance, connection, term of contract, generating capacity, and construction lead time. Ontario's FIT prices were originally designed with the intention of allowing a reasonable rate of return, defined as 11% after-tax return on equity, for developers of all types of renewable energy projects. However, we noted that:

- There was minimal documentation to support how FIT prices were calculated to achieve the targeted return on equity, because of the numerous changes to the financial model and assumptions used by the OPA.
- There has been a lack of independent oversight on the reasonableness of FIT prices. Although the OEB has historically been mandated to oversee and approve electricity prices, it has no role or legislative responsibility to review or approve FIT prices. The OPA informed us that the first review of FIT prices will be conducted in-house by OPA staff, supported by consultants as needed, during fall 2011. However, the Ministry indicated that the government has not decided whether to involve an independent third party in the review.

The OPA said it initially developed Ontario's FIT prices based on the long-established and successful FIT programs in Germany and Spain. We noted that the internal rates of return offered to the developers in these countries varied depending on project risks and ranged from just 5% to 7% in Germany to between 7% and 10% in Spain. When Ontario's FIT prices were first developed in spring 2009, they were already higher than those of Germany and Spain, which have both significantly dropped their FIT prices since then due to lower component costs arising from technological advances. However, Ontario's prices have remained unchanged, except for a drop in the rate for small ground-mounted solar projects. According to the Ministry and the OPA, it was a deliberate decision by the government to maintain price stability in order to retain investor confidence and offer very attractive prices to investors in order to encourage the start-up of a "green" industry in Ontario.

Revision of FIT Prices

By July 2010, less than a year after the launch of FIT, the OPA had received more than 16,000 applications, about 13,500 of which were for ground-mounted solar projects. According to the OPA, this overwhelming response highlighted the unexpected popularity of microFIT ground-mounted solar projects at the price of 80.2¢/kWh, the same price that was being paid for rooftop solar projects. The original FIT price of 80.2¢/kWh would provide developers of these ground-mounted solar projects with a 23% to 24% after-tax return on equity instead of the 11% intended by the OPA. Therefore, in July 2010 OPA proposed cutting the price by about 27%, from 80.2¢/kWh to 58.8¢/kWh.

The proposed price cut brought a strong response during a 30-day round of consultations. Many developers objected to the proposed 58.8¢/kWh price and demanded that the OPA grandfather the 80.2¢/kWh price for those applications already filed. In August 2010, the OPA issued a more modest price cut of about 20%—to 64.2¢/kWh instead of 58.8¢/kWh—and agreed to pay 80.2¢/kWh for all applications received by the OPA up to then, including those still awaiting approval. The OPA applied the price cut only to new applications in order to ensure price and policy stability and prevent any potential lawsuits. We also noted that the price cut had limited impact because it was not done in a timely way. Specifically:

- The OPA had proposed since February 2010 that immediate action be taken to reduce the FIT price for ground-mounted solar projects. The OPA informed us that the price cut was not announced until July 2010, five months later, because the government needed time to analyze the situation. Due to this delay, the OPA received more than 11,000 applications from February to June 2010, all of which qualified for the full price rather than the reduced one because of the decision to grandfather the price in order to maintain investor confidence.
- The number of applications for ground-mounted solar generation dropped significantly, from more than 2,000 in June 2010 to fewer than 200 in August 2010, and remained stable at that level thereafter. Because the OPA grandfathered the original price of 80.2¢/kWh for all applications already filed, the reduced price of 64.2¢/kWh applied only to new applications received after the announcement of the price cut in August 2010 (about 200 per month).

In addition, we noted that the revised price of 58.8¢/kWh originally proposed by the OPA would have provided developers with an 11% after-tax return on equity intended for all renewable energy projects. However, the revised price went from 58.8¢/kWh to 64.2¢/kWh without adequate documentation to support how the OPA arrived at the higher price. The OPA indicated that 64.2¢/kWh was a reasonable price based on justifications provided by developers and other stakeholders. We estimated that, had the OPA been successful in making the price cut to 58.8¢/kWh when it was initially recommended, electricity ratepayers would have saved about $950 million over the 20-year contract terms, while developers would still have received their 11% after-tax return.

Cross-jurisdictional Comparison of FIT Prices

Our research found that Ontario's FIT prices were generally higher than those of other jurisdictions, especially for solar projects, as illustrated in Figure 9. According to the Ministry, Ontario's prices were set higher than elsewhere to create investor confidence and more quickly attract investment capital amidst a global recession. A unique feature of Ontario's FIT program, the domestic content requirement, also led to higher prices because the cost of Ontario-made generation components is higher than that of comparable equipment made in lower-cost jurisdictions such as China.

Our research also noted that many jurisdictions have mechanisms in place to control the increase of FIT prices. For example, Germany reduces prices automatically by a certain percentage every year for new projects, while Spain regularly revises its prices

Figure 9: Comparison of FIT Prices as of April 2011 (¢/kWh in Canadian $) [1]
Prepared by the Office of the Auditor General of Ontario

	Solar (Rooftop)	Solar (Ground-mounted)	Wind (Offshore)	Wind (Onshore)	Hydroelectric	Bioenergy
Canada						
Ontario	53.90-80.20	44.30-64.20	19.00	13.50	12.20-13.10	10.30-19.50
United States						
Michigan	33.54-47.91	33.54-47.91	4.31-15.91	7.67-11.98	9.29-15.33	7.47-14.28
Vermont	28.75	28.75	13.42-19.16	13.42-19.16	–	11.50
Washington [2]	14.37-28.75	14.37-28.75	14.37	14.37	–	14.37
Wisconsin	23.96	23.96	6.32-8.82	6.32-8.82	8.82	5.83-14.85
Europe						
Denmark	–	–	10.80	10.80	–	5.40
Germany	29.24-39.80	29.24-39.80	18.01	12.62	4.81-17.55	10.68-16.00
Spain	37.31	37.31	10.14	10.14	10.80	18.09
Asia						
South Korea	63.33	63.33	9.51	9.51	6.52	5.46
Australia						
Australian Capital Territory	46.33	46.33	–	–	–	–
New South Wales	20.27	20.27	–	–	–	–
Queensland	44.60	44.60	–	–	–	–
South Australia	44.60	44.60	–	–	–	–
Victoria	60.82	60.82	–	–	–	–
Western Australia	40.55	40.55	–	–	–	–

