KEY GOVERNING LEGISLATION, STANDARDS AND CODES

1.0 INTRODUCTION

Hydro One Inc. is subject to direction from its shareholder (the Government of Ontario), Ontario Energy Board (OEB) decisions and government legislation and regulations. Each one of these sources has the potential to be a driver for change affecting Hydro One policies, processes and work programs, with associated cost implications. Hydro One complies with regulatory and legislative requirements and incurs costs to do so. When new legislation or regulations are passed or when OEB decisions are released, Hydro One responds by developing appropriate programs or initiatives to implement the required changes in a cost effective fashion.

As the electricity industry in Ontario continues to evolve, Hydro One also actively participates in the design of industry-related changes with the intent of ensuring that costs and impacts to the system and its customers are reasonable and manageable. The costs of implementing the outcomes of ongoing industry changes may include communicating changes to customers, modifying the impacted business processes, information systems, policies and procedures and staff training programs.

This exhibit provides a summary of the key electricity legislation and regulation, industry standards and guidelines and other relevant legislation that governs and drives Hydro One Transmission's business.

2.0 KEY ELECTRICITY LEGISLATION AND REGULATIONS

2.1 Ontario Government Legislation

The *Electricity Act*, *1998* and the *Ontario Energy Board Act*, *1998*, as amended from time to time, primarily establish the broad legislative framework for Ontario's competitive electricity market. The *Electricity Act*, *1998* implemented the fundamental principles of the restructuring of Ontario's electricity industry, enabling the implementation of open non-discriminatory access to transmission and distribution systems. The *Ontario Energy Board Act*, *1998* expanded the jurisdiction and mandate of the OEB to include regulation of the electricity and natural gas markets. Both statutes have been amended several times. Amending statutes include: *Reliable Energy and Consumer Protection Act, 2002 Electricity Pricing, Conservation and Supply Act, 2002, Ontario Energy Board Amendment Act (Electricity Pricing), 2003, Electricity Restructuring Act, 200 , Ontario Energy Board Consumer Protection and Governance Act, 2003, the Energy Conservation Responsibility Act, 2006 and the most recent Green Energy and Green Economy Act, 2009.*

Bill 100, the *Electricity Restructuring Act, 2004*, was passed by the Ontario Legislature at the end of 2004, and as stated above, amended the *Electricity Act, 1998* and the *Ontario Energy Board Act, 1998.* As result of Bill 100 the Ontario Power Authority (OPA) was created. The OPA is responsible for identifying needed generation and transmission infrastructure for the Province.

In addition, Bill 150, *the Green Energy and Green Economy Act ("GEGEA"), 2009*, received royal assent on May 14th, 2009, and amends and repeals various acts through legislation. In particular, *the Electricity Act, 1998*, was amended to facilitate renewable energy generation development and modernization of Ontario's grid. *The Electricity Act*, *1998,* contains new subsections defining smart grid and renewable energy generation and mandates transmitters and distributors to grant priority connection access to renewable energy generation facilities that meet requirements specified by regulation. The GEGEA will expedite the growth of clean, renewable sources of energy, like wind, solar, hydro, biomass and biogas, through various tools including the Feed-in Tariff program established by the OPA. The Act also includes a clause to facilitate consultation with and participation of Aboriginal Peoples in the development and implementation of renewable energy generation facilities and transmission and distribution systems. The GEGEA also amends *the Ontario Energy Board Act, 1998*, expanding the role and increasing direct involvement of the Board to promote conservation, facilitate smart grid development and ensure the timely expansion and reinforcement of transmission and distribution systems to accommodate the connection of renewable energy generation in the Province.

2.2 Environmental Legislation

Hydro One Transmission is subject to a wide range of legislation, regulation and standards related to environmental impacts. The following are the major acts that govern Hydro One Transmission's activities. Many others can apply in specific circumstances but the following are applicable to most Transmission work.

2.2.1 Federal Legislation

- *Canadian Environmental Assessment Act,* 1992, and its regulations, govern projects which fall within federal jurisdiction (e.g. on federally owned or regulated lands including Federal parks and First Nation reserves).

Fisheries Act, which regulates projects affecting fish habitat and pollution prevention

Species at Risk Act which protects endangered or threatened organisms and their habitats. It also regulates species which are not yet threatened, but whose existence or habitat is in jeopardy.

Canadian Environmental Protection Act, 1999 regulates the management of hazardous substances such as Polychlorinated Biphenyls ("PCBs"). On September 17 2008, the federal government published its final regulations under the Canadian Environmental Protection Act that govern end of use ("EoU") dates, as well as other matters related to the management of PCBs and related contaminated assets. The new regulations impose timelines for disposal of PCBs based on different types of equipment, in-use status and PCB contamination thresholds. In response to this, Hydro One initiated the PCB Retirement Program to identify and phase-out its PCB inventory to comply with the new Regulation's EoU requirements.

- *Transportation of Dangerous Goods Act*, 1992 which promotes public safety in the transportation of dangerous goods (e.g. this legislation regulates SF6 use and transportation)

2.2.2 Provincial Legislation

- *Environmental Assessment Act*, which regulates the planning and environmental approvals of projects, such as high voltage lines and transformer stations.
- *Environmental Protection Act*, which regulates air, noise and liquid discharges plus waste management. Environmental Compliance Approvals are required for new stations plus station upgrades, refurbishments and expansions.
- *Ontario Water Resources Act*, which regulates liquid discharges, sewage works and water works (approvals are now under the Environmental Protection Act).
- *Endangered Species Act,* which protects identified species at risk and their habitats. Permits are required if designated species will be affected by transmission projects.

- Niagara Escarpment Planning and Development Act which regulates transmission projects within the Niagara Escarpment.
- *Pesticides Act*, which regulates the storage, use and application of pesticides.
- *Dangerous Goods Transportation Act,* which regulates the transport of dangerous goods.
- *Ontario Heritage Act,* which in association with the Environmental Assessment Act protects historical and culturally significant heritage buildings, archeological sites and artifacts.
- *Public Lands Act,* which outlines the use, planning, management, development, and ownership of lands and forests and the control that the Ministry of Natural Resources has over such lands. Hydro One is required to obtain a permit for site alteration on Crown lands or infrastructure on or over Crown lands.
- *Forest Fires Prevention Act*, which requires clearing within 300m of forests or woodlands as a preventative measure.
- *Fish and Wildlife Conservation Act,* provides for the management, perpetuation and rehabilitation of the wildlife resources in Ontario, and to establish and maintain a sustainable wildlife population consistent with all other proper uses of provincial natural resources.
- *Public Transportation and Highway Improvement Act*, which requires approval for new structures or construction that affect existing and planned highways from the Ministry of Transportation
- *Conservation Authorities Act*, which ensures the conservation, restoration and responsible management of water, land and natural habitat and may require permits from designated Conservation Authorities.

2.2.3 Municipal Legislation

Transmission projects are designed to comply with municipal by-laws (e.g. regulating noise). Projects may be subject to development charges and require approval of site development plans (e.g. landscape plans). Depending on t he scope of projects, facilities are subject to Building Permits under the Provincial Building Code Act (but administered by municipalities).

2.3 Market Rules

- The Market Rules are administered by the Independent Electricity System Operator (IESO) under authority granted to it by the *Electricity Act, 1998*.
- The Market Rules define the IESO-Administered Markets and describe how they will operate.
- Hydro One is bound to follow the Market Rules and also "good utility practice" in its day-to-day operations.
- The IESO is responsible for ensuring compliance. In cases of disagreement, the rules set out a procedure for resolving disputes.

3.0 INDUSTRY STANDARDS AND GUIDELINES

3.1 North American Electric Reliability Corporation (NERC) Standards, Northeast Power Coordinating Council (NPCC) Regional Standards and Criteria.

Following the 2003 blackout, the Federal Energy Regulatory Commission (FERC) of the United States, named the North American Electric Reliability Corporation (NERC), as the Electric Reliability Organization (ERO). As part of its mandate, NERC sets standards for the reliable operation and planning of the bulk power system. These standards represent the minimum requirements and are mandatory for entities. In the Ontario context, the obligation on Hydro One and other Market Participants to meet these standards is enshrined in the IESO's Market Rules. For further discussion on NERC and NPCC see Exhibit A, Tab 4, Schedule 1.

3.1.1 Compliance Auditing of Reliability Standards for Ontario Market Participants

NERC has delegated the compliance and enforcement of these standards to eight regional entities. Ontario fits within the footprint of the Northeast Power Coordinating Council (NPCC). These regional entities, including NPCC, began to enforce compliance of these standards in 2008 using monitoring methods such as self-certification, spot checks, investigations and audits.

3.1.2 Definition of the Bulk Electric System

On November 18, 2010 FERC issued a final rule (Order 743) requiring NERC to revise its definition of the term "bulk electric system" (BES). Hydro One has been represented on the NERC team to address the issues of non-jurisdictional entities and to consult with other major Canadian entities and stakeholders. A proposed BES definition and changes to the NERC Rules of Procedure (RP) for an exception from BES definition has been approved by the NERC Board of Trustees and filed with FERC on January 25, 2012. FERC will assess and potentially approve the filing or remand with further instructions.

The proposed definition applied in Ontario will result in significantly more transmission facilities that will have to comply with NERC reliability standards. It is estimated that the cost impact of the BES definition change could be in the order of several hundred millions of Capital plus an annual O&M expense of between $15M and $30M. These estimates will change with future revisions to the BES definition and/or changes to NERC Standards. The proposed NERC RP for an exception from the BES definition acknowledges that non-jurisdictional entities can develop and implement their own exception process. Hydro One is working with the IESO and the OPA to develop such a process that will be able to exempt facilities that are not necessary for the operation of the interconnected BES or do not have an adverse impact on the interconnected system.

3.2 OTHER INDUSTRY STANDARDS

Hydro One also complies with other relevant national and international standards such as the Canadian Standards Association (CSA), the IEEE and the International Electrotechnical Commission (IEC) for the design of its transmission system and equipment.

4.0 OTHER RELEVANT LEGISLATION AND STANDARDS

4.1 Standards and Safety

Safety is of utmost importance in Hydro One Transmission's work activities. Hydro One Transmission is committed to complying with safety standards and regulations. Some major Safety Acts that are more relevant to Hydro One Transmission are:

- *Technical Standards and Safety Act, 2000,* which regulates boiler and pressure vessels, among other items.
- *Occupational Health and Safety Act,* which requires Hydro One Transmission to comply with industrial design and construction safety regulations, including filing notices of any projects before construction commences
- Hydro One Transmission must also comply with the health regulations of the Ministry of Health under the *Public Health Act.*

4.2 Rights of Aboriginal Peoples of Canada - Canadian *Constitution Act, 1982*

Section 35 of Canada's *Constitution Act, 1982,* recognizes existing aboriginal and treaty rights of Canada's aboriginal peoples. The *Green Energy Act, 2009*, states that the *Green Energy Act, 2009*, shall be interpreted in a manner that is consistent with s. 35 of the *Constitution Act, 1982*, and with the duty to consult aboriginal peoples. As stated in s. 2.1 above, the *Electricity Act, 1998*, now includes clauses authorizing the Minister of Energy and Infrastructure to direct the OPA to facilitate consultation with and participation of aboriginal peoples in the development and implementation of renewable energy generation facilities and transmission and distribution systems. Consultation with aboriginal peoples is often a requirement where new Hydro One Transmission projects could potentially affect aboriginal interests.

5.0 THE TRANSMISSION SYSTEM CODE

Hydro One is bound by the terms of its Transmission licence to adhere to the requirements of the Transmission System Code, administered by the OEB. The Code addresses standards for the operation, maintenance, management and expansion of transmission systems and requires Hydro One to operate and maintain its system in accordance with "good utility practice." The Transmission System Code sets out the obligations of electricity transmitters with respect to their customers, including the rules governing the economic evaluation of transmission system connections and expansions and also the minimum standards for facilities connected to a transmission system. It also includes a Connection Agreement which covers the technical and commercial responsibilities of both transmitters and their customers.

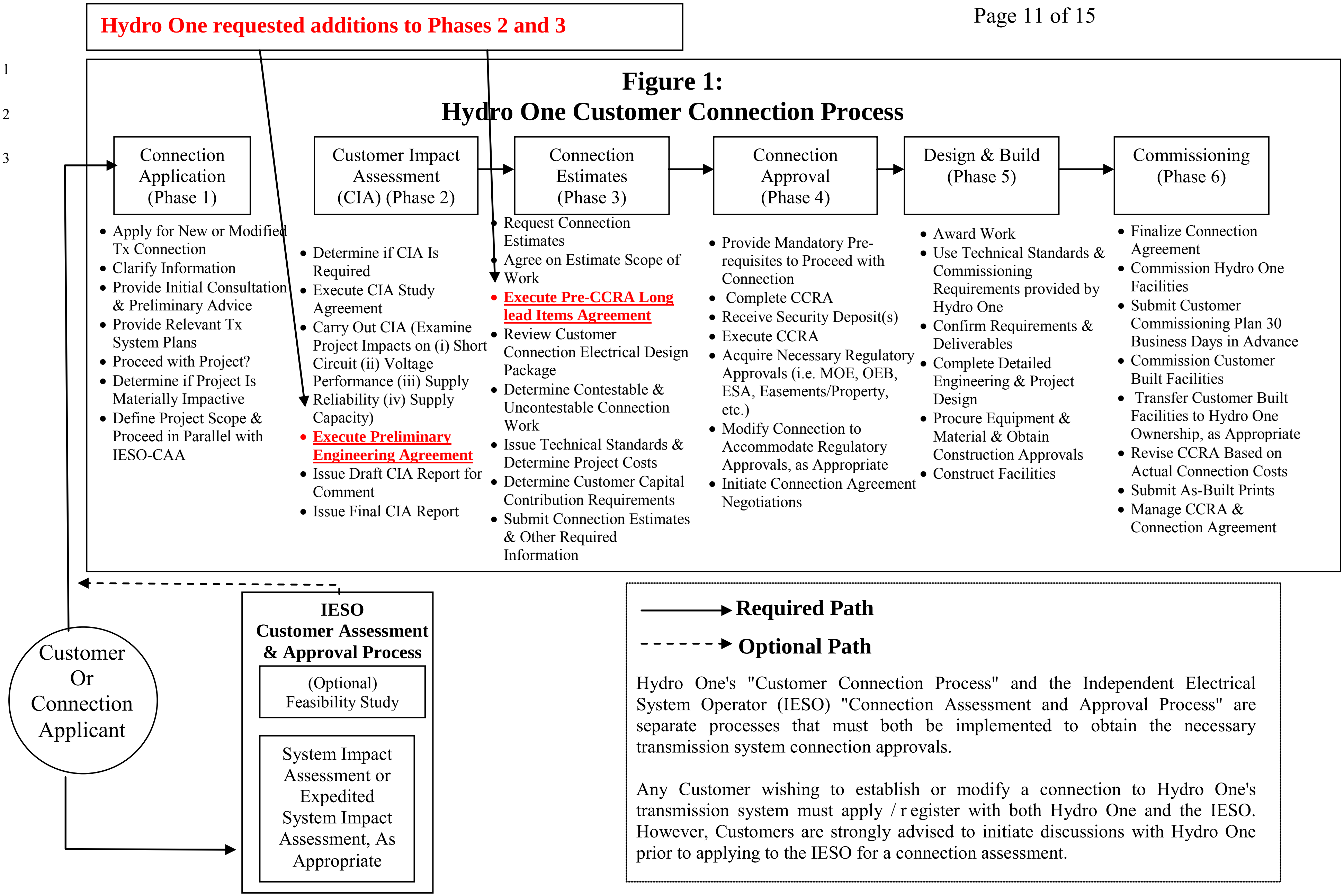
5.1 Proposed Changes to Hydro One's Transmission Connection Procedures

As required by the Transmission System Code, Hydro One submitted its Transmission Connection Procedures to the Board and received approval in EB-2006-0189.

Since the Board approved Hydro One's Transmission Connection Procedures in 2007, the Ontario Government's Green Energy and Green Economy Act and the Ontario Power Authority's FIT program contracts have resulted in a s ignificant number of new generation projects requesting to connect to the transmission system across Ontario. Hydro One's Connection Procedures did not contemplate the number of new generation projects being planned nor the level of transmission reinforcements required to facilitate these connections. As a result, Hydro One is requesting Board approval of several modifications to the Connection Procedures to reflect current electricity marketplace conditions.

<u>Specifically, Hydro One is requesting the Board approve the following changes:</u>

A) To Figure 1: Hydro One Customer Connection Process
The addition of two new steps, execution of Preliminary Engineering Agreement ("PEA") within Phase 2 and execution of Pre-CCRA Letter Agreement for the Purchase of Long lead Items ("Pre-CCRA- Long Lead ") within Phase 3 of Hydro One's Board approved Connection Process. Both steps have been highlighted within Figure 1: Hydro One Customer Connection Process that appears on page 3 of the Connection Procedures approved in EB-2006-0189.


Hydro One requested additions to Phases 2 and 3
Figure 1:
Hydro One Customer Connection Process
Connection Application (Phase 1)
• Apply for New or Modified Tx Connection
• Clarify Information
• Provide Initial Consultation & Preliminary Advice
• Provide Relevant Tx System Plans
• Proceed with Project?
• Determine if Project Is Materially Impactive
• Define Project Scope & Proceed in Parallel with IESO-CAA
Customer Impact Assessment (CIA) (Phase 2)
• Determine if CIA Is Required
• Execute CIA Study Agreement
• Carry Out CIA (Examine Project Impacts on (i) Short Circuit (ii) Voltage Performance (iii) Supply Reliability (iv) Supply Capacity)
• Execute Preliminary Engineering Agreement
• Issue Draft CIA Report for Comment
• Issue Final CIA Report
Connection Estimates (Phase 3)
• Request Connection Estimates
• Agree on Estimate Scope of Work
• Execute Pre-CCRA Long lead Items Agreement
• Review Customer Connection Electrical Design Package
• Determine Contestable & Uncontestable Connection Work
• Issue Technical Standards & Determine Project Costs
• Determine Customer Capital Contribution Requirements
• Submit Connection Estimates & Other Required Information
Connection Approval (Phase 4)
• Provide Mandatory Pre-requisites to Proceed with Connection
• Complete CCRA
• Receive Security Deposit(s)
• Execute CCRA
• Acquire Necessary Regulatory Approvals (i.e. MOE, OEB, ESA, Easements/Property, etc.)
• Modify Connection to Accommodate Regulatory Approvals, as Appropriate
• Initiate Connection Agreement Negotiations
Design & Build (Phase 5)
• Award Work
• Use Technical Standards & Commissioning Requirements provided by Hydro One
• Confirm Requirements & Deliverables
• Complete Detailed Engineering & Project Design
• Procure Equipment & Material & Obtain Construction Approvals
• Construct Facilities
Commissioning (Phase 6)
• Finalize Connection Agreement
• Commission Hydro One Facilities
• Submit Customer Commissioning Plan 30 Business Days in Advance
• Commission Customer Built Facilities
• Transfer Customer Built Facilities to Hydro One Ownership, as Appropriate
• Revise CCRA Based on Actual Connection Costs
• Submit As-Built Prints
• Manage CCRA & Connection Agreement
Customer Or Connection Applicant
IESO Customer Assessment & Approval Process
(Optional) Feasibility Study
System Impact Assessment or Expedited System Impact Assessment, As Appropriate
Required Path
Optional Path
Hydro One's "Customer Connection Process" and the Independent Electrical System Operator (IESO) "Connection Assessment and Approval Process" are separate processes that must both be implemented to obtain the necessary transmission system connection approvals.
Any Customer wishing to establish or modify a connection to Hydro One's transmission system must apply / r egister with both Hydro One and the IESO. However, Customers are strongly advised to initiate discussions with Hydro One prior to applying to the IESO for a connection assessment.

B) To section 2.3 of Security Deposit Procedure

To provide clarity in respect to security deposit requirements where more than one customer/generation proponent is connecting at approximately the same time Hydro One requests the following paragraph be added in section 2.3 under the heading "Additional Security Deposit".

> "In a case where more than one customer triggers the need for a transmission upgrade, a customer may be required to provide an additional security deposit or extend the term of a security deposit after Hydro One has executed Agreements and collected initial security deposits. This would occur when a customer's proportional share of the upgrade cost increases because of other customer projects being delayed or cancelled that would have been contributors to the upgrade as originally planned and calculated in the Agreements".

C) To section 2.4 Customer Impact Assessment Procedure

Since the current Connection Procedures were approved by the Board in 2007, the Ontario Government issued OReg 326/09 which requires the Independent Electricity System Operator ("IESO") and Hydro One to complete a System Impact Assessment ('SIA") and Customer Impact Assessment ("CIA") respectively within 150 days after the service guarantee clock is started by the IESO. Therefore, Hydro One is requesting the Board approve the addition of the following paragraph immediately following the first paragraph under the heading "Requirement for A CIA Study" within section 2.4 of the Connection Procedures.

> "For renewable energy projects awarded by the OPA in accordance with OReg 326/09, the joint SIA/CIA phase of the process shall be completed within 150 days after the Independent Electricity System Operator

("IESO") starts the service guarantee clock for the performance of the SIA/CIA studies".

D) To section 4.0 Schedule of Fees & Charges

Hydro One requests the Board to approve the Fees for the two new agreements that are being added in Phases 2 and 3 of the Connection Process in A) above; the Preliminary Engineering Agreement ("PEA") and the Pre-CCRA Letter Agreement for Purchase of Long lead Items. The cost for both of these Agreements is based on Actual Costs. The agreements would be added to the current Schedule of Fees & Charges as shown below as the two new underlined Agreements.

Table 1
Hydro One Customer Connections Process
Schedule of Charges & Fees
For Transmission Customers

ACTIVITY	COST
Inspection, Testing and Commissioning Activities	Actual Costs
Engineering and Design Activities	Actual Costs

STUDIES	COST PER STUDY
Standard Customer Impact Assessment (CIA) Study	$15,000
Complex CIA Study	Actual Costs
Detailed Connection Estimate Studies	Actual Costs
Feasibility Studies	Actual Costs
Preliminary Engineering Agreement (PEA)	***Actual Costs***
Pre-CCRA Letter Agreement for Purchase of Long Lead Items	***Actual Costs***

E) To section 5.0 Timelines for Connection Process

Connection and integration of renewable generation to the transmission system is relatively new to Hydro One and often requires unique engineering and never done before connection designs which in turn requires significantly more time than traditional load or generator connections to connect. Hydro One requests the Board approve the following typical connection process timelines for new load and generation customers. To this end Hydro One would like to replace the existing table entitled "Hydro One Customer Connection Process Timelines" with the following table:

Table 2
Hydro One Customer Connection Process Timelines (Current)

	Timeline "On Best Efforts Basis"	**Trigger**
Phase 1 - Connection Application	14 Calendar Days	From Date of Submitted Customer Application Form
Phase 2 – Customer Impact Assessment (CIA)	90 Calendar Days	From Date of IESO Issuing Draft System Impact Assessment (SIA)
Phase 3 – Connection Estimates	45 Calendar Days	From Date Electrical Design Package Received & Payment Received - As Appropriate.
Phase 4 – Connection Approval	30 Calendar Days – or longer if EA & Other Regulatory Approvals are Required	From Date of Issuing Draft Connection Cost Recovery Agreement (CCRA) for Customer Signature
Phase 5 – Design & Build	Project Specific (Up to 2 years) - To Be Negotiated With Customer as per CCRA	As per CCRA
Phase 6 - Commissioning	**45 Calendar Days**	From Date of Signed Connection Agreement (Customer must submit a commissioning plan to Hydro One at least 30 business days prior to proposed commissioning tests)

Table 3
Hydro One Typical Customer Connection Process Timelines (Proposed)

	Typical Timelines	Trigger
Phase 1 – Connection Application	1-2 months	From initial contact to date of completed Customer Joint (SIA/CIA) Application Form
Phase 2 – Customer Impact Assessment (CIA)*	3-5 months	From date of IESO Issuing Draft System Impact Assessment (SIA)
Phase 3 – Connection Estimates	4-8 months	From Date Estimate Agreement Executed to Date Estimate completed
Phase 4 – Connection Approval	1 month or longer if regulatory approvals, expropriation and permits are required	From Date of Connection Cost Recovery Agreement Executed
Phase 5 – Design & Build	Project Specific (normally 12 to 24 months) To be negotiated with customers as per CCRA terms.	Execution of CCRA
Phase 6 – Commissioning	1-2 months	At least 30 days before Date of Signed Connection Agreement; Customer must submit a commissioning plan to Hydro One for proposed commissioning tests

The timelines provided above represent typical connection timelines to the transmission system which can take anywhere from 18 months to more than 3 years to complete. Project specific timelines for each phase can be influenced by numerous factors such as connection voltage and geographical location.

Connecting to the transmission system is a complex, multi-phase engineering process that can take a number of years to complete and thus can also be impacted by changes to regulatory and government policies during implementation.

SUMMARY OF HYDRO ONE TRANSMISSION POLICIES

1.0 INTRODUCTION

Hydro One Transmission has a number of policies that apply to transmission customers, assets and systems, and financial management. Policies are subject to periodic review and/or revision as a result of statutory or regulatory change, or as the business evolves. The objectives of these policies are to ensure:

- compliance with statutory and regulatory obligations;
- fair and consistent commercial relationships with customers;
- efficient management of assets;
- consistent criteria for decision making;
- compliance with generally-accepted accounting principles;
- consistency for transaction processing; and
- accurate and timely recording and reporting of financial information.

2.0 CHANGES TO POLICIES

In keeping with good corporate governance, Hydro One Transmission has reviewed and revised a number of policies and procedures since the Board's review of Transmission Revenue Requirements and Rates for 2011 and 2012 (EB-2010-0002). The most significant change is listed in the following section.

2.1 Adoption of U.S. Generally Accepted Accouting Principles (US GAAP)

Consistent with the exemptive relief provided by the Ontario Securities Commission allowing Hydro One Inc. to make its quarterly consolidated securities filings under US

GAAP for the three-year period ending December 31, 2014, Hydro One Networks adopted US GAAP for external financial reporting effective January 1, 2012. In its EB-2011-0268 decision dated November 23, 2011, the Board approved Networks' request to adopt US GAAP as its approved basis for regulatory accounting and reporting for its Transmission Business.

Given the similarity between US GAAP and legacy Canadian GAAP, as defined in Part V of the Handbook of the Canadian Institute of Chartered Accountants, no accounting policy changes have occurred through the adoption of US GAAP in 2012 that affect either the 2012 or 2013 rate base or revenue requirement compared to Canadian GAAP. In its application to adopt US GAAP for rate-setting purposes (EB-2011-0268), Networks requested that a symmetrical variance account be established to record the 2012 impact of differences between CGAAP and USGAAP be established. This was approved by the Board. As at the time of filing, no differential impacts had been recorded in this account.

No other financial accounting policy changes have been made that impact the 2013 rate base or revenue requirement.

PLANNING PROCESS

1.0 INTRODUCTION

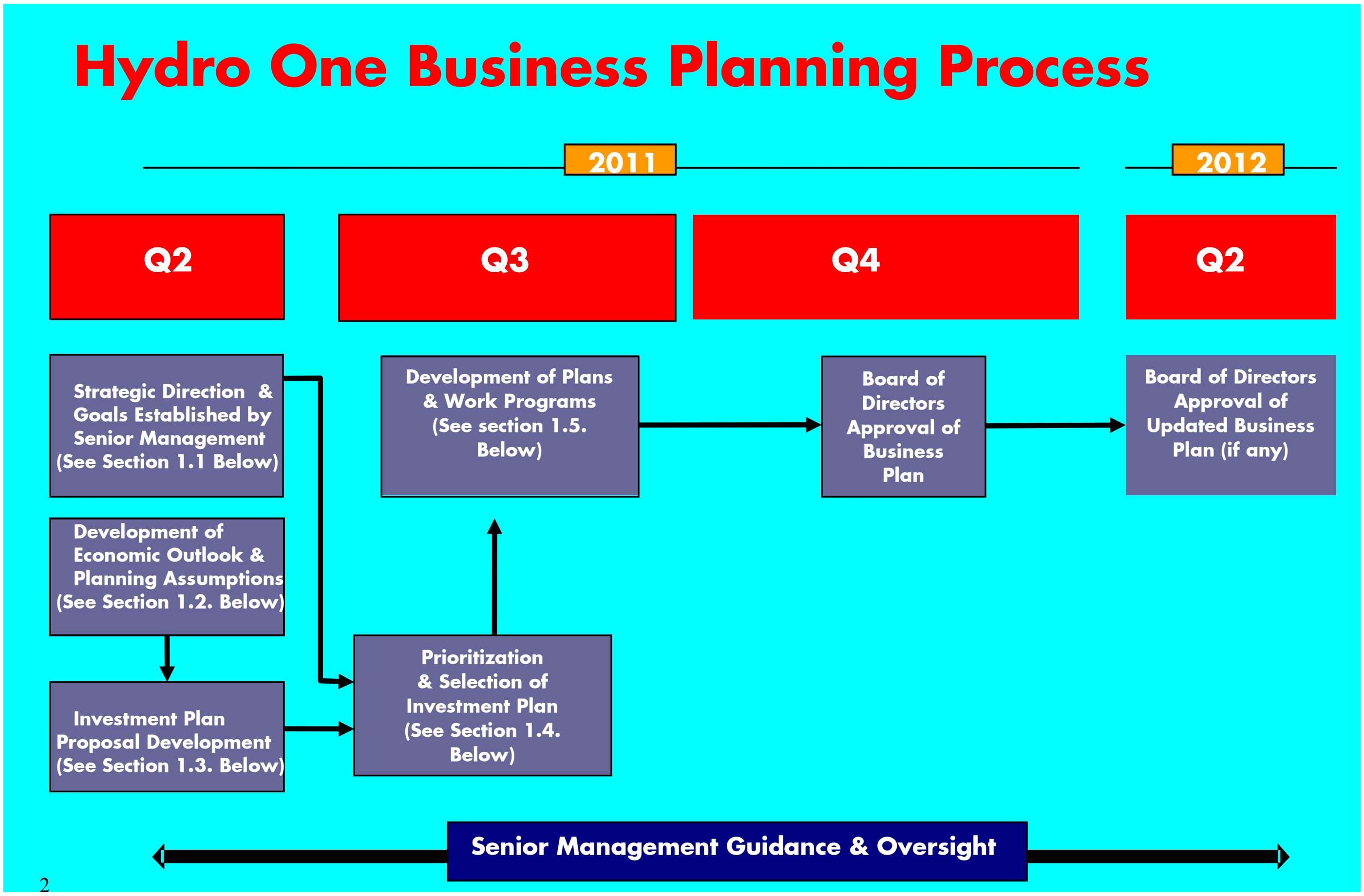
Business planning is performed annually and focuses on the development of a five year plan which comprises a detailed plan for the first three years in the planning cycle and a less detailed outlook for the remaining two-year period. The planning cycle in 2011 pertained to the 2012-2016 period. The results as they apply to 2013 and 2014 (the test years) form the basis for the rate submission.

The typical annual business planning process consists of five stages:

1. Strategic direction and goals established;
2. Development of economic outlook and forecast assumptions;
3. Investment proposals developed;
4. Prioritization and selection of investment plan; and
5. Development of business plans and work programs;

Figure 1 provides an overview of the planning process:

Figure 1



The key dates applicable to the 2012-2016 planning cycle include:

Date	Action
April 2011	Strategic direction and goals established by Senior Management
May 2011	Business plan instructions issued
June 2011	Investment proposals developed
July 2011	Investment plan prioritized and selected
November 2011	Hydro One Inc. Board approval of business plan
April 2012	Hydro One Inc. Board approval of updated business plan

1.1 Strategic Direction and Goals Established by Senior Management

Hydro One Transmission's strategic direction and goals are reviewed and established by the CEO and other members of the senior management team. T he strategic goals are included in the business planning instructions for reference by planners as the business plan is being developed. Hydro One's corporate vision and strategic objectives are shown in Exhibit A, Tab 4, Schedule 1.

1.2 Development of Economic Outlook and Planning Assumptions

To facilitate the preparation of the business plan, an economic outlook and customer load forecast is developed and included with the planning instructions issued. This includes forecasts of key economic statistics, interest rates, labour escalation rates, income tax rates, and cost rates for benefits. The assumptions used for the 2012 business plan are attached to this exhibit as Appendix A. A detailed discussion of these variables is filed at Exhibit A, Tab 15, Schedule 1. Please note, Cost of Capital assumptions have subsequently been updated to better reflect current market contions. These can be found in Exhibit B1, Tab 1, Schedule 1.

1.3 Investment Plan Proposal Development

As part of the investment plan development phase, customers' needs (including anticipated load growth and generator connections), criticality of asset, operational performance, and asset age and asset condition are examined in the context of risk to identify areas requiring investments resulting in risk mitigation. Exhibit A, Tab 15, Schedule 3 provides a detailed discussion of the Company's investment planning process.

1.4 Prioritization and Selection of Investment Plan

The individual investments resulting from the planning process go through a risk-based prioritization process. The outcome of the risk-based prioritization process is a list of investments that is consistent with Hydro One Transmission's strategic goals and takes into account levels of investment and associated risk mitigation against such goals as financial, operational, environmental, safety, regulatory and legal considerations. A final investment plan is then endorsed and confirmed by the Hydro One senior management team. The investment plan prepared during 2011 provided the basis for the 2013 and 2014 plans. Please see Exhibit A, Tab 15, Schedule 4 for a more detailed description of the work prioritization and selection process.

1.5 Development of Plans and Work Programs

During the planning process, plans and work programs are further refined consistent with the economic and forecast assumptions. As part of this process, sufficient detail is provided to facilitate preparation of the 2013 and 2014 Rate Application. At the end of this process, the Hydro One senior management team provides direction as necessary in order to balance the various factors under consideration including customer service levels, rate impacts and economic considerations.

The operations, maintenance and administration ("OM&A") budget and the capital budget that result from this planning process are discussed at Exhibit C1, Tab 3 and Exhibit D1, Tab 3 respectively. Refer to Exhibit A, Tab 15, Schedule 5 for an overview of the project approval process for Hydro One Transmission.

The financial plan is prepared, incorporating OM&A and capital work program levels consistent with the investment plan, as well as forecasts of revenue, cost of power, depreciation and amortization expense, financing charges, income tax, and working capital.

The resulting plan and underlying assumptions are finalized and presented for approval to the Hydro One Inc. Board of Directors. The 2012-2014 Budget and Outlook was approved by the Board of Directors at its November 2011 meeting.

1.6 Planned Productivity Enhancements

As Part of Cornerstone Phase 3, Hydro One is currently implementing the Business Planning and Consolidation (BPC) module of SAP. This project will leverage the existing Business Warehouse framework to deliver an integrated financial model to support Business Planning and Budgeting and Forecasting. This will enable the following:

- A rolling 10 year Business Plan leveraging integrated SAP master and transactional data.
- A robust, transparent, streamlined, repeatable Business Planning process.
- A multi-year budgeting, forecasting and trending toolset for projects and programs retracted back to Enterprise Central Component.
- Cost centre planning, standard costing/rate models for labour and TWE.

See Exhibit D1, Tab 4, Schedule 3 for additional information on the Cornerstone Project.

APPENDIX A

2012 BUSINESS PLAN ASSUMPTIONS

1.0 ECONOMICS

	2012	2013	2014	2015	2016
CPI – Ontario (%)	2.1	2.1	2.0	2.0	2.0
Tx cost escalation for Construction (%)	3.8	2.7	2.2	3.0	2.6
Tx cost escalation for Operations & Maintenance (%)	2.7	2.5	2.1	2.9	1.9

CPI-Ontario forecasts were based on the IHS Global Insight April 2011 forecast.

2.0 INTEREST RATES

	2012	2013	2014	2015	2016
HO1 5-Year Bond Rate (%)	2.90	3.45	4.45	4.65	4.75
HO1 10-Year Bond Rate (%)	3.94	4.49	5.49	5.69	5.79
HO1 30-Year Bond Rate (%)	4.96	5.51	6.51	6.71	6.81
90-Day Banker's Acceptance Rate (%)	1.50	3.74	4.62	4.87	4.87

H1 bond rates for 2012- 2016 were prepared based on the October 2011 edition of Consensus Forecasts. Hydro One credit spreads are based on an average of indicative new issue spreads for October 2011 from the dealers in Hydro One's medium term note syndicate.

The 90-Day Banker's Acceptance Rate for 2012-2016 was prepared based upon the June 2011 Global Insight Forecast.

Interest Capitalized – US GAAP	2012	2013	2014	2015	2016
Interest Capitalized Tx (%)	4.18	4.73	5.73	5.93	6.03

The interest capitalized rates are the summation of 10-year Government of Canada Forecast and the October 2011 assumed DEX Mid Term spread. The 10-year Government of Canada Forecast was prepared based on the October 2011 edition of Consensus Forecasts.

3.0 LABOUR ESCALATION

Note that the allowed financial impact of labour escalation is capped at 3.0% annually (this excludes the impact of changes in payroll burden costs) for each staff category (i.e. Society, PWU, MCP). If your subsidiary's labour escalation exceeds 3.0% in any staff category in any given year then reduction in other costs and/or staff will be required to offset the incremental increases.

Specific details on annual labour escalation are provided below.

(a) Society Staff

A 2.5% economic increase effective April 1, 2012 is planned. The Society Collective Agreement is up for renegotiations for 2013. It is assumed economic increases will remain at 3.0% for the negotiated term for the 2012-2016 business plan term.

COLA provisions for 2010 were not triggered and there are COLA provisions in 2011 and 2012. At this time, the COLA provisions have not been triggered for the fourth year of the Society Collective agreement (April 1, 2011-March 31, 2012). If this COLA provision is triggered, it will mean that Salary Schedules will be adjusted to reflect the change above the trigger effective at the end of the applicable year.

Automatic annual salary progressions will occur (in addition to the economic increases above) until staff reaches the terminal step.

For staff hired prior to October 1, 2007, annual progressions will occur on October 1 of subsequent years or on date of appointment to a new Society represented position. For staff hired after October 1, 2007, annual progressions will occur on the anniversary of their hire date.

(b) PWU Staff

The Power Worker's Union Collective Agreement has reached a tentative agreement that dictates an economic increase of 3.0% for 2011 and 2012. Economic increases are assumed to remain at 3.0% for the negotiated 2012-2016 business plan term.

PWU (excluding Hiring Hall) Headcount as of March 31, 2011 is 3,839.

Step Progressions – past experience (i.e.2010) indicates that 19.24% of PWU staff is eligible to receive automated progressions annually. Progressions will result in an average salary increase of 3.55%.

(c) MCP Staff

As of March 31, 2011 there is 710 MCP staff. It is anticipated that a 3.0% annual increase per year in base pay for the 2012 year and 3.0% annual increase for the 2013-2016 period.

(d) Incentive Plan Payouts

All incentive plans have been discontinued, with exception of the MCP Short Term Incentive Plan. Payout under this plan is assumed to be 20% in all years.

4.0 INCOME & CAPITAL TAX RATES

	2012	2013	2014	2015	2016
Federal Tax Rate	15.00%	15.00%	15.00%	15.00%	15.00%
Provincial Rate	11.25%	10.50%	10.00%	10.00%	10.00%
Total Statutory Tax Rate	26.25%	25.50%	25.00%	25.00%	25.00%
Capital Tax Rate	NIL	NIL	NIL	NIL	NIL

5.0 BENEFIT COSTS RATES (PAYROLL BURDEN)

Company	Category	2012	2013	2014	2015	2016
Networks	Non-Regular Staff					
	% of total earnings*	5.76%	5.80%	5.85%	5.85%	5.85%
	Regular Staff					
	% of total earnings*	5.76%	5.80%	5.85%	5.85%	5.85%
	% of base pensionable earnings**	28.16%	28.18%	28.06%	27.66%	27.66%
	Pension					
	% of base pensionable earnings	29.51%	29.08%	28.78%	28.39%	28.39%

*CPP, Emp, Insurance, Emp. Health Tax, Workers' Compensation Schedule 1 Premiums
**Health, Dental, Life Insurance, Maternity, Retirement Bonus, Post-Retirement Health, dental, Life Insurance, Ontario Health Premiums (OHP), OPRB - Inergi
- Base Pensionable Earnings includes pensionable bonus.
- Total Earnings includes base pay, bonus, overtime, taxable benefits and taxable allowances.