1. Prices vary depending on project size, with smaller projects typically qualifying for higher prices. Prices were converted to Canadian currency based on the average exchange rates in April 2011.
2. These base rates are increased if the components are manufactured in Washington.

based on pre-set capacity targets. Washington State has imposed an annual maximum payment per contractor, while several American and Australian states set caps on capacity that, when reached, result in termination of a FIT program.

In Ontario, the government chose to maintain price stability until the two-year program review could be undertaken rather than incorporating any price or capacity adjustment mechanisms such as the following:

- The initial FIT prices proposed by the OPA in March 2009, prior to the passage of the *Green Energy and Green Economy Act*, included an automatic 9% drop in the contract price for every 100 MW of power contracted from ground-mounted solar projects. However, the OPA informed us that the Minister removed this adjustment, fearing that it would discourage manufacturing investments and hamper the development of renewable energy. We estimated that if this adjustment had been implemented as first proposed, the cost of the FIT program could have been reduced by about $2.6 billion over the 20-year contract terms.
- The absence of caps or limits to the number of contracts signed under Ontario's FIT program led to the current oversubscription. The OPA informed us that it designed the FIT program at a time when no long-term energy plan was in place and it was unsure about the quantities

of power the FIT program was intended to procure. The OEB indicated that ceilings, caps, or other measures must be in place to minimize the risk of higher consumer prices and less-than-optimal deployment of resources.

Both the Ministry and the OPA were aware of the high FIT prices in Ontario and of the price reduction and program-control mechanisms in other jurisdictions. However, the Ministry indicated that the government's decision was not to change prices before the first planned review of the FIT program—targeted to take place in fall 2011, two years after the program's introduction—so as to create stability and instill investor confidence.

However, we noted that in October 2010, the OPA did recommend that instead of reviewing the FIT program in fall 2011 and making incremental changes as issues arise, an "immediate program review" should be conducted to ensure that priority issues are addressed more fully and that ad hoc changes are avoided to preserve the credibility and stability of the FIT program. One of the top-priority issues identified by the OPA was the significant reduction in the cost of solar technologies—about 50% since 2009—as the technology matured and improved. The OPA specifically recommended reducing FIT prices for solar projects to reflect current market conditions and introducing a plan to signal further price reductions in future. However, the OPA informed us that no decision had been forthcoming regarding its concern about the very generous prices being offered to investors in renewable energy projects.

FIT Contract Term: Additional Contract Payment

A situation called curtailment occurs when the Independent Electricity System Operator (IESO) instructs generators to reduce all or part of their output in order to mitigate an oversupply of electricity. Compared to other renewable energy contracts such as RES and RESOP, the FIT contract has a unique feature that offers renewable energy generators an "Additional Contract Payment" to compensate them for any revenue lost as a result of curtailment instruction. Accordingly, electricity ratepayers still have to pay renewable energy developers even when those generators are not producing electricity during periods of curtailment.

The IESO has not yet curtailed renewable energy generators under the FIT program because no FIT projects have been on-line, and therefore no "Additional Contract Payment" has been triggered or included in electricity bills to date. However, the OPA and the IESO acknowledged that when more renewable energy projects under the FIT program are added to the grid, the power surplus will grow and such curtailments will be likely (see "Operational Challenge: Surplus Power" later in this report).

There has been inadequate assessment of the potential costs of curtailing renewable energy, even though there is a strong likelihood of curtailment in the future for these energy sources. For example, the OPA has performed several scenario analyses, but none included the impact of curtailing renewable energy. The OPA indicated that its plans are based on situations where supply equals demand, but not where there are surpluses and where the curtailment of renewable energy may be required.

The OPA also noted that the calculation of curtailment costs depends on a number of factors and assumptions that could be very volatile. The only analysis on curtailment we found was done by the IESO in 2009. It estimated that the substantial addition of renewable energy would result in curtailment of between 2,000 and 2,500 hours per year and that the cost of paying renewable generators for not producing electricity could range from $150 million to $225 million a year. However, these projections were based on 2008 data and we were advised that no updated projections had been done since then.

Agreement with the Korean Consortium

While the FIT program was intended to provide a channel for renewable energy investments by homeowners, farmers, small businesses, and community groups, the Ministry was also negotiating with a consortium of Korean companies under separate terms to build more renewable energy projects.

The consortium, led by two large Korean companies, approached the Ministry in June 2008 and proposed to make a major investment in Ontario's renewable energy sector. This led to ongoing talks between the Ministry and the consortium and the signing of a memorandum of understanding in December 2008. In June 2009, the Minister travelled to Korea for more discussions; six months later, the Minister, on behalf of the government, signed the $7-billion Green Energy Investment Agreement (GEIA) with the consortium. The consortium committed to build 2,000 MW of wind projects and 500 MW of solar projects in Ontario in five phases by 2016, with the equipment to be manufactured in this province.

Neither the OEB nor the OPA was consulted about the agreement. The OPA was not involved until summer 2009, when the Ministry inquired about available transmission capacity to accommodate consortium projects. On September 29, 2009, the ongoing negotiations with the consortium were publicly announced, and Cabinet was briefed on the negotiations and prospective agreement shortly thereafter. We were advised that Cabinet had subsequent briefings prior to finalization of the agreement in January 2010. In April 2010, the Ministry directed the OPA to negotiate with the consortium on the Power Purchase Agreements (PPAs), which outline contractual obligations and payment terms for each renewable energy project to be developed by the consortium. As of April 2011, details of the PPAs had not yet been finalized. Subsequent to our audit fieldwork, six PPAs were signed in August 2011.

The draft PPAs with the consortium are substantially similar to FIT contracts, but the consortium will receive two additional incentives: priority access to Ontario's transmission system; and, originally, an additional $437 million on top of the standard FIT prices, contingent on the fulfillment of the consortium commitment to build four manufacturing plants in Ontario. Subsequent to our audit fieldwork, the Ministry renegotiated the GEIA with the consortium, which had requested a one-year commercial operation date extension for phases one and two of its projects because of challenges in completing its regulatory and environmental studies. In July 2011, as a result of the date extension and other changes, the Ministry amended the GEIA to reduce the additional $437 million payment to $110 million.

According to the Ministry, the consortium agreement is neither a non-competitive procurement nor a sole-source deal. Instead, it is an "investment arrangement" with an objective of establishing a sound green energy sector in Ontario since no other company has proposed to invest in Ontario's renewable energy sector at the size and scale of the consortium and its partners. However, we noted that the normal due diligence process for an expenditure of this magnitude had not been followed. For large projects such as the consortium agreement, we expected but did not find that a comprehensive and detailed economic analysis or business case had been prepared. According to the Ministry, the decision to enter into the agreement with the consortium was made by the government. Although the Cabinet was briefed about the agreement, the Ministry indicated that there had been no formal Cabinet approval because it was not required.

RECOMMENDATION 3

To ensure that the price of renewable energy achieves the government's dual goals of cost-effectiveness and encouraging a green industry, the Ministry of Energy and the Ontario Power Authority should:

- work collaboratively to give adequate and timely consideration to the experiences of other jurisdictions and lessons learned from previous procurements in Ontario when setting and adjusting the renewable contract prices;
- work with the Independent Electricity System Operator to assess the impact of

curtailing renewables as part of its energy planning in order to identify ways to optimize the electricity market; and

- ensure that adequate due diligence is undertaken, commensurate with the size of electricity-sector investments.

MINISTRY RESPONSE

The Ministry will continue to take into consideration the experiences of other jurisdictions while ensuring that the program remains stable and sustainable. As planned, the Ministry will undertake a mandatory two-year review of the Feed-in Tariff (FIT) program (as required in the Minister's FIT direction) in conjunction with the OPA. The review will examine potential FIT price reductions, as well as FIT support programs, contract rules, and how the program is meeting the government's policy objectives. Recommendations for improving the FIT program will be made to the Minister.

The Ministry will continue to work with the Independent Electricity System Operator (IESO) during the development of new rules and tools to better integrate renewable energy sources into the market. This ongoing work includes more precise forecasting of load and intermittent generation and the ability to dispatch (turn down or off) renewable energy facilities such as wind that until now have been able to run whenever they were available to.

In order to fulfill the Ministry's key objectives of electricity reliability, sustainability, and cost-effectiveness, the Ministry agrees to continue to provide a full analysis of new investments, including through the Integrated Power System Plan, which is to be updated every three years. This will ensure that system planning continues to reflect the most up-to-date and accurate information and challenges affecting the system. The Ministry will continue to work collaboratively with the IESO, OPA, and all partners in the sector to ensure the system is capable of meeting new challenges.

OPA RESPONSE

A mandatory two-year review of the FIT program will be carried out in the near future. Experience from other jurisdictions and previous Ontario procurements will be considered as part of the review.

A reliable and sustainable electricity system will from time to time have surplus power. A key objective of the OPA, the Ministry, and the IESO is to strike the right balance between ensuring that clean, reliable electricity facilities are built and are available when required, and ensuring that ratepayer value is maximized. For the last two years, the OPA has been working with the IESO and other stakeholders on the issue of potential surplus energy and curtailment for renewable energy and other types of generation. This process has included looking at the appropriate contractual options available to curtail resources when necessary at the lowest possible cost to ratepayers. The FIT contracts do contain curtailment provisions. The OPA and IESO have been actively collaborating on aligning other renewable energy contracts to make operators more responsive to market rules.

The OPA will continue to perform due diligence with respect to the design of plans and the execution of contracts on behalf of electricity ratepayers, and will continue to provide the Ministry and other sector stakeholders with updated plans and status and outlook reports.

Co-ordination and Planning for the Procurement of Renewable Energy

The development of renewable energy initiatives involves planning and co-ordination with other parties, including the Ministry of the Environment, the Ministry of Natural Resources, federal agencies, and municipalities. We noted several instances where renewable energy initiatives led to potentially unnecessary compensation and potential lawsuits because of conflicts with environmental impact and planning decisions. Among them:

- In June 2009, the Ministry of the Environment changed the regulations governing the placement of wind turbines, affecting some onshore wind contracts already awarded by the OPA. One developer filed a claim against the OPA and, in order to avoid litigation, the OPA agreed to settle by paying the developer up to $2.4 million.
- In June 2010, the Ministry of the Environment proposed a policy relating to offshore wind turbines. In February 2011, the government decided to suspend all offshore wind projects pending completion of independent scientific research. Although this decision affected all offshore wind projects under FIT, the OPA was not informed of the decision until three days before the public announcement. Affected developers felt that they had been incurring costs in good faith even though the government was planning to suspend offshore projects, resulting in ongoing negotiations since then between the developers and the OPA.
- In October 2010, the Ministry cancelled a signed contract with a private-sector developer to build a 900 MW gas-fired project in the GTA because decreased electricity demand, the supply of more than 8,000 MW of new and cleaner power, and increased conservation efforts had made it unnecessary. The OPA has been negotiating with the developer to reach agreement over the amount of possible compensation to be paid for the cancellation of the signed contract.