TRANSMISSION 10 YEAR OUTLOOK

FORWARD LOOKING INFORMATION DISCLAIMER

For 10-Year Transmission Asset Management Outlook 2012-2021

This 10-Year Transmission Asset Management Outlook 2012-2021 contains, forward-looking statements that are based on current expectations, estimates, forecasts and projections about the business of Hydro One Networks Inc. and the industry in which Hydro One Networks Inc. operates and includes beliefs and assumptions made by the management of our company. Such statements include, but are not limited to, statements about increased maintenance or replacement of transmission system assets; statements about a need for new or upgraded transmission infrastructure; statements about the phasing-out of coal-fired generation; statements about the possibility of retiring older nuclear generation units and the replacement thereof with new nuclear generating stations; statements about a greater emphasis on renewable generation resources; statements about the growing contribution of conservation and demand management; statements about the replacement of centralized generation facilities by distributed generation; statements about changing electricity generation and demand profiles; statements about the need for new transmission infrastructure, operating paradigms and technologies; statements about reductions in the energy sector's carbon footprint; statements about leveraging opportunities through innovation and leadership; statements about projected transmission requirements; statements about future work scope; statements about future consultation with affected First Nations and Métis communities and the impact of increased consultation with aboriginal peoples on location, timing and costs on major transmission projects; statements about the possibility of a tightening of the applicable standards relating to Critical Infrastructure Protection; statements about the transmission development work program being influenced by policies and priorities set by the Ontario government, and plans issued by the OPA and the OEB; statements about transmission development being driven by the need to connect new generation resources, meet load growth, and implement government policy; statements about the implementation of transmission development initiatives and programs; statements about the opportunities and challenges which will drive the implementation of advanced technology and process applications and work methods; statements about environmental sustainability and actions to mitigate the potential effects of climate change; statements about minimizing greenhouse gas emissions; statements about programs to help customers and employees reduce electricity usage; statements about strategic actions; statements about strategic drivers; statements about proactively carrying out work consistent with approaches outlined in OEB discussion papers; statements about capital and OM&A expenditures; statements about safety performance targets; statements about ensuring safety; statements about customer satisfaction targets; statements about momentary and sustained interruption targets; statements about unsupplied energy targets; statements about system unavailability targets; statements about planned improvements to its transmission system to improve interruption performance; statements about delivery point outages targets; statements about the sustainment of transmission assets, including its impact on reliability performance; statements about future requirements to accommodate the connection of renewable generation resources and their associated capacity contributions; statements about changing power flow patterns; statements about opportunities to improve energy conservation and demand management; statements about the reduction in transmission system losses; statements about factors which could affect assets and their operating performance, including: asset demographics, asset condition, obsolescence, performance, utilization, criticality, economics, and health, safety and environment; statements about necessary or increased investments to prevent premature end-of-life of assets, failure of assets, or unacceptable asset performance; statements about future remediation programs and expenditures; statements about expected asset demographics; statements about expected asset refurbishment rates; statements about expected asset service life; statements about equipment replacement scenarios; statements about vegetation management programs and expectations; statements about levels of preventative and corrective maintenance activities and preventative maintenance requirements; statements about the adoption of leading-edge technologies and best practices; statements about the evaluation and prioritization of asset and operational risks; statements about applying new equipment technologies; statements about the possible need for large interconnection reinforcements and additional inter-area transmission network facilities in Ontario; statements about planning for new load customer load connections and consequences of not proceeding with these projects; statements about planning for new transmission connected generation, statements about targets for renewable energy capacity; statements about the future need for transmission stations in order to facilitate renewable distributed generation connections; statements about the consequences of not proceeding with investments in inter-area supply including interconnections; statements about projected completion and in-service dates; statements about planned FIT projects; statements about planning studies to identify future transmission development; statements about the time and expense involved in conducting consultations and obtaining approvals for major transmission projects; statements about the transmission operating strategy; statements about hiring and developing junior staff; statements about enhancing computer tools and systems; statements about enhancing, modifying, and expanding physical infrastructure required for the control and operation of the transmission system from a backup facility; statements about potential transmission effects from power system changes; statements about the possible future need for organizational structures to operate distributed generation – intensive distribution; statements about improvements to work efficiencies and effectiveness; statements about enhancements to improve grid operating and control facilities; statements about technology enhancement; statements about the Star system concept; statements about energy storage, including statements about various storage technologies; statements about solar power system integrations; statements about wind generation performance validation; statements about transmission system optimization; statements about future power quality; statements about future involvement in projects to assess applicability of initiatives; statements about reduction in transmission line losses; statements about energy hub management systems; statements about the development of a risk assessment and management regime for natural and human hazards; statements about weather and climate modeling and response; statements about satellite imaging applications; statements about shortfalls in and competition over available skilled and qualified workers; statements about future retirements from Hydro One; statements about additional training requirements; statements about recruitment; statements about skills and training, skills transfer, knowledge retention and succession planning initiatives; statements about business management work methods and processes, statements about possible economic and financial crises, and statements about risk considerations.

Words such as "aim", "could", "would", "expect," "anticipate," "intend," "attempt," "may," "plan," "will," "believe," "seek," "estimate," and variations of such words and similar expressions are intended to identify such forward-looking statements. These statements are not guarantees of future performance and involve assumptions and risks and uncertainties that are difficult to predict. Therefore, actual outcomes and results may differ materially from what is expressed, implied or forecasted in such forward-looking statements. Hydro One does not intend, and Hydro One disclaims any obligation to update any forward-looking statements, except as required by law.

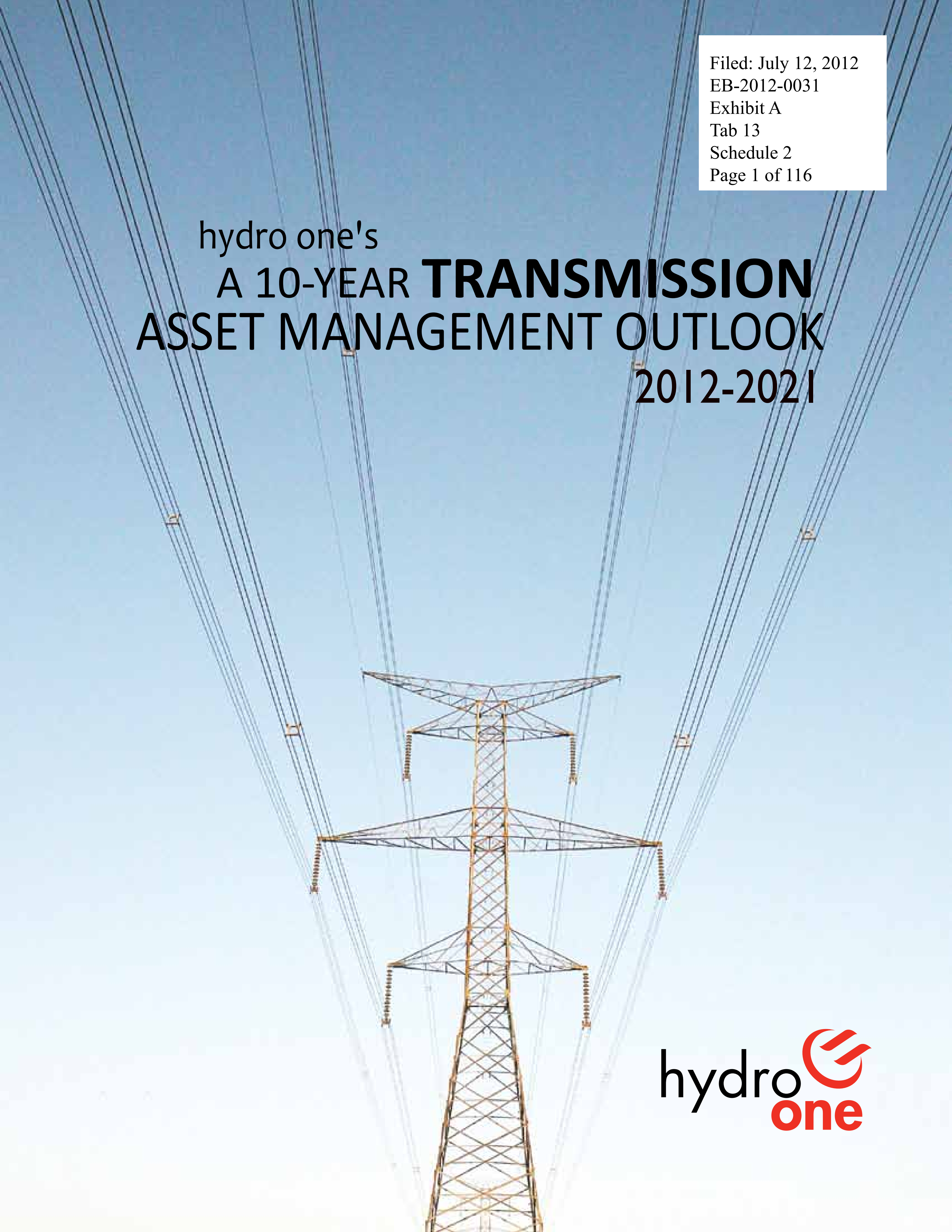
These forward-looking statements are based on a variety of factors and assumptions including, but not limited to: no unforeseen changes in the legislative and operating framework for Ontario's electricity market; favourable decisions from the OEB and other regulatory bodies concerning outstanding rate and other applications; no delays in obtaining the required approvals; no unforeseen changes in rate orders or rate structures for our distribution and transmission businesses; no unfavourable changes in environmental regulation; a stable regulatory environment; and no significant event occurring outside the ordinary course of business. These assumptions are based on information currently available to Hydro One including information obtained by Hydro One from third-party sources. Actual results may differ materially from those predicted by such forward-looking statements. While Hydro One does not know what impact any of these differences may have, its business, results of operations, financial condition and its credit stability may be materially adversely affected.

Factors that could cause actual results or outcomes to differ materially from the results expressed or implied by forward-looking statements include, among other things:

- the risks associated with being controlled by the Province including the possibility that the Province may make declarations pursuant to our memorandum of agreement with it, as well as potential conflicts of interest that may arise between us, the Province and related parties;
- the risk of possible changes to legislation and regulations impacting our work plans;
- public opposition to and delays or denials of the requisite approvals and accommodations for projects necessary to increase transmission and distribution capacity;
- the risk that previously granted regulatory approvals may be subsequently challenged, appealed or overturned;
- the risk that unexpected capital expenditures may be needed to support renewable generation or resolve unforeseen technical issues;
- the risks related to our work force demographic and our potential inability to attract and retain qualified personnel;
- the risks associated with the execution of our capital and maintenance programs necessary to maintain the performance of our aging asset base;
- the risk that we will be unable to source the materials or equipment necessary to support our work programs;
- the operational risks associated with implementing and monitoring of new technologies;
- the risks associated with deferring necessary work needed to address issues associated with aging assets;
- the risks associated with being subject to extensive regulation, including risks associated with Ontario Energy Board action or inaction;
- the timing and results of regulatory decisions regarding our revenue requirements, cost recovery and rates;
- the risk that faster or slower load growth than expected could result in work programs being potentially mismatched to actual needs;
- the risk that lower than expected load growth could lead to lower revenues being recovered, leading to re-prioritization of priorities of transmission sustainment, transmission development, and other work programs;
- the changing nature and location of generation, leading to changes in traditional power flow patterns;
- the current power system architecture may not be well-suited to new power flow patterns;
- the risk that major load or generation proponents could back out of proposals to build new major transmission facilities;
- additional sources of reliable generation being available and rapidly dispatchable;
- unanticipated changes in our costs;
- the risk that we are not able to arrange sufficient cost effective financing to repay maturing debt and to fund capital expenditures and other obligations;
- the risk to our facilities posed by severe weather conditions, natural disasters or catastrophic events and our limited insurance coverage for losses resulting from these events;
- the risks associated with information system security and with maintaining a complex information technology system infrastructure and transitioning most of our financial and business processes to an integrated business and financial reporting system;
- the potential for substantial and currently undetermined or underestimated environmental costs and liabilities;
- the risk that assumptions that form the basis of our recorded environmental liabilities and related regulatory assets may change;
- the risk that the presence or release of hazardous or harmful substances could lead to claims by third parties and/or governmental orders;
- the risk that future environmental expenditures is not recoverable in future electricity rates;
- the risk of more restrictive PCB regulations;
- the risk that a public or worker safety incident could lead to revisiting safety standards, work procedures and/or transmission facility designs;
- the impact of the ownership by the Province of lands underlying our transmission system;
- the impact of the Green Energy Act and the Long Term Energy Plan on our company and the costs and expenses arising therefrom;
- the operational risk associated with representation by most of our employees by two labour unions; and
- the impact of increased competition on our transmission business.

Hydro One cautions you that the above list of factors is not exclusive. Some of these and other factors are discussed in more detail under "Risk Considerations" in this 10-Year Transmission Asset Management Outlook 2012-2021. You should review the section entitled "Risk Considerations", as found in Section 11 in detail.

In addition to the above, with respect to the maps contained in Section 6 of this 10-Year Transmission Asset Management Outlook 2012-2021, the in-service (I/S) dates are for illustrative purposes only, and should not be relied upon or used for planning specific customer load or customer generation projects, or any other initiatives. These projections are forward-looking, and are dependant upon many factors and assumptions that may cause these dates to be materially different from current projections.



hydro one's A 10-YEAR **TRANSMISSION** ASSET MANAGEMENT OUTLOOK 2012-2021

hydro one

hydro one's A 10-YEAR **TRANSMISSION** ASSET MANAGEMENT OUTLOOK 2012-2021

Foreword

Electricity is an essential commodity that the people of Ontario, its industries, and its businesses depend on. Electricity directly affects customers' economic well-being and that of the Province as a whole. Hydro One's transmission grid is an integral part of Ontario's electricity infrastructure and plays a critical role in ensuring the safe, reliable and cost-effective delivery of electricity.

Hydro One is committed to providing quality service to its transmission customers from the generators who produce the electricity, to large, directly connected industrial customers, and local distribution companies (LDCs). The distribution companies in turn perform a vital role as electricity service providers to smaller industrial, commercial and residential customers in their service areas. In addition, Hydro One's transmission system supplies electricity to Hydro One's distribution network, which serves more than one million retail customers who are not served by an LDC.

Hydro One owns and operates substantially all of Ontario's electricity transmission system. As measured by revenues, Hydro One accounted for approximately 97% of the province's transmission capacity. Hydro One's transmission system includes a vast network of approximately 29,000 circuit kilometres of high-voltage transmission lines throughout the Province and 26 interconnection points with neighbouring provinces (Quebec, Manitoba) and states (New York, Michigan and Minnesota). In 2011, Hydro One transmitted about 142 TWh of electricity from 99 directly-connected generators to 93 transmission-connected customers, 49 LDCs, and the Hydro One distribution network.

Our role as a transmitter dates back more than 100 years. In carrying out our mandate, Hydro One, as the steward of the majority of Ontario's transmission infrastructure, is committed to ensuring a robust, reliable and sustainable provincial transmission system to satisfy the electricity needs of our customers, to contribute to the economy and to add value for our shareholder, the Province of Ontario. This requires working closely with our customers, First Nations and Métis communities, and other stakeholders to understand their needs while providing quality service focused on the safe, reliable and cost-effective delivery of electricity. Hydro One is also committed to working closely with stakeholders and customers in the wise and effective use of electricity through conservation and demand management programs, and by leveraging innovative technologies such as smart grid initiatives.

In May, 2009, the government passed the *Green Energy and Green Economy Act (GEGEA)* or *Bill 150*. This was followed by the release of the *Long-Term Energy Plan (LTEP)* in November of 2010 and the Ontario Energy Board's proposed plan for *A Renewed Regulatory Framework for Electricity (RRFE)* in November of 2011. Under the *GEGEA*, the *LTEP*, and the planned *RRFE*, there will be fundamental changes and developments that will affect our transmission system, and transmission planning, in the years ahead. Furthermore, adjustments and enhancements to business practices may be needed consistent with the Report of the Commission on the Reform of Ontario's Public Services (the "Drummond Report").

Looking forward, Hydro One faces many challenges and competing priorities affecting its transmission business and infrastructure. There is a need to sustain and renew the existing asset base to maintain reliable performance as many of these assets are aging. At the same time, there is a need to prepare for the future and ensure continued reliable electricity supply and delivery. This will include transmission development work and projects to accommodate the evolving electricity infrastructure in Ontario. Many of the existing generation resources are aging and will be replaced. Ontario's coal-fired generation resources will be phased out by 2014. Increasingly, there will be more renewable resources and distributed generation as part of the generation mix, and our need for electricity in the future will be shaped by conservation and demand management initiatives.

We are at a critical juncture. We must embrace opportunities to contribute to a greener and more environmentally sustainable Ontario. At the same time, we must ensure a progressive, modern and flexible transmission system and infrastructure for the future. As part of our process of continuous improvement, we will embrace innovation and show leadership in achieving our objectives. We are committed to find better ways to meet the needs of our customers for affordable and reliable power.

Rick Stevens
Vice President, Asset Management
Hydro One Networks Inc.


C-GHOX

Executive Summary

This document presents Hydro One's 10-Year Transmission Asset Management Outlook for the period 2012-2021.

Hydro One's Corporate Strategy sets the stage and direction for the Transmission Asset Management Outlook. Hydro One's Strategic Plan (The Five Year Vision – Innovation and Leadership: Renewing Ontario's Power Grid) establishes a set of clear objectives to achieve its mission and vision; namely, to be "an innovative and trusted company delivering electricity safely, reliably, and efficiently to create value for our customers". The development of a 10-year outlook for transmission asset management is a key step in achieving those objectives.

This Outlook provides discussion of Hydro One's transmission assets and anticipated transmission needs and developments over the next 10 years. Meeting transmission needs is essential to achieve Hydro One's mission and vision. The Outlook provides a roadmap to the work and projects necessary to ensure safe, reliable and economic operation of the Hydro One transmission system and its development into the future based on currently known conditions.

The projected transmission system needs and developments in the current Outlook are significant with respect to their magnitude, time frame required for implementation, and system operational changes. These are primarily driven from several perspectives which flow directly from the Ontario government's *Green Energy and Green Economy Act* (*GEGEA, 2009*), the Government's *Long-Term Energy Plan* (*LTEP, 2010*), associated Ministry directives and directions, and the OEB's proposed plan for *A Renewed Regulatory Framework for Electricity* (*RRFE, 2011*):

- There is a growing need to sustain Hydro One's existing transmission system assets into the future. These assets currently comprise about 97% of the transmission system infrastructure in Ontario. This is necessary to maintain reliable system performance in the face of an aging asset base.

- Simultaneously, the electricity system in Ontario will be undergoing major transformation and renewal. Future load growth must be met and, consistent with government policy, the existing coal-fired generating stations will be phased out by 2014. Existing generation resources are aging and a considerable proportion of the power system's centralized generation facilities will need to be replaced, often with resources of significantly different operating characteristics and different geographic distributions. Conservation and demand management will be emphasized, and the future generation resource mix will include more renewable resources and more distributed generation. Workable energy storage options may emerge, and other technological innovations will be introduced. These factors are all expected to change the way the system is used and operated, and significant associated transmission development will be required in order to ensure continued reliable and affordable service.

Further, the Report of the Commission on the Reform of Ontario's Public Services (the "Drummond Report") calls on additional business efficiencies from Hydro One and other entities.

The need to sustain and renew the existing transmission asset base, coupled with the projected changes to the electricity system and generation resource mix will introduce new challenges and demands on the transmission system. They will also present opportunities. The plans outlined in this Outlook demonstrate Hydro One's commitment to meeting these challenges and leveraging them through innovation and leadership to meet the needs of our customers and the Province.

Consistent with the perspectives outlined above and with Hydro One's transmission asset management methodology, the Outlook discusses four interrelated and complementary strategic work programs: Transmission Sustainment, Transmission Development, Transmission Operating, and Technology Advancement. These four components combined constitute the overall Hydro One Transmission Asset Management Outlook.

In the last few years, it has become clear that the economic outlook for the Province, and for Hydro One's customers, is changing as a result of global financial upheaval. Where known, the effects of these changes have been considered in the development of future plans.

There are many variables and circumstances which could affect the projected requirements and plans presented in this Outlook, including changes in load forecasts, policy direction, and economic circumstances. Hence, the plans presented herein should not be considered necessarily to provide a definitive roadmap of system development over the full planning timeframe. It is possible, perhaps even likely, that not all of the proposed transmission projects will necessarily be built by Hydro One or developed as outlined.

However, this Outlook is based on the best available information and analysis available at the time it was written, and it has been designed with flexibility in mind. It therefore represents a reasonable snapshot of the projected transmission system requirements over the next 10 years. It will be updated on an as needed basis to accommodate changed circumstances as they become apparent.

1. INTRODUCTION

Hydro One's 10-Year Transmission Asset Management Outlook provides an overview and discussion of Hydro One's transmission assets, and the evolving transmission system and infrastructure over the period 2012-2021, based on anticipated needs and developments.

Hydro One's transmission system is facing a significant period of rapid change with many challenges over the next 10 years and beyond. Portions of the current transmission system infrastructure date back more than 100 years. Transmission system assets are aging and many will require increased maintenance or replacement in the coming years simply to maintain existing system capabilities.

At the same time, consistent with government energy policy: all forms of coal-fired generation will be phased out by 2014; there will be a greater emphasis placed on renewable generation resources (wind, hydroelectric, solar, biomass); older nuclear generation units are likely to be retired; and new nuclear generating stations may (or may not) be built to replace them. New transmission infrastructure will likely be needed to incorporate these changes.

In addition, the contribution of conservation and demand management is expected to grow substantially and older, centralized generation facilities will increasingly be replaced by distributed generation. Electricity generation and demand profiles will change, and new transmission infrastructure, operating paradigms, and technologies will be needed if Hydro One is to maintain transmission system safety, reliability, power quality, and customer satisfaction.

These changes are all expected to result in a significant reduction in the energy sector's carbon footprint and contribute to a greener and more environmentally sustainable Ontario. However, these changes will also present unique challenges and opportunities for Hydro One with respect to its transmission system infrastructure and operating practices. The plans discussed in this Outlook will enable Hydro One to meet these challenges and leverage opportunities through innovation and leadership so that it can continue to serve its shareholder and customers well.

1.1 Context

Hydro One Inc. (HOI) is a holding company with subsidiaries that operate in the business areas of electricity transmission, distribution, and telecommunications services. HOI is incorporated under the *Ontario Business Corporations Act* and is subject to, and governed within the broad legislative framework of the *Electricity Act and the OEB Act*. The Province of Ontario is its sole shareholder.

HOI's core mandate is the safe, reliable and cost-effective transmission and distribution of electricity to Ontario's electricity users. Hydro One's core transmission and distribution businesses involving planning, construction, operation and maintenance are managed by Hydro One Networks Inc. (a subsidiary of HOI), which is licensed and regulated by the Ontario Energy Board (OEB). This document focuses on Hydro One's transmission business only.

With respect to transmission, the OEB sets transmission rates, issues codes and licenses, and approves the construction of new transmission lines greater than two kilometres.

Hydro One is one of several transmission system owner/ operators operating within the context of the electricity market in Ontario. In 2011, Hydro One's transmission system accounted for approximately 97% of Ontario's total transmission capacity. The Independent Electricity System Operator (IESO) administers the electricity market and is also responsible for directing the operation of the bulk power system in the province, and for ensuring adherence to electricity reliability standards.

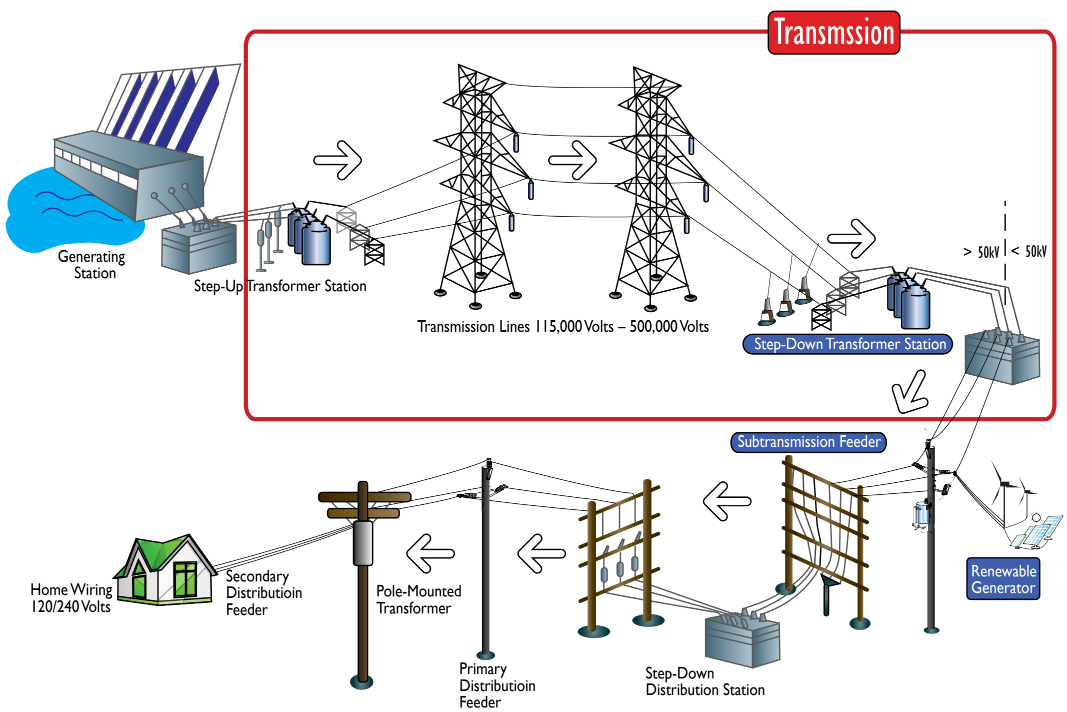
The Ontario Power Authority (OPA) was established by the *Electricity Act, 1998,* as amended by the *Electricity Restructuring Act, 2004,* and is licensed by the OEB. As part of its mandate, the OPA forecasts long term electricity demand and supply requirements for the adequacy and reliability of the Ontario electric system; conducts independent planning for conservation and demand management, electricity supply and transmission; and develops integrated power system plans (IPSP) for Ontario. The Ontario government has issued directives and its Long Term Energy Plan, identifying specific transmission projects; these projects are factored into OPA and Hydro One's plans. With respect to transmission, the OPA generally identifies new or upgraded transmission required to incorporate new generation, relieve constraints on the transmission system or to accommodate increasing electricity demand on an area supply basis. Hydro One contributes to the development of those transmission plans by working cooperatively with the OPA. Hydro One in turn uses the OPA's plans and projections when developing detailed plans (such as those found in this Outlook) and when obtaining necessary approvals for the construction of required transmission facilities.

On April 26, 2012, the Government of Ontario introduced Bill 75, to be known as the *Ontario Electricity System Operator Act, 2012*, which will reflect the amalgamation of the OPA and the IESO. This proposed legislation will amend the *Electricity Act, 1998* and the *Ontario Energy Board Act, 1998* as well as make some complementary amendments in other legislation. The proposed name for the amalgamated entity is the Ontario Electricity System Operator ("OESO"). The functions and objects of the OPA and the IESO as presently set out in the *Electricity Act, 1998* for each entity will be substantially the same in the amalgamated entity under Bill 75 with a governance structure in place to separate the functions and activities of the OESO related to market operations and procurement and contract management activities. For the purposes of this document, Hydro One retains reference to OPA and IESO respectively.

The Outlook is the logical outcome of these influences, and underscores Hydro One's mission and vision, and its corporate strategy for meeting that mission and vision. Hydro One's mission and vision is:

"to be an innovative and trusted company delivering electricity safely, reliably, and efficiently to create value for our customers."

Figure 1.1 Transmission System - Simplified



The corporate strategy is expressed in Hydro One Strategic Plan (The Five Year Vision 2011-2015). That plan establishes the corporate strategic business values of *Health and Safety*, *Stewardship*, *Excellence*, and *Innovation*, and identifies associated strategic objectives and desired results. The corporate strategic objectives and desired results are discussed further in Section 2. Consideration of these objectives and target results by management has led to the identification of strategic drivers and actions for transmission sustainment, development, operating and technology advancement work programs, and, ultimately, to the formulation of work plans discussed in this Outlook.

1.2 Document Scope

This document provides a discussion and outlook of Hydro One's transmission assets, projected transmission requirements, and developments for the period 2012-2021. The preparation of a 10-year outlook is one of the key planning activities identified in the Hydro One strategic plan, most recently published in 2011. The purpose of the 10-Year Transmission Asset Management Outlook is to help position Hydro One to meet future transmission challenges consistent with the company's mandate.

The identified work scope in the Outlook represents a snapshot of the projected requirements during the next 10 years to sustain and develop the transmission system, while ensuring a safe, reliable and cost-effective system. The projected requirements are forward looking and are intended to meet the future transmission needs of Ontario and of Hydro One's transmission customers. In particular, the transmission system needs identified in this Outlook are responsive to government policy and regulatory initiatives as communicated in *Green Energy and Green Economy Act* (*GEGEA, 2009*), the Ontario government's *Long-Term Energy Plan* (*LTEP, 2010*), and the OEB's proposed plan for *A Renewed Regulatory Framework for Electricity* (*RRFE, 2011*), and the *Drummond Report (2012)*.

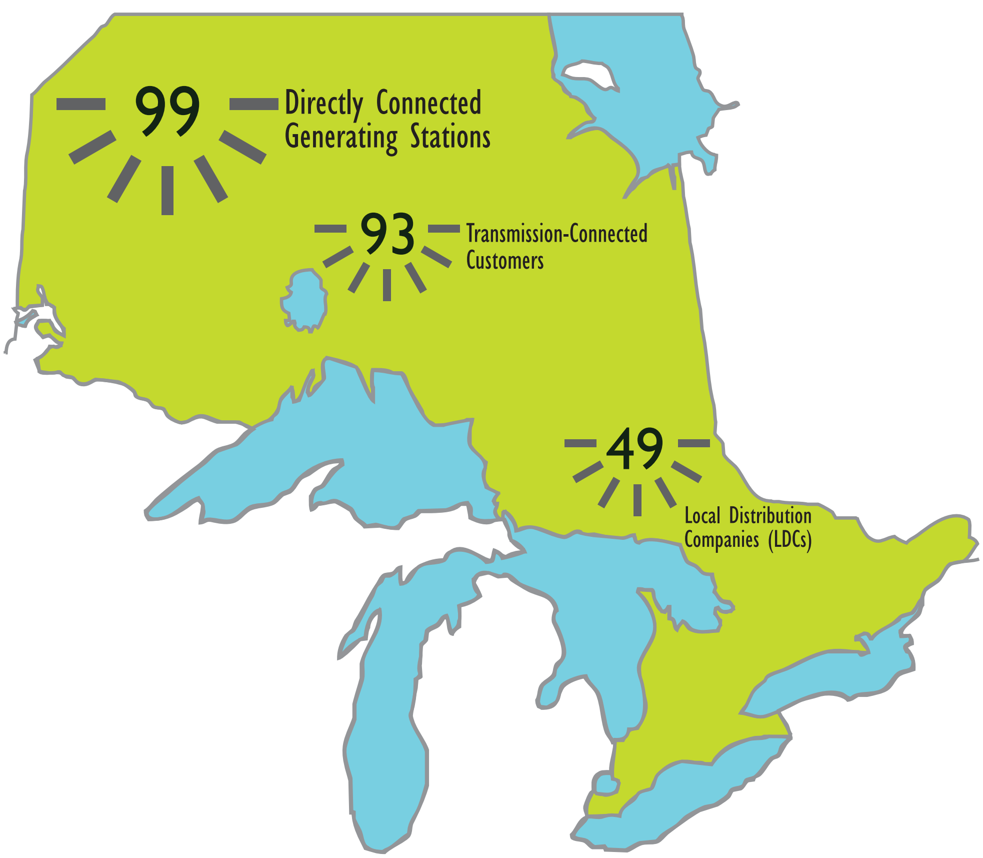
The Hydro One 10-Year Transmission Asset Management Outlook will be updated periodically or as warranted based on changed circumstances.

The Outlook discusses the management of the transmission assets in the context of four key interrelated and complementary components underpinning Hydro One's transmission asset management framework:

- Transmission Sustainment;
- Transmission Development;
- Transmission Operating; and
- Technology Advancement.

These are discussed more fully in subsequent sections of this document.

Figure 1.2 Hydro One's Transmission Customers



1.3 Hydro One's Transmission System

Hydro One's transmission system enables the safe, reliable and cost-effective delivery of electricity from generators in the province to local distribution companies (LDCs) and a number of large, directly connected industrial or end-use customers. As such, it is an integral and critical part of the province's electricity infrastructure.

Hydro One Networks Inc. is established by provincial statute and licensed by the OEB to own, operate and maintain transmission facilities in Ontario. It is wholly owned by Hydro One Inc., which is in turn owned by the Government of Ontario. As such, Hydro One Networks Inc. and Hydro One Inc. must operate in a manner consistent with legislation, regulations, decisions and directives from the OEB, and government policy.

The Hydro One transmission system is used for transmitting electricity between supply points and customers, as illustrated in Figure 1.1.

Hydro One transmits electricity to several large end-use transmission customers (with loads > 5 MW) and LDCs including Hydro One Brampton and Hydro One Distribution, as indicated in Figure 1.2. Depending on the configuration and ownership of facilities, Hydro One provides customers with one or more of the four main types of transmission service: network, line connection, transformation connection and wholesale meter service.

As of January, 2012, Hydro One transmitted electricity from 99 directly connected generating stations to 93 transmission-connected customers, 49 LDCs, and Hydro One distribution businesses. The electricity is transmitted through a high

Figure 1.3 Hydro One Transmission System Interconnections

voltage system with transmission lines operating at 500 kV, 345 kV, 230 kV, 115 kV and 69 kV. In 2011, the total amount of electricity transmitted was approximately 142 TWh.

Hydro One is unique in its operations compared to other transmitters. Global and North American benchmarks for transmitters typically only consider operations at 230 kV or higher as "transmission system" voltages. Elsewhere, distribution companies typically operate at voltage levels of 115 kV and 69 kV or lower. LDCs in Ontario operate at voltage levels of 50 kV or lower. This must be borne in mind when making comparisons between Hydro One operations and seemingly comparable operations elsewhere.

Hydro One's transmission assets form about 97% of the IESO controlled transmission grid in Ontario, and is one of the largest transmission systems in North America. The Hydro One transmission system is also connected to three other Ontario transmitters: Great Lakes Power; Canadian Niagara Power; and Five Nations Energy. These three transmitters comprise the bulk of the remaining 3% of the licensed transmission facilities in Ontario.

The Hydro One transmission system has a number of interconnection facilities, at 26 interconnection points, with the neighbouring provinces of Manitoba (3) and Quebec (9) and with the neighboring States of New York (9), Minnesota (1) and Michigan (4). These interconnection facilities allow the transfer of electrical energy between Ontario and these jurisdictions. Actual import and export capabilities of the interconnections depend on limitations at the interface as well as within Hydro One's system and the transmission systems in the other jurisdictions. Figure 1.3 is a schematic of the existing interconnections with the neighbouring provinces and states.

The Hydro One transmission system includes 285 transmission stations and approximately 29,000 circuit kilometers of high voltage transmission lines which operate at 500 kV, 230 kV and 115 kV, with minor lengths operating at 345 kV and 69 kV. The Hydro One Transmission system can be considered as consisting of two major asset categories: lines and stations. Each of these categories is comprised of a number of major components as indicated in Table 1.1.

Table 1.1 Major Components of Lines and Stations

Lines	Stations
• overhead conductors • underground cables • wood or steel support structures • foundations • insulators • connecting hardware • grounding systems	• transformers • circuit breakers • switches • bus bars • insulators • reactors • capacitors • connecting hardware • protection and control equipment • grounding systems • revenue meters

Table 1.2 summarizes the number of key physical assets comprising the Hydro One transmission system as at December 31, 2011.

Table 1.2 Hydro One Transmission System - Key Assets

Hydro One Transmission System Assets At December 31, 2011	
Stations	
> Transmission Stations	285 (Total)
Transformer Stations	250
Switching Stations	35
> Circuit Breakers	4,490 (Total)
Oil Circuit Breakers	1,923
Air-blast Circuit Breakers	190
SF6 Circuit Breakers	1,376
GIS Circuit Breakers	99
Metalclad Circuit Breakers	866
Vacuum Circuit Breakers	36
> Transformer Banks (115 kV and above)	719 (Total)
Step-down transformers	572
Auto-transformers	134
Phase shifters	5
Regulators	8
Lines	
> Overhead Transmission Lines (circuit-km)	28,636 (Total)
500 kV Overhead Lines	3,778
345 kV Overhead Lines	6
230 kV Overhead Lines	14,098
115 kV Overhead Lines	10,753
69 kV Overhead Lines	1
> Underground Cables (circuit-km) (115 kV and above)	291 (Total)

Note:

[1] The number of transformers and circuit breakers are the equivalent three-phase banks.
The number of individual three-phase and single-phase transformers are 705 and 42 units, respectively. These exclude operating spares.
The number of individual three-phase and single-phase circuit breakers are 4,418 and 234 units, respectively.

2. TRANSMISSION ASSET MANAGEMENT FRAMEWORK

2.1 Background

Hydro One manages its transmission assets within the framework of an asset management system. The Hydro One asset management system is consistent with required good practices in the management of physical assets to achieve business goals as discussed in the British Standards Institute (BSI) specification document PAS 55-1:2008 ("Asset Management, Part 1: Specification for the optimized management of physical assets", BSI publication (September 2008)).

Asset management is defined in PAS 55-1:2008 as: "systematic and coordinated activities and practices through which an organization optimally and sustainably manages its assets and asset systems, their associated performance, risks, and expenditures over their life cycles for the purpose of achieving its organizational strategic plan". The term "organizational strategic plan" is used in PAS55-1 to mean an "overall long-term plan for the organization that is derived from, and embodies, its vision, mission, values, business policies, stakeholder requirements, objectives and the management of its risks".

The Hydro One corporate strategic plan is developed with the guidance and oversight of the Hydro One Board of Directors. The Transmission Asset Management work programs are, in turn, formulated based on the corporate strategic plan.

Hydro One's transmission asset management planning methodology considers four interrelated and complementary strategic asset management work programs pertaining to: Transmission Sustainment; Transmission Development; Transmission Operating; and Technology Advancement. Each of these components is generated based on both corporate-wide planning considerations (such as a determination to limit customer rate impacts) and its own specific planning considerations (such as the effect of various government policies on the specific work program in question).

The final component of Hydro One's asset management system is the implementation of approved work programs and monitoring performance to ensure corporate goals are met.

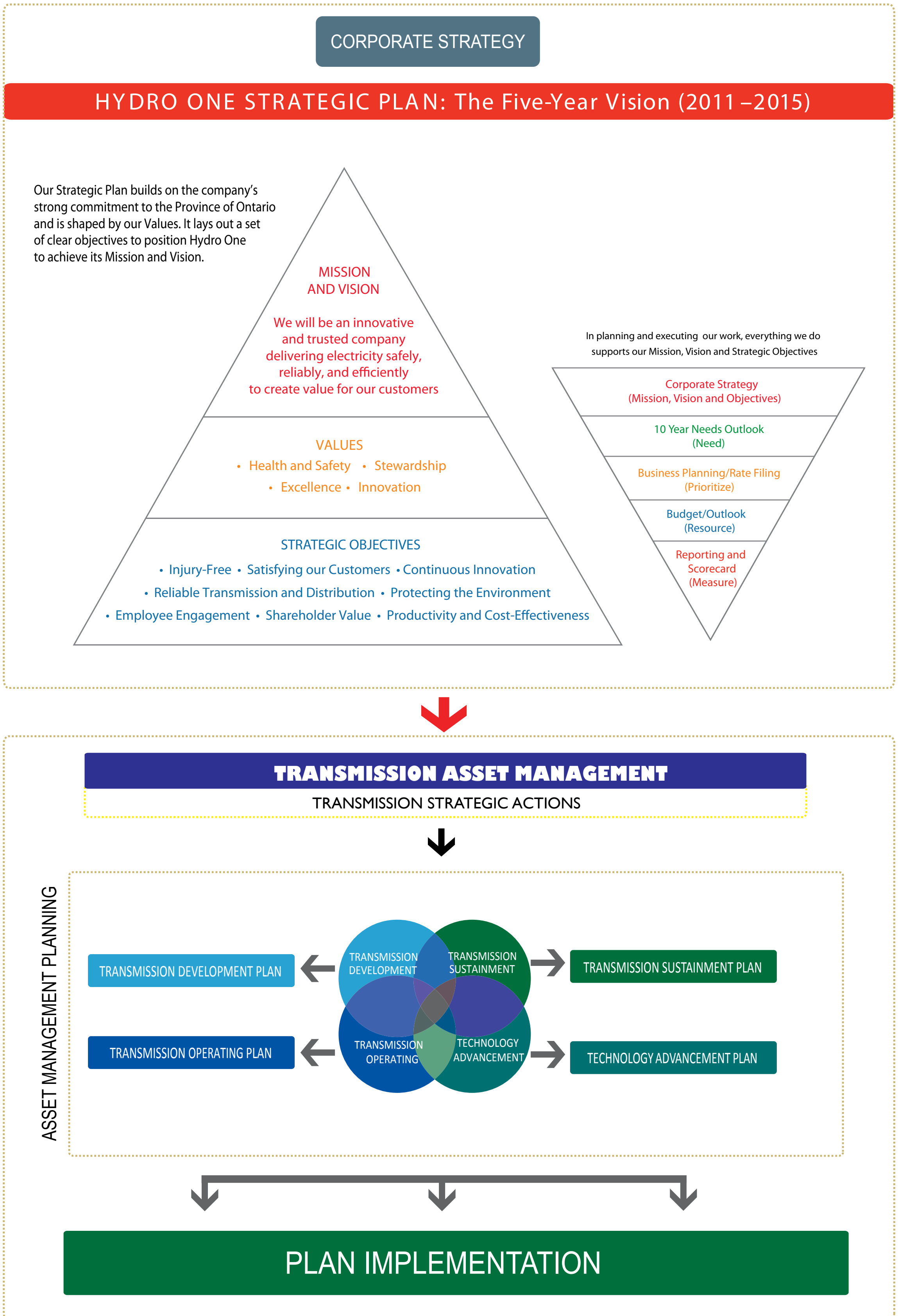
The framework of the asset management system and the way it leads to the identification of strategic objectives, strategic drivers and the formulation of transmission asset work programs is shown conceptually in Figure 2.1.

This document focuses on transmission work programming aspects only, based on projected transmission needs and requirements over the next 10 years.

2.2 Corporate Strategy

Hydro One's corporate strategy is based on our mission and vision and our values. Our mission and vision is to be an innovative and trusted company delivering electricity safely, reliably and efficiently to create value for our customers. Our values represent our core beliefs:

Figure 2.1 Framework for Formulation of a Transmission Asset Work Programs



- ***Health and Safety*** – nothing is more important than the health and safety of our employees and those who work on our property, as well as maintaining a safe environment for the public.
- ***Excellence*** – We achieve excellence through continuous training, ensuring we are prepared and equipped to deliver high quality service.
- ***Stewardship*** – We invest in our assets and people to build a safe, environmentally sustainable electricity network in a commercial manner.
- ***Innovation*** – We innovate through new processes, people and technology to allow us to find better ways to meet the needs of our customers.

2.3 Strategic Objectives

Hydro One has eight strategic objectives that are inextricably linked with one another. They drive the fulfillment of our mission and vision.

1. ***Creating an injury-free workplace and maintaining public safety:*** Health and safety must be integrated into all that we do. We must continue to create a passion for preventing injury. We will strengthen our already strong safety culture through our Journey to Zero initiative and achieve world-class results. We will continue to reinforce that nothing is more important than the health and safety of our employees.

2. ***Satisfying our customer:*** We will meet our commitments, make customers our focus in our planning, communicate effectively, coordinate across lines of business, and maximize opportunities to improve our corporate image.

3. ***Continuous innovation:*** Innovation is critical to achieving our mission and vision and represents one of our core values. Over the next two decades, Hydro One will install innovative solutions that improve the reliability and efficiency of the transmission and distribution systems and provide our customers with more capability to manage their power costs.

4. ***Building and maintaining reliable, cost-effective power delivery systems:*** Our transmission strategy is to provide a robust and reliable provincial grid that accommodates Ontario's emerging generation profile, manages an aging asset base and meets demand requirements through prudent expansion and effective maintenance. Our distribution strategy is focused on incorporating ADS technology, providing reliable service over a diverse geography, supporting the connection of renewable generation, seeking efficiencies through productivity initiatives and remaining open to opportunities to rationalize the distribution sector.