RECOMMENDATION 4

To avoid unintended costs arising out of changes to regulatory requirements and changes to supply and demand situations, the Ontario Power Authority and the Ministry of Energy should work collaboratively with other ministries and agencies to ensure that they are made aware on a timely basis of anticipated policy and regulatory changes.

MINISTRY RESPONSE

The Ministry agrees that close collaboration with other ministries and agencies on proposed policy and regulatory changes is vitally important.

The government carefully considered, supported by scientific research, its policy decision to create uniform provincial standards for placement of wind turbines away from homes. The government considered this policy choice to be better than having each municipality decide the setback distances in an ad hoc way.

With respect to the offshore wind development, the Ontario government and the U.S. Department of Energy have worked collaboratively on developing wind resources in the Great Lakes. The collaboration involves joint scientific research to inform the creation of a uniform regulatory framework and policies. It is necessary to suspend further offshore projects until the scientific research is completed.

The Ministry will continue to build on its existing practice of ensuring strong and regular staff connections between relevant ministries, recognizing that it can inform agencies or other parties of new policy direction only after a duly authorized decision is made.

OPA RESPONSE

The OPA agrees with this recommendation and continues to work closely with Hydro One and the Independent Electricity System Operator to assess and manage the impacts of new generation on the electricity system.

RELIABILITY OF RENEWABLE ENERGY

Solar and wind energy are by their nature intermittent, and the growing contribution of these unpredictable resources to the energy-supply mix has increased uncertainty and created challenges for the Independent Electricity System Operator (IESO). It has to balance supply and demand to ensure that renewable energy can be efficiently integrated into the operation of Ontario's power system without compromising the reliability, stability, and efficiency of the system.

The power-generating capacity of a power plant can be measured in two ways: "capacity factor" (the ratio of the actual output of a power plant in a given period to the theoretical maximum output of the plant operating at full capacity) and "capacity contribution" (the amount of capacity available to generate power at a time of peak electricity demand, which is usually in July and August).

The power-generating capacity of current wind and solar technology is much lower than other energy sources, as illustrated in Figure 10. Wind generators operate at 28% capacity factor but have only 11% availability at peak demand due to lower wind output in the summer. Solar generators operate at just 13% to 14% capacity factor on average for the year but have 40% availability at peak demand in the summer.

We analyzed the performance of all wind farms in Ontario in 2010 based on IESO data. Although the average capacity factor of wind throughout the year was 28%, it fluctuated seasonally, from 17% in the summer to 32% in the winter. It also fluctuated daily, from 0% on summer days, when electricity demand was high, to 94% on winter days, when demand was lower.

Our analysis also indicated that wind output was out of phase with electricity demand during certain times of day. For example, during the morning hours, around 6:00 a.m., wind output usually decreased just as demand was ramping up. Throughout the day, demand remained high but wind output typically dropped to its lowest level for the day. During the evening hours, around 8:00 p.m., when demand was ramping down, wind output was rising, and it remained high overnight until early morning. This somewhat inverse relationship between daily average wind output and daily average demand was particularly pronounced in the summer and winter months.

Figure 10: Capacity Factors (Expected Output) and Capacity Contributions (Output during Peak Electricity Demand), by Energy Source (%)
Source of data: OPA and IESO

	Capacity Factor	Capacity Contribution
nuclear	84	95-100
coal	66	90-100
hydroelectric	90	71
bioenergy	75-85	65-100
natural gas	85	50-100
solar	13-14	40
wind	28	11

The OPA has recognized that the lack of correlation between electricity demand and intermittent renewable energy has created operational challenges, including power surpluses and the need for backup power generated from other energy sources. The IESO has been working through its Renewable Integration Project to mitigate these challenges by engaging stakeholders and establishing technical working groups to discuss design principles, forecasting, and future markets for renewable energy.

Operational Challenge: Surplus Power

The IESO informed us that increasing the proportion of renewable energy in the supply mix has exacerbated a challenge called surplus base-load generation (SBG), a power oversupply that occurs when the quantity of electricity from base-load generators is greater than demand for electricity. Base-load generators are designed to run at a steady output 24 hours a day to meet the constant need or minimum demand for electricity. Ontario's base-load fleet includes nuclear units, certain hydro stations, and intermittent renewable energy sources such as wind. The IESO informed us that Ontario did not have any SBG days from 2005 to 2007, but experienced four such days in 2008, 115 days in 2009, and 55 days in 2010. The jump in SBG days was attributed to several factors, including an increase in wind power and a drop in electricity demand.

Given that electricity demand is expected to remain relatively flat for at least the next few years as more renewable energy comes on-line, there will almost certainly be more SBG days in the years to come, creating operational challenges and costs that will ultimately be borne by electricity ratepayers.

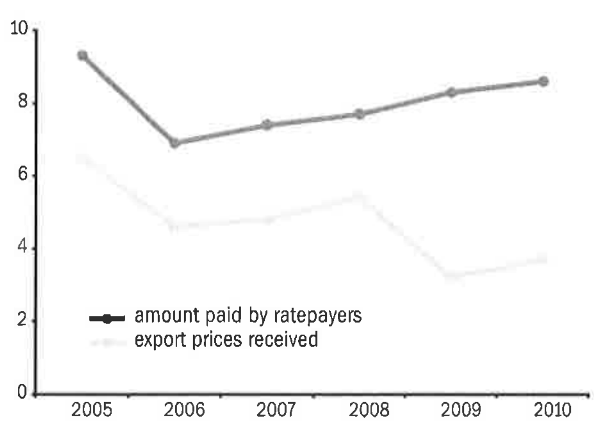
In 2008, the IESO forecast that, because most generators cannot ramp wind power up or down in response to demand, SBG hours will increase significantly over the next decade. The vast majority of new renewable energy in the next few years is expected to come from wind generators, which typically have their highest output overnight and early morning, when SBG events are more prevalent.