5. ***Protecting and sustaining the environment:*** Consistent with our value of stewardship, Hydro One plays a central role in reducing Ontario's carbon footprint, through the delivery of clean and renewable energy and through measures that allow our customers to manage and reduce their energy use.

6. ***Employee Engagement:*** We believe our primary strength is the capability of our people. In order to sustain this advantage, we must address the issues of labour demographics, diversity, development of critical core competencies, and skill and knowledge retention. Our labour strategy will enable us to make significant gains in the areas of labour flexibility, productivity improvement and cost reduction.

7. ***Maintenance of a commercial culture that increases value for our shareholder:*** We are committed to keeping rates as low as possible for our customers, and delivering income and dividends to our shareholder. This is possible through our focus on reducing costs, managing our assets effectively and increasing productivity.

8. ***Productivity improvement and cost-effectiveness:*** To achieve our mission and vision, we must constantly strive for productivity through efficiency and effective management of costs. Productivity is key to meeting our other strategic objectives and, in particular, to achieving value for our customers and our shareholder.

Hydro One recognizes the pivotal role innovation will play in building a smart electricity grid that supports a clean environment for Ontario. We are committed to becoming the industry leader in putting innovative solutions to work for the well-being of the Ontario economy and its residents.

As an award winning company, in 2011, we were named one of the best 50 corporate citizens in Canada by Corporate Knights, the leading corporate ranking of Canadian corporate citizenship, which considers companies' relative carbon, water, waste, energy impacts as well as pension fund quality, board diversity, ratio of lowest paid worker to CEO-pay, and tax dollar generation.

2.4 Other Planning Consideration

There are a number of planning principles and considerations which have influenced the development of work programs presented in this Outlook. The most important of these are discussed in the subsections which follow.

2.4.1 General Planning Principles

Hydro One sustains and maintains, expands, and operates its transmission assets to meet customer needs in accordance with reliability standards, regulatory requirements as well as environmental and legal requirements. In addition to sustaining its transmission system assets to provide continued reliable, cost effective service to the extent practical, it implements transmission system expansion to:

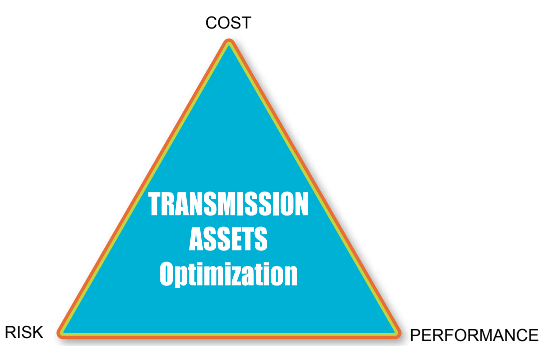
- accommodate overall load growth and geographic shifts in demand;
- accommodate new transmission capacity arising out of government and OEB directives (e.g., those resulting from the feed-in tariff program and other green initiatives advocated through the Ontario Government's *Green Energy and Green Economy Act (GEGEA, 2009*), Government's *Long-Term Energy Plan (LTEP, 2010)*, OPA plans, and customer requests;
- alleviate internal system constraints;
- increase interconnection capabilities with neighbouring utilities; and
- ensure continued reliable and safe operation of the transmission system as the Hydro One distribution system is transformed into an Advanced Distribution System.

Hydro One primarily uses two concurrent approaches when considering transmission investments:

- A forward looking approach with respect to anticipated transmission system needs and developments, typically looking ahead roughly 10 years into the future;
- A life cycle management approach which considers and balances asset performance, costs and associated risks during the asset service life in order to achieve asset optimization.

Three competing needs are considered and balanced when contemplating transmission asset investments: Cost, Performance, and Risk. This is illustrated in the following figure:

Figure 2.2 Competing Considerations



2.4.2 Reliability

Transmission system reliability is a key business value for Hydro One, and power system reliability has particular significance in transmission planning.

In Ontario, electricity transmission system reliability is regulated and enforced by the Independent Electricity System Operator (IESO), through market rules requiring market participants (including Hydro One) comply with reliability standards, criteria, and rules established by the North-American Electric Reliability Corporation (NERC), the Northeast Power Coordinating Council (NPCC), and the IESO. These standards are enforced by the Market Assessment and Compliance Division (MACD) of the IESO.

Hydro One applies NPCC's technical criteria when analyzing the technical aspects of its power system plans and operations. This analysis ensures the design and operation of the bulk power system is sufficiently reliable that the loss or unintentional separation of a major portion of the power system will not result from specified contingencies. NPCC's technical criteria are based on a broader set of criteria and standards developed by NERC that are adopted across North America.

Further, the IESO establishes criteria which clarify how relevant NPCC and NERC standards should be applied and implemented within Ontario. These criteria are used to assess the current and future adequacy and security of the IESO-controlled grid; for identifying the need for system enhancements; and for evaluating the effectiveness of planned transmission enhancements.

2.4.3 Power System Changes and Transmission Impacts

The nature, location, and operating characteristics of generation and load connected to the transmission system are changing as the power system ages and evolves. These changes can affect the way the transmission system needs to be maintained, operated, and developed. Significant changes, and their potential effects on the transmission system, are summarized in Table 2.1. Transmission work plans must anticipate and address these effects.

2.4.4 Environmental Sustainability

Hydro One continues to support the need for environmental sustainability and for actions to mitigate the potential effects of climate change. Accordingly, Hydro One considers the following factors:

- Planning, construction, maintenance, and operation of Hydro One's transmission system assets needs to embody the principles of environmental protection, energy efficiency and environmental sustainability; The environment needs to be considered by taking a life cycle approach, starting with planning, and moving through engineering, construction, operation and maintenance, to equipment end-of-life disposal and recycling;
- The planning and development of new transmission facilities must involve consultation with the public, including First Nations and Métis communities, for projects which could potentially have significant impacts.

Table 2.1 Power System Changes & Transmission Operating Impacts*

Seq. No	Power System Changes & Potential Transmission Effects
1	**Coal-fuelled stations shut down (more than 8000 MW by 2014) and end-of-life for some nuclear units** • Significant changes in transmission flow "patterns"; voltage impacts; reactive power shortfalls; transient stability concerns (lower inertia in electricity system); generation dispatch and frequency regulation.
2	**Renewable Generation with Variable and Highly Intermittent Generation (Capacity of 10,700 MW as outlined in the LTEP)** • Voltage variations as a result of the high variability in power output from renewable generation resources. • Harmonics (resulting in higher frequency electrical currents above 60 Hz) which can cause power equipment damage. • System resonance causing equipment damage. (At certain harmonic frequencies and for certain system configurations the combination of capacitive and inductive equipment in an AC circuit can result in near zero effective impedance, with the result that the electrical current and/or voltage become unacceptably large.) • Generation dispatch and power system frequency control in a system with large amounts of renewable generation. (Potential need for conventional generation or energy storage backup.) • Reversal of power flow on electrical feeders, potentially impacting transformer operations, under certain load - generation conditions. • Increase in electrical short circuit levels which could exceed equipment capabilities and Transmission Code limits. • Impacts of incorporating new protection and control equipment
3	**Connections to Distribution Systems, Including ADS (Advanced Distribution System)** • A DMS (Distribution Management System) and other systems will be implemented to improve reliability and help manage the large amount of distribution connected renewable generation (with variable and intermittent output). Interfaces are needed between these systems and the existing Transmission Operating systems to ensure more effective overall power system reliability and address issues noted above in item 2 of this table.
4	**Load Changes (Including PHEVs)** • As industrial, commercial and residential consumers use more power electronic devices (including electronic drives and electric vehicles), harmonics are introduced into the power system which can result in power quality concerns.
5	**CDM** • CDM options will be implemented primarily on the distribution system. Resulting changes in load flow patterns and timing on the transmission system, if large enough, might affect transmission system equipment loading and operating paradigms. • If power system voltage reduction is used to reduce load as a CDM initiative, the operating flexibility to provide load-generation balance under emergency condition would be significantly reduced (past practice has been to use power system voltage reduction under emergency conditions).

[* - This table identifies power system changes, and potential transmission impacts. This table is not intended to identify system operating functions carried out by the IESO and/ or Hydro One's OGCC.]

- Opportunities for minimizing greenhouse gas emissions and the risks and opportunities associated with possible impacts of climate change on our transmission system should be considered (e.g., vegetation management);
- Hydro One should continue to offer programs to help customers and employees become more aware of how to reduce their electricity usage and its effect on the environment.

There are a number of potential environmental sustainability considerations/ opportunities are discussed in Section 8.

2.4.5 Conservation and Demand Management (CDM)

The CDM initiatives are implemented at the customer's facilities, usually at distribution system voltage levels. The CDM Code under section 70.2 of the OEB Act sets out CDM targets for each local distribution companies (LDCs) in Ontario, including Hydro One Distribution. There could be some transmission customers (e.g., large industrial) who could potentially be supported by Hydro One with their CDM work.

Hydro One's continues with its ongoing internal energy conservation efforts.

2.4.6 Changing Regulatory Requirements

The OEB's policy on *Framework for Transmission Project Development Plans (FTPDP, 2010)* describes an electricity transmitter "designation process" for potential transmission projects. The OEB policy encourages new transmission entrants in Ontario, to support competition and drive economic efficiencies. Accordingly, transmission projects described in the document may not necessarily be built by Hydro One.

In early November of 2011, the OEB issued a set of five OEB staff discussion papers with an overarching objective of renewing the regulatory framework. Four of the discussion papers have possible implications for transmission planning. These are discussed more fully in Section 3.9 of this Outlook.

For projects which would potentially have significant impacts on First Nation and Métis Communities, the Crown has a duty to consult. Further discussion is provided in Section 3.8.

2.4.7 Increased focus on Critical Infrastructure Protection

Since terrorists attacked New York in 2001 there has been an increased focus on protection of Ontario's critical infrastructure. Critical Infrastructure Protection (CIP) standards have been developed and made mandatory. The CIP standards requirements and charges needs to be factored in Hydro One's work programs. In addition, there is an awareness that the standards applicable to Critical Infrastructure Protection are being tightened.

2.4.8 Workforce Demographics

Hydro One faces unprecedented challenges with respect to the aging demographics of the current workforce and a coincident shortage of workers in certain fields. These issues are discussed more fully in Section 9.

2.5 Transmission Work Programs

Hydro One's transmission work programs fall into four different categories: transmission sustainment; transmission development; transmission operating; and technology advancement. These are explained further in the following sub-sections.

2.5.1 Transmission Sustainment

The Transmission Sustainment work program covers the work required to maintain the existing transmission system infrastructure and facilities at the required performance level. The latter may vary over time due to changed needs and circumstances driven from either a system or local area perspective. Sustainment work ranges from preventative and corrective maintenance to full-scale replacement of transmission assets. Owing to the long lead time to manufacture of major equipment such as transformers, circuit breakers and other equipment, Hydro One has an inventory of spare equipment and parts.

Decisions to maintain or replace transmission system assets are made on the basis of a life-cycle management approach, which considers and balances asset performance, costs and associated risks during the asset service life in order to achieve asset optimization.

Transmission Sustainment work programs are discussed more fully in Section 5.

2.5.2 Transmission Development

This is the work required to increase the capacity and effectiveness of the transmission system and to meet evolving customer requirements. Going forward, the Transmission Development work program, while aligned with Hydro One's corporate strategy, will, to a large extent, be influenced by the policies and priorities set by the Ontario government as reflected in the *GEGEA*, the *LTEP*, plans issued by the Ontario Power Authority, and the Ontario Energy Board's proposed plan for *A Renewed Regulatory Framework for Electricity* (*RRFE, 2011*). In particular, transmission development will be driven by the need to connect and incorporate new generation resources to replace retiring generation, meet load growth, and implement government policy regarding increasing the contribution of renewable and distributed generation resources.

The implementation of Transmission Development initiatives and programs will also likely be needed to meet evolving service and/or design standards for customer reliability, power quality, system security, interoperability, equipment and facilities, and communications.

Transmission Development work programs are discussed more fully in Section 6. Noting OEB's electricity transmitter designation process, these projects may not necessarily be built by Hydro One.

2.5.3 Transmission Operating

The Transmission Operating work program covers the work to safely and reliably operate the transmission system on a 24/7 basis. This is accomplished through a combination of central control and dispatch through the Ontario Grid Control Centre (OGCC) and, where necessary, directing local response and action by field crews operating from service centers located throughout Hydro One's service territory.

Transmission Operating work programs are discussed more fully in Section 7.

2.5.4 Technology Advancement

Technology Advancement work is related to the application of advanced technologies and work methods to the Hydro One transmission system to enhance and add value to the system and business. This will ensure that Hydro One remains in the forefront in maintaining, operating, and developing a modern, sustainable, efficient and flexible transmission system, and will help Hydro One to achieve the corporate vision.

Going forward, there will be many opportunities and challenges which will drive the implementation of advanced technology and work method applications in Hydro One's transmission system. In particular, there will be technologies and work methods related to: the connection and integration of significant numbers and amounts of distributed renewable energy generation and storage resources; the development support for Hydro One's Advanced Distribution System (ADS) in the distribution system, which impacts the interfaces with the transmission system; and the relevant support for initiatives to increase and maximize the CDM potential in Ontario.

Technology Advancement supports Hydro One's innovation business value which encourages continuous improvement and promotes the leveraging of innovative ideas, practices and processes, advanced technologies, and new tools into practical applications and solutions which benefit Hydro One's customers.

Transmission Advancement work is discussed more fully in Section 8.

3. REGULATORY FRAMEWORK

3.1 Introduction

Hydro One Networks Inc. must comply with government legislation and regulations, decisions issued by its regulator, the Ontario Energy Board (OEB), and the terms and conditions of its Transmission Licence (issued by the OEB). Hydro One, as a participant in the Ontario electricity market, must comply with the market rules, which are established and administered by the Independent Electricity Market Operator (IESO). It must also comply with reliability standards and criteria established by NERC (the North American Electricity Reliability Corporation) and the Northeast Power Coordinating Council (NPCC) to which NERC has delegated authority for certain regional reliability standards and associated standards enforcement roles. Finally, as part of its role in the Ontario electricity sector, Hydro One is expected to provide new or upgraded transmission infrastructure to enable the connection of generation facilities as contemplated in integrated power system plans issued by the Ontario Power Authority.

Each one of these has the potential to be a driver for change affecting Hydro One policies, processes, and work programs.

3.2 Fundamental Legislation

The *Electricity Act, 1998* and the *Ontario Energy Board Act, 1998*, as amended from time to time, are the primary legislative instruments which establish Hydro One and create the legislative framework for Ontario's competitive electricity market. The *Electricity Act, 1998* implemented the fundamental principles of the restructuring of Ontario's electricity industry, enabling the implementation of open non-discriminatory access to transmission and distribution systems. The *Ontario Energy Board Act, 1998* expanded the jurisdiction and mandate of the OEB to include regulation of the electricity and natural gas markets.

3.3 Hydro One's Transmission Licence

Hydro One's transmission licence, issued in 2003, authorizes the company to: own, operate, and maintain its transmission assets; carry out transmission planning and investments to meet load growth and maintain adequate reliability; provide open, non-discriminatory access to the transmission system; and, comply with standards and codes, legislation, regulations, and market rules.

On February 17, 2011, the Minister of Energy directed the OEB it to amend the transmission licence of Hydro One to require Hydro One to proceed with three priority transmission projects in southwestern Ontario, as identified in the government's *Long Term Energy Plan (LTEP, 2010)*, and to increase short circuit and/or transformer capacity at up to 15 of its transformer stations to enable the connection of small scale renewable energy generation facilities. On February 28, 2011, the OEB issued a Decision and Order to amend Hydro One's transmission licence in accordance with this directive. Work to comply with this directive is underway.

3.4 Transmission System Code

Hydro One is bound by the terms of its transmission licence to adhere to the requirements of the Transmission System Code, administered by the OEB. The code addresses standards for operation, maintenance, management and expansion of transmission systems and requires Hydro One to operate and maintain its system in accordance with "good utility practice".

The Transmission System Code sets out the obligations of electricity transmitters with respect to their customers. As part of this, it establishes the rules governing the economic evaluation of transmission system connections and expansions and also sets the minimum standards for facilities connected to a transmission system. It also includes a Connection Agreement which covers the technical and commercial responsibilities of both transmitters and their customers.

The Transmission System Code was amended in October, 2009 to facilitate the timely and economically efficient connection of renewable generation in Ontario. The revised code defines the term "enabler facility" as a line connection or transformation facility allowing connection to the transmission system of two or more generators located within a renewable resource cluster. In addition, the revised code outlined technical requirements and cost responsibility for the development of such a facility taking into account the nature of renewable generation and the location of renewable clusters in Ontario.

3.5 Transmission Rates

The OEB approves both the revenue requirements of regulated transmission and distribution businesses and the rates they can charge. Hydro One's transmission rates are established as Uniform Transmission Rates, established for all transmitters in Ontario which are based on the fully allocated costs associated with providing each of the following three transmission service elements:

- ***Network services*** – the transmission network is the integrated part of Hydro One transmission system that is shared by all users and includes all 500 kV, 230 kV, and 115 kV facilities that can be classified as commonly used;

- ***Line connection services*** – connection facilities are the radial parts of Hydro One transmission system which are dedicated to serving a single or a group of customer(s) or generator(s);

- ***Transformation connection services*** – the transformation connection assets consist of the transformation facilities that step down voltages from transmission levels to distribution levels to supply customers.

3.6 Green Energy and Green Economy Act (GEGEA)

Ontario's *GEGEA* or *Bill 150* received Royal Assent on May 14, 2009. The *GEGEA* changed parts of the regulatory and policy framework of the electricity sector through legislation. It was an omnibus bill which included the establishment of a new *Green Energy Act* (*GEA*) and amended more than 15 then-existing statutes. Many of the associated policies are being promulgated through Ministry of Energy directives to agencies or authorities such as the OEB and OPA through changes to their mandates or through regulations made by the Lieutenant Governor in Council. The *GEA* and amendments to the *Electricity Act, 1998* and to the *Ontario Energy Board Act, 1998* will have specific implications for Hydro One.

The primary objective of the *GEGEA* is to advance the government's policies and direction with respect to:

- increased development and implementation of renewable-energy generation facilities;
- development and implementation of an advanced distribution system, or smart grid, within prescribed timelines;
- the achievement of prescribed conservation and demand management targets by distributors; and
- procedures to consult Aboriginal Peoples (First Nations and Métis communities) and other specified persons or groups, and measures to facilitate their participation in the development of renewable energy generation facilities, transmission and distribution systems.

The *GEGEA* includes extended obligations on transmitters and LDCs for the filing of plans and investment decisions with the OEB with respect to the first three objectives outlined above.

3.7 Ontario's Long-Term Energy Plan

On November 23, 2010, the Ministry of Energy released the *LTEP*, which sets out Ontario's expected electricity needs until 2030. The *LTEP* addresses seven key areas: demand, supply, conservation, transmission, Aboriginal communities, capital investments, and electricity prices.

The *LTEP* identified five priority transmission projects to effectively accommodate renewable projects, serve new load, and support reliability. These priority projects together with the Bruce to Milton 500 kV line, in addition to various other station and circuit upgrades, are expected to enable approximately 4,000 MW of additional renewable energy. The five priority transmission projects are described in Table 3.1.

On December 22, 2010, Hydro One was requested to proceed immediately with the planning and development work to advance three projects referred to in the *LTEP*, namely, series compensation in southwest Ontario; re-conductoring west of London; and a new line west of London.

When the Government issued its *LTEP* in November, 2010, it also issued a directive outlining the planned future mix of electricity generation from coal fuelled, nuclear, hydroelectric, and renewable energy sources. The directive re-emphasized government's intention to retire coal fuelled generation by 2014 and supported continued procurement of new, cleaner generation sources.

3.8 First Nations and Métis Consultation

Where appropriate, the Crown, together with Hydro One, will consult with affected First Nations and Métis communities for projects and activities which could potentially have significant impacts on their communities.

Further, Hydro One is committed to continue building positive, mutually beneficial relationships with First Nations and Métis communities, including support for employees interacting with community members and promoting business and workforce developments.

3.9 Renewed Regulatory Framework For Electricity

In early November of 2011, the OEB issued a set of five OEB staff discussion papers with an overarching objective of renewing the regulatory framework. This initiative is intended to help ensure the reliable and cost-effective delivery of electricity to Ontario consumers, in light of the significant anticipated investment needed for the renewal of existing assets and to connect new generation. The OEB staff discussion papers emphasize the need for an electricity system which is economically efficient; cost-effective; reliable, coordinated; and appropriately cost-allocated to benefit consumers, with tempered electricity rates and/ or total bills. The five discussion papers are as follows.

- ***Developing Guidance for the Implementation of Smart Grid in Ontario (EB-2011-0004)***: This OEB staff document issued for industry stakeholdering includes potential OEB Smart Grid (SG) policy, SG development expectations, and SG plan evaluation criteria. This work advances the SG objective of customer control, power system flexibility, and adaptive infrastructure while also meeting 10 Ontario government SG policy objectives outlined in an Order-In-Council dated November 23, 2010. The 10 government SG policy objectives are: efficiency; customer value; co-ordination; interoperability; security; privacy; safety; economic development; environmental benefits; and reliability.

- ***Approaches to Mitigation for Electricity Transmitters and Distributors (EB-2010-0378)***: This OEB staff document for industry stakeholdering provides potential approaches and tools for the OEB and utilities to mitigate the effects of unavoidable and significant customer rate and/or bill impacts.

- ***Defining and Measuring Performance of Electricity Transmitters and Distributors (EB-2010-0379)***: This OEB staff document for industry stakeholdering focuses on appropriate standards for performance and efficiency, provision of appropriate incentives, and review of utility performance.

- ***Regional Planning for Electricity Infrastructure (EB-2011-0043)***: This OEB staff document for industry stakeholdering focuses on coordinated planning on a regional basis for cost-effectiveness which is to be carried out among all parties (e.g., distributors,

Table 3.1 Priority Transmission Projects Identified in the LTEP

Project	Type	Need	Target Completion Date
Series compensation in Southwestern Ontario	Upgrade	Add renewables to grid	2014*
Rewiring west of London	Upgrade	Add renewables to grid	2014
West of London	New Line	Add renewables to grid	2017
East-West Tie	New Line	Maintain system reliability. allow more renewables. accommodate electricity requirements of new mineral processing projects	2016-2017
Line to Pickle Lake	New Line	Serve industry needs and help future remote community connection	Pending consultation

[* Planned Completion Date Is Now 2015]

transmitters, the OPA, and industrial customers). This planning approach in part addresses fair cost allocation issues among all customers.

- ***Distribution Network Investment Planning (EB-2010-0377)***: This OEB staff document for industry stakeholdering includes potential OEB requirements to enhance the quality and consistency of information filings with the OEB. For a cost of service filing, the document notes specific requirements including: an overview of capital expenditure; an asset management plan; a Green Energy Act plan; a Capital Expenditure for the Green Energy Act plan; load and revenue forecasts; and loss adjustment factors.

Pending completion of OEB's stakeholdering and finalization of OEB requirements, Hydro One intends to be proactive, and will participate in discussions regarding the issues raised. In some cases Hydro One is already carrying out work consistent with the proposed approaches outlined in the OEB staff discussion papers.

3.10 Transmitter Designation Process

The OEB issued a policy on *Framework for Transmission Project Development Plans (FTPDP, 2010)*, that encourages new electricity transmission entrants in Ontario, to support competition and drive economic efficiencies. The Ontario government's *LTEP (2010)* list the East-West Tie transmission project to be a designated project. This policy will affect transmission projects which may be built by Hydro One.

3.11 2011 Annual Report by the Auditor General

The Office of the Auditor General of Ontario released its "2011 Annual Report" on December 5, 2011, following its audit on a number of government programs and agencies. In regards to the Ontario's electricity sector, the audit was intended to assess whether there were adequate systems and procedures in place to ensure that:

- the electricity sector provides reliable and sustainable energy at a reasonable cost; and
- renewable energy resources are obtained in a cost-effective manner and within the context of applicable legislation and government policy.

The report observed that about half of the total charges on a typical electricity bill are not subject to OEB oversight and regulation. To ensure that consumers' interests are protected, the report called for more frequent consultations between the OEB, Ministry of Energy, and the OPA with respect to pricing undertakings by the Ministry and the OPA; and clear reasoning for each charge on consumer power bills to identify the entity receiving the proceeds from each charge.

The report also recognized that the growing contribution of intermittent solar and wind energy has increased uncertainty and created challenges for the planning and operational processes of the grid. To ensure that the reliability of the grid is not significantly affected by renewable energy generation over the next few years, the report asked the OPA to continue working with the IESO to assess the operational challenges, and advise the government to adjust the supply mix and energy plan accordingly.

3.12 Reliability Standards

Hydro One Networks, as an interconnected utility, is subject to reliability standards and criteria established by NERC (the North American Electricity Reliability Corporation) and the Northeast Power Coordinating Council (NPCC) of which Hydro One is a member. Compliance with NERC and NPCC reliability standards and criteria is mandatory as stipulated in Hydro One's transmission licence and the electricity market rules for Ontario.

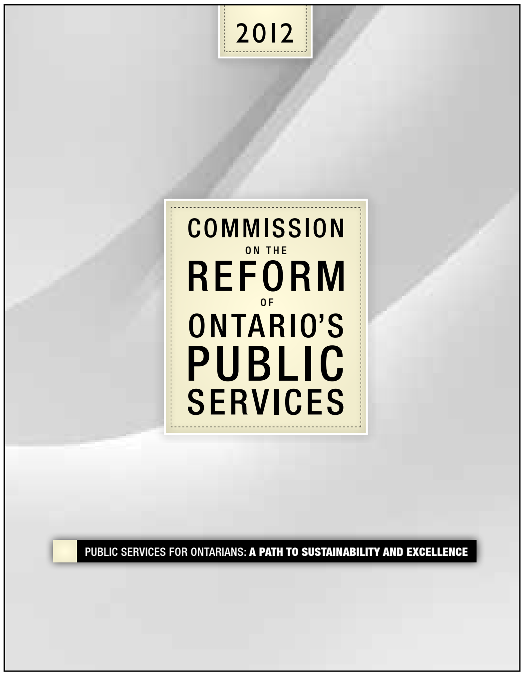
NERC's mission is to improve the reliability and system security of the bulk power system in North America. It does so by: developing and enforcing reliability standards; monitoring the reliability performance of the bulk power system; assessing future adequacy; auditing transmission system owners, operators and users for preparedness; and educating and training industry personnel. NERC is a self-regulatory organization that relies on the diverse and collective expertise of electricity industry participants. As the Electric Reliability Organization, NERC is subject to audit by the U.S. Federal Energy Regulatory Commission (FERC) and government authorities in Canada.

In addition to the reliability standards and criteria issued by NERC and enforced by the NPCC for the North East Region (which includes Ontario), the NPCC may prescribe additional and more stringent reliability standards and criteria to reflect the specific requirements of the region. Some of these are the direct result of the August 14, 2003 Blackout which seriously affected North Eastern North America. In Ontario, the Independent Electricity System Operator (IESO) is mandated by the *Electricity Act, 1998*, to be the monitor and overseer of compliance with the applicable NERC and NPCC reliability standards and criteria. Fines and other sanctions can be issued to non-compliant market participants.

The mandatory nature of these reliability standards and criteria requires Hydro One to make transmission system investments, in order to ensure compliance.

3.13 2012 Drummond Report

The February 15, 2012 Report on the Commission on the Reform of Ontario's Public Services (the "Drummond Report") contains 362 recommendations to address Ontario's $16 billion deficit within five years. The key recommendations which could impact Hydro One include:



Drummond Report, 2012

[a] Efficiencies:
Review the roles of various electricity sector agencies to identify areas for economies in administration. This includes examining the potential to coordinate back-office functions. Encourage operational efficiencies in line with industry's best practices, including strategic partnerships.

[b] Major Transmission Projects Strategic Partnerships:
Consider additional strategic partnerships for select, large transmission development projects to meet system needs, allow revenue and risk sharing, and afford development opportunities to local communities.

[c] Locational Electricity Pricing:
Government should restructure the electricity market so consumers located closer to generating stations can benefit from lower electricity prices.

[d] Integrated Power System Plan (IPSP):
The OPA needs to produce and issue an updated IPSP on the basis of the province's Long-Term Energy Plan.

[e] Local Distribution Companies (LDCs) Consolidation:
Consolidate Ontario's 80 LDCs along regional lines to create economies of scale.

[f] Non-Divesture Of Government Business Enterprises:
Do not partially or fully divest Hydro One (and other government business enterprises) – unless the net long-term benefit to Ontario is considerable and can be demonstrated through comprehensive analysis.

SYSTEM RELIABILITY & PERFORMANCE

4. SYSTEM RELIABILITY & PERFORMANCE

4.1 Reliability Framework

Transmission system reliability is a key business value for Hydro One, and power system reliability has particular significance in transmission planning.

As noted in Section 2.4.2, transmission system reliability in Ontario is regulated and enforced by the Independent Electricity System Operator (IESO), through market rules requiring market participants (including Hydro One) to comply with reliability standards, criteria and rules established by the North American Electric Reliability Corporation (NERC), the Northeast Power Coordinating Council (NPCC), and the IESO. These standards are enforced by the Market Assessment & Compliance Division (MACD) of the IESO.

In this context, the term "reliability" is defined as follows:

> *The degree of performance of the bulk electric system that results in electricity being delivered to customers within accepted standards and in the amount desired. Reliability may be measured by the frequency, duration, and magnitude of adverse effects on the electric supply. Electric system reliability can be addressed by considering two basic and functional aspects of the electric system – adequacy and security.*

Adequacy is the ability of the electric system to supply the aggregate electrical demand and energy requirements of the customers at all times, taking into account scheduled and reasonably expected unscheduled outages of system elements. Security is the ability of the electric system to withstand disturbances such as electrical short circuits or unanticipated loss of system elements.

Compliance with reliability standards and criteria requires Hydro One Transmission to make investments as necessary.

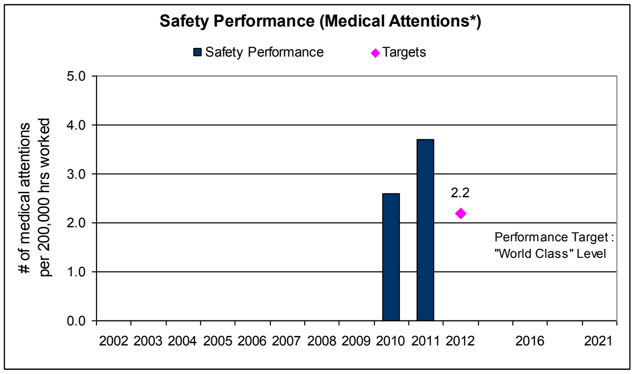
4.2 Transmission System Performance

Hydro One has established performance measures and targets in the areas of safety, customer satisfaction, reliability, and service delivery performance. This section provides an overview discussion of those key transmission system performance criteria.

4.2.1 Safety

The nature of the industry is such that its workers are exposed to many potential hazards and risks on a daily basis. Recognizing this, safety is of paramount importance to Hydro One. The company has implemented a safety management system which assesses work activities, associated risks and safety control measures, sets safety objectives and includes defined safety programs to manage the various risks.

Figure 4.1 Safety Performance (Medical Attentions Metric) – Actual and Targets



* Medical Attentions measure was initiated in year 2010, therefore no historical information is provided for years 2002-2009.

Figure 4.2 Customer Satisfaction – Actual and Targets

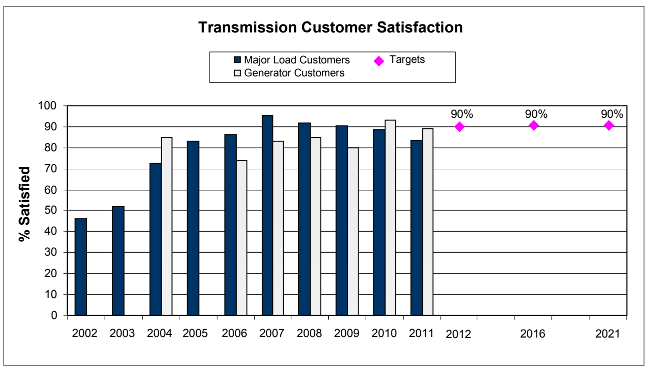


Table 4.1 Transmission Reliability Measures

Service Quality Area	Reliability Measures	Description
Customer Reliability	Frequency of Delivery Point Interruptions (average # of interruptions per delivery point*)	The average number of planned, forced and momentary interruptions experienced at customer delivery points
	Duration of Delivery Point Interruptions (average # of minutes of interruptions per delivery point)	The average duration of planned and forced interruptions experienced at customer delivery points
	Unsupplied Energy (system minutes of energy not supplied)	Energy not supplied to customers as a result of planned and forced interruptions
System Unavailability	Transmission System Unavailability (Percentage of system not available)	The extent to which transmission lines are not available for use by market participants due to planned and forced outages on the transmission system

** Delivery Points are the interface points between the Hydro One transmission system and its load customers. They consist of: (a) all Hydro One owned step-down transformer stations' low-voltage buses, and (b) stations owned by end-use transmission customers, including Local Distribution Companies and other transmitters interfacing at 115 kV or higher.*

Hydro One includes the "Medical Attentions" metric to track the effectiveness of its overall safety management program. The Medical Attentions metric replaces the Lost Time Injuries as the primary Health and Safety performance measure for Hydro One. This change was made because the frequency of lost time injuries is historically quite low and does not provide the best measure upon which to base Hydro One's improvement initiatives.

The Medical Attentions metric measures the number of injuries per 200,000 hours worked that require treatment by medical practitioner (i.e., beyond first aid). Figure 4.1a shows the historical safety performance using this performance measure over the period 2002-2011. Performance targets for 2012 and the longer term are also shown on this figure.

Ensuring safety in Hydro One in the future will require constant vigilance and focus. This is highlighted as a result of projected increases in the volume and number of work programs and changes and increases in staff, many of whom will either be new to the electricity industry or to the workforce.

4.2.2 Customer Satisfaction

Customer satisfaction is a priority for Hydro One. Customer satisfaction is measured using customer surveys which are designed to assess customer attitudes towards cost-effectiveness and service quality. Attributes considered include overall electricity price, value for service received, reliability and power quality, meeting commitments, community presence, communication effectiveness, and corporate image and reputation). These surveys are conducted with both major (large, directly connected) customers and generator customers to gauge customer satisfaction.

The historical performance for this measure over the 2002-2011 time frame is shown in Figure 4.2 along with the performance targets in future years. Hydro One's longer term customer satisfaction target is to achieve an average satisfaction level of 90% across all customer segments.

4.2.3 Transmission Reliability

Hydro One applies a number of measures to track transmission system reliability. These measures also reflect service quality and are can be thought of in terms of two broad categories: Customer Reliability and System Unavailability. Each of these categories may have one or more specific reliability measures as indicated in Table 4.1. These reliability measures are commonly used in the transmission industry. They are discussed further in the next subsections.

4.2.3.1 Frequency of Delivery Point Interruptions

Figure 4.3a and 4.3b shows the historical performance over the period 2002-2011 for the Frequency of Delivery Point Interruptions reliability performance measure and the target levels set for future years. Based on benchmarking data with comparable North American utilities, that portion of Hydro One's transmission system operating at or above 230 kV ranks in the first or second quartile depending on the particular metric used. For its 115 kV system, Hydro One ranks in the third or fourth quartile depending on the metric used. These results are not unexpected given the largely rural nature of Hydro One's 115 kV system and the long distances covered across the province. In urban areas, where the 115 kV system tends to have two or more supply sources, performance is better.

The objective over the next 10 years is to steadily improve transmission system performance to achieve a frequency of delivery point interruptions measure target as indicated in Figure 4.3a and 4.3b, and move Hydro One Networks overall ranking for sustained interruptions to the first quartile compared to other utilities.

4.2.3.2 Duration of Delivery Point Interruptions

Figure 4.4 shows the historical performance of the Duration of Delivery Point Interruptions reliability measure over the period 2002-2011 and the performance targets established for future years. Benchmarking results indicate that the portion of Hydro One's transmission system operating at or above 230 kV ranks in the second quartile with respect to the duration of sustained forced outage interruptions. The corresponding results for the predominantly rural 115 kV system show rankings in the third or fourth quartile depending on the metric used. The portion of the 115 kV system in urban areas with two or more supply sources has much better system performance.

In July of 2011, a forest fire in Northern Ontario caused damage to over 80 wood pole structures and some transmission line equipment. A total of 628 customers were affected during the outage and there was 16 MW of load loss. In total, this forest fire event contributed 70 minutes to T-SAIDI, about half of the total average of interruption duration in 2011. The effect of this fire on the Duration of Delivery Point Interruptions performance measure has been shown graphically in Figure 4.4.

Hydro One Networks plans to make steady improvements to its transmission system over the period 2012-2021 to achieve a first quartile performance ranking compared to other utilities for this measure.

Figure 4.3a Frequency of Delivery Point (DP) Momentary Interruptions – Actual and Targets

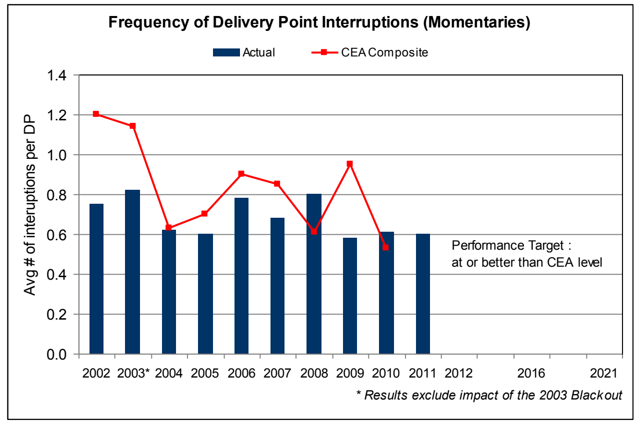


Figure 4.3b Frequency of Delivery Point (DP) Forced Sustained Interruptions – Actual and Targets

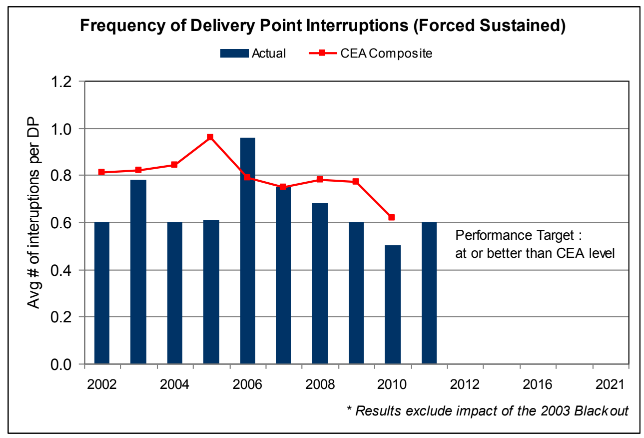


Figure 4.4 Duration of Delivery Point (DP) Interruptions – Actual and Targets

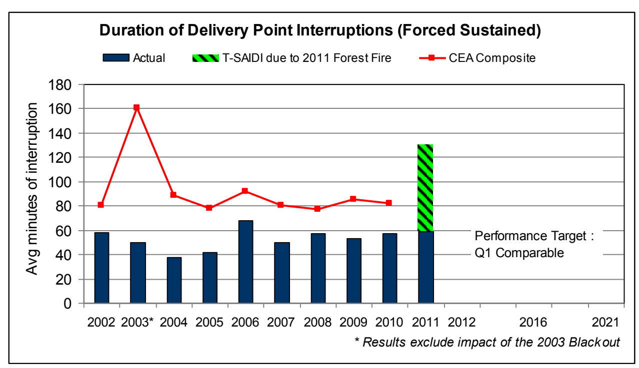


Figure 4.5 Transmission Unsupplied Energy – Actual and Targets

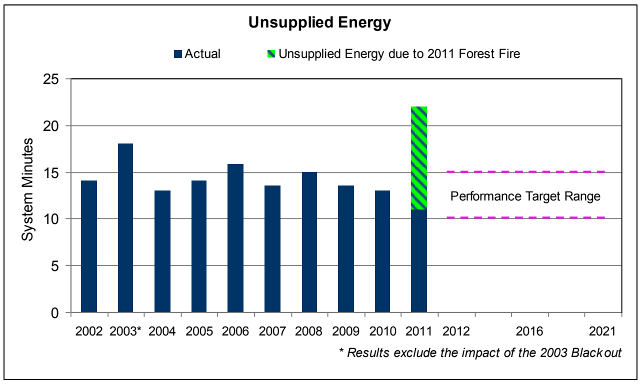


Figure 4.6a Transmission System Forced Unavailability (Line Equipment) – Actual and Targets

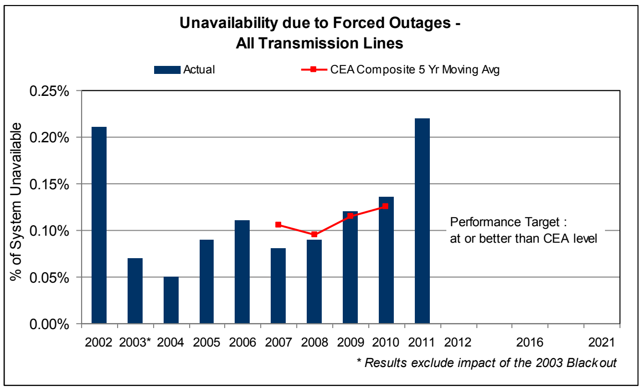


Figure 4.6b Transmission System Forced Unavailability (Station Equipment) – Actual and Targets

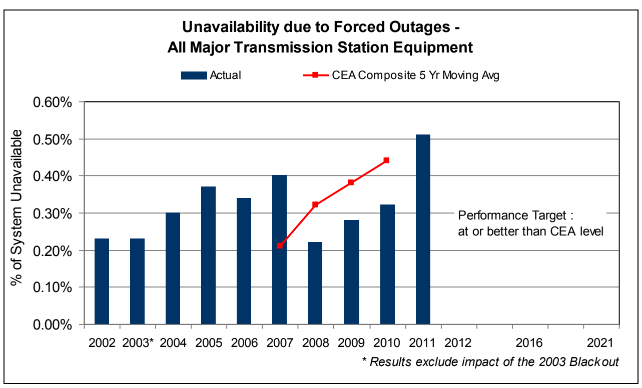
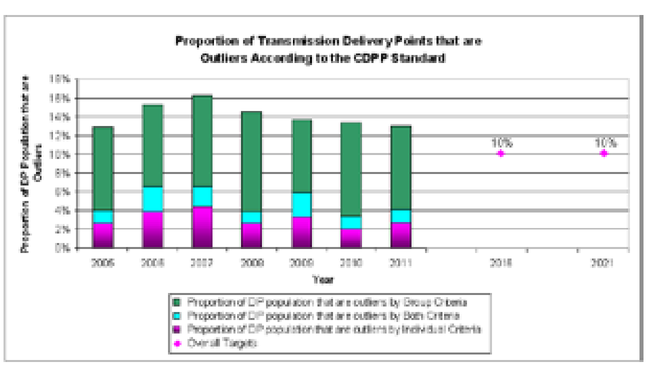


Figure 4.7 Proportion of Transmission Delivery Points that are Outliers – Actual and Targets



* Note: 2011 results are preliminary values.

4.2.3.3 Unsupplied Energy

Figure 4.5 shows the historical results for this reliability measure over the period 2002-2011 and the target range over the next 10 years. The Unsupplied Energy measure is not commonly tracked for benchmarking comparisons and the performance targets can therefore not be correlated to utility benchmarking results. However, improvement to the transmission system performance as outlined in the previous sections will also reflect onto this measure.

4.2.3.4 Transmission System Unavailability

Figure 4.6a and 4.6b shows the results for transmission system unavailability due to forced outages of line equipment and station equipment over the period 2002-2011 and a performance target range for the next 10-year period. Achievement of these targets will lead Hydro One transmission into the first quartile ranking by 2021 compared to other utilities.

4.2.4 Service Delivery Performance

Aside from the system wide transmission performance measures described in Section 2.5 of the OEB's Transmission System Code (TSC), Hydro One is also required to track reliability performance at customer load delivery points.

The Customer Delivery Point Performance (CDPP) Standard in the TSC helps to identify Delivery Point performance outliers for Hydro One's transmission system. The CDPP is comprised of two components: (1) the reliability of supply, which is dependent on the size of load being served ("Group Criteria"); and (2) the customers' individual historical delivery point performance ("Individual Criteria"). The CDPP Standard was developed by Hydro One in 2002 and reviewed with stakeholders during the period 2002-2004. It was accepted by the Ontario Energy Board (OEB) in 2008.

This standard was originally designed in 2002 on the assumption that about 10% of Hydro One's Delivery Points would be performance outliers.

Figure 4.7 illustrates the proportion of delivery points that are outliers, with annual historical results plotted from 2005 to 2011.

According to the CDPP standard, "…..Networks level of incremental investment for improving the performance of an outlier will be limited to the present value of three years worth of transformation and/or transmission line connection revenue associated with that delivery point. Any funding shortfalls for improving delivery point reliability performance will be made up by affected delivery point customers in the form of a financial/capital contribution." (*RP-1999-0057/EB-2002-0424* - Hydro One Networks Inc. Supplementary Submission. Customer Delivery Point Performance Standards, Revised September 2004).

Although Hydro One is not obligated to address the Delivery Point outliers beyond those required by the CDPP standard, Hydro One plans to carry out cost-effective remedial action. Addressing performance "outliers" will contribute significantly to achieving Hydro One's top quartile Q1 reliability objectives.

4.2.5 Power Quality

Reliability performance measures include power interruption events experienced by customers. In the past, power disturbances experienced by customers owing to power quality events were not included in Hydro One's performance measures. For example, a fault on a feeder close to a transformer station may cause the bus voltage at the station to dip well below normal operating voltage levels. Such a voltage dip, with duration of less than one second, can adversely affect customer loads and their business operations. These kinds of events are now systematically recorded and analyzed at about 30 points in Hydro One's electrical network.

With an increasing number of permanent power quality monitors installed in the Hydro One network system, it will be possible to develop baseline levels for power quality performance measures, including voltage dips, transients and harmonics.

4.3 Performance Benchmarking

4.3.1 System Reliability

Performance benchmarking of transmission system reliability is challenging owing to the absence of a uniform standard within the electricity industry. Typically, each benchmarking study initiative establishes its own definitions and reports results consistent with such definitions. Definitions and the number of participating utilities vary from study to study.

Benchmarking Hydro One Transmission & Comparable Canadian Transmission Companies

Transmission reliability performance benchmarking for Canadian utilities continues to be undertaken by the Canadian Electricity Association (CEA). Results are reported by the CEA on an annual basis.

Summary of Findings – Canadian Utilities

- Hydro One's delivery performance for multi-circuits or lines supplied via the 230/115 kV "backbone" transmission system is in the top quartile compared to other large Canadian transmission companies. Most transmission stations serving urban centers are served by this type of transmission arrangement.
- Hydro One's delivery performance for 115 kV delivery points which are served by single circuits or lines is generally poorer than its delivery performance for delivery points with multi-circuit supplies. The 115 kV system in urban areas with two or more supply sources has much better system performance.

Benchmarking Hydro One Transmission & Comparable North American Transmission Companies

In order to provide additional reliability comparison perspectives, Hydro One also participates in a statistical and comparative study of transmission reliability in the U.S., administered by SGS, a utility consultancy. Hydro One's performance relating to frequency and duration of interruptions are illustrated in Figures 4.8 and 4.9. The graphs show Hydro One's relative quartile performance of delivery point reliability compared to other transmission companies that participated in the SGS study. Although there are some inconsistencies in both definitions and reporting practices within the study, the results are considered accurate enough for broad, system performance comparisons. The measures are system averages for frequency and duration and include forced interruptions to transmission delivery points. The study includes delivery point interruptions by transmission

Figure 4.8 Delivery Point Outages per 100 miles for Delivery Points Served by >=230kV (From SGS Transmission Reliability Benchmarking Study Results) – Actual and Targets

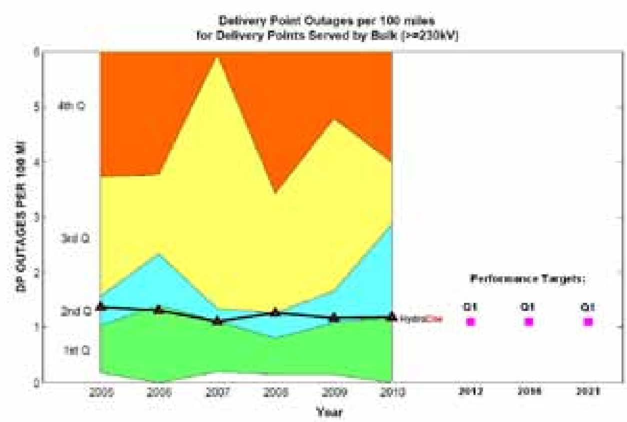
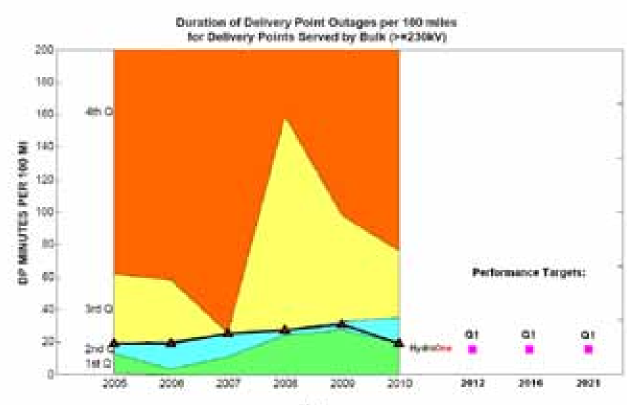


Figure 4.9 Delivery Point Outage Duration per 100 miles for Delivery Points Served by >=230kV (From SGS Transmission Reliability Benchmarking Study Results) – Actual and Targets



* Notes:
(1) The quartile values are reported as part of the study results.
(2) Measures are system averages for frequency and duration and include non-planned interruptions to transmission delivery points due to circuit outages only.

line outages only. Other transmission system failures at the sub-station level affecting delivery points are not included in the study results.

The results indicate that for 230 kV and above systems, Hydro One is generally performing in the second quartile within this study. For systems in the 100-161 kV range, Hydro One is primarily in the third or fourth quartile depending on the metric used. Hydro One's transmission lines, and particularly those at the 115 kV level typically run though remote geographic locations, with longer radial circuits than most comparable transmission companies.

4.3.2 Cost Effectiveness

Hydro One's cost effectiveness is compared with other Canadian utilities using survey information carried out by the Canadian Electrical Association (CEA) - Committee on Performance Excellence (COPE).

Cost Effectiveness Logic

There is no single industry measure for cost effectiveness, however certain measures are considered valid. The two major elements of these measures are the comparability of input costs and the largest indicator of output. Measures in terms of cost per unit output are commonly used in the utility industry.

Comparability of costs is essential for rigour, and costs at the macro level are more consistent with accounting practices. Accordingly for costs:

- Total Cost provides the most consistent comparison;
- Operations, Maintenance, and Administration costs plus Sustaining Maintenance Capital costs provides the best view of managed costs;
- Operations, Maintenance, and Administration costs provide the best view of operational costs.

The output parameters focus on three elements: Gross Fixed Assets (GFA); System Peak (MW) load; and electrical energy delivered times kilometres (MWh x km). These output parameters provide the following:

- GFA is the best indicator of overall assets managed;
- The infrastructure is generally built and managed to provide system capacity, and System Peak (MW) load is considered the appropriate surrogate;
- MWh x km is the appropriate normalizer for energy transported by the transmission system over distances to customers, as each element individually can be misleading, (e.g., long low voltage lines or large volume over very short distances).

Cost Comparisons

For a comprehensive view of overall Cost Effectiveness, Hydro One uses three main indicators. These indicators are expressed in terms of the managed costs per dollar of assets managed; total cost per MW of system peak capacity; and operating cost per MWh-km of energy transported.

Figures 4.10 to 4.12 provide graphs which illustrate historical trends for the three main indicators for the 2006 to 2010 period. Comparative information prior to 2006 is unavailable.

Figure 4.10 indicates that Hydro One has performed better than the CEA average in terms of dollars spent per MW of system peak capacity for the five years surveyed.

Figure 4.11 indicates that Hydro One has performed better than the CEA average in terms of dollars spent per dollar of gross fixed assets for the five years surveyed.

Figure 4.12 indicates that Hydro One has performed better than the CEA average in terms of cost per circuit MWh-km delivered for the five years surveyed.

Figure 4.10 Total Cost per MW of System Peak Capacity

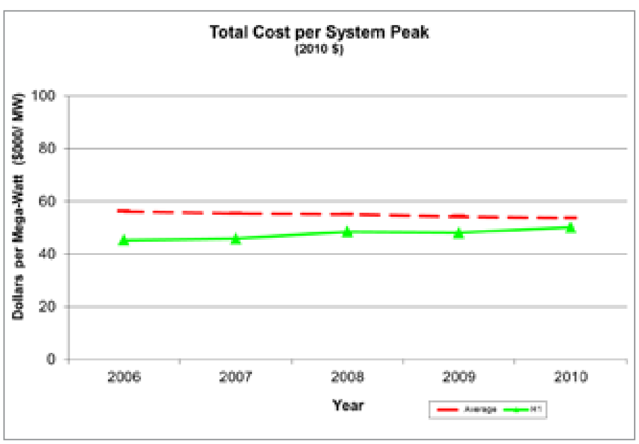


Figure 4.11 Total OM&A plus Sustainable Maintenance Capital (SMC) as a Percentage of Gross Fixed Assets

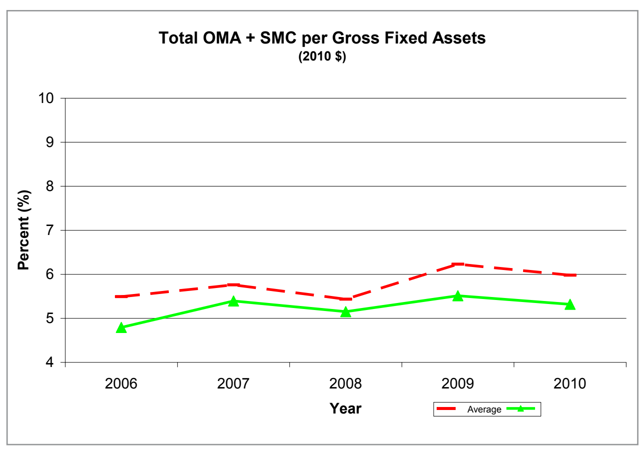
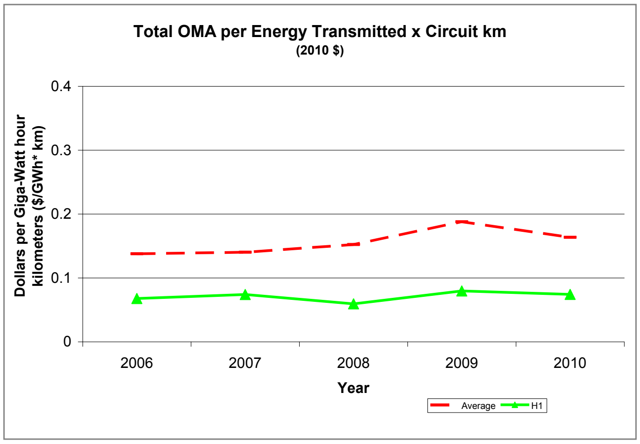


Figure 4.12 Total OM&A per Energy transmitted times Circuit Kilometres



Other Measures

The most recent 2010 COPE survey included a number of other performance metrics. The survey results for the nine individual utility members are kept confidential, and the average results are available for comparisons. Table 4.2 lists the cost related performance metrics along with Hydro One's performance compared to the average results.

Hydro One's performance is better than average on 85% of the cost related performance metrics examined in the CEA study.

Table 4.2 Comparison to CEA Average Performance

Performance Indicator	Hydro One's Performance Compared to the CEA Average Results
Total Cost per Energy Transmitted	Better than Average
Total Cost per System Peak	Better than Average
Total OMA Cost per Circuit km	Poorer than Average
Total OMA Cost per Energy Transmitted * Circuit km	Better than Average
Total OMA per Gross Fixed Assets (%)	Better than Average
Direct OM Cost per Circuit km	Poorer than Average
Direct OM per Energy Transmitted * Circuit km	Better than Average
Direct OM Cost per Gross Fixed Assets (%)	Better than Average
Total OMA + Sustaining Maintenance Capital per Energy Transmitted GWh * Circuit km	Better than Average
Total OMA + Sustaining Maintenance Capital per System Peak	Better than Average
Total OMA + Sustaining Maintenance Capital per Gross Fixed Assets (%)	Better than Average
Gross Fixed Assets per Energy Transmitted	Better than Average
Gross Fixed Assets per System Peak	Better than Average

TRANSMISSION SUSTAINMENT

5. TRANSMISSION SUSTAINMENT

This section provides an overview of the projected work scope for Transmission Sustainment over the 10-year Outlook horizon. Transmission Sustainment constitutes one of the major transmission work programs.

5.1 Sustainment Considerations

The transmission sustainment work program has been established to ensure that the existing transmission system remains adequately reliable and economical to meet customer needs. It covers the work ranging from preventative and corrective maintenance to refurbishment and full-scale replacement of assets as required to ensure that the existing transmission infrastructure and facilities remain at the required performance level. Decisions to maintain or replace transmission system assets are made on the basis of a life-cycle management approach which considers and balances asset performance, costs and associated risks during the asset service life in order to achieve asset optimization. Efficiencies associated with bundling related work and balancing workloads with available resources are also considered.

The development of short and long term asset sustainment work is guided by Hydro One's corporate strategy, which reflects the four strategic business values of Health and Safety, Stewardship, Excellence, and Innovation, and a set of underpinning strategic objectives (discussed in Section 2).

5.2 Factors Affecting Sustainment of Assets

There are a number of factors which could affect Hydro One's transmission assets and their operating performance during their expected service life. These factors must be considered in asset sustainment planning and management to provide an integrated perspective in investment planning and to facilitate appropriate investment decisions. These are illustrated in Figure 5.0. They include:

1. asset demographics;
2. asset condition;
3. obsolescence;
4. performance;
5. utilization;
6. criticality;
7. economics;
8. health, safety, and environment;
9. other regulatory and policy considerations.

5.2.1 Asset Demographics

Asset demographics, particularly statistics regarding asset ages, provide useful information with respect to the asset's projected end-of-life compared to the asset's original design life.

Hydro One manages a large number of fixed assets that are mostly in the middle to late stages of their expected lifespan. A significant percentage of those fixed assets are nearing their expected end-of-life (EOL) over the next few years. In general, OM&A costs associated with an asset can increase in the mid-life region due to the need for more extensive maintenance as certain component parts begin to wear out. Investments are required in order to prevent premature equipment EOL and to maintain performance. These trends are evident in all transmission stations and lines assets. When assets reach EOL they require replacement (assuming the functionality they have provided in the past is still required), and this affects capital costs.

Hydro One studies demographic trends to identify long term Capital and OM&A funding requirements that are likely to persist given the ages of transmission system assets.

The number of assets that will need replacing due to failure or unacceptable asset performance is expected to increase gradually over the long-term as the system progressively ages. The impacts on overall performance of the transmission system and impact on workforce requirements will need to be monitored closely through Hydro One's ongoing maintenance and performance analysis programs.

5.2.2 Asset Condition

Another important factor in asset sustainment planning is the actual condition of an asset based on its service conditions, operating history, physical inspection results, and performance over the years. Hydro One conducts regular assessments of the condition of its assets. These condition assessments are critical in determining the fitness-for-service of the assets and the results are used as one of the key inputs into the planning and development of asset sustainment programs.

The purpose of asset condition assessment (ACA) is to detect and quantify long-term asset degradation and provide some means of quantifying remaining asset life. The rate of change in asset condition over time helps to identify deterioration trends and helps to establish maintenance, refurbishment or replacement requirements based on an asset's ability to perform reliably. Other asset assessment tools include the results of incident investigations for specific assets. Factors such as technical obsolescence, spare parts availability, and asset performance (which include asset failure rates and trends) are also given consideration when making an EOL asset decision.

ACA information is one of several factors used by planners in defining the sustainment investment programs (capital and OM&A) to manage asset operational risks. In the future, such decisions will be complemented by results from the Asset Analytics initiative. This initiative is discussed further in Section 10.1.

Hydro One has been using condition assessment practices for many years. ACA results are based on a consistent approach with the objective of applying a clear and unambiguous interpretation across the asset classes.

ACA ratings are assigned to assets as follows:

Table 5.1 ACA Ratings Interpretation

ACA Rating	Action	Timeframe For Action (Where Applicable)
Very Poor	Decide on equipment replacement	At earliest
Poor	Plan replacement/ refurbishment	1 to 5 years
Fair	Integrate into short/long term planning	5 to 10 years
Good	Long term planning	10 to 20 years
Very Good	-	> 20 years

Figure 5.0 Factors Affecting Sustainment of Assets

5.2.3 Obsolescence

Obsolescence refers to the risks associated with obtaining original equipment manufacturer (OEM) or qualified third party technical support, spare parts, and resources with the necessary skill sets to perform routine or major maintenance.

Equipment manufacturers will typically support their products and provide spare parts and necessary repair/ refurbishment capabilities for a fixed period of time following initial manufacture. Thereafter, equipment owners may be required to support the products themselves or find alternative, and usually very expensive, third party service providers to support any products which remain in-service.

OEM and/or third party support for products can be dropped for a number of reasons including:
- to prompt sales of alternate models or products as a result of commercial failure of a supplier;
- acquisition of manufacturers or service providers by competitors with an interest in a different product or technology;
- because of the emergence of newer, better technologies which drops interest in older technologies;
- geo-political events make purchases from a particular country or region impossible or excessively costly.

The risk of obsolescence is generally greater for equipment which is near, or beyond, its expected service life. In addition, prototype models of new technologies often become obsolete relatively quickly as new developments are made to improve functionality, performance and safety of the equipment. For example, oil, air-magnetic, and air-blast circuit breakers are examples of early circuit breaker technologies, some of which are in use in the Hydro One transmission system; and, these are no longer manufactured or supported by the OEM.

Unlike some other asset types, protection and control systems have seen dramatic technological changes over the last 10 or more years. These changes have occurred primarily due to the introduction of digital technology that has quickly enabled integrated functionality of protection, control, monitoring and telecommunications systems. This has rendered many of the “older” electromechanical and solid state systems functionally obsolete.

5.2.4 Performance

Transmission reliability performance is examined on an ongoing basis to identify system, customer or equipment performance trends, issues and risks. Hydro One also assesses historical performance trends in comparison to data on national performance levels obtained from the Canadian Electrical Association (CEA) and other North American utilities. Generally, the Hydro One bulk power system (230 kV and above) performs “well”. The 115 kV system performs at a “poor” level relative to other comparable North American utilities, since Hydro One operates a relatively large number of long length radial transmission lines (with no alternate flow path in the event of failure) compared to other utilities.

Outage events and equipment failures are investigated to identify the root cause of failures, ascertain the suitability of inspection and/or maintenance requirements, and develop a remedial action plan, as appropriate, to proactively address future reliability risks. Below normal performance, deteriorating performance trends, or high risk issues are addressed and managed using sustaining remedial actions that may consist of increased maintenance, monitoring, refurbishment or replacement.

Addressing performance issues early is a valuable tool for helping to avoid coincidental equipment failures which can lead to greater incidence of high impact, low probability interruption events.

5.2.5 Utilization

As the power system expands, existing transmission equipment can be loaded and stressed to higher levels. When loading and stresses exceed the equipment nameplate ratings and design capability, the equipment must be replaced with higher rated units to ensure continued safety and reliability of supply.

For example, connection of new generation sources can increase the short circuit levels of the transmission system. Any breaker exposed to a fault higher than its capability (rating) could suffer severe consequences ranging from burnt contacts to an explosive failure. This scenario represents a safety hazard and must be rectified immediately either by reducing the maximum short circuit levels to which it could be exposed, or by replacing or upgrading the circuit breaker to one of higher rating.

In addition, existing equipment, particularly older equipment, may not be ideal for service as the performance or functional requirements change over time. Faster or greater equipment wear can result when exposed to more severe service than originally intended. Such equipment should be replaced or refurbished with more capable, standard units or maintenance schedules should be reinforced to address increased wear out. For example oil circuit breakers have been found to be unsuitable for handling high voltage capacitor or reactor switching duties. Where oil circuit breakers are found with such service conditions they are scheduled for replacement. Until the replacement occurs, reinforced maintenance schedules are applied to examine and, if necessary, replace worn out contacts, thereby reducing the risk of breaker failure.

5.2.6 Criticality

Transmission system criticality refers to the priority of assets based on their relative importance or criticality to the business. The criticality of transmission stations, lines and other assets and components, considers factors such as the effect on public and employee safety, the degree of importance to the sustained operation and reliability of the transmission system, and compliance with regulatory requirements.

Criticality is used as a proxy measure for the risk impacts and consequences of asset and equipment failures on customers and system reliability. This is a major factor in helping to prioritize sustainment work and investment requirements.

5.2.7 Economics

The cost incurred to sustain an asset and maintain its functionality has a direct impact on attainment of Hydro One's "Shareholder Value" business value. At some point in an asset's life, it will become more cost effective to replace the asset than continue repairing it. In addition, the cost incurred to sustain an asset can be considered to provide an indirect indication of the condition of the asset. Sustainment costs for a specific asset rising above some reference value determined for a group of similar assets may point to technical as well as economic concerns, particularly where the costs considered include corrective, preventative and emergency maintenance costs, but exclude upgrade or replacement costs.

5.2.8 Health and Safety, Environment

Certain legacy equipment may have design defects, manufacturing defects, or exhibit faster than expected deterioration which could pose potential health, safety, and/or environmental concerns. Hydro One makes no compromises with regard to such situations. Those situations which could possibly result in unacceptable risks are identified and practical risk mitigation steps are put in place. Risk mitigation may result in new sustainment work programs being formulated or current plans being advanced to address identified concerns.

The sites on which Hydro One's transformer and switching stations are located may, in some instances, contain contaminated soil that requires remediation. Soil contamination has occurred at some sites as a result of various practices which were common in the past. These include: application of certain long lasting chemicals such as wood preservatives and arsenic-based herbicides; storage and use of mineral insulating oil, fuel, PCBs; and storage and use of other materials. Those practices conformed to regulations in force at the time but the resulting contamination could exceed modern day allowable limits. The extent of remediation at any particular site depends on the historical and current practices used at that site, the type and extent of any contamination, and current applicable regulations and compliance requirements.

Over the years, Hydro One carried out site clean-up and remediation programs to ensure compliance with applicable regulations and consistent with its corporate philosophy with respect to environmental stewardship. These programs will continue as part of Hydro One's transmission asset sustainment work programs for as long as needed to remediate known problems.

In addition to site remediation, Hydro One has an ongoing effort to identify and remediate transmission equipment which may contain unacceptable levels of PCBs. Very few of Hydro One's transmission assets are contaminated with PCBs at levels in excess of 500 ppm, but sustainment program work will continue to be required for several years to identify such assets. As PCB regulations become more restrictive, further work definition may be required.

5.2.9 Other Regulatory and Policy Considerations

The broader transmission regulatory framework is discussed in Section 3. Government policy and OEB-approved revenues and rates will affect the scope of Hydro One's sustainment programs and the ability to make the required sustainment investments.

Hydro One must also comply with the reliability standards and criteria prescribed by NERC and the NPCC. To the extent that these regulatory authorities prescribe new or changed regulations that could impact transmission assets and infrastructure or transmission operating, Hydro One is legally obligated to meet these requirements. This can affect the scope and pace of Hydro One's sustainment efforts, both by raising the priority of some work and by shifting resources away from other planned work.

5.3 Asset Base and Priorities

5.3.1 Stations and Lines

The key physical assets comprising the Hydro One Transmission System are summarized in Table 5.2. As indicated, the assets are grouped into the two major categories of Stations and Lines.

Table 5.2 Hydro One Transmission System – Key Assets

Hydro One Transmission System Assets At December 31, 2011	
Stations	
> Transmission Stations	285 (Total)
Transformer Stations	250
Switching Stations	35
> Circuit Breakers	4,490 (Total)
Oil Circuit Breakers	1,923
Air-blast Circuit Breakers	190
SF6 Circuit Breakers	1,376
GIS Circuit Breakers	99
Metalclad Circuit Breakers	866
Vacuum Circuit Breakers	36
> Transformer Banks (115 kV and above)	719 (Total)
Step-down transformers	572
Auto-transformers	134
Phase shifters	5
Regulators	8
Lines	
> Overhead Transmission Lines (circuit-km)	28,636 (Total)
500 kV Overhead Lines	3,778
345 kV Overhead Lines	6
230 kV Overhead Lines	14,098
115 kV Overhead Lines	10,753
69 kV Overhead Lines	1
> Underground Cables (circuit-km) (115 kV and above)	291 (Total)

Note:

[1] The number of transformers and circuit breakers are the equivalent three-phase banks.
The number of individual three-phase and single-phase transformers are 705 and 42 units, respectively. These exclude operating spares.
The number of individual three-phase and single-phase circuit breakers are 4,418 and 234 units, respectively.

5.3.2 Transmission Asset Classes and Priorities

The transmission assets that make up the two major asset categories of stations and lines are grouped into a total of 43 different asset classes. As mentioned earlier, the importance or criticality of a particular asset class to the transmission system is determined based on assessment of a number of factors including: public and employee safety risks; degree of importance to the sustained operation and reliability of the transmission system; system security issues; supply chain considerations; environmental considerations; compliance with regulatory requirements; and economics.

Based on these assessments, the 43 asset classes have been classified into one of three priority groups as indicated in Figure 5.1. Priority 1 assets represent the highest priority assets from both a value and risk standpoint. Priority 1 assets account for about 80% of total sustainment program funding, with Priority 2 assets at approximately 15% and Priority 3 assets at 5%.

5.4 Sustainment Work Program

Hydro One's transmission assets are aging, and approaching their expected end-of-life. If the pace of sustainment work is inadequate, this could affect reliability performance and challenge Hydro One's resources. Most utilities in North America face similar aging infrastructure challenges. Replacing the entire old infrastructure "like for like" is not a straightforward task owing to the need to balance competing requirements and priorities of reliability, cost, financial returns, and the environment. Further, the current transmission infrastructure dates back more than 100 years and some replacement parts may no longer be available. Operating requirements for some assets may also have changed significantly from their original design, meaning that like-for-like replacement of aging equipment, even if possible, is often not optimal.

The development of short and long term work programs for managing the maintenance and refurbishment/replacement of existing transmission system infrastructure is guided by Hydro One's corporate strategy, and a set of underpinning strategic objectives, as discussed in Section 2.

Hydro One's sustainment work program aims to maximize the value of existing assets while leveraging opportunities for infrastructure renewal that make the transmission system more robust and flexible, and also address the industry's imperatives for connecting more new, clean and renewable generation sources.

5.5 Transmission Asset Portfolios - Capital

Transmission asset sustainment portfolios have been established to provide an overview of the current and projected demographics, condition, and performance (where data is available) for individual asset classes in the Hydro One transmission system. For each portfolio, information is provided as to how sustainment work programs can address the challenge of aging infrastructure and maintain the current levels of asset condition and performance. Additional information is provided with regard to alternative levels of work, recognizing key uncertainties (e.g., faster or slower pace of equipment deterioration near end-of-life).

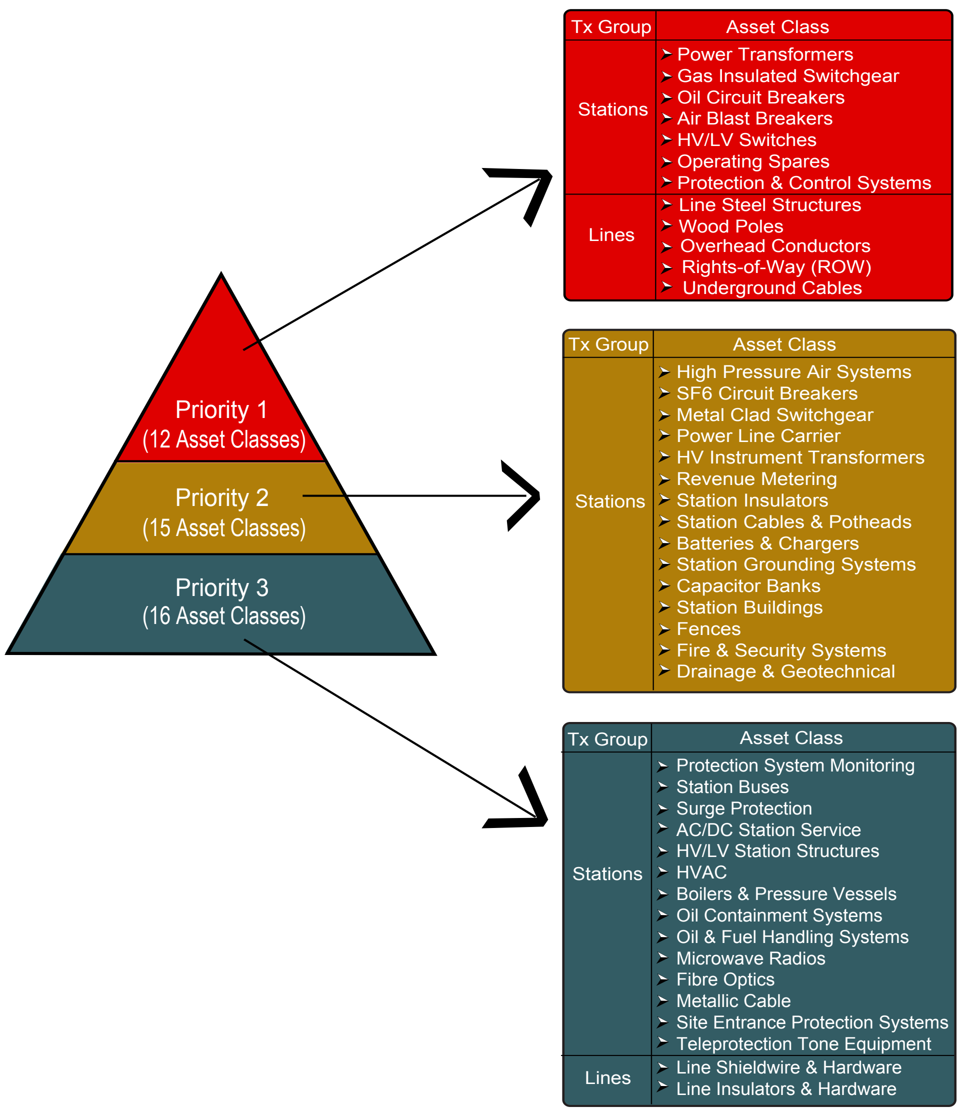
The use of transmission asset sustainment portfolios supports the 10-Year Transmission Asset Management Outlook objectives by providing an integrated and long-term perspective for the management and replacement of existing transmission assets. Collectively, these asset portfolios provide a broad view regarding key transmission assets with an emphasis on capital asset replacement. Sustainment portfolios are presented as listed in Table 5.3:

Table 5.3 Sustainment Portfolios

Portfolio	Section
Power Transformers	5.5.1
Circuit Breakers	5.5.2
Overhead Conductors	5.5.3
Underground Cables	5.5.4
Steel Structures	5.5.5
Wood Poles	5.5.6
Right-of-Way Vegetation Management	5.5.7
Protection and Control Relays	5.5.8

Sustainment O&M work programs are discussed in Section 5.7.

Figure 5.1 Transmission Asset Classes and Priorities



5.5.1 Power Transformer Portfolio

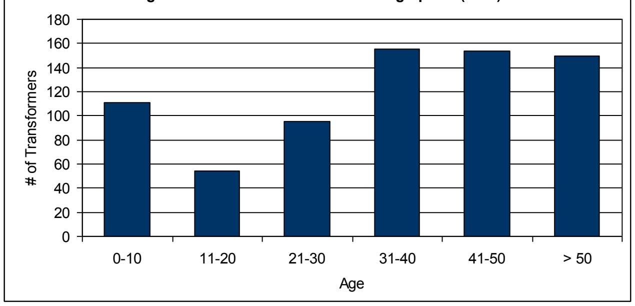
Description

The function of power transformers in a power system is to step-up or step-down voltages at connection points. The class of power transformers includes auto-transformers, step-down transformers, phase-shifters, and regulators.

Demographics

Figure 5.2a provides the demographics for Hydro One's fleet of 719 transmission system power transformers. Data was current as of 2011.

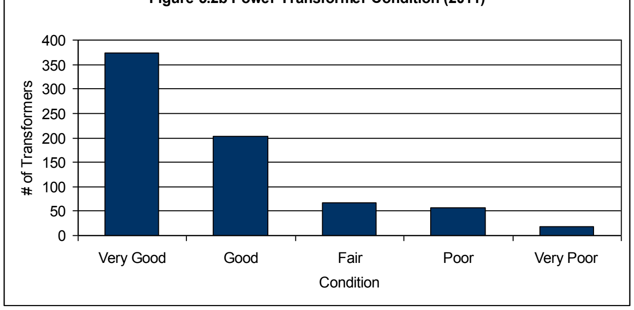
Figure 5.2a Power Transformer Demographics (2011)



Asset Condition Assessment (ACA)

Figure 5.2b provides the ACA for the power transformer fleet as of 2011. A total of 74 transformers are in "Poor" or "Very Poor" condition.

Figure 5.2b Power Transformer Condition (2011)



Reliability Performance

Figure 5.2c provides the annual number of power transformer Class 1 equipment failures from 2002 to 2011. Class 1 failures are failures that are not repairable in the field.

Figure 5.2c Transformer Class 1 Failures (2002-2011)

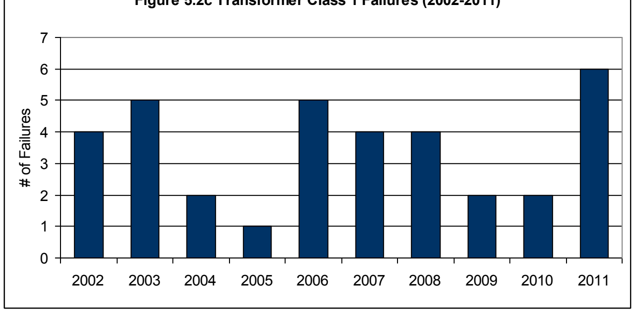


Figure 5.2d shows Hydro One's power transformer forced outage frequency annually from 2002 to 2011. The average forced outage frequency for power transformers in the Canadian Electricity Association's multi-utility database is also shown for comparison purposes.

Figure 5.2d Transformer Forced Outage Frequency (2002-2011)

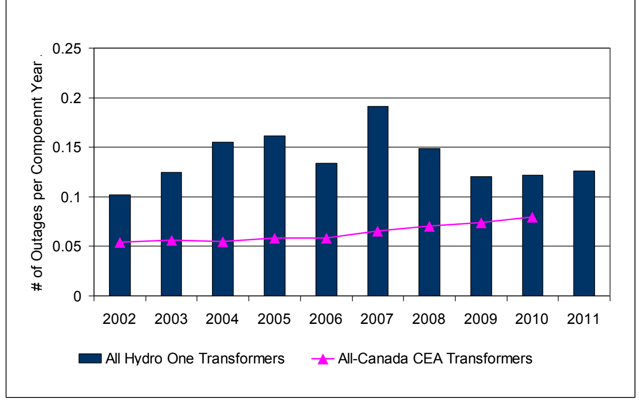
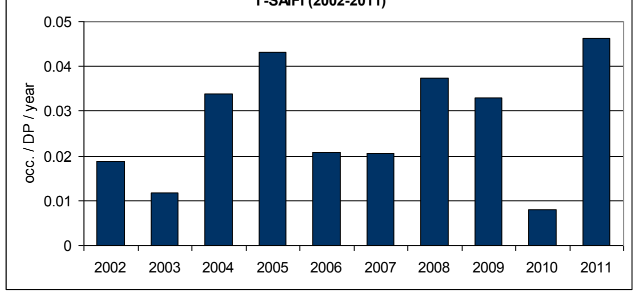


Figure 5.2e illustrates the annual contribution of power transformer failures (all failure classes) on T-SAIFI (the delivery point interruption frequency attributable to transmission system anomalies) from 2002 to 2011.

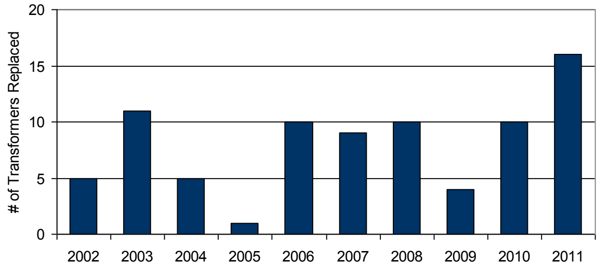
Figure 5.2e Transformer Failure Contribution to T-SAIFI (2002-2011)



Historical Equipment Replacement

Figure 5.2f provides the number of power transformers replaced in the last 10 years under the sustainment work program only. Further, to meet development needs in the last 10 years, an average of six to seven transformers per year were replaced to upgrade transformer station capacity, or installed to build new transformer stations.

Figure 5.2f Recent Transformer Replacement (Sustainment) 2002-2011



Equipment Replacement Scenarios

Figure 5.2g depicts the effect that replacing power transformers at different annual rates for 10 years would have on the demographics of the entire population of transformers. Information is provided for five different scenarios: replacement rates of 25 units/year, 20 units/year, 15 units/year, 10 units/year, and no replacements. It can be seen, after replacing 15 of the oldest power transformers on the system each year for a period of 10 years, roughly 154 power transformers would still be in-service beyond their assumed expected service life (50 years). No replacements in any year would result in roughly 304 transformers being beyond their expected service life after 10 years. For comparison, the number of power transformers beyond their expected service life at present is 150, or roughly 21% of the existing power transformer fleet.

Figure 5.2g Projected # of Transformers Beyond Expected Service Life After 10 Year Period & For Different Annual Replacement Rates

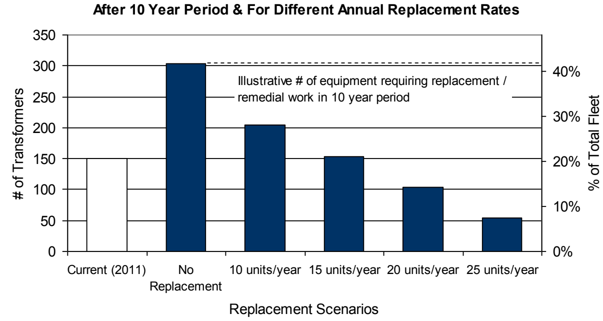
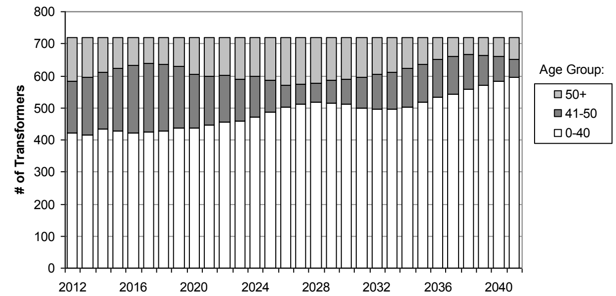


Figure 5.2h provides an annual age profile of the power transformer fleet over a 30 year time horizon assuming a specific transformer replacement pace of 15 units per year. At this replacement rate the average age of the fleet of power transformers would be in the range of 25 to 30 years in the mid to long term.

Figure 5.2h Transformer Demographics 30-Year View Considering a Replacement Rate of 15 Units / Year



Note, while the average replacement rate for this planning scenario is 15 transformers per year, a determination as to the actual number of units replaced in any year, and identification of the specific units, would be based on sustainment program factors discussed earlier.

5.5.2 Circuit Breaker Portfolio

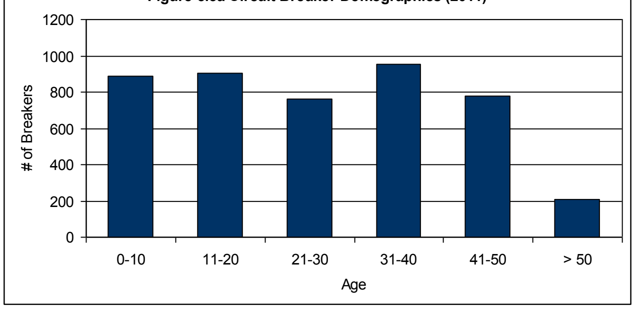
Description

Circuit breakers are mechanical switching devices capable of carrying, and breaking currents under normal circuit conditions and also carrying for a specific time, and breaking currents under specified abnormal conditions such as short circuits. The medium in which circuit interruption is performed may be designated by a suitable prefix, for example, air-blast circuit breaker, gas circuit breaker, oil circuit breaker, or vacuum circuit breaker.