Since the prevalence of SBG events could threaten the reliability of the electricity system, the IESO has been taking action to ease the power surplus. However, there are technical difficulties and cost implications of these actions. Among them:

- Storing surplus power is difficult because of the seasonal nature of renewable energy and the need for unrealistically large storage capacity.
- Exporting surplus power is, according to the OPA and the IESO, a common and preferred way to mitigate power surpluses. Since 2006, Ontario has been a net exporter. The IESO indicated that although it is difficult to quantify, the increase in renewable energy has led to an increase in exports and put downward pressure on export prices. We noted that:
  - In 2010, 86% of wind power was produced on days when Ontario was already in a net export position.
  - The price Ontarians pay for electricity and the price Ontario charges its export customers—which are determined by the interaction of supply and demand in the electricity market—have in recent years been moving in opposite directions. Although export customers paid only about 3¢/kWh to 4¢/kWh for Ontario power, electricity ratepayers of Ontario paid more than 8¢/kWh for this power to be generated, as illustrated in Figure 11.
  - Based on our analysis of net exports and pricing data from the IESO, we estimated that from 2005 to the end of our audit in 2011, Ontario received $1.8 billion less for its electricity exports than what it actually cost electricity ratepayers of Ontario.
  - A study in September 2009 also noted that Denmark, which relies heavily on wind power, has been faced with a similar situation and exported large amounts of surplus power to Norway and Sweden in order to balance domestic supply with demand.
- Reducing hydro power can be done by diverting, or spilling, water from hydro generators. The IESO informed us that although the magnitude and timing of spill activities have not been well documented, Ontario

Figure 11: Electricity Charge Paid by Ratepayers in Ontario vs. Export Price Received by Ontario from Other Jurisdictions (¢/kWh)

Source of data: IESO



spilled water to reduce electricity supply on 96 days in 2009 and 10 days in 2010. Because the overall cost to produce hydro power is often lower than that of all other types of power, reducing hydro power to "make room" for wind and solar power is an expensive mitigation strategy to reduce surplus power, particularly as hydro, wind, and solar power are all considered renewable energy sources.

- Reducing nuclear power is viewed as a last resort because nuclear units are designed to run constantly and produce at maximum capacity. Ramping nuclear units up and down involves significant costs and can lead to equipment damage. If a nuclear unit is shut down, it typically takes 48 to 72 hours to restart it. With nuclear energy accounting for the majority of Ontario's electricity, such downtime is risky and costly. The IESO requested that nuclear generators shut down or reduce electricity supply 205 times in 2009 and 13 times in 2010.
- Reducing renewable power can be an efficient way to reduce supply. Wind generators can be brought on-line or off-line quickly—an ideal characteristic to address surpluses. Although this helps to address the degree to which the electricity system is overloaded, it may not result in cost savings because if the IESO instructs wind generators to shut down under a surplus-power situation, the generators still get paid under the FIT program (see the section titled "FIT Contract Term: Additional Contract Payment" earlier in this report).

Operational Challenge: Backup Power Requirement

To maintain reliability, there is always a need for backup power generation in the event that a generator must shut down unexpectedly. However, intermittent renewable energy sources such as wind and solar require fast-responding backup power and/or storage capacity to keep the supply of electricity steady when the skies are cloudy or the wind dies down. The OPA informed us that because viable large-scale energy storage is not available in Ontario, wind and solar power must be backed up by other forms of generation. This backup power is generated mainly from natural gas, because coal will be phased out by the end of 2014. The backup requirements have cost and environmental implications. For example:

- The IESO confirmed that consumers have to pay twice for intermittent renewable energy—once for the cost of constructing renewable energy generators and again for the cost of constructing backup generation facilities, which usually have to keep running at all times to be able to quickly ramp up in cases of sudden declines in sunlight levels or in wind speed. The IESO confirmed that such backups add to ongoing operational costs, although no cost analysis has been done.
- The use of gas-fired backup generation will reduce the net contribution of renewable energy to environmental protection, as indicated by studies from other jurisdictions (see the "Environmental and Health Impacts" section later in this report).

Despite these concerns, the cost and environmental impacts of such backup generation capacity were not formally analyzed to ensure that this information would be available to policy decision-makers. We noted that:

- Prior to the passage of the *Green Energy and Green Economy Act* in 2009, the Ministry did not quantify how much backup power would be required. It was not until February 2011 that the Minister issued a new supply-mix directive that asked the OPA to consider backup options, such as converting coal-fired plants to gas-fired operation, importing power from other jurisdictions, and developing storage systems. The OPA has not yet made any recommendations to the Ministry.
- The only analysis on backup power that the Ministry cited was a study done by a third

party engaged by the OPA as part of its 2007 IPSP development. The study noted that 10,000 MW of wind would require an extra 47% of non-wind sources to handle extreme drops in wind. We noted that the third party who carried out this study also operated an Ontario wind farm, raising questions about the study's objectivity. In spite of this, the OPA and the Ministry did not confirm or update this study's projections and did not determine how much backup power would be required.

According to the OPA, a new IPSP will assess the operational challenges of surplus power and backup requirements. At the time of our audit, the new IPSP was still under development.

RECOMMENDATION 5

To ensure that the stability and reliability of Ontario's electricity system is not significantly affected by the substantial increase in renewable energy generation over the next few years, the Ontario Power Authority should continue to work with the Independent Electricity System Operator to assess the operational challenges and the feasibility of adding more intermittent renewable energy into the system, and advise the government to adjust the supply mix and energy plan accordingly.

MINISTRY RESPONSE

The Ministry agrees that system reliability and stability is a key element in energy system planning. The Ministry will work collaboratively with the IESO, the OPA, and all partners in the sector to ensure that the system is capable of meeting new challenges.