Demographics

Figure 5.3a provides the demographics of the 4,490 transmission system circuit breakers as of 2011.

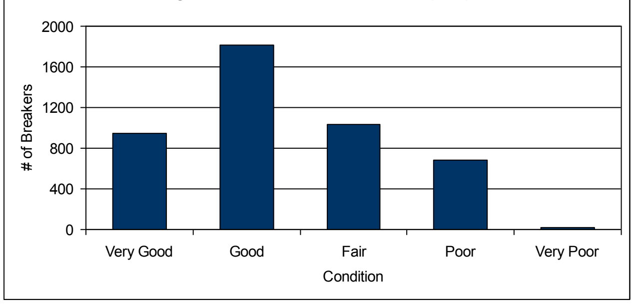
Figure 5.3a Circuit Breaker Demographics (2011)



Asset Condition Assessment (ACA)

Figure 5.3b provides the ACA of the circuit breakers as of 2011. 699 circuit breakers, or roughly 15% of the fleet, are currently in "Poor" or "Very Poor" condition.

Figure 5.3b Circuit Breaker Condition (2011)



Reliability Performance

Figure 5.3c provides the annual number of Class 1 circuit breaker equipment failures (failures that are not repairable in the field) between 2002 and 2011. There were no Class 1 failures in several of these years.

Figure 5.3c Circuit Breaker Class 1 Failures (2002-2011)

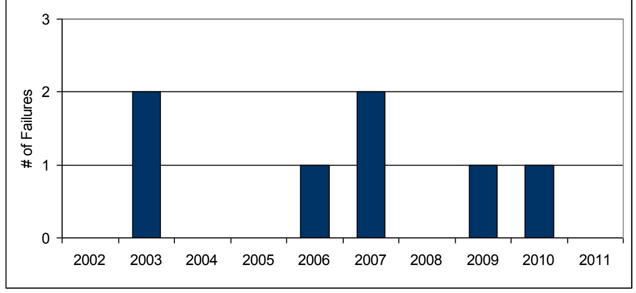


Figure 5.3d shows the annual circuit breaker forced outage frequencies from 2002 to 2011. The average forced outage rate for circuit breakers in the Canadian Electricity Association's multi-utility data base is also shown.

Figure 5.3d Circuit Breaker Forced Outage Frequency (2002-2011)

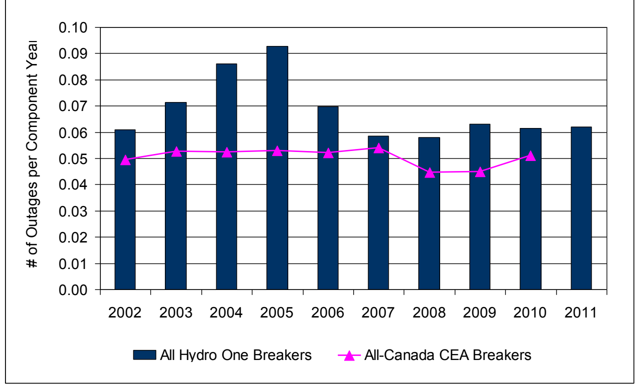
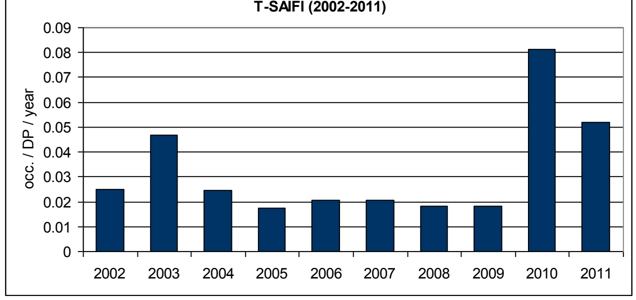


Figure 5.3e illustrates the effect of circuit breaker failures (all failure classes) on the delivery point interruption frequency, as measured by T-SAIFI, from 2002 to 2011.

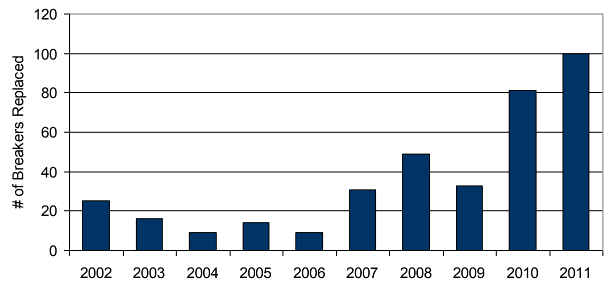
Figure 5.3e Circuit Breaker Failure Contribution to T-SAIFI (2002-2011)



Historical Equipment Replacement

Figure 5.3f provides the number of transmission system circuit breakers replaced in the period 2002 to 2011 under the sustainment work program only. In the last five years the replacement rate has averaged about 59 units per year.

Figure 5.3f Recent Circuit Breaker Replacement (2002-2011)



Equipment Replacement Scenarios

Figure 5.3g depicts the effect that replacing circuit breakers at different annual rates for 10 years would have on the demographics of the entire circuit breaker population. Information is provided for five different scenarios: replacement rates of 50 units/year, 60 units/year, 70 units/year, 80 units/year, and no replacements. It can be seen, after replacing 70 of the oldest circuit breakers on the system each year for a period of 10 years, roughly 157 circuit breakers would still be in-service beyond their expected service life of 40 years (55 years for oil circuit breakers). No replacements in any year would result in roughly 857 circuit breakers being beyond their expected service life after 10 years. For comparison, the number of circuit breakers beyond their expected service life at present is 282, or roughly 6% of the circuit breaker fleet.

Figure 5.3g Projected # of Breakers Beyond Expected Service Life After 10 Year Period & For Different Annual Replacement Rates

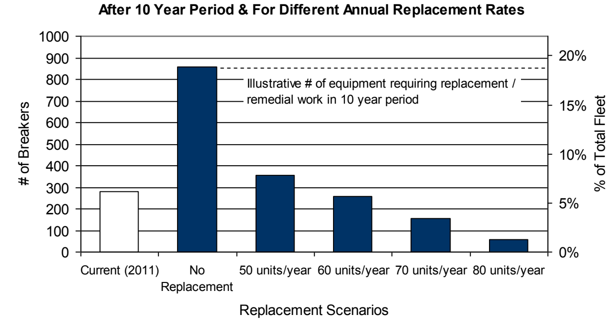
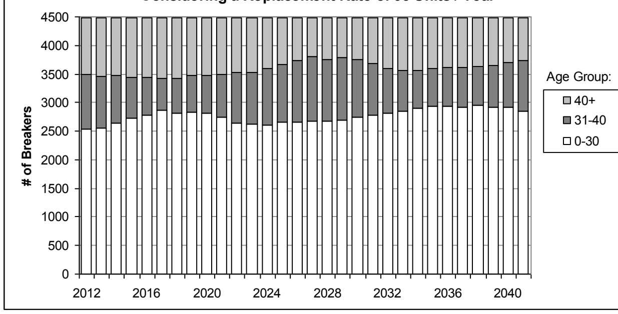


Figure 5.3h provides an annual age profile of the circuit breaker fleet over a 30 year time horizon assuming a specific replacement pace of 95 units per year. At this replacement rate the average age of the fleet of circuit breakers would be about 25 years in the mid to long term.

Figure 5.3h Circuit Breaker Demographics 30-Year View Considering a Replacement Rate of 95 Units / Year



While the average replacement rate for this planning scenario is 95 circuit breakers per year, a determination as to the actual number of units replaced in any year, and identification of the specific units, would be based on sustainment factors discussed earlier.

5.5.3 Overhead Conductor Portfolio

Description

Overhead transmission of electricity remains one of the most important elements of today's electric power system. Overhead transmission lines (conductors) deliver power produced at generating plants to industrial sites, and to substations from which distribution systems supply residential and commercial customers. The Hydro One transmission system operates primarily at voltage levels of 115 kV, 230 kV, and 500 kV.

Demographics

Figure 5.4a provides the demographics of Hydro One's roughly 29,000 circuit-km of transmission system overhead conductors (all voltages).

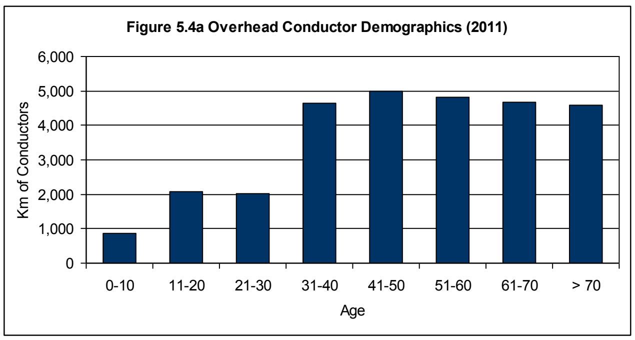


Figure 5.4a Overhead Conductor Demographics (2011)

Asset Condition Assessment (ACA)

Figure 5.4b provides the ACA of the overhead conductors as of 2011. Roughly 4,500 circuit-km of conductors (16% of the total) are in "Poor" condition.

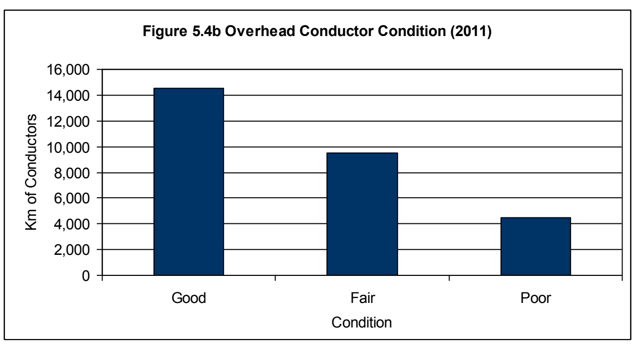


Figure 5.4b Overhead Conductor Condition (2011)

Reliability Performance

Figure 5.4c illustrates the overhead conductor forced outage frequency (number of sustained failures per 100 km of conductor per year) for the period 2002 to 2011. The corresponding average overhead conductor failure frequency for utilities in the Canadian Electricity Association is also shown for comparison purposes.

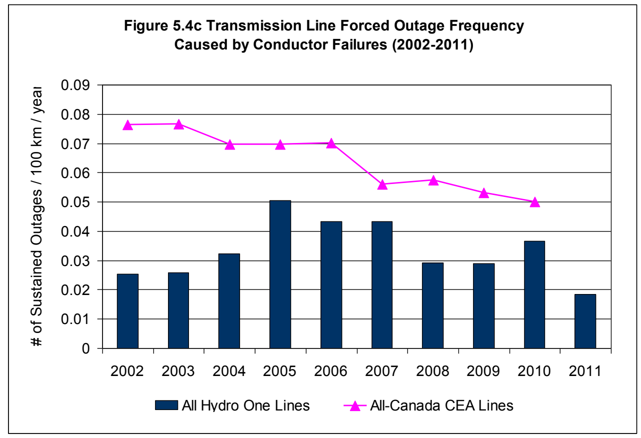


Figure 5.4c Transmission Line Forced Outage Frequency Caused by Conductor Failures (2002-2011)

Figure 5.4d depicts the effect of overhead conductor failures on the delivery point interruption frequency, as measured by T-SAIFI, from 2002 to 2011.

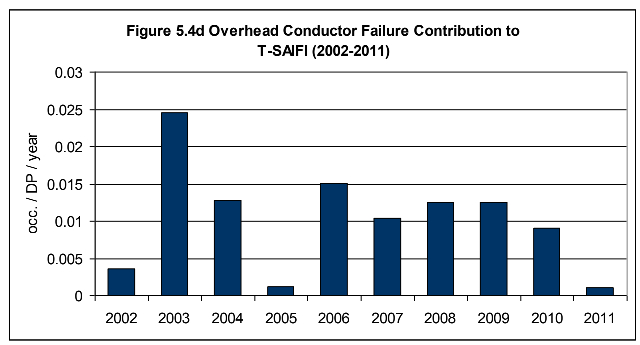


Figure 5.4d Overhead Conductor Failure Contribution to T-SAIFI (2002-2011)

Historical Equipment Replacement

Figure 5.4e provides the number of kilometers of overhead conductors replaced in the last 10 years.

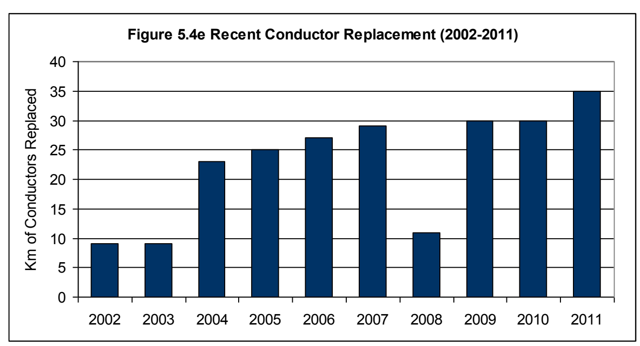


Figure 5.4e Recent Conductor Replacement (2002-2011)

Since a small fraction of overhead conductors have been replaced in the past several years it is not possible to provide statistics which demonstrate a meaningful correlation between conductor replacement and improvements in reliability.

Equipment Replacement Scenarios

Figure 5.4f depicts the effect of replacing different quantities of overhead conductors would have on the demographics of the entire overhead conductor population. Information is provided for five different scenarios: replacement rates of 50 km/year, 250 km/year, 400 km/year, 550 km/year, and no replacement. It can be seen, after replacing 250 km of the oldest conductors on the system each year for a period of 10 years, roughly 6,700 km of conductors would still be in-service beyond the expected service life of 70 years. No replacements in any year would result in roughly 9,200 km of overhead conductors being beyond the expected service life after 10 years. For comparison, the total length of overhead conductors beyond the expected service life at present is roughly 4,600 km, or about 16% of the total length of overhead conductors in Hydro One's transmission system.

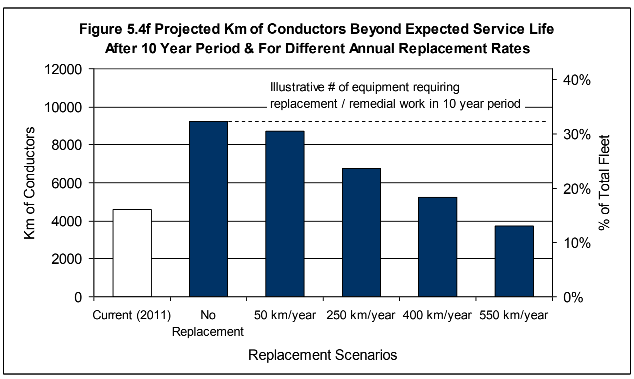
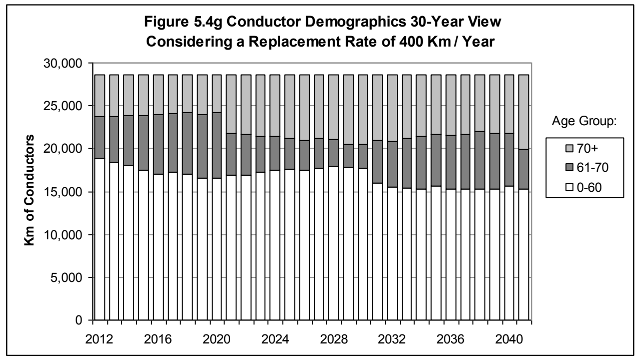


Figure 5.4g provides an annual age profile of Hydro One's overhead conductor inventory over a 30 year time horizon assuming a specific replacement pace of 400 km per year. At this replacement rate the average age of conductors would be about 50 years in the mid to long term.



If this average replacement rate were adopted, any determination as to the actual number of kilometers replaced in any year, and identification of the specific lines that would be replaced, would be based on sustainment factors discussed earlier.

5.5.4 Underground Cable Portfolio

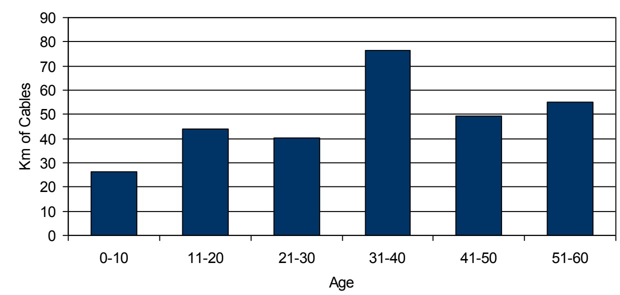
Description

Underground cable systems are used for electric energy transmission where overhead construction is impractical, unsafe, costly, or environmentally unacceptable. The principal transmission system applications have been in heavily urbanized areas where overhead rights-of-way are unavailable or prohibitively costly, or where local ordinances mandate undergrounding.

Demographics

Figure 5.5a provides the demographics of Hydro One's roughly 290 circuit-km of transmission system underground cables for the year 2011.

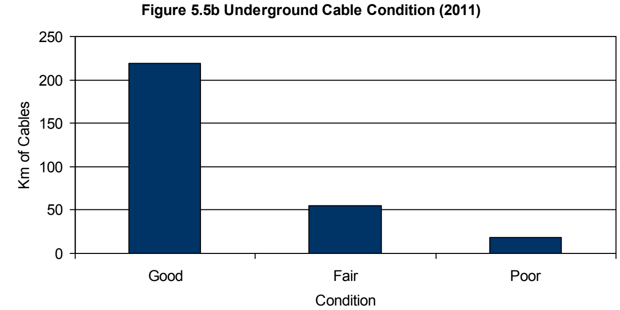
Figure 5.5a Underground Cable Demographics (2011)



Asset Condition Assessment (ACA)

Figure 5.5b provides the ACA of the underground cable inventory. Roughly 18 circuit-km or 6% of the total underground cable inventory is deemed to be in "Poor" condition.

Figure 5.5b Underground Cable Condition (2011)



Reliability Performance

Figure 5.5c illustrates the underground cable forced outage frequency (number of sustained outages per 100 km of cable per year) for the period 2002 to 2011. The corresponding average underground cable failure frequency for utilities in the CEA is also shown for comparison purposes.

Figure 5.5c Underground Cable Forced Outage Frequency (2002-2011)

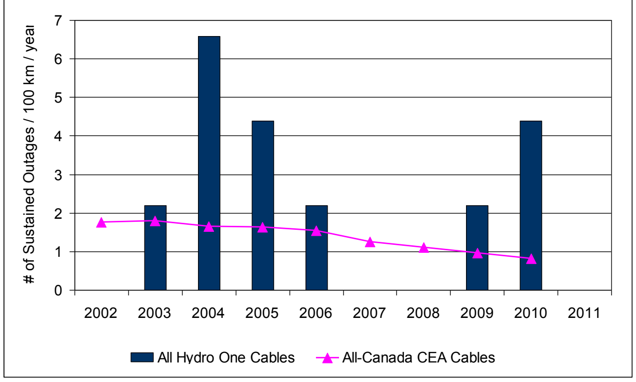
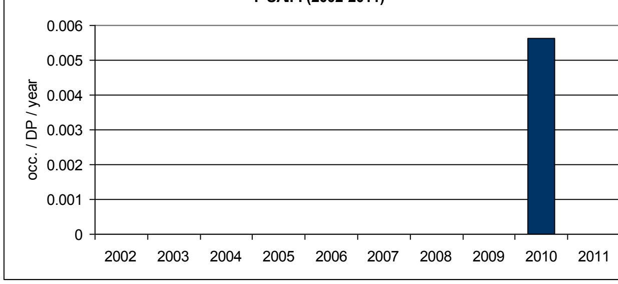


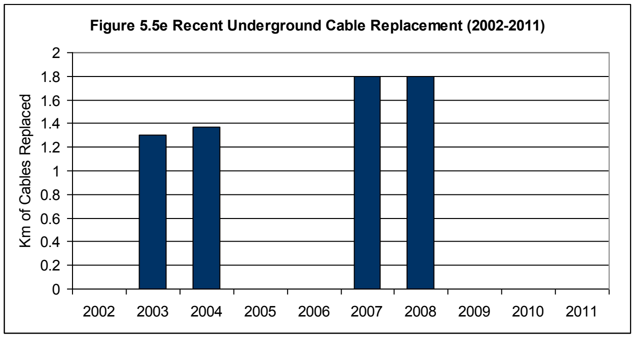
Figure 5.5d depicts the effect of underground cable failures on the delivery point interruption frequency, as measured by T-SAIFI, from 2002 to 2011. There has only been one underground cable failure impacting customer reliability over the last 10 years. The outage occurred in 2010 due to a leaking cable section.

Figure 5.5d Underground Cable Failure Contribution to T-SAIFI (2002-2011)



Historical Equipment Replacement

Figure 5.5e provides the total length (km) of underground cables replaced in each of the last 10 years. Only a few kilometers of underground cables have been replaced in this time period, making it impossible to generate meaningful statistics correlating cable replacement with changes in reliability.



Equipment Replacement Scenarios

Figure 5.5f illustrates the effect of adopting different underground cable replacement scenarios (i.e., different total lengths of cables replaced on an annual basis) on the number of kilometers of underground cables that would still be in service beyond their expected service life of 50 years at the end of a 10 year period. For instance, at the end of a 10 year program of replacing three km of underground cable per year, roughly 75 km of un-replaced cable would still be in-service beyond the expected service life. At present, roughly 55 km of underground cable has been in service longer than the expected service life.

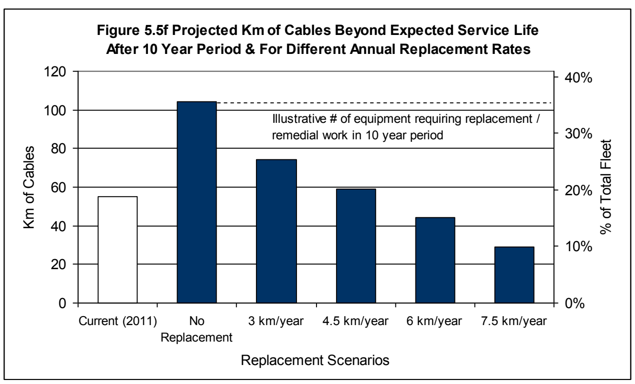
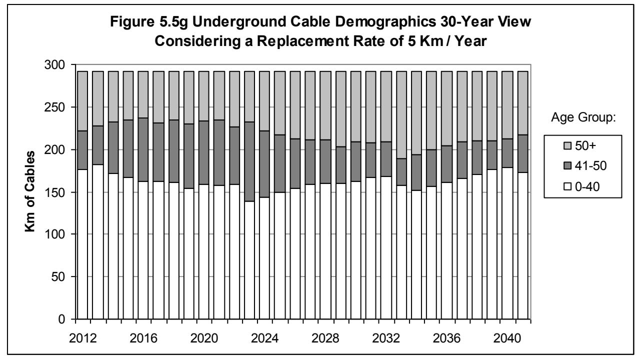


Figure 5.5g provides an annual age profile of the underground cable inventory over a 30 year time horizon assuming that five km per year are replaced throughout the period. At this replacement rate the average age of underground cables would be in the range of 30 to 35 years in the mid to long term.



If this average replacement rate were adopted in practice, the determination as to the actual number of kilometres of cable to be replaced in any given year, and identification of the specific cables that would be replaced, would be based on sustainment factors discussed earlier.

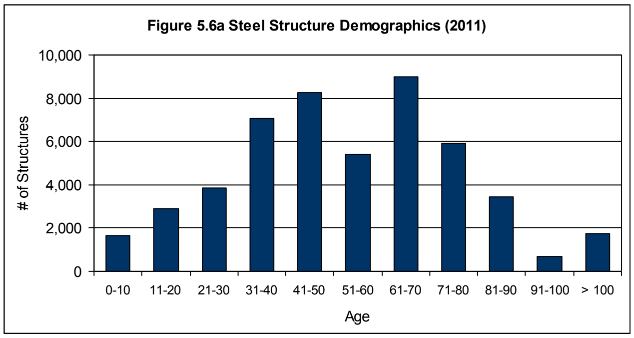
5.5.5 Steel Structure Portfolio

Description

Steel structures (towers) provide support and ground clearance to the transmission overhead lines. A zinc-based galvanized coating is used to help protect steel structures from corrosion.

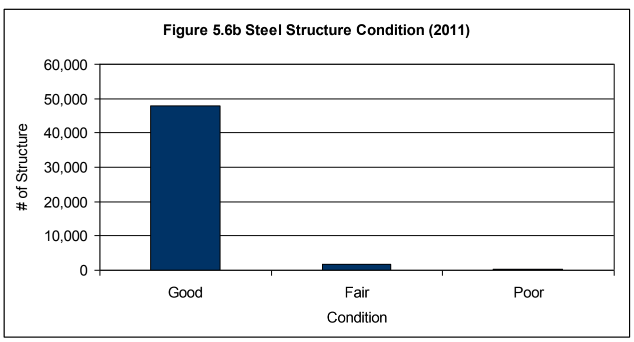
Demographics

Figure 5.6a provides the demographics of Hydro One's roughly 50,000 transmission steel structures (as of 2011).



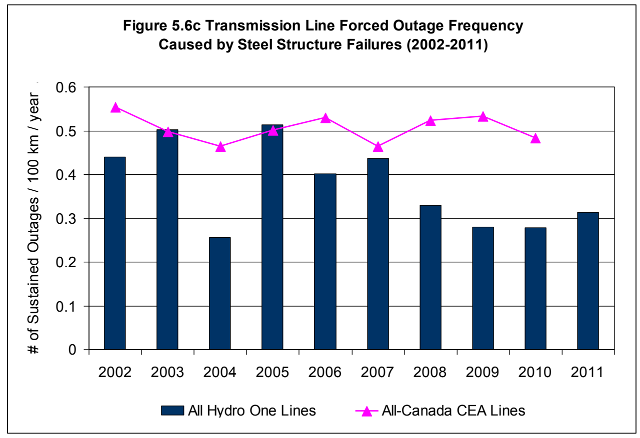
Asset Condition Assessment (ACA)

Figure 5.6b provides the ACA of the steel structures. The vast majority of steel transmission structures are currently considered to be in "Good" condition, though about 266 steel structures are identified to be in "Poor" condition.

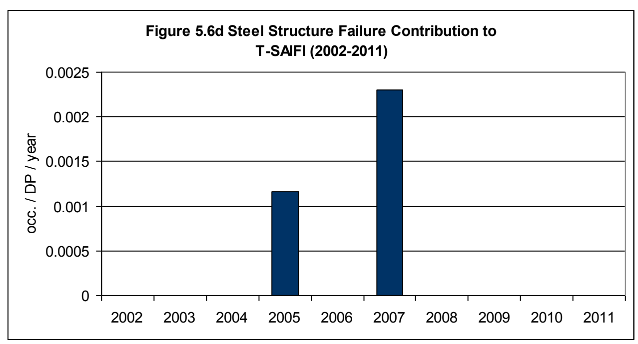


Reliability Performance

Figure 5.6c provides the frequency of forced outages caused by steel structure failures from 2002 to 2011 expressed in terms of the number of sustained outages per 100 km of transmission line. Weather related structural failures (e.g., due to tornados, ice storms, and so on) are excluded in this data. The average forced outage frequency due to steel transmission structure failure for utilities in the Canadian Electricity Association's multi-utility database is provided as a comparator.



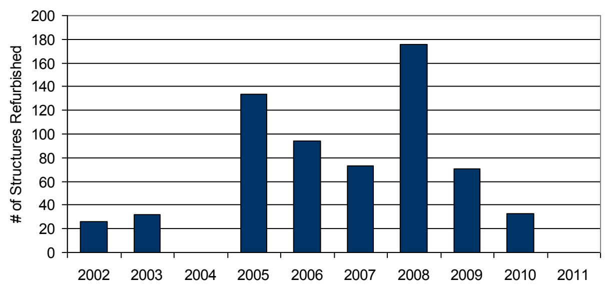
The annual contribution of steel transmission structure failures on T-SAIFI (the transmission related delivery point interruption frequency) from 2002 to 2011 is shown in Figure 5.6d. As can be seen from this figure, there is relatively little effect of steel structure failures on delivery point reliability, largely due to the system back-up built into transmission circuits.



Historical Equipment Refurbishment

Tower coating and/or refurbishment (includes tower parts replacement) has been identified as the preferred alternative, since it costs roughly half the cost for tower replacement. Figure 5.6e indicates the number of steel structures that have been refurbishment in the recent past. Over the past five years the refurbishment rate has averaged about 70 structures per year.

Figure 5.6e Recent Steel Structure Refurbishment (2002-2011)

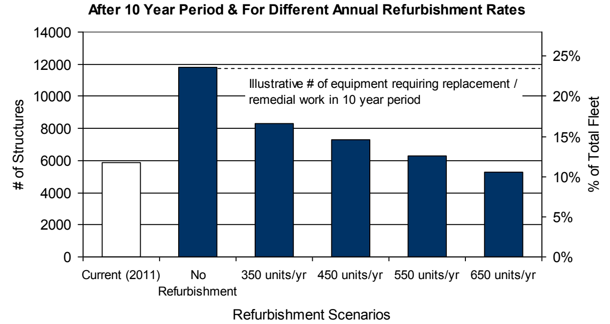


There is insufficient statistical evidence at this time to enable meaningful correlations to be made between steel structure replacement/refurbishment and effects on reliability.

Equipment Refurbishment Scenarios

Figure 5.6f depicts the effect on the demographics of the entire population of steel transmission structures of refurbishing different numbers of structures each year for a 10 year period. Information is provided for five different scenarios: refurbishment rates of 350 units/year, 450 units/year, 550 units/year, 650 units/year, and no refurbishments.

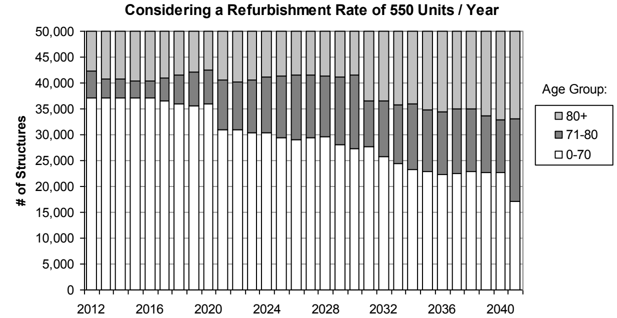
Figure 5.6f Projected # of Steel Structures Beyond Expected Service Life After 10 Year Period & For Different Annual Refurbishment Rates



It can be seen, after refurbishing 350 of the oldest transmission structures each year for a period of 10 years, roughly 8,300 structures would remain, with more than their expected service life of 80 years. No refurbishments in any year, would result in roughly 11,800 steel structures being beyond their expected service life after 10 years. For comparison, the number of steel structures currently beyond their expected service life is roughly 6,000 or about 12% of the total number of steel structures in Hydro One's transmission system.

Figure 5.6g provides an annual age profile for the inventory of steel transmission structures over a 30 year time horizon assuming a specific refurbishment rate of 550 units per year. At this refurbishment rate the average age of the inventory would be in the range of 55 to 70 years in the mid to long term. In the mid to longer term, the proportion of steel structures of concern increases, since the work involves refurbishment work (rather than replacement of structures).

Figure 5.6g Steel Structure Demographics 30-Year View Considering a Refurbishment Rate of 550 Units / Year



Note that while the average refurbishment rate for this planning scenario is 550 steel structures per year, a determination as to the actual number of units replaced in any year, and identification of the specific units, would be based on sustainment factors discussed earlier.

5.5.6 Wood Pole Portfolio

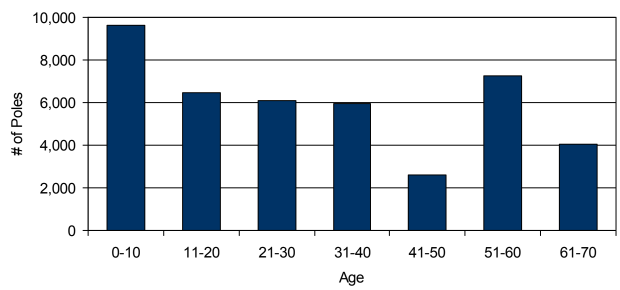
Description

Wood poles provide support and ground clearance to overhead transmission lines that are not supported by steel structures. The majority of Hydro One's wood pole fleet is located in Northern Ontario, typically in remote locations. Many of these structures support radial circuits.

Demographics

Figure 5.7a provides the demographics of Hydro One's roughly 42,000 transmission system wood poles (as of 2011)

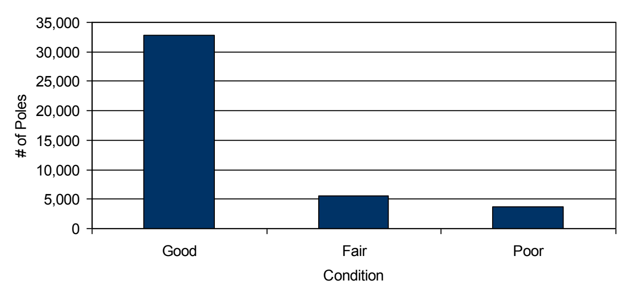
Figure 5.7a Wood Pole Demographics (2011)



Asset Condition Assessment (ACA)

Figure 5.7b provides the ACA of the population of wood poles as of 2011. Roughly 3,700 wood poles in the transmission system, or about 9% of the total number of wood poles, are presently considered to be in "Poor" condition.

Figure 5.7b Wood Pole Condition (2011)



Reliability Performance

Figure 5.7c shows the annual frequency of forced outages caused by wood pole failures in the transmission system from 2002 to 2011 (number of occurrences per 100 km length of conductor-strung wooden poles). The average forced outage frequency due to wood pole failures in the Canadian Electricity Association's multi-utility database is provided as a comparator.

Figure 5.7c Transmission Line Forced Outage Frequency Caused by Wood Pole Failures (2002-2011)

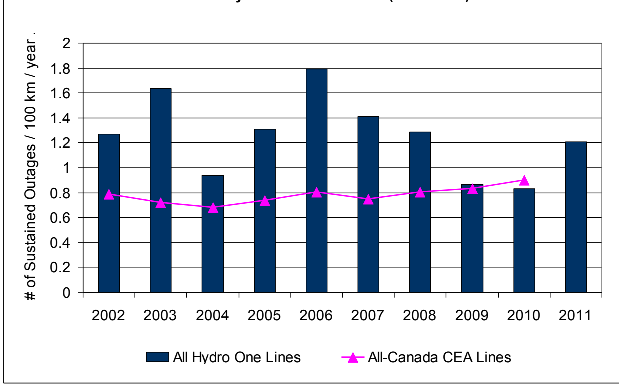
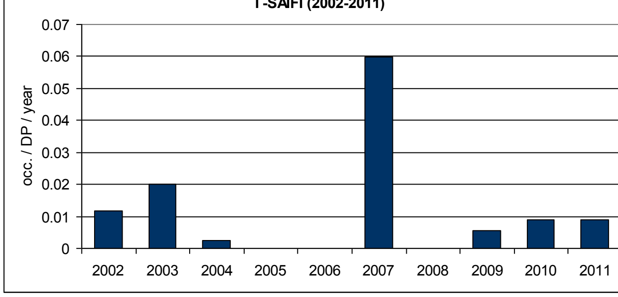


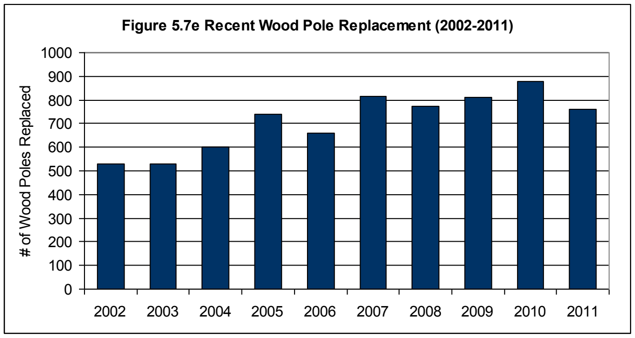
Figure 5.7d provides an indication of the annual contribution of wooden pole failures on the delivery point interruption frequency, as measured by T-SAIFI, for years 2002 to 2011. There has been a fair amount of variability in the effect of wood pole failures on delivery point reliability in the past five years or so. This suggests that there is not strong statistical support to correlate wood pole failure rates to delivery point reliability.

Figure 5.7d Wood Pole Failure Contribution to T-SAIFI (2002-2011)



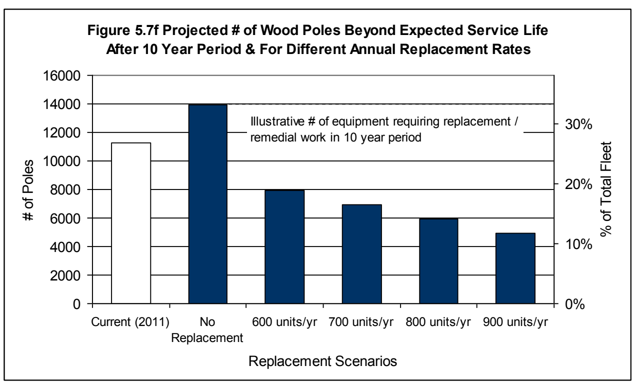
Historical Equipment Replacement

Figure 5.7e provides the number of wood poles replaced in the last 10 years. The replacement rate has averaged about 710 wood pole replacements per year, and has climbed slightly over the time period.



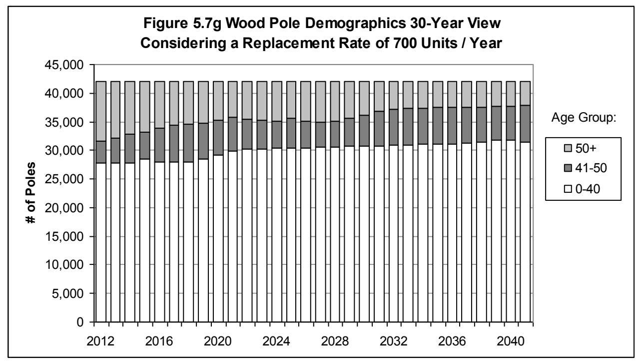
Equipment Replacement Scenarios

Figure 5.7f depicts the effect on the demographics of the entire population of transmission system wood poles, assuming different annual replacement rates for a 10 year period. Information is provided for five different scenarios: replacement rates of 600 poles/year, 700 poles/year, 800 poles/year, 900 poles/year, and no replacements.



It can be seen, after replacing 600 of the oldest transmission wood poles each year for a period of 10 years, roughly 8,000 poles would remain, with more than their expected service life of 50 years. No replacements in any year would result in roughly 14,000 wood poles being beyond their expected service life after 10 years. For comparison, the number of wood poles in the transmission system that are currently beyond their expected service life is roughly 11,300 or roughly 27% of the total number of wood poles in Hydro One's transmission system.

Figure 5.7g provides an annual age profile of Hydro One's transmission system wood pole inventory over a 30 year time horizon assuming a constant replacement rate of 700 wood poles per year. At this replacement rate the average age of wood poles in the transmission system would be about 30 years in the mid to long term.



If this average replacement rate were adopted in practice, the determination as to the actual number of poles to be replaced in any year, and identification of the specific poles that would be replaced, would be based on sustainment factors discussed earlier.

5.5.7 Right-of-Way (ROW) Vegetation Management Portfolio

Description

The vegetation management program clears vegetation from the floor and edges of ROW in order to provide access to transmission line assets and mitigate the risk of vegetation interfering with the electrical system. Vegetation maintenance activities include brush control, line clearing, and condition patrol.

Brush control involves the management of specific plant types on the ROW floor to minimize the presence of trees that can grow tall enough to contact the overhead lines.

Line clearing includes the removal of damaged or diseased trees along the edge of, and on, the ROW that pose a threat of falling into a line along with tree trimming required to maintain clearances to energized facilities, thereby reducing the likelihood of power interruptions.

Demographics

Figure 5.8a illustrates demographic data pertinent to the Vegetation Management Portfolio. It shows the total number of hectares (ha) of transmission ROW cleared one year ago, two years ago, and so on. The total area and length of transmission ROW which Hydro One must maintain is roughly 82,000 ha and 21,000 km, respectively.

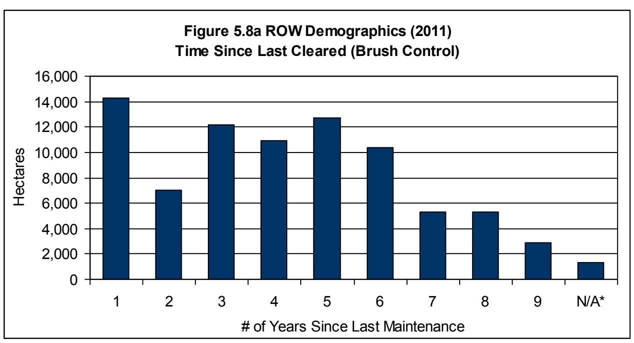


Figure 5.8a ROW Demographics (2011) Time Since Last Cleared (Brush Control)

(*brush control status to be determined as part of ongoing work.)

Asset Condition Assessment (ACA)

ROW condition can generally be related to time since last cleared. ROW condition will deteriorate as the interval between treatments increases. Therefore, the ROW vegetation management demographics shown in Figure 5.8a can be used as a surrogate for ROW condition.

Reliability Performance

Figure 5.8b provides the number of forced outages caused each year by trees/vegetation per 100 km of transmission ROW from 2002 to 2011. The average of all utilities in the Canadian Electricity Association database is provided as a comparator.

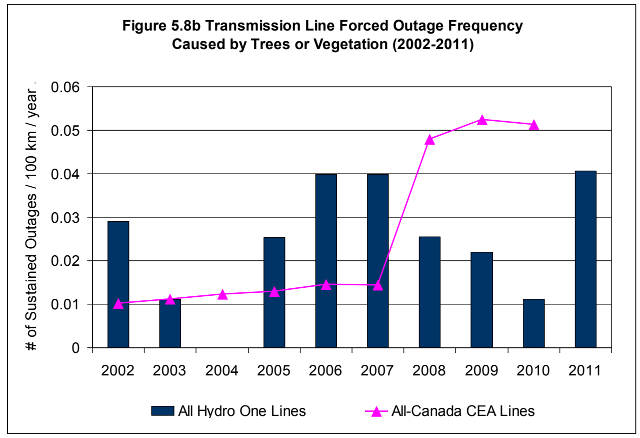


Figure 5.8b Transmission Line Forced Outage Frequency Caused by Trees or Vegetation (2002-2011)

Figure 5.8c illustrates the contribution that vegetation contact with transmission system components makes to the overall T-SAIFI value - the overall customer interruption frequency index for failures on the transmission system.