Ontario, as part of the North America–wide interconnected network, is required to plan for an agreed-to level of reliability, which is developed and monitored by the North American Electric Reliability Corporation. A focus of this requirement is on the ability to reliably meet annual peak electricity demand. A system that fails to do so would create reliability risks with other interconnected systems.

We note that the increases in renewable energy generation do not increase greenhouse gas emissions. Without renewable energy generation, the gas-fired generation would have to run more frequently, resulting in higher greenhouse gas emissions.

OPA RESPONSE

The OPA agrees with the recommendation and is working with the IESO to improve the integration of renewable energy and to explore how changes to the supply mix and to contractual requirements could maximize the benefits of intermittent generators for the Ontario electricity grid and ratepayers. The OPA will continue to provide advice for the government's consideration in determining the supply mix. Ongoing planning has already contributed to greater understanding of the issues and solutions required to integrate renewable energy.

DELIVERY OF RENEWABLE ENERGY

As a result of the *Green Energy and Green Economy Act, 2009* and the FIT program, there has been enormous demand for connecting renewable energy to Ontario's electricity grid. As a result, additional transmission and distribution developments are required to facilitate the connection and delivery of renewable energy resources.

Impact of Renewable Energy on Transmission and Distribution Systems

Because the FIT program has created many new points of generation, especially in northern Ontario, significant investments are required to update and expand transmission and distribution systems to get the electricity from numerous remote and widely dispersed renewable energy generators to population centres in southern Ontario. Costs associated with these investments are paid by electricity ratepayers through increases in the delivery charges on electricity bills. Specifically:

- The Ministry's Long-Term Energy Plan identified five priority transmission projects, including three designed to accommodate renewable energy, at an estimated total cost of about $2 billion. According to the OPA, the three priority projects were intended to accommodate 1,900 MW of renewable energy at an estimated cost of between $450 million and $850 million, and also to contribute to system reliability and increase transmission capability. Hydro One indicated that the actual timing and cost of these priority projects is uncertain, because they depend on complex and often lengthy approval processes by the OEB, the Ministry of the Environment, and others. There may also be unexpected capital expenditures due to unforeseen technical problems, because new technology is required for transmission and distribution systems to support renewable energy.
- In addition to the three priority projects, the Bruce–Milton line is expected to go into service in December 2012 to deliver 1,500 MW of nuclear power and 1,700 MW of renewable energy in southern Ontario. The cost of this line was initially estimated at $635 million, but the estimate was raised in March 2011 to $755 million. Hydro One attributed the $120-million cost overrun to delays in project approvals and higher-than-anticipated labour and material costs. The overrun could increase further by the time Bruce–Milton is complete. The three other priority projects could face similar cost overruns if similar labour and material cost pressures arise.
- Hydro One files applications with the OEB to seek approval to recover the costs of transmission and distribution charges on electricity bills. Its most recent distribution rate application estimated that investments of $169 million in 2010 and $296 million in 2011 would need to be recovered from electricity ratepayers for the cost of connecting renewable energy to the distribution systems and modernizing the electricity grid.

Apart from the cost implications, the OPA was aware that only limited capacity was readily available to FIT when the program was launched. To date, Ontario's existing transmission and distribution systems have already been operating at or near capacity, but there has been a higher-than-anticipated number of FIT projects attempting to connect into the system. The capacity limitation has hindered the timely connection of renewable energy to the grid and kept the FIT program from achieving its full potential.

As of April 1, 2011, more than 3,000 FIT applications with a total capacity of about 10,400 MW could not be accommodated by the existing transmission infrastructure and were awaiting connection. Of the 10,400 MW awaiting connection, only about 2,400 MW will be accommodated by the future transmission capacity of the Bruce–Milton line and the three other priority projects. The remaining 8,000 MW will not be connected unless new lines are built or existing ones upgraded. Most of this is from FIT applications prior to June 2010, and these have been awaiting an Economic Connection Test (ECT) to determine whether it is economical to build additional transmission infrastructure. Therefore, connecting renewable energy projects to the grid is subject to both technical and economic considerations, and there is no guarantee that every project will be connected. However, the Ministry informed us that the requirement to conduct the ECT process was superseded by the Long-Term Energy Plan (LTEP) in November 2010. Therefore, as of April 2011, the OPA had not yet started the first ECT, which was to have been conducted in August 2010 and every six months thereafter on a rotating basis.

Allocation of Capacity to Korean Consortium

As noted earlier, the Ministry signed an agreement with a consortium of Korean companies that agreed to develop 2,500 MW of renewable energy resources in Ontario in five phases by 2016. Besides paying the consortium contract prices higher than the standard FIT prices if it meets its job-creation targets, another aspect of the consortium agreement is its impact on transmission capacity for other renewable energy projects. In April 2010, the Minister directed the OPA to give priority to connecting the consortium projects to the grid when assessing the availability of already-limited transmission capacity. This commitment to the consortium affected the FIT contract allocation process and the timely connection of renewable energy from other generators. Specifically:

- When the OPA evaluated the FIT applications and the availability of transmission capacity, it had to consider the locations and sizes of the consortium projects and their transmission requirements. According to the OPA, the required Economic Connection Test was delayed because the OPA could not start to assess the transmission availability until the consortium finalized the connection points for phases two and three of its projects.
- Two of the three priority transmission projects were selected partly because they were expected to meet the timing requirements of the consortium agreement. Specifically, the OPA's forecasts of the likely locations of the consortium projects indicated that 1,323 MW of the existing transmission capacity and about 1,177 MW of the future transmission capacity from the Bruce–Milton line and the other three priority projects will be made available to the consortium.

Planning of Transmission Systems

Planning and co-ordinating the timelines of transmission development is not unique to the FIT program; its open nature, however, has created uncertainties and challenges for the OPA.