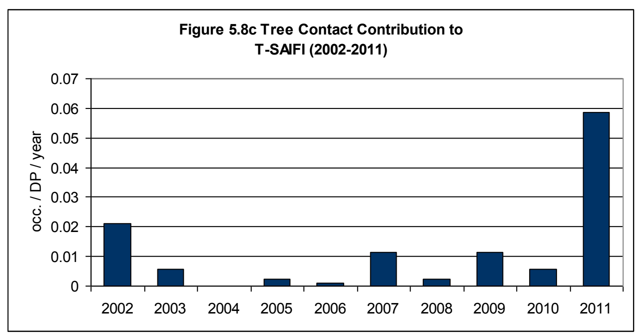


Figure 5.8c Tree Contact Contribution to T-SAIFI (2002-2011)

Historical Vegetation Management Accomplishment

Figure 5.8d provides the accomplishment levels of the vegetation management program, in terms of the amount of brush control (ha), line clearing (km), and condition patrol (km) in the last 10 years.

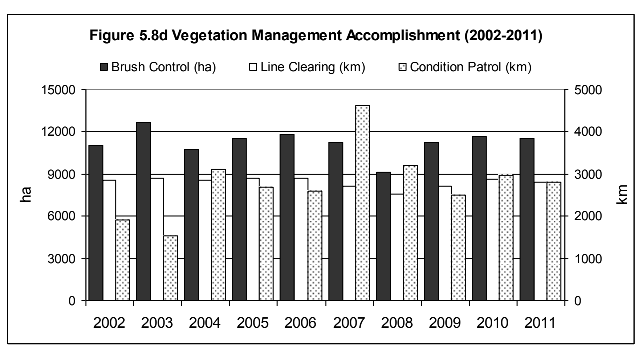


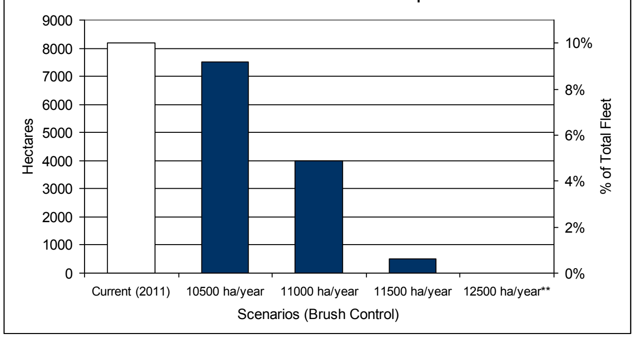
Figure 5.8d Vegetation Management Accomplishment (2002-2011)

Over that time span, an average area of 11,300 ha and 2,800 km of ROW has been cleared of vegetation annually, providing an average cycle length (time between clearings) of about seven years.

Vegetation Management Scenarios

Figure 5.8e depicts the effect of a number of different vegetation management scenarios (i.e. different amounts of brush control on an annual basis) on the ability to accomplish an average vegetation maintenance cycle of about seven years (ROWs cleared every seven years, on average) by the end of a 10 year period.

Figure 5.8e Projected Area of Backlog ROW*
After 10 Year Period & For Different Annual Replacement Rates



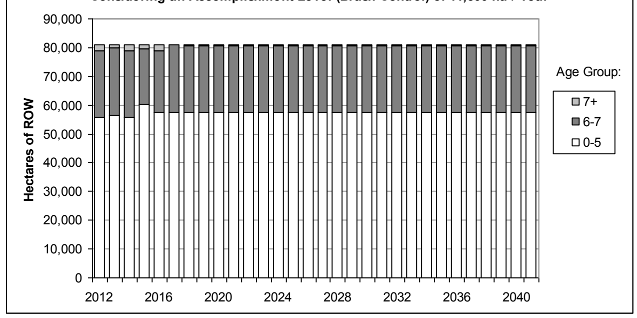
(* Backlog ROW is the portion of ROW not been cleared within the past 7 years)
(** Clearing 12,500 ha/year would shorten the ROW maintenance cycle to approximately 6.5 years)

For instance, if 11,000 ha were cleared per year for 10 years, there would remain 4,000 ha that had not been cleared within the previous seven years (the "backlog"). If 11,500 ha were cleared per year for 10 years, the backlog at the end of the ten year period would be about 500 ha. At present, there are roughly 8,200 ha of ROW that have not been cleared within the past seven years.

Clearing 12,500 ha per year for 10 years would allow Hydro One to clear all ROW every 6.5 years, on average.

Figure 5.8f provides an annual view of the average age of uncleared vegetation on ROWs over a 30 year time horizon assuming that 11,500 ha of ROW is cleared each year throughout the period. At this clearing rate, the average age of ROW vegetation would remain roughly constant at four years.

Figure 5.8f ROW Demographics 30-Year View
Considering an Accomplishment Level (Brush Control) of 11,500 ha / Year



The specific planned vegetation management program including timing would include sustainment factors discussed earlier.

5.5.8 Protection and Control Relay Portfolio

Description

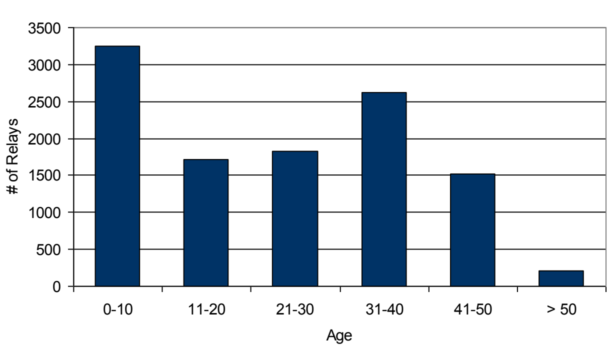
Protection and control (P&C) relays and their associated telecommunications systems are connected throughout the transmission network for the purpose of sensing and reacting to abnormal system conditions. They detect and, in conjunction with circuit breakers, isolate abnormal system conditions that could result from natural events, physical accidents, equipment failure, or operator error.

P&C relays include a range of technologies, including electromechanical, solid state, PALC (Programmable Auxiliary Logic Controller) based, and microprocessor-based IEDs (intelligent electronic devices).

Demographics

Figure 5.9a provides the demographics of the roughly 11,000 transmission system P&C relays.

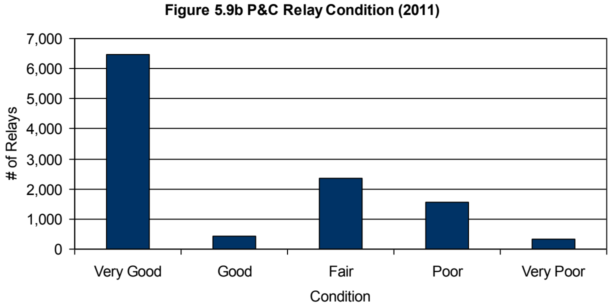
Figure 5.9a P&C Relay Demographics (2011)



Asset Condition Assessment (ACA)

Figure 5.9b provides the ACA of the P&C relays employed in Hydro One's transmission system as of 2011. A total of about 1,900 relays are considered to be in "Poor" or "Very Poor" condition.

Figure 5.9b P&C Relay Condition (2011)



Reliability Performance

Figure 5.9c provides the frequency of forced outages caused by P&C relay failures along with the corresponding average forced outage frequency derived from the Canadian Electricity Association's multi-utility database.

Figure 5.9c All Equipment Direct Forced Outage Frequency Caused by Protection and Control Equipment (2002-2011)

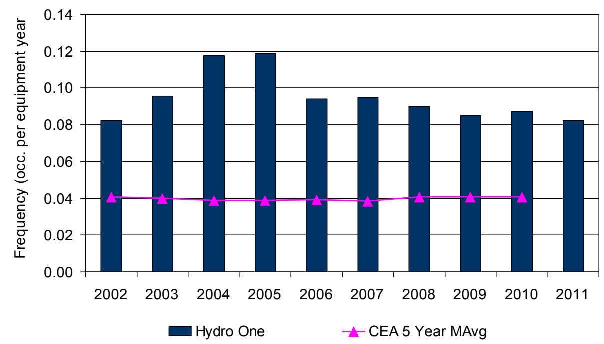
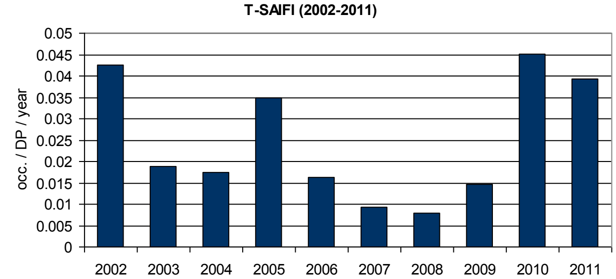


Figure 5.9d illustrates the contributions of P&C relay failures towards transmission system delivery point interruption frequency (as measured by T-SAIFI) over the period 2002 to 2011.

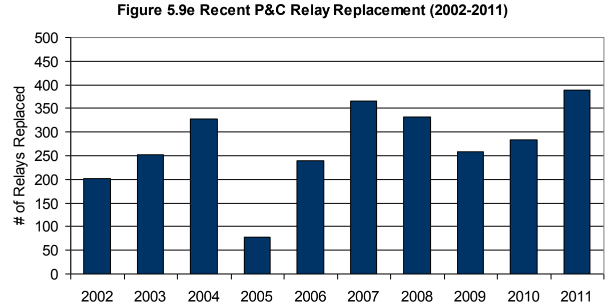
Figure 5.9d P&C Equipment Failure Contribution to T-SAIFI (2002-2011)



Historical Equipment Replacement

Figure 5.9e provides the number of P&C relays replaced in the last 10 years. An average of 273 P&C relays has been replaced annually over the last ten years.

Figure 5.9e Recent P&C Relay Replacement (2002-2011)



Equipment Replacement Scenarios

Figure 5.9f depicts the effect that replacing P&C relays at different annual rates for 10 years would have on the demographics of the entire P&C relay population. Information is provided for five different scenarios: replacement rates of 200 units/year, 300 units/year, 400 units/year, 500 units/year, and no replacements. It can be seen, after replacing 400 of the oldest P&C relays on the system each year for a period of 10 years, roughly 2,000 would still be in-service beyond their expected service life (40 years for electromechanical relays, 25 years for solid state, microprocessor, and PALC relays). No replacements in any year would result in roughly 6,000 P&C relays being beyond their expected service life after 10 years. For comparison, the number of relays beyond their expected service life at present is roughly 3,500 or roughly 32% of the P&C relay fleet.

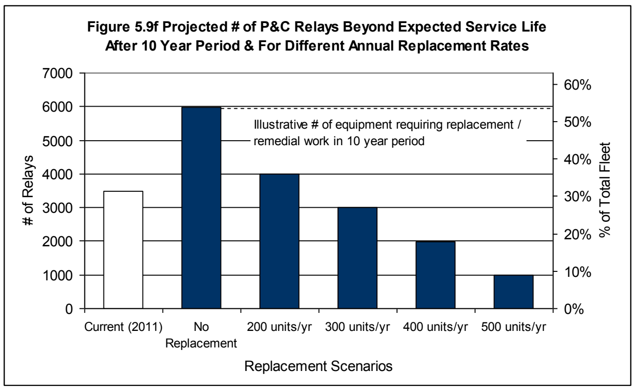
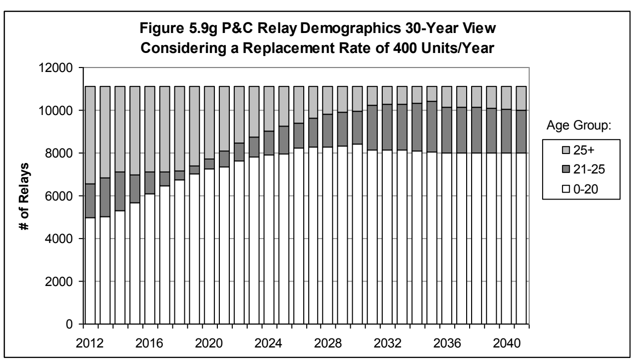


Figure 5.9g provides an annual age profile of the P&C relay population over a 30 year time horizon assuming that 400 relays are replaced each year. At this replacement rate the average age of the P&C relay population would be about 15 years in the mid to long term.



Note that while the average replacement rate for this planning scenario is 400 P&C relays per year, a determination as to the actual number of units replaced in any year, and identification of the specific units, would be based on sustainment factors discussed earlier.

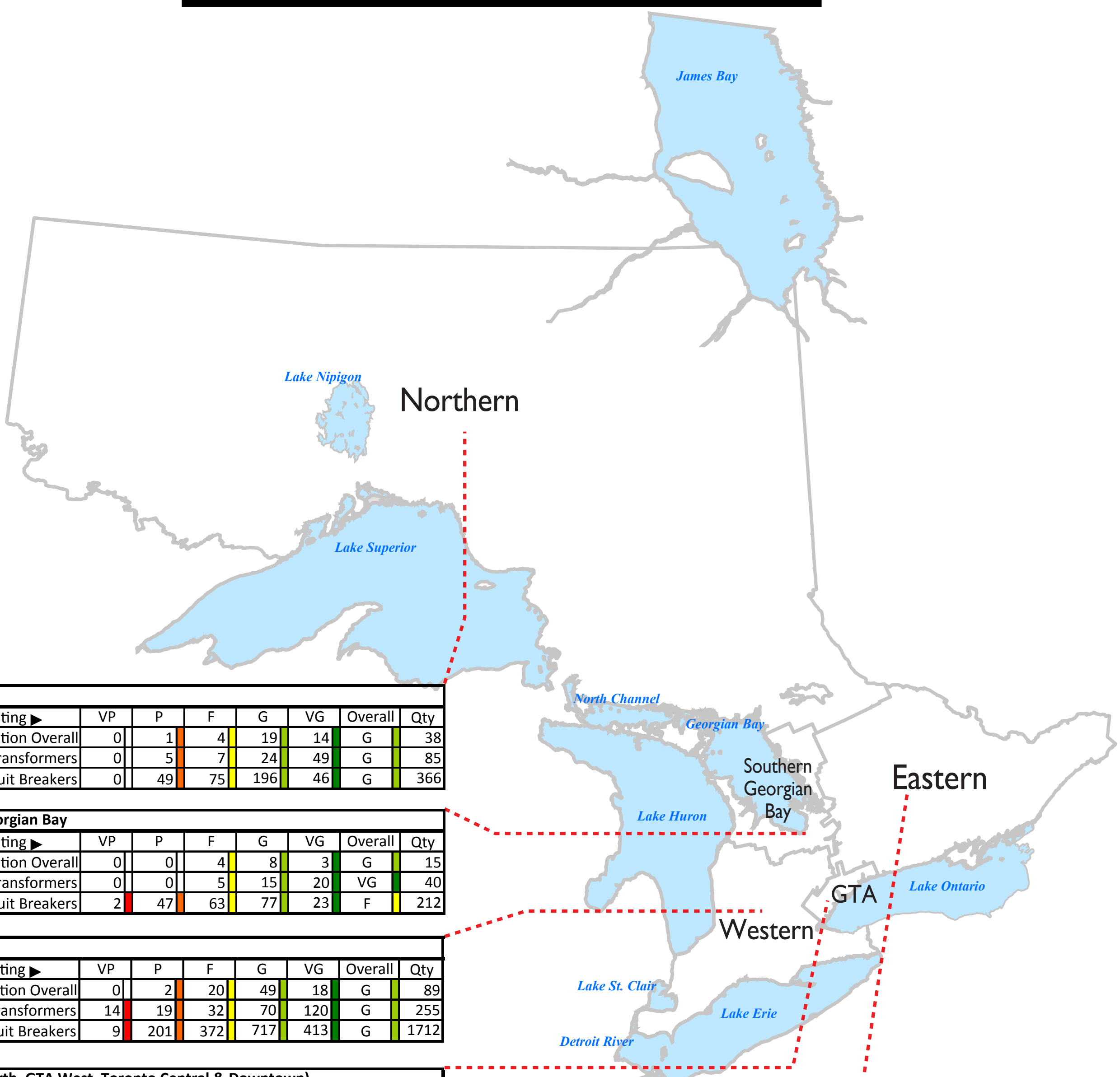
5.6 Transmission Station Asset Condition Assessment (ACA) Overview

Figures 5.10a and 5.10b on the following pages, provide maps of Ontario showing a consolidated view of overall condition assessment results for transformer and switching stations respectively, covering five planning zones.

Figure 5.10a Transmission Planning Zones – Overall: Transformer Station ACA

Overall Zone

STN	ACA Rating ▶	VP	P	F	G	VG	Overall	Qty
G	Station Overall	0	6	50	130	64	G	250
	Transformers	18	56	68	203	374	G	719
	Circuit Breakers	16	648	975	1715	908	G	4262



Northern

STN	ACA Rating ▶	VP	P	F	G	VG	Overall	Qty
G	Station Overall	0	1	4	19	14	G	38
	Transformers	0	5	7	24	49	G	85
	Circuit Breakers	0	49	75	196	46	G	366

Southern Georgian Bay

STN	ACA Rating ▶	VP	P	F	G	VG	Overall	Qty
G	Station Overall	0	0	4	8	3	G	15
	Transformers	0	0	5	15	20	VG	40
	Circuit Breakers	2	47	63	77	23	F	212

Western

STN	ACA Rating ▶	VP	P	F	G	VG	Overall	Qty
G	Station Overall	0	2	20	49	18	G	89
	Transformers	14	19	32	70	120	G	255
	Circuit Breakers	9	201	372	717	413	G	1712

GTA (GTA North, GTA West, Toronto Central & Downtown)

STN	ACA Rating ▶	VP	P	F	G	VG	Overall	Qty
G	Station Overall	0	0	9	30	15	G	54
	Transformers	2	17	12	55	119	G	205
	Circuit Breakers	2	220	291	502	274	F	1289

Eastern

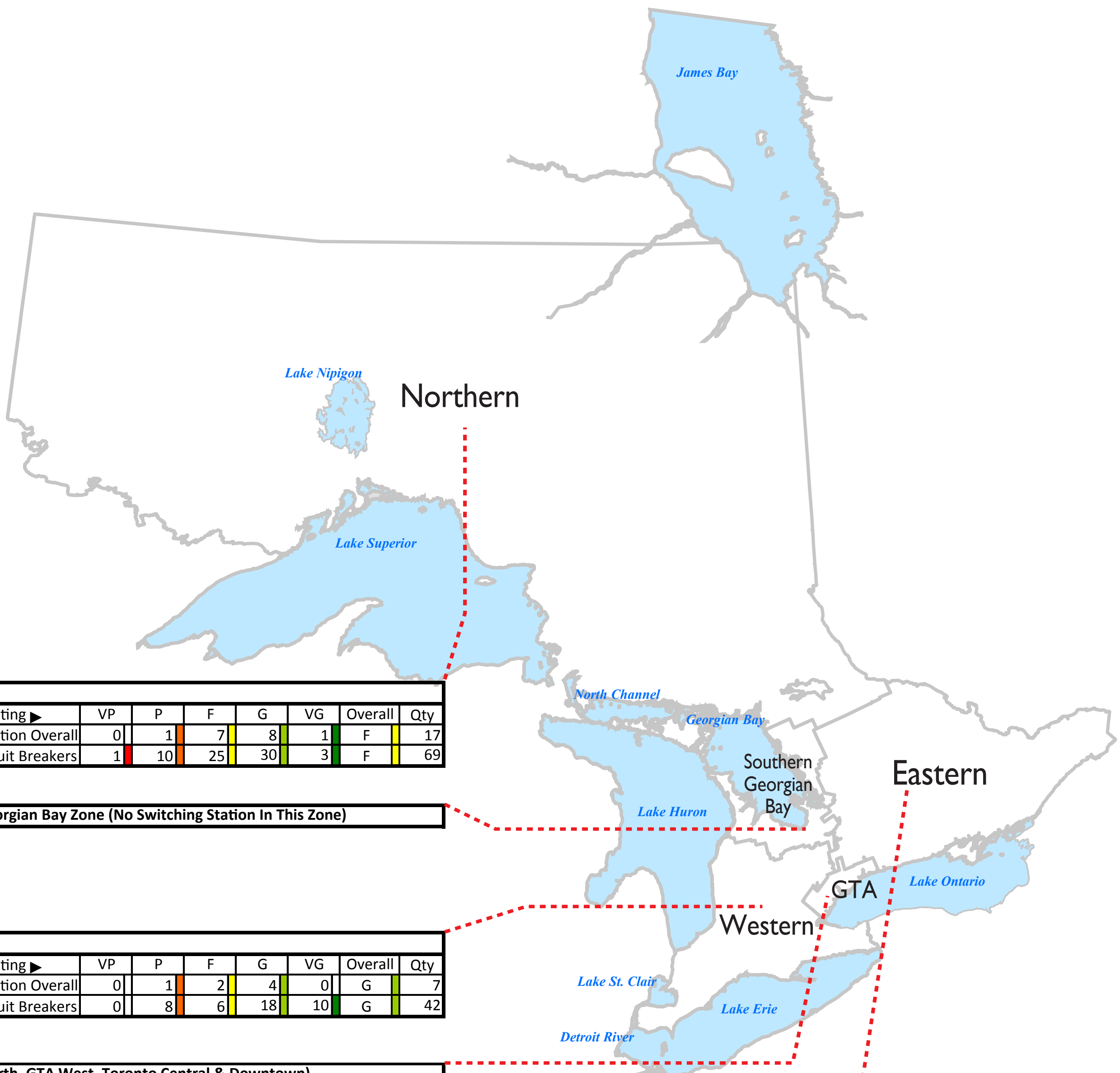
STN	ACA Rating ▶	VP	P	F	G	VG	Overall	Qty
G	Station Overall	0	3	13	24	14	G	54
	Transformers	2	15	12	39	66	G	134
	Circuit Breakers	3	131	174	223	152	F	683

[Note 1: ACA – Asset Condition Assessment]

[Note 2: VP=Very Poor; P=Poor; F=Fair; G=Good; VG=Very Good]

Figure 5.10b Transmission Planning Zones – Overall: Switching Station ACA

Overall Zone								
STN	ACA Rating ▶	VP	P	F	G	VG	Overall	Qty
G	Station Overall	0	3	14	16	2	G	35
	Circuit Breakers	1	34	63	96	34	G	228



Northern								
STN	ACA Rating ▶	VP	P	F	G	VG	Overall	Qty
F	Station Overall	0	1	7	8	1	F	17
	Circuit Breakers	1	10	25	30	3	F	69

Southern Georgian Bay Zone (No Switching Station In This Zone)

Western								
STN	ACA Rating ▶	VP	P	F	G	VG	Overall	Qty
G	Station Overall	0	1	2	4	0	G	7
	Circuit Breakers	0	8	6	18	10	G	42

GTA (GTA North, GTA West, Toronto Central & Downtown)								
STN	ACA Rating ▶	VP	P	F	G	VG	Overall	Qty
F	Station Overall	0	0	3	2	1	F	6
	Circuit Breakers	0	11	22	28	11	F	72

Eastern								
STN	ACA Rating ▶	VP	P	F	G	VG	Overall	Qty
G	Station Overall	0	1	2	2	0	G	5
	Circuit Breakers	0	5	10	20	10	G	45

[Note 1: ACA – Asset Condition Assessment]

[Note 2: VP=Very Poor; P=Poor; F=Fair; G=Good; VG=Very Good]

5.7 Sustainment O&M

Asset sustainment work is required by the transmission business to maintain existing infrastructure and facilities operating at their expected performance level. Sustainment investments are carried out on a life cycle basis to optimize O&M and capital costs and business value objectives over the service life of an asset.

During the past few years, process reengineering efforts have been undertaken to improve maintenance effectiveness and productivity using a Reliability Centered Maintenance (RCM) methodology. This initiative is the foundation of the Preventive Maintenance Optimization (PMO) Process. This process optimizes asset maintenance/inspection activities and capital investment to achieve equipment performance objectives. PMO maintenance practices and programs are reviewed/updated on a priority basis for continuous improvement to resolve issues, reduce maintenance costs and incorporate field experience and information from equipment experts and maintenance specialists. The maintenance requirements for all transmission assets (lines, transformers, circuit breakers, protection & control, etc.) are documented in Hydro One's transmission maintenance standard.

The PMO program typically uses a time-based approach for routine, preventative and diagnostic type maintenance tasks consistent with the cycle times in the transmission maintenance standard. This is analogous to changing the oil in one's car every six months or every 5,000 km. The RCM approach is typically used to identify the need for more costly, selective intrusive maintenance tasks that are warranted based on the actual condition assessment from the results of diagnostic tests. This is analogous to changing out a car's transmission system only when actual performance/signs indicate that the gears are beginning to slip.

The PMO program is also driven by asset demographics, asset condition, reliability standards and equipment performance. As transmission assets age and enter their mid-life or approach their end-of-life, it is expected that increased levels of preventive and corrective maintenance activities will be required to arrest condition deterioration and sustain equipment performance. "Old" equipment is simply more likely to fail than new equipment, and most types of equipment operated beyond their expected service life are statistically prone to experience more frequent and longer outages. PMO strives to keep up reliability while getting the most out of existing transmission assets.

In parallel with the efforts to update maintenance standards, a modern enterprise work management system that uses SAP application software was installed in June, 2008 to provide an integrated platform for planning and managing Hydro One's asset work and procurement/supply chain functions. This system manages the scheduling, work implementation and reporting of routine and condition based maintenance activities by the required due dates. This business process transformation initiative provides the basis for further improving sustaining maintenance effectiveness and efficiency gains.

5.7.1 Maintenance Plan

Hydro One's Sustainment Maintenance Plan has been developed with the main objective of achieving maintenance optimization. The plan's key building blocks that support full implementation of the PMO process are identified below:

- Identify preventive maintenance (PM) requirements and asset condition information requirements.
- Develop condition based maintenance triggers and implement results in PM programs.
- View and align planned work at a station to minimize outages and site visits.
- Collect asset condition information.
- Selectively extend lives of major equipment, through replacement of used or third party supplied parts.
- Analyze and measure performance to drive maintenance requirements and ensure reliability expectations and standards are met.
- Adopt cost effective technologies to develop and assess preventive maintenance (PM) strategies and validate PM models on a routine basis.
- Manage change control processes.
- Communicate and provide training.

The focus moving forward will be to fully leverage the SAP system to further optimize maintenance plans, provide accurate asset condition information, and better integrate required work. A large part of this effort will be to increase the use of condition-based maintenance triggers and online condition diagnostic tools to minimize costly intrusive maintenance on all major transmission assets. This requires developing and integrating asset condition and performance analysis information to provide ongoing feedback and drive maintenance activities which will ensure reliability centered maintenance and performance objectives are met.

Implementing a standard Mobile IT solution that facilitates work implementation and asset condition reporting is required to improve efficiency and accuracy of information collected. Providing real-time integration of data entered in the field with asset condition/performance analysis results will also drive additional process efficiency improvements, provide immediate maintenance feedback/direction and enhance knowledge transfer capability.

Hydro One will continue to lead PMO innovation and adopt leading edge technologies and industry best practices to further improve sustaining maintenance strategies and non-intrusive diagnostic techniques. This could include establishing a multi-discipline team to address maintenance issues on a routine basis for all major transmission assets and developing a process to better evaluate/prioritize asset and operational risks in order to further enhance optimization of maintenance work programs.

Hydro One manages its sustaining maintenance O&M program for:

- Stations, which funds the work required to maintain existing assets located within transmission stations including power system telecommunication facilities.

- Lines, which funds the work required to maintain overhead transmission lines and underground cables, including vegetation control on transmission lines ROW.

Hydro One is striving to carry out an adequate volume of sustainment O&M work on an asset base which is increasing with time as transmission development work is completed and new facilities are placed into service. At the same time, Hydro One has a capital investment program to replace end-of-life and high risk existing assets. A PMO program that leverages the maintenance management system and new technology will continuously improve and drive the necessary asset maintenance over the asset life cycle.

The maintenance work which Hydro One performs includes asset inspection, condition monitoring, and routine maintenance. For key transmission assets, some of the scope of work included in inspection, condition monitoring and maintenance (ICM) is provided in Table 5.5.

Other sustainment O&M work programs include on demand corrective maintenance work. This is the work needed to correct actual or incipient failures of equipment. Examples include responses to line conductor break/failures and other types of equipment repair requiring immediate attention.

Table 5.5 Sustainment O&M Work Scope

Equipment & O&M Work Scope (High Level)
Power Transformers & Tap Changers Visual Inspection; thermography; transformer & tap changer oil tests; tap changer servicing; power factor tests
Circuit Breakers Visual inspection; thermography; interrupter tests and servicing
Overhead Lines (including Conductors, Steel Structures, Wood Poles) Preventive Maintenance; asset condition assessment (ACA)
Underground Cables Preventive Maintenance; cable diagnostics; cable locate service
Right-of-Way (ROW) Vegetation Management Brush control; line clearing; condition patrol
Protection & Control Re-verifications; preventive maintenance

5.8 Sustainment Work Integration & Bundling

The preceding sections focused on the sustainment of individual groups of electricity transmission assets. Since the early 2000s, Hydro One has integrated and bundled sustainment work where practical, particularly if it is known that there are several assets at a station in need of replacement in the relatively near future (e.g., more than one transformer and/or several circuit breakers at a station). Work is also bundled where major station work is required, coincident with major sustainment work on transmission lines in the vicinity of the stations. However, it is important to recognize that the degree to which work in a particular location can be bundled must respect system constraints, such as the need to manage the length of outages, satisfy reliability requirements, and so on.

The integration and bundling of sustainment work achieves efficiency gains by replacing all end-of-life components within a station as part of the same project. This economically effective approach uses staff and maintenance equipment more efficiently and contributes to greater customer satisfaction through better outage co-ordination and fewer planned outages. This approach complements existing province-wide equipment replacement and on-going maintenance programs to minimize overall station costs and reliability impacts on the transmission system.

Depending on system needs and constraints (e.g., availability of equipment and outages), such work could potentially be carried out at a pace of 4 to 6 projects per year in the mid- to long term. Consideration should be given to refurbishing/replacing equipment on nearby "greenfield" locations to reduce work complexity and the lengths of outages required, particularly where relatively large volumes of work can be effectively bundled into a single project.

5.9 Applying Newer Equipment Technologies

Newer technologies are introduced into the power system when these offer advantages in power system performance such as reliability improvement, maintenance reduction, lower life cycle costs, and/or additional functionality or operational flexibility.

New transmission equipment could be used in the power system for 50 years or more and its acquisition tends to be capital intensive. It is therefore prudent to carefully evaluate new technologies before they are applied in the transmission system. This is done as specific projects or work programs to which new technologies might be applied.

The following discussion provides a general sampling of some of the newer technologies or different technology applications which might be useful in transmission sustainment work, and does not necessarily indicate any preference by Hydro One at this time.

Power Transformers

The main materials for transformers have not changed in a significant way for over a century. Vacuum based tap-changers and better online and gas monitoring equipment is already being used by Hydro One.

The substitution of SF6 gas in place of insulating oil is emerging, and could have special applications where land is a premium, albeit at higher cost than traditional approaches.

The potential use of three single-phase, in place of one three-phase 750 MVA auto-transformers could be considered on a case and location specific basis in the future. More vendors could build the single-phase units, and there could be fewer operational and maintenance challenges.

Circuit Breakers

In some cases, equipment vendors are phasing out specific types of circuit breakers. There is a shift inert to gas insulated switchgear (GIS) technology, which are usually more physically compact. For low temperature operating conditions (e.g., northern Ontario), potential future use of mixed gas technology (e.g., SF6/N2, SF6/CF4) could be considered. The application of specific circuit breaker technology could be undertaken on a case specific, or project specific basis.

Overhead Lines

Conductors with higher electrical current ratings and more compact design are being offered by manufacturers. Such conductors are being considered, where power system considerations indicate such needs.

Composite material utility poles (produced with epoxy type resins and possibly glass fibers or comparable materials) could be substituted for conventional wood poles. Composite poles are marketed as lighter weight with lower transport and installation cost and higher mechanical strength. They are also marketed as not susceptible to insects and wood-pecker damage, suitable for use in water-drenched/swampy areas, and offering lower life cycle costs. Challenges faced in the use of composite poles include higher initial costs, more difficult maintenance due to climbability issues, and concerns with respect to longevity (owing to material deterioration in the presence of ultra-violet light).

Underground Cables

With advances in underground cable construction there is a shift away from fluid-filled cables. Cross-linked polyethylene (XLPE) cable has been used, and is a good candidate technology for consideration.

Protection & Control

In the past, transmission system automation included various P&C systems complemented with different telecommunication systems. This often resulted in use of multiple and, in some cases, proprietary telecommunication protocols. This, plus the purchase of hardware and software from multiple vendors, has sometimes resulted in the need to resolve interfacing issues arising from the use of otherwise incompatible components.

The electricity industry in North America, Europe and elsewhere are now applying the IEC 61850 (International Electrotechnical Commission) standard for power system electrical substation automation. As P&C equipment requires replacement, the IEC61850 standard should be applied appropriately to provide for flexibility in the installation, operation, and maintenance of related equipment.

6. TRANSMISSION DEVELOPMENT

The Transmission Development work program covers the work required to increase the capacity and effectiveness of the transmission system and to meet evolving requirements. This section provides an overview of the projected work scope for Transmission Development.

6.1 Development Considerations

The development of short and long term transmission development work is guided by Hydro One's corporate strategy, which reflects the four strategic business values of Health and Safety, Stewardship, Excellence, and Innovation, and a set of underpinning strategic objectives (discussed in Section 2).

Going forward, the Transmission Development work program will reflect the policies and priorities set by the Ontario Government as reflected in the *Green Energy and Green Economy Act, 2009 (GEGEA)* and the *Long Term Energy Plan (LTEP)* for the Province. As government policy and the OPA's plans evolve, Hydro One will continue to review and refine its strategic plan and associated investment decisions to best serve the energy needs of customers.

With the realities of rate impacts on customers, Hydro One's challenge is to strike a balance between the work and founds associated with supporting the GEGEA and LTEP while ensuring that the corporate strategy and key business values of Health and Safety, Stewardship, Excellence, and Innovation are not compromised.

6.1.1 Transmission Planning Considerations

A number of considerations need to be borne in mind when formulating transmission development plans. These include: the need to address system reliability requirements; the changing nature of the generation resources that are likely to be connected to the power system as it ages; the growing impact of conservation and demand management programs; operational issues raised by incorporating large quantities of intermittent and variable generation resources; and the need to comply with government policy and associated directives and initiatives. These, and other transmission planning considerations applicable to the formulation of transmission development plans, are discussed more fully in Section 2 of this Outlook.

6.2 Major Drivers of Need for Development

Transmission Development plans arise to meet a number of needs that may originate from government policies and direction as reflected in the GEGEA and LTEP, load customers, generators, or the OPA. The need for new transmission facilities may also be identified by Hydro One or IESO on the basis of System Impact Assessment (SIA) studies that are carried out in response to new load or generation connection projects.

Also, potential large electricity purchases from neighbouring utilities can result in the need for major interconnection reinforcements and additional inter-area transmission network facilities in Ontario.

High level overview information with respect to various Transmission Development projects currently underway or being contemplated, including planning zone and sub-zone information, is presented in Sections 6.3 and 6.4.

The major drivers of the need for Transmission Development fall into three broad categories, as shown in Figure 6.1:

- **To meet the needs of load or generation customers.** This could include transmission facilities to connect new loads or new generating resources, or to enable additional capacity for existing loads or existing generating resources.

- **To reinforce or increase the capability of the transmission network in Ontario or the interconnections with neighbouring provinces or states.** This serves to maintain adequate customer supply and system security or to alleviate power transfer limitations.

- **To enhance performance and mitigate risk associated with meeting service standards for customer reliability and/or power quality, standards for system security, or design standards for equipment and facilities.**

These three categories can be refined further into subcategories as indicated in the following diagram (Figure 6.2) and in Table 6.1.

Figure 6.1 Transmission Development Drivers

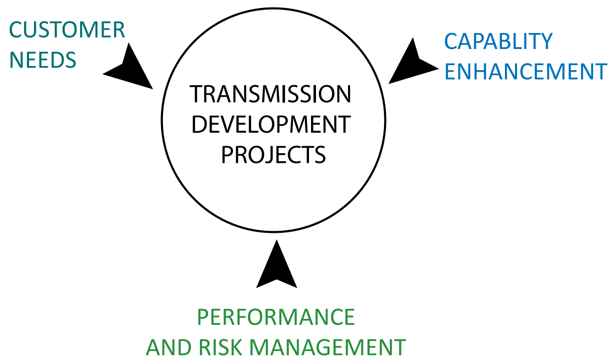


Figure 6.2 Major Drivers of Transmission System Development

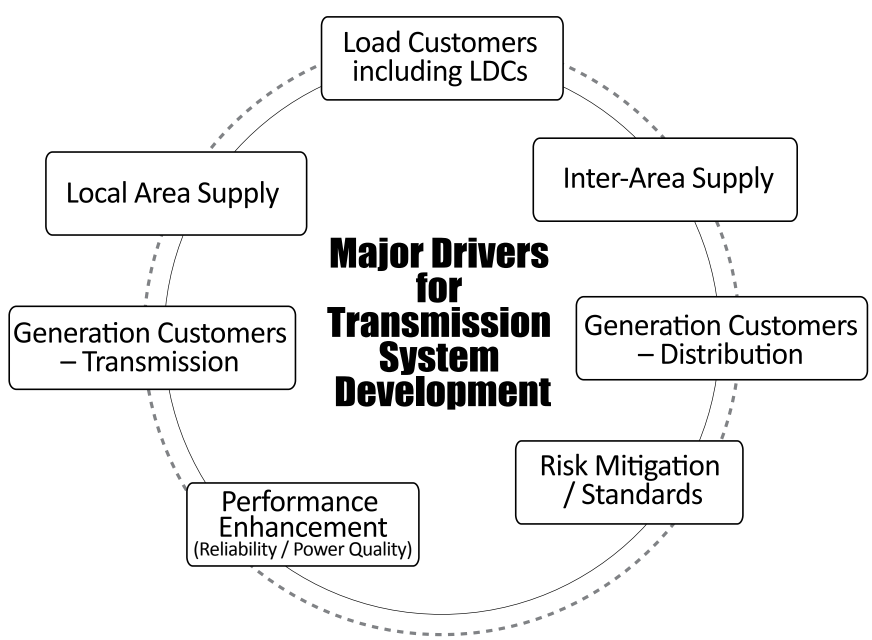


Table 6.1 Drivers of Need for Transmission Development

Major Driver Category	Sub-category	Scope or Project Examples*
• To meet the needs of load or generation customers	• Load Customer Connections • Generator Customer Connections	• New and/or modified transmission connection facilities, e.g., new line connections, new feeder positions at existing Transformer Stations (TSs), capacity increases at TSs, or new TS construction. • Radial connections plus related improvements/modifications to network and up-stream connection facilities, e.g., enhancements to protection systems, voltage or reactive power support, circuit breaker and station upgrades.
• To reinforce or increase the capability of the transmission networks in Ontario or the interconnections with neighbouring provinces or states	• Local Area Supply • Inter-Area Supply - Inter-area network transfer capability improvements - Interconnection capability improvements	• New or upgraded facilities for voltage control, equipment operating performance, system stability, and/or operating flexibility to address load growth and local area reliability issues. • New or upgraded transmission facilities to increase transfer capability between generation areas and load centers in Ontario and/or with neighbouring utilities, e.g., - new Bruce-Milton 500 kV double-circuit line; - the 1250 MW Quebec-Ontario bi-directional HVDC to 230kV/115kV intertie; - installation of Static VAR Compensators (SVC), Series Capacitors or Shunt Capacitors in existing transmission facilities to complement existing transmission facilities.
• To enhance performance and mitigate risk associated with meeting service standards for customer reliability and/or power quality, standards for system security, or design standards for equipment and facilities.	• Customer Delivery Point Performance Improvements • Power Quality (PQ) Improvements • Regulatory Compliance & Risk Mitigation (for system security and safety)	• Restore degraded customer delivery point reliability performance to historical baseline levels or better. • Installation of PQ monitors at customer locations to collect, assess and address PQ needs of customers. • Compliance with NERC/NPCC mandatory standards. • Plans to address system security and safety issues.

* Note: There could be overlapping requirements driving the need for some projects

The planning details for each type of development investment, including Load Connection, Generation Connection, Local Area Supply, Inter-Area Supply, and Performance Enhancement and Risk Mitigation are described below.

6.2.1 Load Customers

The planning for new customer load connections is driven primarily by electricity load customer requests. These projects are initiated based on customers' requirements for capacity, reliability, and/or power quality. The connection needs may be satisfied through new and/or modified transmission connection facilities including: new line connections; new feeder positions at existing Transformer Stations (TSs); increase of capacity at existing TSs; or construction of new TSs. Since these types of projects are customer driven, the magnitude and timing of work can vary significantly from year to year.

In accordance with the Transmission System Code (TSC), new load connection facilities such as transformer stations may be provided by the transmission customer or the customer may request Hydro One to provide the required connection facilities. The costs of these investments are the responsibility of the benefiting customer(s) and the costs are fully recovered from these customers via incremental connection revenues and/or capital contribution based on cost recovery agreements between Hydro One and the load customer(s).

The consequences of not proceeding with these projects include impairment of customers' ability to supply their load, increased risk of electricity service interruptions, and violation of Hydro One's transmission licence conditions related to "Obligation to Connect."

6.2.2 Generation Customers – Transmission

The planning for new transmission connected generation is driven primarily by customer requests that are significantly influenced by government initiatives for procurement of new generation and private sector investments.

Hydro One is required to connect new generators and ensure system security and reliability is maintained for existing connected customers. In addition to the dedicated generation connection facilities, upstream transmission system reinforcements may also be required to incorporate new generation. For example, protection system modifications, voltage or reactive power support, and/or breaker or station upgrades to accommodate higher short circuit levels may be required. The generator customers contribute to the costs of these investments in accordance with the TSC and based on cost recovery agreements between Hydro One and the generator customer(s).

Since 2004, the Ontario Government has taken a number of specific measures towards reliably meeting the province's electricity demand in an affordable, cost effective and environmentally responsible manner. Key elements of this have included the proclamation of the *GEGEA* and the release of the *LTEP*, both of which focus on the following:

- Increasing the renewable energy (hydroelectric, wind, solar and biomass) contribution to the Ontario supply-mix. Targets for renewables include the following:
  - Hydroelectric capacity of 9,000 MW
  - Renewable energy from wind, solar and bioenergy of 10,700 MW by 2018
- Eliminating coal-fired generation in Ontario by 2014 by retiring four coal-fired generating stations in Ontario with a total installed capacity of about 3,400 MW: Lambton GS (950 MW), Nanticoke GS (1,880 MW), Thunder Bay GS (306 MW), and Atikokan GS (211 MW).
- Continued reliance on nuclear generation to provide approximately 50% of the province's electricity supply.

Based on the OPA's Progress Report on Electricity Supply (3rd Quarter 2011), specific generation procurement initiatives have exceeded 20,000 MW and have included the following:

Table 6.2 OPA Capacity Procurement

Renewable Energy

Directive	Capacity Procured (MW)
300 MW Renewable Energy Supply (RES) I	345
1,000 MW RES II	799
2,000 MW RES III	426
Renewable Energy Standard Offer Program (RESOP)	874
OPG Hydroelectric Energy Supply	1,013
Existing Hydroelectric Facilities	1,069
Feed-In Tariff (including microFIT) – on going	4,596
Korean Consortium	1,070
Combined Heat and Power (Renewable)	85
Total	10,277

Clean Energy

Directive	Capacity Procured (MW)
2,500 MW Clean Energy Supply (CES)	1,682
Combined Heat & Power (CHP)	420
Early Movers Clean Energy Supply	1,004
Downtown Toronto and Goreway	1,389
Western GTA Supply	642
Northern York Region Supply	393
Lennox GS	2,140
Total	7,670

Nuclear Energy

Directive	Capacity Procured (MW)
Bruce A Restart & Refurbishment	3,000

A significant portion of the generation procurement initiatives listed above are connected or planned for connection to the Hydro One transmission system.

The transmission system modifications required to connect a generator are, in general, dependent on the connection location, available transmission capacity at the point of connection, and proximity of the connection location to load centres. Major new transmission reinforcements and upgrades, including additional voltage support, are likely to be required in some areas of the province to enable the connection of renewable generation.

6.2.3 Generation Customers – Distribution

A key component of Ontario's LTEP is the development of 10,700 MW of generation capacity from renewable resources (wind, solar, biogas, landfill gas and biomass). A significant portion of this 10,700 MW of renewable generation is to come from projects that are connected to Ontario's electricity distribution systems that are supplied from Hydro One owned transformer stations (TS).

- The Renewable Energy Standard Offer Program (RESOP) was specifically designed to promote the development of small, renewable, distributed generation (DG) projects (≤ 10 MW). A total of 874 MW of renewable generation capacity was procured by the OPA under this program and about 569 MW is in commercial operation.

- The microFIT (Feed-in Tariff) program covers projects smaller than 10 kW that are connected to the distribution system.

- Capacity Allocation Exempt (CAE) FIT projects are generally small projects (≤ 500 kW) for connection to the distribution system.

- Non-CAE FIT projects in the 0.5 to 20 MW range are generally planned for connection at distribution system voltage levels (≤ 50 kV).

Hydro One's goal is to enable and maximize the connection of renewable DG in accordance with the government's policies and initiatives. Facilitation of renewable DG connections is expected to result in the need for new TSs and/or upgrading of existing TSs.

The installation of significant amounts of generation on the distribution system could also result in the need for new or modified protection and control facilities on the upstream transmission system. This is typically the minimum transmission investment that is required to enable connection of large scale generation on the distribution system and includes such facilities as high voltage transfer trip (HVT/T) protection systems.

6.2.4 Local Area Supply

The term "local area" refers to a confined subsystem or radial portion of the system supplying multiple transmission delivery points serving one or more customers. The geographic and electrical size of a local area varies based on the area system characteristics and its connectivity to the bulk transmission system.

Local area supply systems operate primarily at 230 kV and 115 kV, with a few pockets at 69 kV. They link the inter-area network to load centers, such as LDCs and large industrial customers, and, in some cases, to local generators.

The planning for local area supply is generally driven by load growth and/or local area reliability. System studies are carried out to identify needs and potential solutions to resolve constraints related to local area supply adequacy. These studies use an approach that considers conservation, demand management, generation, and transmission system reinforcements.

Solutions based on transmission system reinforcements may consist of special protection systems, installation of capacitor banks, and major transmission expansion projects such as construction of new transmission lines in the area, and/or additional 230/115 kV autotransformer capacity. These major projects typically require long lead-times, particularly if there are approvals required under Ontario's Environmental Assessment (EA) Act or Section 92/95 of the OEB Act.

6.2.5 Inter-Area Supply (Including Interconnections)

The integrated inter-area network, or bulk electric system, operates primarily at 500 kV or 230 kV over relatively long distances to incorporate major generation resources and deliver their output to major load centers in the Province through interconnection points to major transmission stations.

The network is also interconnected with the transmission systems in Manitoba, Michigan, Minnesota and New York, and can be connected to specific generators in Quebec, enabling electricity imports and exports. Hydro One recognizes the value of electrical interconnections among utilities. These interconnections continue to ensure that neighbouring electricity systems provide emergency support and economic interchange of electricity at a level that is mutually beneficial to the interconnected utilities.

The solutions for enabling electrical transport of additional large quantities of out of province resources would require building major new transmission facilities involving inter-provincial border crossing(s) and potentially reinforcing existing inter-area transmission facilities within Ontario. Projects could include 500 kV transmission lines and/or HVDC (high voltage direct current) transmission lines, together with AC-DC-AC type convertor stations, shunt capacitors/reactors, and static-var-compensators (SVCs). Such major facilities involve long lead-times for the approval process (based on requirements such as the EA Act; Section 92/95 of the OEB Act).

Planning for network upgrades is based on either increasing the inter-area transfer capability between generation and load centers within Ontario or increasing the interconnection capability with neighbouring utilities.

System studies are carried out to identify needs and potential solutions. Solutions may range from the installation of capacitor banks or static-var compensation to major transmission reinforcement or interconnection projects. New or upgraded transmission facilities may be part of the preferred solution. Projects in this category may include those directly related to recommendations from the OPA, based on direction and policy directives from the Ontario Government.

Major network upgrades may involve long lead-times in the approval process (based on requirements under the EA Act and/or Section 92/95 of the OEB Act) and construction phase of the project.

The consequences of not proceeding with these investments include increased risks to reliability and security of the interconnected system as a result of the lack of adequate transmission capacity to integrate supply sources and load demand. Constraints in the provincial transmission system can inhibit the use of Ontario's own generation resources and imports and exports of power through interconnection facilities. These could result in negative economic or supply adequacy impacts, as well as potentially inhibiting the fulfillment of contractual provisions under agreements signed by the Ontario Government and the OPA.

6.2.6 Performance Enhancement and Risk Mitigation

The planning for performance enhancements and risk mitigation projects is focused on upgrading transmission system assets to minimize high impact risk and address power quality issues to ensure safe, secure and reliable operation of Hydro One's transmission system in accordance with the market rules, the Transmission System Code, and other industry standards such as the NERC and NPCC standards.

Investments in this area are grouped into the following categories:

[1] Delivery Point Performance Projects

Delivery Point Performance (DPP) investments are initiated to improve the performance at one or more customers' delivery points.

A customer's delivery point is defined as an "outlier" delivery point (ODP) when the reliability performance of that delivery point is worse than its historical baseline performance over a defined period of time. The annual work level for DPP projects is generally based on the goal to manage and contain ODPs to less than 10% of the total number of delivery points.

[2] Power Quality Projects

Power quality (PQ) in broad terms is the set of conditions that enable customer's electrical facilities to function in their intended manner without loss of performance. This means that Hydro One's facilities need to support delivery of electricity with minimal variations in voltage and frequency. With industry and consumers making use of advanced electrical/electronic devices, PQ is of increasing concern among electricity customers.

Hydro One's Power Quality projects are undertaken to work with customers to address their power quality concerns. As part of this, Hydro One has been proactive in the installation of PQ monitors to collect and assess data which is used to better understand the system and/or customer issues that adversely affect power quality.

[3] Risk Mitigation Projects

This program is used to identify work needed to ensure compliance to mandatory standards (such as the NERC and NPCC standards) and mitigate emerging high risk situations These projects may need to be given high priority and completed at short notice to address concerns regarding supply reliability or legislative, regulatory, environmental, and safety requirements. Accordingly, the work levels under this program can vary greatly based on identified issue(s) and the nature and timing of required remedial actions.

The risk of not proceeding with these investments can include non-compliance with applicable regulatory requirements, increased customer complaints, and an inability to mitigate high-risk safety, security, and/or reliability issues.

6.3 Development Projects

For planning purposes, Hydro One Transmission considers transmission development projects on a gross provincial area or zone basis. The discussion of development projects which follows considers provincial need as well as the need in each of the five planning zones. The five planning zones, depicted in Figure 6.3 are:

- *GTA (Greater Toronto Area)*
- *Western*
- *Southern Georgian Bay*
- *Eastern*
- *Northern*

Each of these zones may be further subdivided into smaller areas or sub-zones, as indicated in the insets for the GTA and Western Zones in Figure 6.3. For example, the GTA zone includes the GTA West, GTA North, Toronto Central & Downtown, and GTA East sub-zones.

The remainder of this Section provides high level overview information regarding Transmission Development projects that have been proposed in response to various requirements or drivers of need indicated in Table 6.1.

The projects are further categorized as follows:

Category A

This category covers the short-term to mid-term time frame (next 5 year horizon) and includes the following projects and plans:

1. All active projects and new projects with planned work in the short-term and mid-term time period;

2. The following major transmission projects in the LTEP:
   - Rewiring west of London with a target completion date of 2014. The project involves re-conductoring the 230 kV circuits between Lambton TS and Longwood TS.
   - Installing SVCs at Milton SS with a target completion date of Q2 2015.
   - New transmission line west of London with a target completion date of 2017 (in the LTEP).
   - New East-West tie-line with a preliminary target completion date of 2017 (in the LTEP).

Category B

This category covers the longer-term time frame (beyond 5 years) and includes projects and plans that are expected to start beyond the next 5 years.

Projects and plans in this category are viewed as potential and are subject to further studies by the OPA, Hydro One, or others.

Also, projects and plans in this category, particularly those that would be required to reinforce or increase the capability of the transmission network in Ontario or the interconnections with neighbouring provinces or states, may be subject to the OEB Designation Process.

Tables 6.3 through 6.6 provide a summary of the total number of projected transmission development projects in each of the planning zones.

Figure 6.3 Transmission Development Planning Zones

Table 6.3 Project Count (Transmission Projects excluding FIT) – Category A

Transmission Planning Zone	Number of Projects
Eastern Zone	10
GTA	20
Northern Zone	12
Southern Georgian Bay	2
Western Zone	17
Total	61

Table 6.4 Project Count (Transmission Projects excluding FIT) – Category B

Transmission Planning Zone	Number of Projects
Eastern Zone	7
GTA	20
Northern Zone	23
Southern Georgian Bay	5
Western Zone	27
Total	82

In addition to the Category A and B projects indicated in Tables 6.3 and 6.4 there are 57 generation projects, including FIT projects, that are planned for direct connection to the transmission system as shown in the following Tables 6.5 and 6.6.

Table 6.5 Project Count – Generation (Transmission FIT) – Category A

Transmission Planning Zone	Number of Projects	MW
Eastern Zone	5	245
GTA	0	0
Northern Zone	22	994
Southern Georgian Bay	1	100
Western Zone	26	2,468
Total*	54	3,797

(* Capacity for five P4/5 Samsung Projects not included in Grand Total)

Table 6.6 Project Count – Generation (Transmission FIT) – Category B

Transmission Planning Zone	Number of Projects	MW
Eastern Zone	1	300
GTA	1	50
Northern Zone	1	6
Southern Georgian Bay	0	0
Western Zone	0	0
Total	3	356

The volume of work that Hydro One will need to carry out over the next 10 years will present significant challenges if all of the Category A and B projects identified in this Outlook proceed as currently assumed.

Current and Future Studies

In addition to the projects identified as Category A and B, other future projects and plans may also be identified by the OPA or Hydro One after completion of planning studies to determine needs and potential solutions. These projects and plans may fall under Category A or B depending on their needs and project initiation dates.

Planning studies which may identify future transmission development projects include the following.

- Studies to identify base transmission development projects and plans.
- Regional planning studies for local area supply adequacy, which are generally driven by load growth and/or local area reliability concerns.

  The following Regional planning studies are currently underway and/or under consideration.

  - Kitchener-Waterloo-Cambridge-Guelph (KWCG);
  - City of Toronto;
  - York Region;
  - Essex-Leamington;
  - City of Ottawa.

6.3.1 Transmission Development Project Approvals

Major transmission upgrades, expansions or modifications may be subject to environmental assessment approvals, OEB approvals, and possibly other approvals. In addition, consultation with communities affected by transmission projects is important for securing local community knowledge relevant to projects and for gaining support. While important, the time and expense of conducting consultations and obtaining approvals can significantly affect the overall cost and timeline of transmission projects.

Environmental Assessment Approval

Development of transmission facilities in Ontario is subject to the Ontario Environment Assessment (EA) Act. This Act ensures that the environment is characterized and considered as part of the project planning process. Hydro One is required to follow the EA process and obtain EA approval for projects with potential for significant environmental impacts.

OEB Section 92 ("Leave to Construct") Approval

Hydro One is required to obtain Section 92 (Leave to Construct) approval from the OEB for major upgrades or modifications to the transmission system. Under Section 92 of the OEB Act:

"*No person shall construct, expand or reinforce an electricity transmission line or an electricity distribution line or make an interconnection without first obtaining from the Board an order granting leave to construct, expand or reinforce such line or interconnection*" [OEB Act, 1998, c. 15, Schedule B, s. 92 (1)].

Transmitter Designation Process

The OEB issued a policy on *Framework for Transmission Project Development Plans (FTPDP, 2010)*, that encourages new electricity transmission entrants in Ontario, to support competition and drive economic efficiencies. This policy will affect transmission projects which may be built by Hydro One.

First Nations and Métis Consultation

Hydro One consults with communities affected by planned major transmission projects as part of the approvals process. As mentioned in Section 3, Hydro One consults with First Nations and Métis communities affected by transmission projects and recent government directives have reinforced the importance of this work. In addition, Hydro One consults with other stakeholders and the general public when undertaking transmission development projects. Such consultations include those that are conducted as part of the projects' approvals processes.

6.4 Transmission Development: At-a-Glance

Significant transmission development projects in the short to mid term which are included in the projected Transmission Development work scope are illustrated below in a series of maps.

Table 6.7 provides a quick cross-reference which links each transmission planning zone to maps of that zone overlaid with abbreviated project titles and associated in-service dates. The projects displayed on the maps show only transmission development capital projects with cash flows more than $3M in either of 2013 or 2014, with the earliest in-service date associated with these particular projects. Therefore, the number of projects displayed on the maps is less than the project counts in Table 6.3 and 6.5.

Table 6.7 Transmission Development Projects: Planning Zones and Associated Figures

No.	Planning Zone	Figure # with Projects in Zone
1	GTA (GTA North, GTA West, Toronto Central & Downtown)	Figure 6.4-1
2	GTA (GTA East)	Figure 6.4-2
3	Eastern	Figure 6.4-3
4	Western (Parts of Central Southwest)	Figure 6.4-4
5	Western (Niagara Peninsula Part 1)	Figure 6.4-5
6	Western (Niagara Peninsula Part 2)	Figure 6.4-6
7	Southern Georgian Bay	Figure 6.4-7
8a	Northern (Part 1)	Figure 6.4-8a
8b	Northern (Part 2)	Figure 6.4-8b

Figure 6.4-1 GTA (GTA North, GTA West, Toronto Central & Downtown) - Transmission Projects

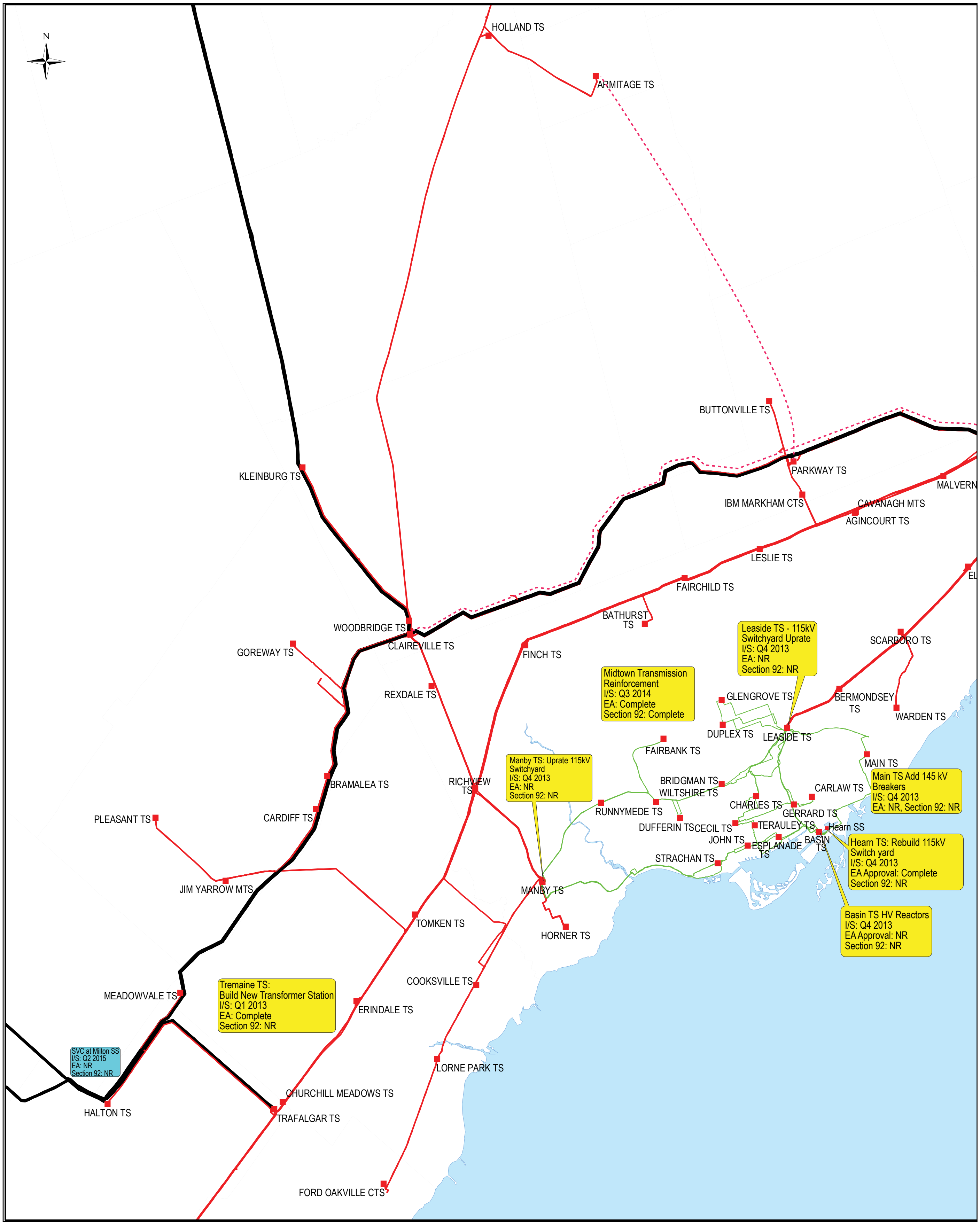


Figure 6.4-2 GTA (GTA East) - Transmission Projects

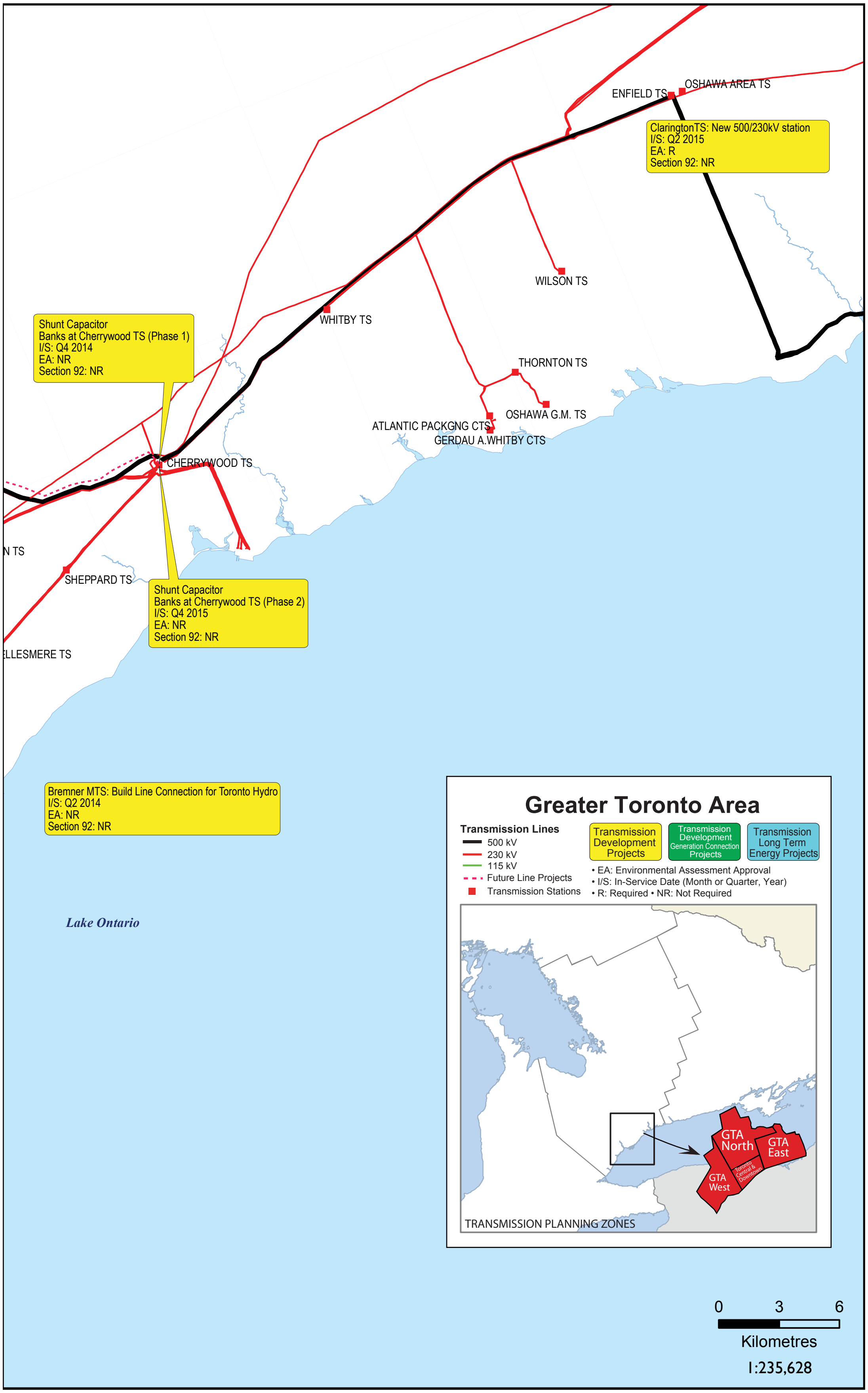


Figure 6.4-3 Eastern – Transmission Projects

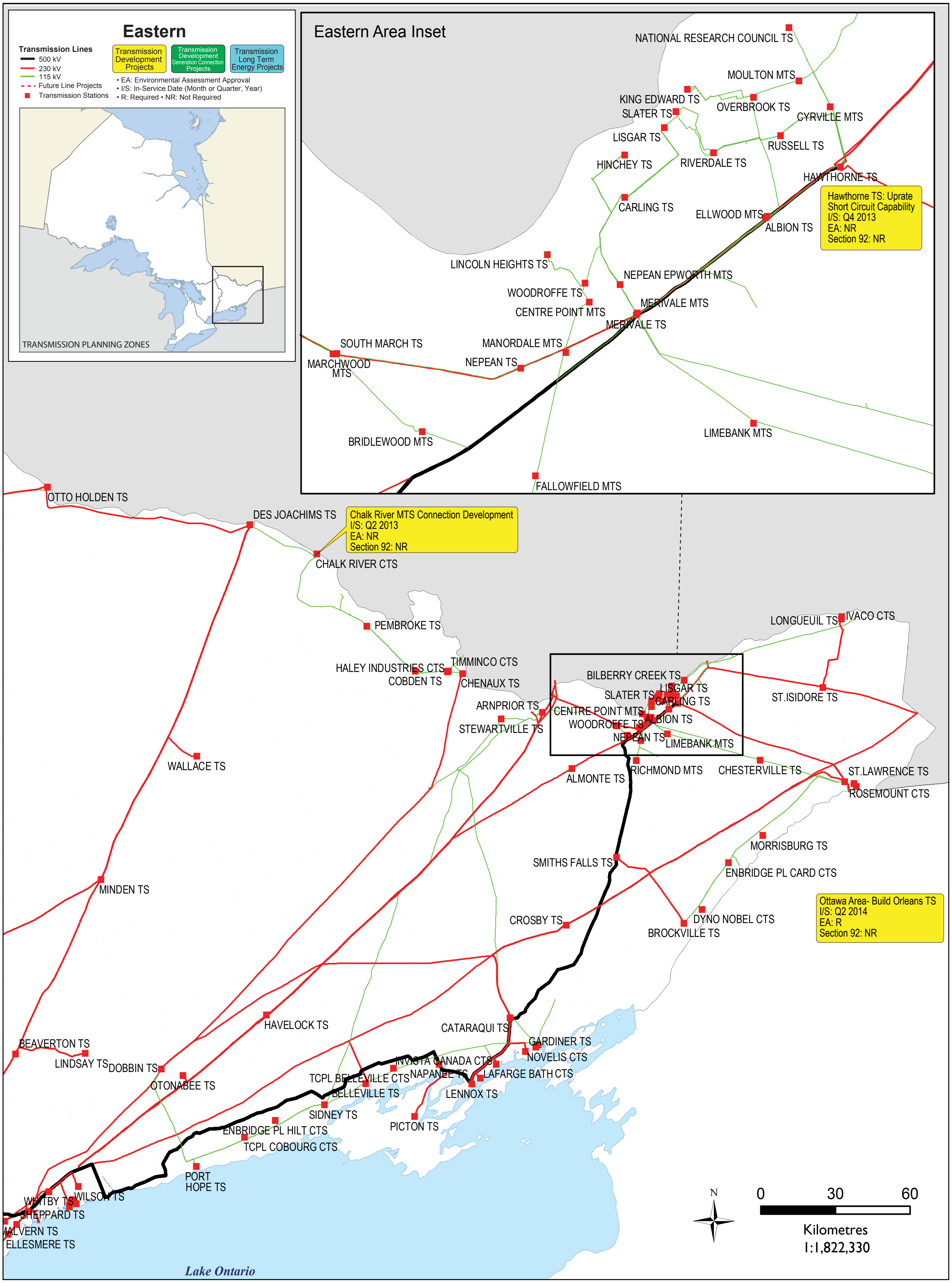


Figure 6.4-4 Western – Transmission Projects

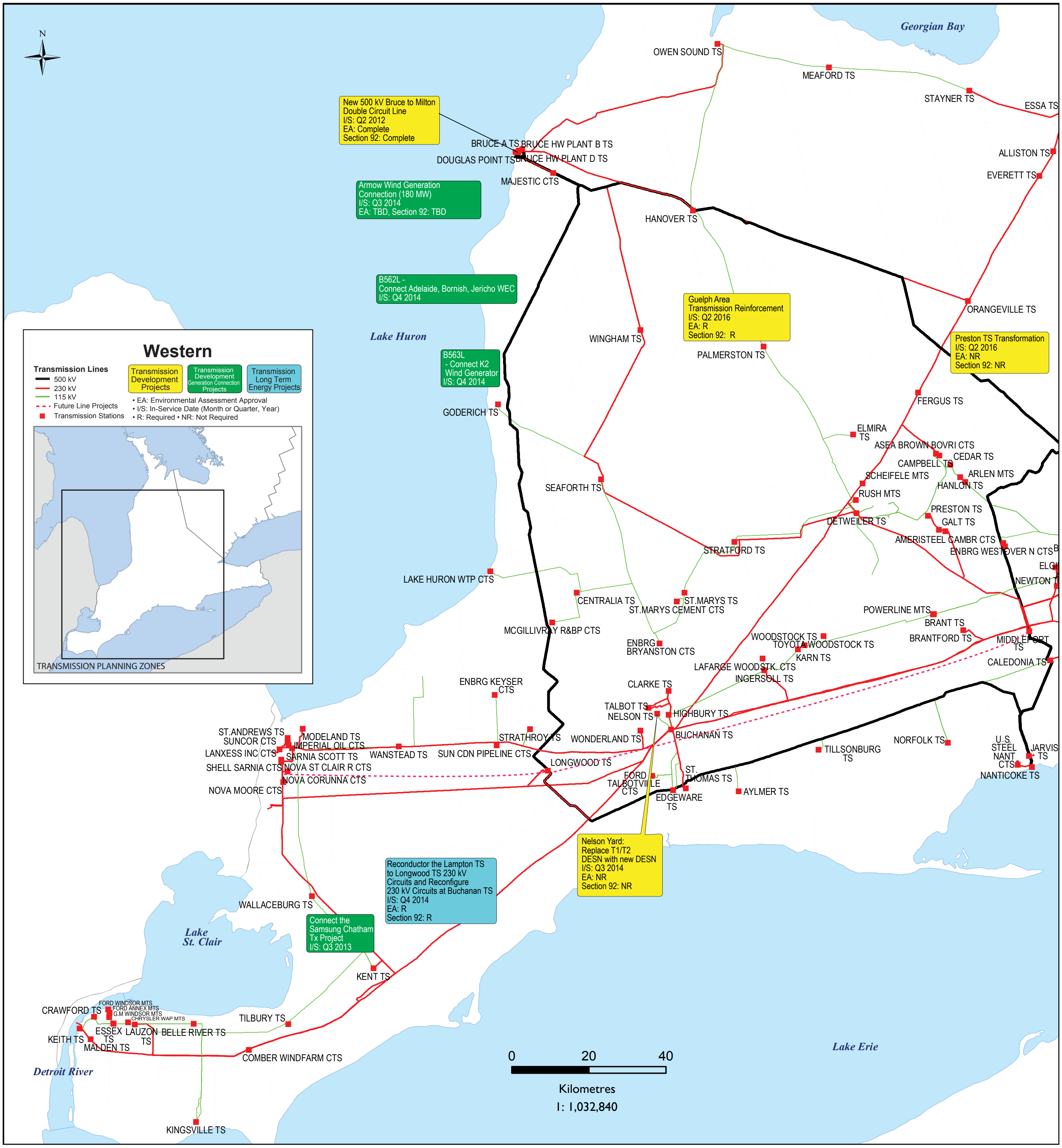


Figure 6.4-5 Western (Niagara Peninsula Part 1) – Transmission Projects

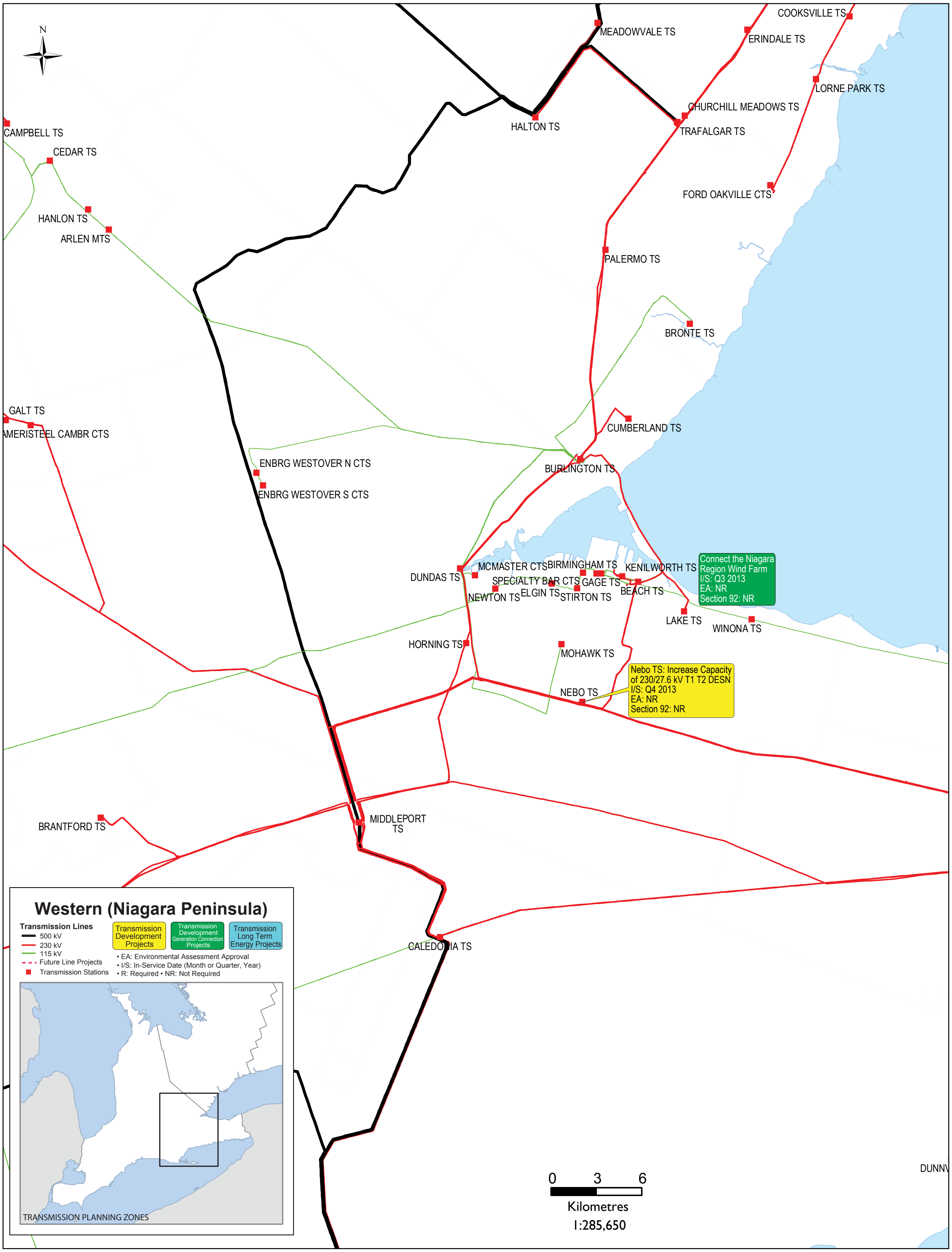


Figure 6.4-6 Western (Niagara Peninsula Part 2) – Transmission Projects

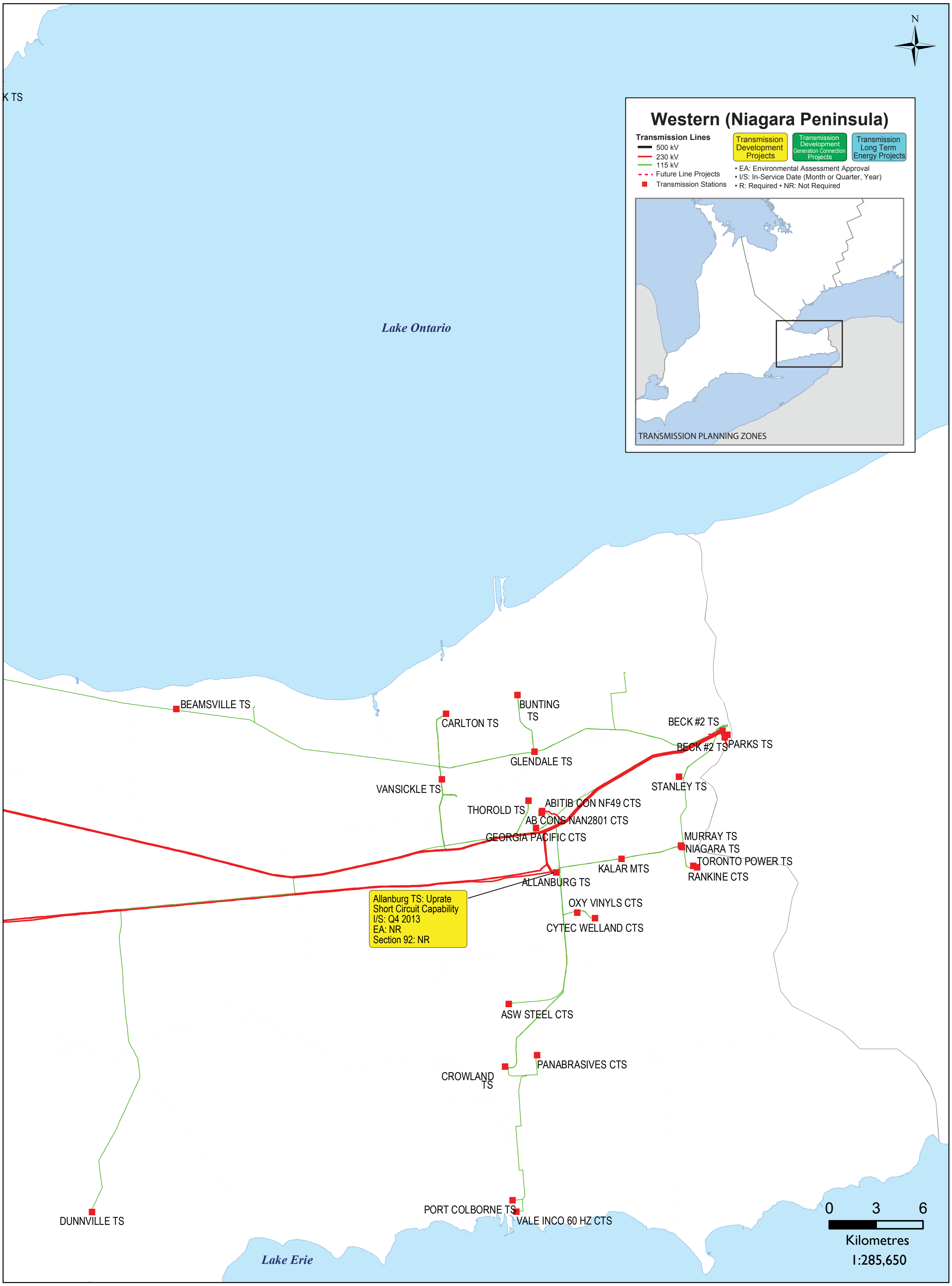
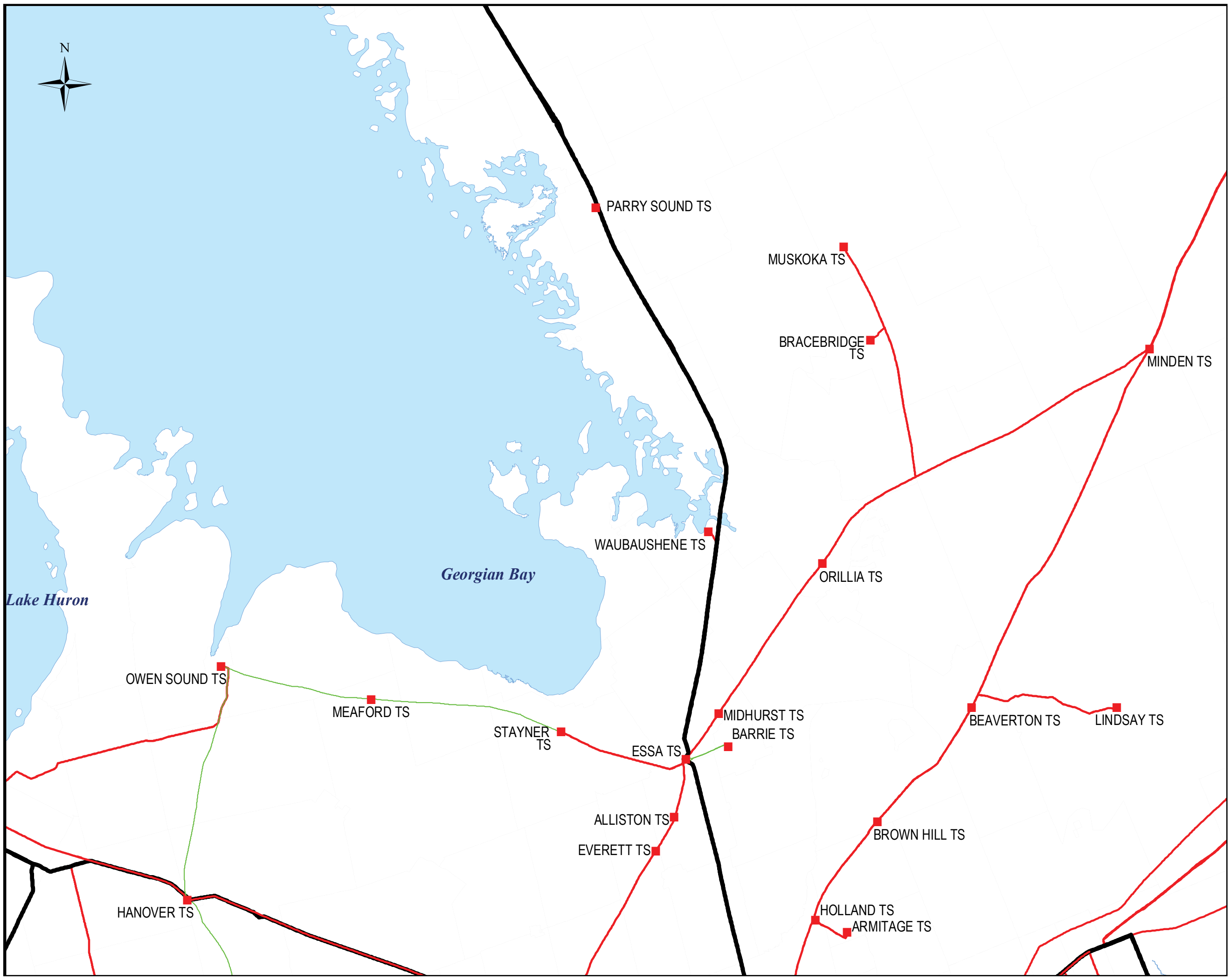
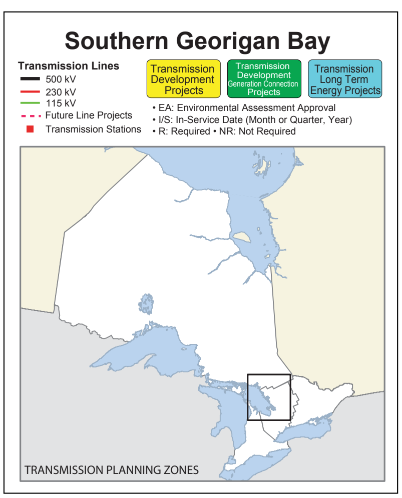


Figure 6.4-7 Southern Georgian Bay – Transmission Projects





[Note: This map is included to illustrate the area transmission facilities. There are no significant projects identified on this map in the short to mid term time period.]