The OPA can identify the capacity and connecting points of renewable energy generators as well as the future needs and locations of transmission lines only after it receives the FIT applications. The OPA noted that this has created a new challenge, which it has dubbed "chicken and egg": transmission capacity requirements cannot be known in the absence of renewable energy generators, and renewable energy generators cannot go forward in the absence of transmission capacity. In essence, new transmission projects cannot be built unless there are proven needs and firm commitments from renewable energy developers, but renewable energy developers are not willing to invest money to build generators without the presence of adequate transmission capacity because of the risk that they will not be connected to the grid. This situation will affect the timeliness of connecting renewable energy to the system because the lead time for transmission projects, about five to seven years, is much longer than the two-to-three-year lead time for renewable energy projects.

RECOMMENDATION 6

To provide investors who have submitted applications for Feed-in Tariff (FIT) projects with timely decisions on whether their projects can be connected to the grid and to ensure that adequate transmission capacity is available for approved projects, the Ontario Power Authority should work with the Ministry of Energy and Hydro One to:

- identify practical ways to deal on a timely basis with the FIT investors who have been put on hold; and
- prioritize the connection of approved FIT projects to the grid.

MINISTRY RESPONSE

The Ministry continues to work closely with the OPA, Hydro One, and local distribution companies to improve connection access for FIT and microFIT projects.

The province's Long-Term Energy Plan identifies five priority transmission projects, which have been identified in large part on the basis of their ability to allow greater renewable connection.

Recently, the Minister of Energy asked Hydro One to expedite infrastructure upgrades for up to 15 of the most severely constrained hydro transformer stations to enable the connection of more microFIT projects. The Minister also issued a directive to the OPA in August 2011 directing the OPA to provide connection options to constrained microFIT proponents.

In addition, working to prioritize and effectively connect FIT and microFIT projects will be a key focus of the two-year review of the FIT program.

OPA RESPONSE

The OPA agrees with this recommendation. The OPA has continued to work closely with the Ministry and Hydro One to improve connection access for FIT and microFIT projects. In August 2011, for example, the OPA began to implement a ministerial directive that allows microFIT proponents to select from various options to relocate constrained projects to areas where connection is possible. Prior to developing the FIT program, the Renewable Energy Supply Integration Team was established by the OPA, the Ontario Energy Board, and Hydro One to provide advice and co-ordinate and streamline activities related to the expansion of renewable energy, including connecting renewable generators to the transmission and distribution systems. The OPA will continue to work with sector partners and the Ministry on connection issues.

SOCIO-ECONOMIC, ENVIRONMENTAL, AND HEALTH IMPACTS OF RENEWABLE ENERGY

Socio-economic Impacts

The *Green Energy and Green Economy Act, 2009* (Act) was intended to support new investment and economic growth in Ontario through the creation of a strong and viable renewable energy sector.

Job Creation in Ontario

The Ministry said the Act is expected to support over 50,000 direct and indirect jobs over three years in transmission and distribution upgrades, renewable energy, and conservation. We questioned whether the job projection information was presented as transparently as possible. For example:

- A majority of the jobs will be temporary. The Ministry projected that of the 50,000 jobs, about 40,000 would be related to renewable energy. Our review of this projection suggests that 30,000, or 75%, of these jobs would be construction jobs and would last only from one to three years, while the remaining 10,000 would be long-term jobs in manufacturing, operations, maintenance, and engineering. However, the high proportion of short-term jobs was not apparent from the Ministry's public announcement.
- The 50,000-job projection included new jobs but not those jobs that would be lost as a result of promoting renewable energy. Experience in other jurisdictions suggests that jobs created in the renewable energy sector are often offset by jobs lost as a result of the impact of higher renewable energy electricity prices on business, industry, and consumers, as indicated in Figure 4. In addition, the closure of Ontario's coal-fired plants by the end of 2014 will lead to job losses, but these were not factored into the Ministry's job projections. Ontario Power Generation, which operates the coal-fired plants, informed us

that the extent of job losses depended on the Ministry's plan: about 2,300 jobs would be lost if the Ministry closed all coal-fired plants, but 600 of these could be saved if certain coal-fired plants are converted to biomass or gas-fired operation. The Ministry's Long-Term Energy Plan noted that Ontario will continue to explore the opportunities for using biomass along with natural gas in the coal-fired plants.

Experiences in Other Jurisdictions

We noted that Ontario's job projections were not consistent with the experiences of other jurisdictions that have a longer history with renewable energy. Studies from these countries highlighted issues with renewable energy that included job losses and high costs per "green" job. We questioned whether the experiences of other jurisdictions had been taken into consideration, and the Ministry confirmed that it had not estimated the potential job losses and the cost per renewable-energy-related job in Ontario. In particular, Ontario's FIT program was modelled on the FIT programs in Germany and Spain, and their job-related experiences could well be relevant to Ontario. For example, we noted the following studies conducted over the past three years:

- A 2009 study conducted in Germany noted that job projections in the renewable energy sector conveyed impressive prospects of gross job growth but omitted such offsetting impacts as jobs lost in other energy sectors and the drain on economic activity caused by higher electricity prices. The study found that the cost of creating renewable-energy-related jobs was up to US$240,000 per job per year, far exceeding average wages in other sectors.
- A 2009 study conducted in Spain found that for each job created through renewable energy programs, about two jobs were lost in other sectors of the economy.
- A 2009 study conducted in Denmark noted that a job created in the renewable sector does not amount to a new job but, rather, usually comes at the expense of a job lost in another sector. The study also found that each job created under renewable energy policies cost between US$90,000 and US$140,000 per year in public subsidies—or about 175% to 250% of the average wage paid to manufacturing workers in Denmark.
- A 2011 study conducted in the United Kingdom (after the FIT program was launched in Ontario) reported that about four jobs were lost elsewhere in the economy for every one new job in the renewable energy sector, primarily because of higher electricity prices.

In November 2010, similar concerns were raised about the Ontario job projections in a report by the Task Force on Competitiveness, Productivity and Economic Progress of the Rotman School of Management at the University of Toronto. The report noted that it is unclear what the jobs estimate includes, because it has offered neither a definition of green jobs nor a transparent calculation of how the 50,000 figure was arrived at. The report also said that it is unclear whether the 50,000 estimate is a gross or net number of jobs. The report further noted that even if 50,000 new jobs were created, the higher energy costs attributable to renewable energy might result in job losses elsewhere in the economy, particularly in industries that use large quantities of energy. Another recent study in Canada estimated that each new job to be created as a result of renewable energy programs would cost $179,000 per year.

RECOMMENDATION 7

To ensure that the provincially reported estimate of jobs created through the implementation of the renewable energy strategy is as objective and transparent as possible, the analysis should give adequate consideration to both job-creation and job-loss impacts, as well as job-related experiences of other jurisdictions that have implemented similar renewable energy initiatives.

MINISTRY RESPONSE

The Ministry's calculation of 50,000 jobs relied on standard Ontario government methodology, including standard investment and job multipliers. The figure of 50,000 jobs has always been characterized by the Ministry as a mix of long-term and short-term jobs.

Lessons learned from other jurisdictions with respect to job-creation and job-loss impacts will be taken into account where they may be comparable or instructive to Ontario, taking into account the fact that renewable-energy-program administration rules vary, as does the composition of the economies.

Environmental and Health Impacts of Renewable Energy

Ontario's 2007 Climate Change Action Plan outlined "coal phase-out, renewables, and other electricity initiatives" as measures to help Ontario achieve its greenhouse gas reduction targets, which call for reductions below 1990 levels of 6% by 2014, 15% by 2020, and 80% by 2050.

The Ministry's 2010 Long-Term Energy Plan reiterated the commitment to improve the health of Ontarians and to fight climate change by investing in renewable energy and phasing out coal, which is the largest source of greenhouse gases and accounts for a number of health and environmental problems.

Environmental Concerns

The Ministry indicated that renewable energy will help reduce greenhouse gases by displacing gas-fired generation. However, as noted earlier, any significant increase in intermittent renewable energy requires backup power by either coal- or gas-fired plants because wind and solar power have relatively low reliability and capacity. In Ontario's case, because coal-fired plants are being phased out by the end of 2014, this backup will need to come from gas-fired plants. Although gas-fired plants emit fewer greenhouse gases than coal-fired plants, they still contribute to greenhouse gas emissions. Our review of experiences in other jurisdictions showed that the original estimated reduction in greenhouse gases had not been reduced to take into account the continuing need to run fossil-fuel backup power-generating facilities. For instance:

- A 2008 study in the United Kingdom found that power swings from intermittent wind generation need to be compensated for by natural-gas generation, which has meant less of a reduction in greenhouse gases than originally expected.
- A 2009 study in Denmark noted that although the country is the world's biggest user of wind energy, it has had to keep its coal-fired plants running to maintain system stability.
- The German government also had to build new coal-fired plants and refurbish old ones to cover electricity requirements that could not be met through intermittent wind generation.

According to the Ministry, Ontario is unique in its commitment to phase out coal by the end of 2014: other jurisdictions did not make that commitment. The Ministry has not yet quantified how much backup power will be required from other energy sources to compensate for the intermittent nature of renewable energy, and accordingly has no data on the impact of gas-fired backup power plants on greenhouse gas emissions.

Health Concerns

In recent years, there have been growing public-health concerns about wind turbines, particularly with regard to the noise experienced by people living near wind farms. In May 2010, Ontario's Chief Medical Officer of Health issued a report concluding that available scientific evidence to date did not demonstrate a direct causal link between wind turbine noise and adverse health effects. However, the report was questioned by environmental groups, physicians, engineers, and other professionals, who noted that it was merely a literature review that presented no original research and did not reflect the situation in Ontario. We also noted that only a limited number of renewable generators were in operation in Ontario when the report was prepared in spring 2010, a few months after the launch of the FIT program.

One of the provisions of the Act was the establishment of an academic research chair to examine the potential effects of renewable energy generators on public health. In February 2010, an engineering professor from the University of Waterloo was appointed to this position but, as of July 2011, there had been no report on the results of any research conducted to date.

RECOMMENDATION 8

To ensure that renewable energy initiatives are effective in protecting the environment while having minimal adverse health effects on individuals, the Ministry of Energy should:

- develop adequate procedures for tracking and measuring the effectiveness of renewable energy initiatives, including the impact of backup generating facilities, in reducing greenhouse gases; and
- provide the public with the results of objective research on the potential health effects of renewable wind power.

MINISTRY RESPONSE

The Ministry agrees that the impacts of increasing the share of renewable energy in Ontario's energy mix should be quantified where possible and underpinned by objective research. For example, a 2005 independent study, *Cost Benefit Analysis: Replacing Ontario's Coal-Fired Electricity Generation,* found that if health and environmental impacts were accounted for, the total cost of coal-fired generation would be $4.4 billion per year. This study helped reaffirm the province's decision to phase out coal and to increase the share of renewable energy in Ontario's energy mix.

The Ministry will continue to rely on the Chief Medical Officer of Health to provide objective advice on the potential health impacts of renewable energy generators. The Chief Medical Officer of Health's recent review found that the scientific evidence does not demonstrate any direct causal link between wind turbine noise and adverse health effects.

The Ministry will continue to work with other ministries to promote further scientifically based information about the impacts of renewable energy. For example, the Ministry of the Environment has appointed an independent research chair for a five-year term to undertake research on the health impacts of renewable energy generators. Considerable work is well under way by the chair and his team to address the important technological, health, and safety aspects of the renewable energy technologies.

OPA RESPONSE

Ongoing plans, including the Integrated Power System Plan, identify the environmental emissions from planned resources, and they clearly identify a reduction in emissions over the time that the OPA has been involved in planning and procuring resources and through the planning horizon.