Figure 6.4-8a Northern (Part 1) – Transmission Projects

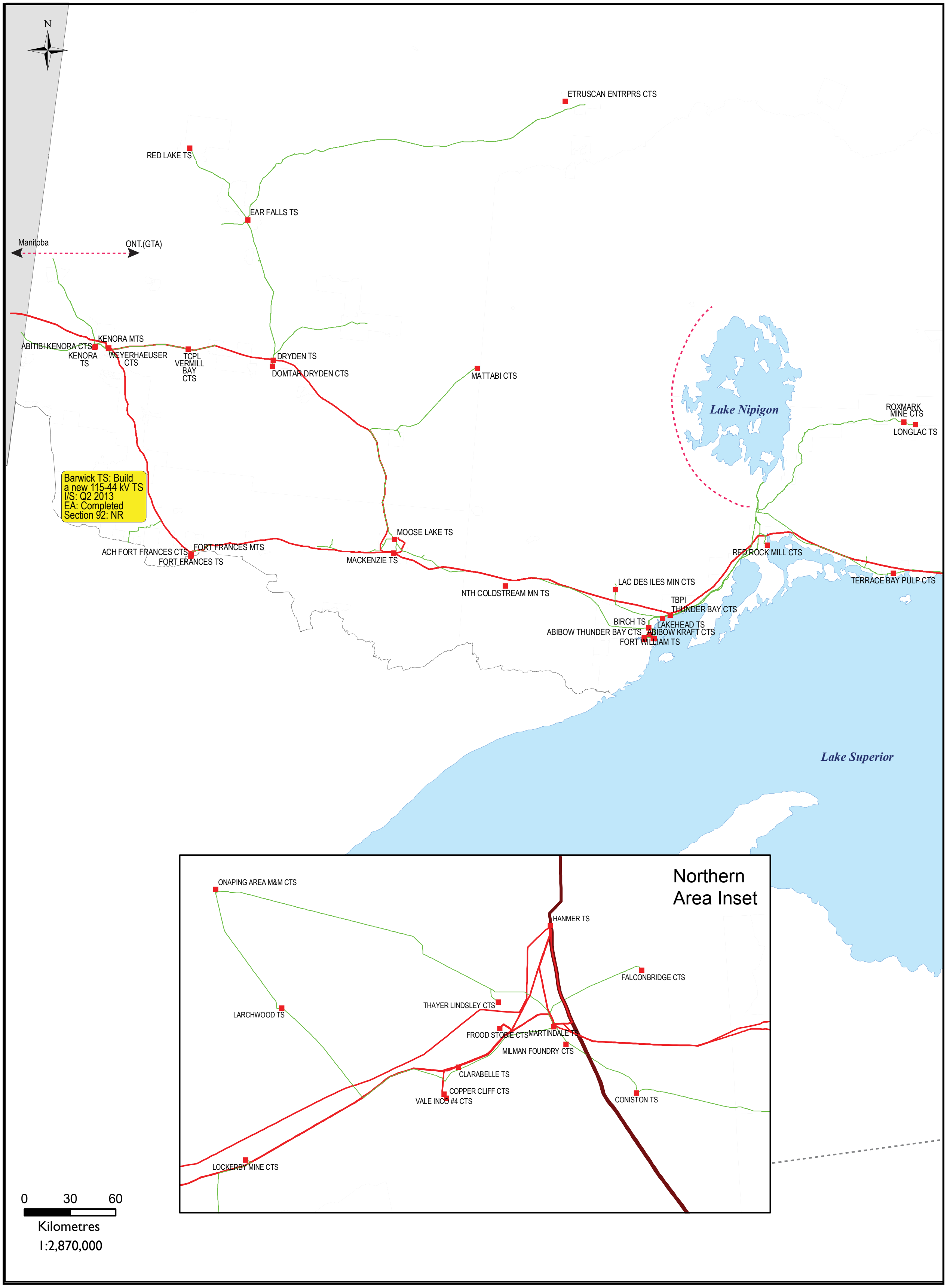
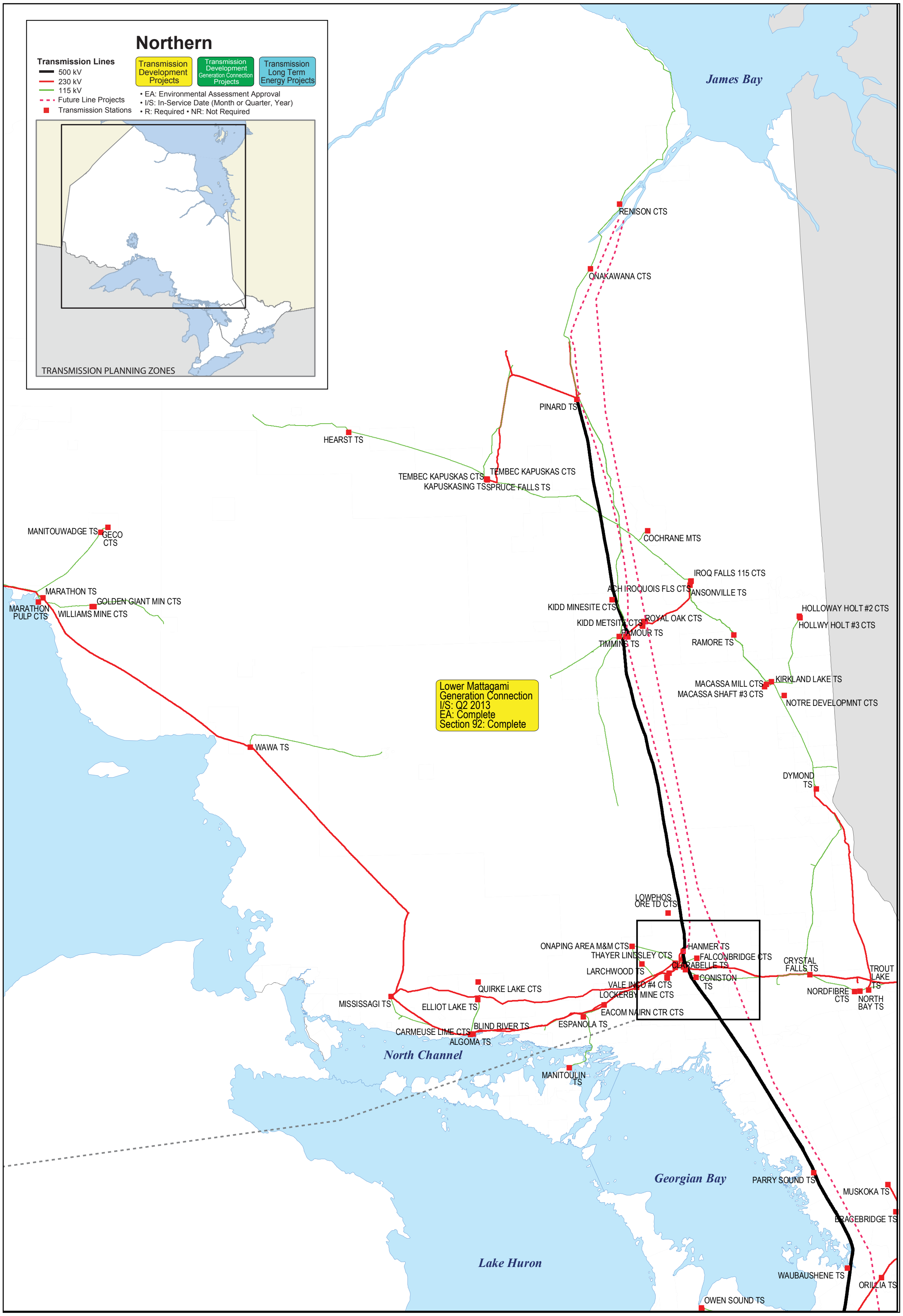


Figure 6.4-8b Northern (Part 2) – Transmission Projects



7. Transmission Operating

The Transmission Operating work program covers the work required to safely and reliably operate the Hydro One transmission system on a 24/7 basis. Operating is a foundational function for Hydro One to deliver electricity in a safe, reliable and cost-effective way to Hydro One customers. This section provides a high level strategy and overview of the projected work for Transmission Operating.

The formulation of short and long term Transmission Operating work is guided by Hydro One's corporate strategy, which reflects the four corporate strategic business values of Health and Safety, Stewardship, Excellence, and Innovation and associated strategic objectives (discussed in Section 2).

7.1 Transmission Operating Functions

The Network Operating Division (NOD) operates and controls the entire Hydro One Transmission system from the Ontario Grid Control Centre (OGCC). Backup facilities are also provided at a separate location in the event that the OGCC is unavailable. A suite of centralized systems and tools, supported by province wide telecommunication and station control infrastructure, is used to carry out the monitoring and control of Hydro One's transmission assets and the system as a whole, the planning and scheduling of transmission equipment outages, and the provision of transmission system performance information.

The operating function faces growing challenges including:

- the efficient scheduling and real time management of an increasing number of equipment outages required to support the growing Sustainment and Development work programs;
- managing customer expectations, including co-ordination of electricity system outages and/or reduced security of supply that are associated with the increases to our work programs mentioned above;
- challenges associated with adjusting to the changing conditions of aging assets that require closer management of operating limits and equipment de-ratings; this results in increasing workload to plan and manage equipment outages;
- new impacts on transmission operation, including power quality resulting from the connection of large amounts of renewable generation directly tapped to transmission lines or connected to the distribution systems and affecting transmission stations; many of these require controls and monitoring to manage transmission system impacts, performance and customer requirements.

The operating function includes the managing of contract and customer business relationships with transmission-connected industrial customers, Local Distribution Companies (LDCs), and transmission-connected generators.

Operating support is also provided for maintenance of operating equipment, computer tools and operating support systems. As needed, there is continual assessment and implementation of new technologies to improve the performance and efficiency of the transmission operating function.

7.2 Transmission Operating Authority

The Network Operating Division (NOD) at the OGCC is the operating authority for Hydro One's transmission system, including connections to other neighbouring transmission systems in Canada and the United States as well as Hydro One's 44 kV and 27.6 kV (M class) distribution system feeders. Customer Operations is the operating authority for the 13.8 kV and 4 kV (F class) distribution system feeders. During real-time operations, NOD monitors and manages Hydro One's transmission system and transformer supply stations for correct voltage levels, equipment loading and ratings. NOD also prepares Utility Work Protection Code (UWPC) documentation including switching orders for transmission and distribution planned and forced outages to ensure a safe working environment for employees.

The transmission operating Sector Controllers at the OGCC control the transmission circuits and M class distribution feeders. The Sector Controllers:

- are organized into four geographic sectors, each of which is responsible for the operation of roughly a quarter of Hydro One's transmission assets;
- operate and manage equipment of all voltage levels in their sector;
- use the Network Management System (NMS) to monitor and control the transmission system.

7.3 Transmission Operating Strategy

The transmission operating strategy includes the following key elements.

[a] Maintain operating facilities at the OGCC and backup center to enable reliable and safe day to day operation of the transmission system, to meet all industry and government regulatory requirements.

[b] Perform essential operating functions such as, directing field switching, load transfer studies and updating operating diagrams to support efficient transmission system operation.

[c] Upgrade and enhance the Network Management System hardware and software applications as necessary to continue to meet NERC Cyber Security and Cornerstone (enterprise work management/ SAP system) integration requirements and to improve operating efficiency.

[d] Develop integrating operation support tools to enhance work protection management and operation data management, and to continue to meet NERC Cyber Security and SAP system integration requirements.

[e] Improve the operating infrastructure, including gateway and wide area networks, to support reliable and efficient transmission operations and to continue to meet NERC Cyber Security requirements.

[f] Continue to support environment, health, and safety programs and raise public awareness of hazards of Hydro One's assets.

[g] Hire and develop junior staff, enabling them to replace more senior staff who will be retiring in the future.

[h] Enhance computer tools and systems to support the control room and back office transmission operating functions at the OGCC and the back-up control center. Leverage the capability and capacity of the NMS to make these enhancements.

[i] Enhance, modify, expand and, if necessary, replace the physical infrastructure equipment required for the control and operation of the transmission system from the OGCC and backup centers. The infrastructure equipment includes operational telemetry, voice communication systems, monitoring and measuring devices, automatic control devices, and data services.

[j] Enhance, modify and expand the tools, systems, and resources needed to manage significant changes in the generation supply mix, connections to the Hydro One distribution system, and their implications (as briefly outlined in Section 2 and reiterated below in Section 7.3.1).

7.3.1 Power System Changes & Operating Impacts

The transmission operating function faces substantial challenges owing to significant changes to the generation resources-mix, the nature of the electricity load, the growing contribution of variable and intermittent (renewable) generation, and increasing conservation and demand management (CDM) initiatives. These power system changes and their potential impacts are summarized in Table 2.1, reproduced here as Table 7.1.

Hydro One is in compliance with the requirements of NERC Critical Infrastructure Protection (CIP) Standards. As power system requirements and CIP Standards change, there will be operating changes needed to maintain compliance with the NERC CIP Standards, and accommodate technology advancements that will ensure effective and reliable transmission operations going forward.

7.3.2 Operating Coordination with DG-Intensive Distribution

Major organizational changes in the Control Room are not required in the short term to ensure safe, reliable, and cost effective transmission operations.

The need for new organizational structures may emerge in the future as new technologies are incorporated, increasing amounts of distributed generation are connected, and other issues, including the need for distributed generation dispatch, become apparent.

Table 7.1 Power System Changes & Transmission Impacts*

Seq. No	Power System Changes & Potential Transmission Effects
1	**Coal-fuelled stations shut down (more than 8000 MW by 2014) and end-of-life for some nuclear units** • Significant changes in transmission flow "patterns"; voltage impacts; reactive power shortfalls; transient stability concerns (lower inertia in electricity system); generation dispatch and frequency regulation.
2	**Renewable Generation with Variable and Highly Intermittent Generation (Capacity of 10,700 MW as outlined in the LTEP)** • Voltage variations as a result of the high variability in power output from renewable generation resources. • Harmonics (resulting in higher frequency electrical currents above 60 Hz) which can cause power equipment damage. • System resonance causing equipment damage. (At certain harmonic frequencies and for certain system configurations the combination of capacitive and inductive equipment in an AC circuit can result in near zero effective impedance, with the result that the electrical current and/or voltage become unacceptably large.) • Generation dispatch and power system frequency control in a system with large amounts of renewable generation. (Potential need for conventional generation or energy storage backup.) • Reversal of power flow on electrical feeders, potentially impacting transformer operations, under certain load - generation conditions. • Increase in electrical short circuit levels which could exceed equipment capabilities and Transmission Code limits. • Impacts of incorporating new protection and control equipment
3	**Connections to Distribution Systems, Including ADS (Advanced Distribution System)** • A DMS (Distribution Management System) and other systems will be implemented to improve reliability and help manage the large amount of distribution connected renewable generation (with variable and intermittent output). Interfaces are needed between these systems and the existing Transmission Operating systems to ensure more effective overall power system reliability and address issues noted above in item 2 of this table.
4	**Load Changes (Including PHEVs)** • As industrial, commercial and residential consumers use more power electronic devices (including electronic drives and electric vehicles), harmonics are introduced into the power system which can result in power quality concerns.
5	**CDM** • CDM options will be implemented primarily on the distribution system. Resulting changes in load flow patterns and timing on the transmission system, if large enough, might affect transmission system equipment loading and operating paradigms. • If power system voltage reduction is used to reduce load as a CDM initiative, the operating flexibility to provide load-generation balance under emergency condition would be significantly reduced (past practice has been to use power system voltage reduction under emergency conditions).

[* - This table identifies power system changes, and potential transmission impacts. This table is not intended to identify system operating functions carried out by the IESO and/ or Hydro One's OGCC.]

Three potential approaches are:

- retain the current operating approach as described in Section 7.2;
- establish a new Control Room Sector that is dedicated to interfacing with Distributed Generators;
- organize the Control Room by voltage with Transmission Operations (>50 kV) separated from Distribution Operations (≤50 kV).

Each of these organizational approaches has advantages and disadvantages. These will be examined further and planned as operational issues begin to emerge and are better understood. Any changes would be made to ensure Hydro One's obligations, corporate targets, and regulatory requirements with respect to reliability and service quality continue to be met.

Traditionally, NOD Sector Controllers control both the transmission and M class distribution systems while Customer Operations is the control authority for the F class distribution system. Going forward, these work functions may need to be re-examined to ensure safe, and efficient operations. Potentially, the normal day to day operations of automated distribution feeders including possible switching (dispatch) of DGs could remain under the control of NOD staff, while maintenance and repair activities remain under the control of Customer Operations.

Planned changes to the roles of organizational units and to the work management methods will need to be driven by safety requirements followed by customer, reliability and productivity considerations.

7.3.3 Mobile Technology

Mobile technologies already provide Hydro One staff with the ability to rapidly disseminate and collect technical information using wireless communication systems. For instance, technologies such as specialized, computer based tablets are widely used by transmission (and distribution) stations and lines field staff for documenting equipment characteristics and asset condition assessment information. Most of these mobile technologies are currently used in a "dock-in" mode rather than being connected in real-time to Hydro One's enterprise systems. However, several systems, such as the enterprise work management (SAP) system and geographic information systems do have provisions to enable mobile technologies to be used in either the connected or disconnected ("dock-in") modes.

It is anticipated that increasing use will be made of connected (real-time or near real-time) data transfer as technology improves and work management methods change. There is the potential to improve work effectiveness and efficiency in a number of Hydro One work areas. These include the ability to directly enter field collected information (e.g., asset condition information) into systems of record. This is expected to yield significant improvements in both data quality and the cost of data entry compared to the more traditional means of collecting data and manually entering such information into data bases at a later date. In addition, mobile technologies could be used to:

- facilitate coordination between the OGCC control room and field workers (thereby improving work protection and system operations);
- improve availability and usability of information needed for asset maintenance (e.g., design specifications, standards, procedures, system maps) for field staff;
- automate detection of important system incidents; automate the creation of work orders as needed;
- provide real time system status information to staff in the field (e.g., breaker status, status of controlled devices, and so on);
- provide real-time information about the availability of resources such as staff, equipment, tools, and spare parts;
- dispatch those resources as needed; and
- provide near real-time updates on the status of work in the field.

7.4 Transmission Operating Investments

7.4.1 Capital Work

Capital work requirements are as follows:

Grid Operating & Control Facilities: ongoing capital sustainment work is required for the Grid Operating and Control Facilities at the OGCC and the Backup Control Centre (BUCC). These facilities consist of the computer tools and systems that support the Control Room and Back Office transmission operating functions, and the buildings and physical plant that support them. These facilities must be sustained in order to meet electricity market and regulatory requirements for monitoring, control and reporting capabilities. In addition, enhancements to improve the real time management of the assets improve efficiency of the operating function and increase staff and ensure public safety.

The existing BUCC requires upgrade work for the physical facilities, including the operating tools and relevant support facilities. For example, the BUCC computer rooms are currently stretched to capacity in terms of physical space, power supplies and environmental controls. As a result, full redundancy of all systems is not currently available and some systems are currently housed in substandard overflow locations, constituting a risk to the reliability of transmission operating facilities. Since the BUCC must be functional should an extreme contingency disable the OGCC, the operating tools and support systems need to be consistently upgraded at the BUCC. The needs of the BUCC, including alternatives, are being examined as part of ongoing work.

Anticipated investments in the next few years include those needed for such things as: sustainment of buildings housing Networks Operations and associated facilities; Network Management System enhancements; tools for Operations support (including NOMS, UWPC); and voice communications upgrades.

The existing office space at OGCC is insufficient to support "back office" functions and anticipated power system IT requirements. Alternatives are being examined, including a possible expansion of the OGCC building, or a separate large adjacent building to consolidate many of the groups currently at different leased facilities at Barrie.

Integrated Operating Infrastructure: This work includes enhancement, modification, end of life replacement and expansion of the physical infrastructure required for the control and operation of the transmission system from the OGCC and backup centre. The infrastructure includes operational telemetry, voice communication systems, monitoring and measuring devices, automatic control devices, and data services.

The infrastructure includes operational telemetry, voice communication systems, monitoring and measuring devices, automatic control devices, and data services.

A partial list of work requirement in the next few years includes: frame-relay replacement; telemetry expansion; cable monitoring infrastructure; communications tower reinforcement; mobile radio replacement; and other telecommunications improvements.

7.4.2 O&M Work

O&M work requirements are as follows:

Operations Control: Ongoing support and maintenance is required for the Grid Operations and Control facilities at the OGCC and the BUCC, along with minor modifications to these facilities. The facilities consist of the computer tools and systems that support the Control Room and Back Office transmission operating function. Such facilities must be operated and maintained in accordance with electricity market and regulatory requirements for monitoring, control and reporting. Further, Hydro One must, on an as-needed basis, update and verify station diagrams, perform field inspections, and conduct load transfer studies in order to support operations at the OGCC. Field switching under the direction of operating staff at the OGCC is also required.

Work contemplated in the next few years includes: operating diagram development, maintenance and printing; voice communications system support and maintenance; load transfer studies; and control system technical support. Ongoing work also includes: customer event investigations; emergency preparedness; field switching; field verification; and equipment inspections.

8. Technology Advancement

Hydro One's key strategic business value of *Innovation* is an endorsement of the principles of continuous improvement and leveraging innovative ideas and thinking, practices, processes, advanced technologies and tools in order to create practical and cost-effective applications and solutions for the benefit of Hydro One's customers. Hydro One's Technology Advancement work program has been formulated as a practical approach to accomplishing these goals.

Over the time period of the Outlook and beyond, technology advancement will play a crucial role in helping Hydro One to take advantage of opportunities to address significant challenges facing its transmission business. Many of these opportunities and challenges arise out of the following influences:

- the connection and integration of significantly-increased levels of renewable and other distributed generation and energy storage resources to the transmission system;
- the further enhancement of the existing transmission system that is already "smart" (compared to distribution systems);
- the need to factor in environmental sustainability, and renew and sustain Hydro One's aging transmission system infrastructure.

The following subsections discuss some key challenges and advanced technology applications, which are listed in Table 8.1.

8.1 Renewable Energy and Other Systems Integration

The majority of renewable generation sources connected to the transmission system will be intermittent and variable in nature. This will present particular technical challenges for grid interconnection and system operations depending on their size, location, turbine/generator type, capacity factor, dispatchability and correlation of generator output with system demand.

Due to the reliance on power electronics and switching devices in the majority of renewable generation facilities, renewable generation sources can introduce issues, such as harmonics, resonance, and power quality (electrical "pollution") in the power systems. The effects of the electrical pollution on power systems that incorporate a significant amount of renewable generation are not yet fully understood.

Electric vehicles and related load could also have an impact on the transmission system.

The following subsections indicate how advanced technologies could be applied to address noted challenges.

Table 8.1 System Challenges and Advanced Technologies

Category	Challenges	Section	System Challenges and Advanced Technologies
Renewable And Distributed Energy Integration	• Intermittent variable generation • Load/Generation balance • Electric vehicles	8.1.1 8.1.2 8.1.3 8.1.4 8.1.5	Distributed Generation Connections - Star System Energy Storage Large Solar Power System Integration Wind Generator Performance Validation Electric Vehicles
Transmission System Optimization	• System architecture change • Harmonics, resonance, voltage variations • System awareness • Enhance system use • Effective energy use	8.2.1 8.2.2 8.2.3 8.2.4	Flexible Alternating Current Transmission System (FACTS) and Power Quality Wide Area Control and Phasor Measuring Unit (PMU) Dynamic Rating of Assets Energy Hub Management System
Transmission System Sustainability	• System losses • Potential reduction in fossil fuel use • Effective equipment asset management	8.3.1 8.3.2 8.3.3 8.3.4 8.3.5 8.3.6	Transmission Loss Reduction Climate Change Remote Communities Satellite Imaging Advanced Maintenance and Diagnostic Technologies Better Use of Aging Equipment Assets

8.1.1 Distributed Generation Connections – Star System

Hydro One has received many connection applications for distributed generation facilities. Not all of this capacity can be readily connected to the existing transmission system and Hydro One expects that connecting such distributed generation facilities will require additional measures.

To ensure the timely and effective connection of distributed generation resources to the grid, Hydro One could use the Star system concept. This concept involves providing dedicated power system facilities which gather the electricity output from clustered renewable generators for electrical connection to a transformer station (TS). These dedicated enabler transformer stations and the associated feeder facilities provide an effective solution for the timely connection of the projected increased levels of renewable generation to the electricity grid.

The Star system concept is illustrated in Figure 8.1. Its premise is to standardize the design for electrical generation connections based on simplicity, with one-directional power flow towards the higher voltage system and a simplified protection and control system. These features would also help alleviate the logjams experienced in the past few years with respect to the connection of renewable generation.

Figure 8.1 Star System for Renewable Generators

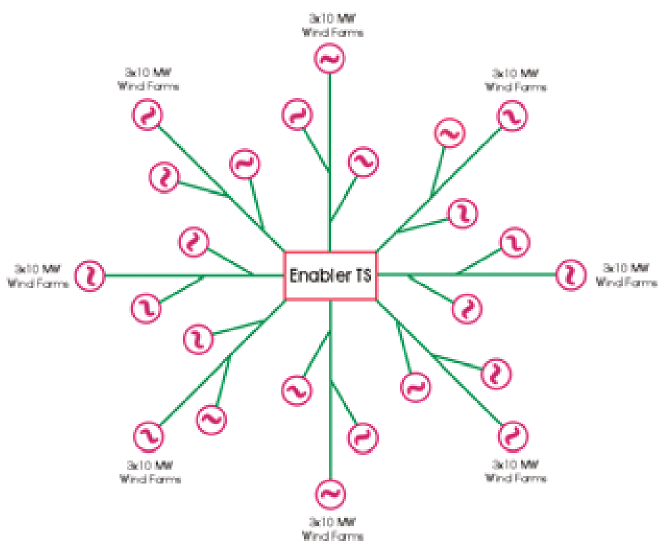
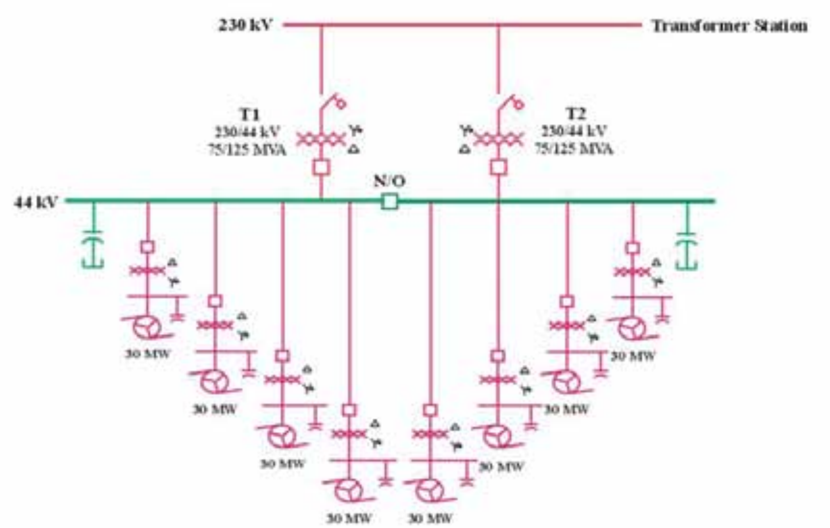


Figure 8.2 Enabler Transformer Station



As indicated in Figure 8.1, each of the eight electrical branches connected to the enabler TS can accommodate up to 3 x10 MW generators, with each branch being the "ray" of a star connected to a central enabler TS. The system configuration can therefore accommodate up to 24 x 10 MW renewable generating facilities.

The electrical connections at a TS are illustrated in Figure 8.2, which also shows the potential enabler transmission lines for connections to other parts of the existing transmission system.

The Star system could potentially eliminate the need for costly transfer-trip electrical protection systems to address operating needs and could potentially reduce the need for SVCs (Static Var Compensators) for rapid control of voltages in the grid system, although less expensive shunt capacitors may still be required.

Although the Star system is dedicated for connecting distributed generation, it may be possible to connect loads as well. However, depending on the combination of connections for generation and load, power quality and electrical protection and control issues could arise. Experience at other utilities suggests a preference for dedicated facilities for generation connections, particularly where situations involve significant amounts of generation.

Hydro One is considering technical planning of the Star system to ensure some of the areas with higher concentrations of potential distributed generation could be configured with the necessary enabler TS and related feeders. The planning also includes associated approvals that may be required (e.g., OEB, environmental approvals and related public consultation processes).

The Star system has the following advantages for operating the grid:

- only a few nodes need to be monitored and controlled for generation dispatch or to address electrical issues, such as harmonics from inverters, thereby allowing them to receive added focus;
- it allows for rapid electrical isolation, re-connection and disconnection;
- it reduces control system "hunting," thereby avoiding potential automatic control action conflicts; and
- there is better assurance of load customer power supply, reliability and power quality.

Disadvantages associated with the Star system include the absence of a fully proven and cost-optimized system at this time.

8.1.2 Energy Storage

Renewable generation resources, in particular wind and solar, are characterized by intermittent and variable supply of electricity. At times, their variable nature could cause the power system to experience rapid and continuous load-generation imbalance, thereby adversely affecting power quality (voltage, frequency).

Energy storage devices could potentially be used in conjunction with intermittent and variable output generators to better manage how, when, and where energy is injected into or absorbed from the transmission system. This offers the following potential advantages.

- **Balancing wind and solar generation**
  Energy storage can be used to manage ramp rates associated with variable power output, particularly from wind resources, and for storing excess renewable energy off-peak for subsequent use during peak periods. This would help to maximize the amounts of renewable generation that could be incorporated usefully into the system.

It is expected that viable energy storage applications will enhance the value of the renewable resources, both to their owners and to the grid.

- **Frequency control**
  Energy storage can assist in managing load imbalances in the supply and demand of electricity, and thereby improve frequency regulation. In particular, storage technologies with high cycling capability, (e.g., flywheels), are well-suited for this function.

- **Increased end-user benefits**
  Energy storage devices deployed at, or close to, the premises of customers could significantly enhance those customers' energy services, particularly if those customers also have sources of renewable generation. Charging energy storage devices from appropriate sources and at appropriate times and then recovering the energy when optimal, offers the promise of lower net electricity costs, improved power quality, the provision of emergency back-up power supply, and more effective enablement of demand management. Of particular interest is the possibility that electric vehicles might be useable as a source of energy storage, which would offer the benefits of local energy storage and would result in better utilization (and possibly increased uptake) of electric vehicles.

From a functional perspective, there are three different categories of application for large scale stationary electric energy storage facilities.

- **Power Quality:** In these applications, the stored energy is only applied for seconds or less, to assure continuity of quality power.

- **Bridging Power:** In these applications, the stored energy is applied from seconds to minutes, usually to assure continuity of service when switching from one source of energy generation to another.

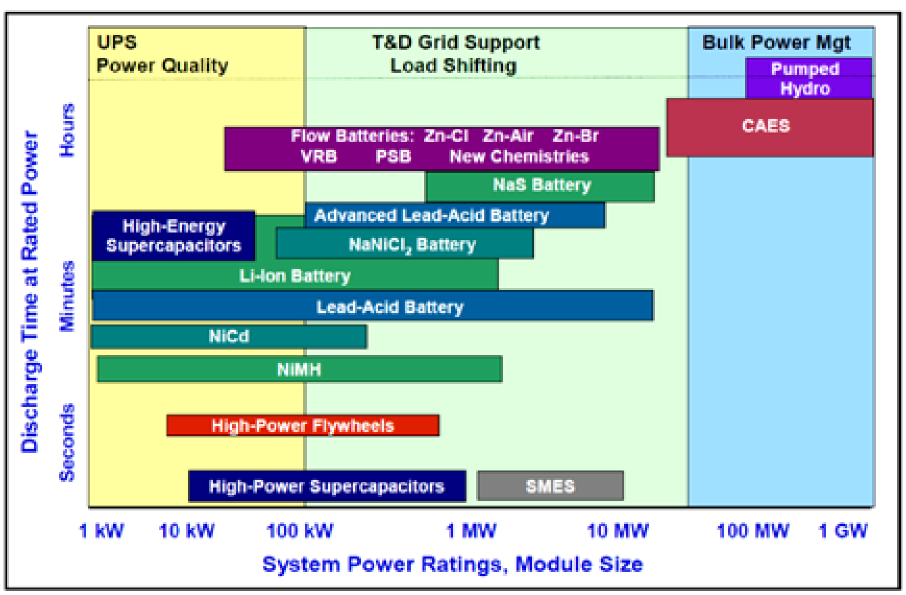
- **Energy Management:** In these applications, the stored energy is applied to decouple the timing of generation and consumption of electric energy. An example is load leveling, which involves the charging of storage devices at times of relatively lower electricity demand (when electricity prices are low) and withdrawing electricity at times of relatively higher system demand (when prices are generally higher). Energy storage for energy management could enable some electricity consumers to be off the grid for hours.

Most storage technologies have specific functional characteristics and are not capable of, or economical for, application in all three functional categories.

Figure 8.3 provides power ratings of various energy storage technologies with respect to the discharge time and potential applications:

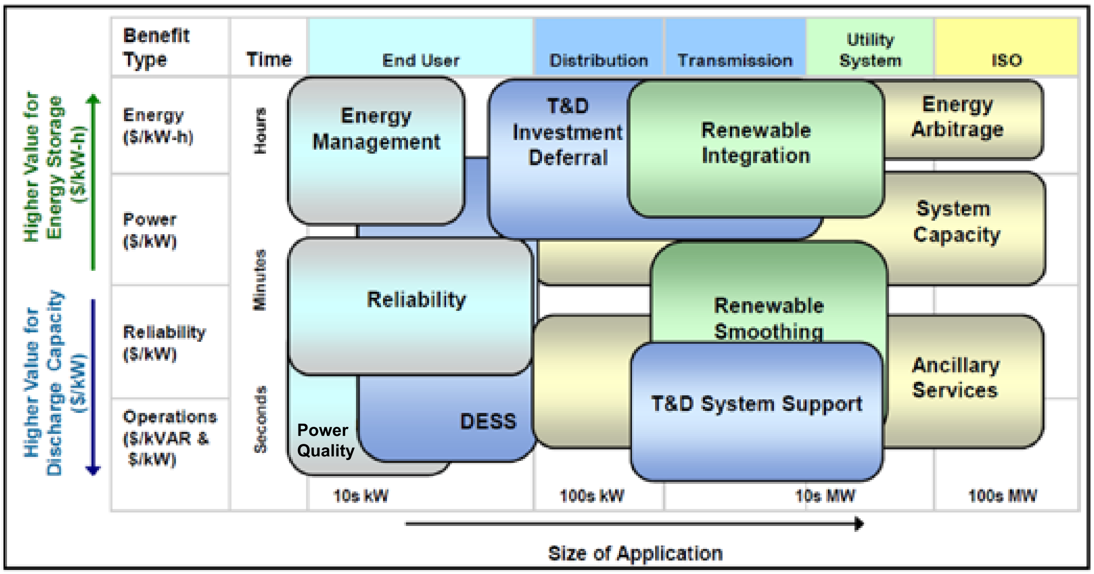
For utility applications, energy storage systems can be used for various purposes. These include load-following, voltage and frequency regulation, power quality control, deferral of transmission or distribution upgrade requirements in some cases, and support of renewable generation. Figure 8.4

Figure 8.3 Energy Storage System Ratings: Rated Power vs. Discharge Time



Source: Electricity Energy Storage Technology Options: A White Paper Primer on Applications, Costs, and Benefits. EPRI, Palo Alto, CA, 2010. 1020676.

Figure 8.4 Utility Applications for Energy Storage



Source: Electricity Energy Storage Technology Options: A White Paper Primer on Applications, Costs, and Benefits. EPRI, Palo Alto, CA, 2010. 1020676.

provides typical sizes, discharge time requirements, and benefits of various storage applications in the electricity industry.

There are developments in cryogenic thermal energy storage systems which use off-peak electricity to make extremely low temperature (about -200^{o}C) liquid nitrogen and oxygen (cryogen). This liquid is then used in a cryogenic heat engine to produce electricity at times of higher demand.

Increased levels of Plug-In Hybrid Electric Vehicles (PHEVs) and electric vehicles (EVs) in the future could result in these vehicles supplying electricity to the grid at times when they are not in use on the road. They essentially would act as an energy storage medium and could, for example, be used to assist in voltage regulation.

The energy storage technologies indicated in Figure 8.3 are all proven concepts. Not all of them are fully commercialized, although they have all been used in utility environments. Table 8.2 provides an overview of the status of these storage technologies including main advantages and disadvantages. The selection of one or more energy storage technologies for utility applications will depend on a number of factors including functionality, capital cost, life efficiency and life-cycle costs.

One of the key challenges is pairing energy storage technologies (with specific capabilities) to power system applications. It is likely that a mix of technologies and applications will prove most practical. Supercapacitors could be used for power quality (e.g., start-up of a large electrical motor); flywheels, and battery technologies with high peak capability for bridging power (e.g., frequency regulation for micro-grids) could be used; high energy capability batteries (e.g., flow batteries) could also be used for energy management applications.

Hydro One will be monitoring future development in energy storage technology, given the potential benefits to utility applications in the presence of significantly increased levels of renewable generation on both the transmission and distribution systems. In some instances, Hydro One will also consider supporting research and development in selected storage technologies for specific application to Hydro One's grid.

Hydro One is already an industry partner in the utility-scale advanced battery storage demonstration project, with multiple sub-projects. Project partners include other Canadian and US utilities; Canadian and Ontario government agencies; academia, and private industry. A 370 kW lithium-ion polymer based battery system from Electrovaya Inc. (with four hour capability) is planned for use as part of this project. This demonstration project includes the following.

- Electrical integration of the energy storage system with a hydrokinetic project to enable storage and release of energy at times more suitable for system use. The hydrokinetic project is comprised of a 15 MW three-blade "free flow turbine" installation, with horizontal-axis turbines designed to capture energy from the natural flows of rivers or tidal water currents. The hydrokinetic installation is planned at the St. Lawrence River near Cornwall, Ontario.

- Repurposing refurbished automotive lithium ion batteries for utility applications in Winnipeg, Manitoba. Additional benefits arising out of this effort could include a reduction in diesel fuel usage when applied at remote communities.

- Integration of the lithium-ion battery storage system in urban downtown Toronto to gain a better understanding of how storage technologies could address challenges faced by urban electricity utilities. These challenges include the supply of electricity to large concentrations of commercial and residential customers, and the fact that there are relatively few options for providing alternative electricity supplies in Ontario's large urban cities , which are already heavily built-up.

Hydro One is also participating in work on a flywheel energy storage system. In this system, electricity is used to accelerate a rotating disc to high speeds in a vacuum. Electricity is regenerated when needed using a generator through braking-action of the disc. This effort is focused on development of appropriate control systems to integrate flywheel energy storage into the Ontario electricity grid, recognizing challenges in the variability and intermittency of renewable generation and the need to keep electrical system voltages within tolerances for customer power quality. A 500 kW flywheel system (with 45 to 60 minutes capability) is being considered for connection into the grid for demonstration purposes. This work is being carried out collaboratively with support from the Ontario Centre of Excellence (OCE), Temporal Power, Hydro One, Toronto Hydro and Ryerson University.

Hydro One is also participating with Ryerson University in a thermal energy storage technology project involving use of off-peak electricity to form ice; later the ice could be used for cooling air when needed during the day.

Energy storage technologies provide an opportunity to leverage resources already connected to the transmission system to enhance reliability and customer service quality, especially in the presence of increased levels of renewable generation, in a cost-effective way.

8.1.3 Large Solar Power System Integration

The Ontario government, through the OPA, is encouraging all forms of renewable energy generation development in

Table 8.2 Energy Storage Technologies' Applications

Storage Technologies	**Main Advantages** (Relative)	**Disadvantages** (Relative)	**Power** Application	**Energy** Application
Pumped Storage	High Capacity, Low Cost	Special Site Requirement		●
CAES	High Capacity, Low Cost	Special Site Requirement, Need Gas Fuel		●
Flow Batteries: PSB VRB ZnBr	High Capacity, Independent Power and Energy Ratings	Low-Energy Density	◑	●
Metal-Air	Very High Energy Density	Electric Charging is Difficult		●
NaS	High Power & Energy Densities, High Efficiency	Production Cost, Safety Concerns (addressed in design)	●	●
Li-ion	High Power & Energy Densities, High Efficiency	High Production Cost, Requires Special Charging Circuit	●	○
Ni-Cd	High Power & Energy Densities, Efficiency		●	◑
Other Advanced Batteries	High Power & Energy Densities, High Efficiency	High Production Cost	●	○
Lead-Acid	Low Capital Cost	Limited Cycle Life When Deeply Discharged	●	○
Flywheels	High Power	Low-Energy Density	●	○
SMES, DSMES	High Power	Low-Energy Density, High Production Cost	●	
E. C. Capacitors	Long Cycle Life, High Efficiency	Low-Energy Density	●	◑

●	Fully capable and reasonable	○	Feasible but not quite practical or economical
◑	Reasonable for this application	None	Not feasible or economical

Source: Electricity Storage Association

Ontario, including solar powered generation. Several large solar generation developments are being proposed in Ontario. A number of technological issues are expected to arise out of this increased use of solar power, and solutions are needed to more effectively integrate large scale photovoltaic (PV) solar farms into the transmission and distribution networks in Ontario.

Hydro One has initiated discussion with OCE in collaboration with universities and a wind farm developer. This project will provide innovative and comprehensive technologies for integration of large-scale PV solar farms into the transmission and distribution systems in Ontario. A broad range of integration issues will be examined including:

- maximum penetration level;
- optimal sitting;
- operation and control of PV solar systems in the electricity system;
- protection and relaying;
- system stability;
- converter/inverter and transformer technologies;
- incorporation of weather conditions in predicting solar power for electricity markets;
- efficient PV solar cells;
- snow and wind loading of solar panels; and
- policy related to land use for solar power generation.

The study will also assess the impact of the integration of large-scale PV solar farms on:

- reverse power flow through transformers;
- voltage regulation;
- reactive power compensation needs;
- power quality issues;
- harmonic injection; and
- line losses in the distribution system.

The project will investigate and develop robust control strategies for coordinated control of large scale PV systems with conventional generation and other renewable power systems based on wind energy and biomass energy.

8.1.4 Wind Generation Performance Validation

Hydro One is on the leading edge of validating adequacy of wind-generator performance involving full-scale power system operational tests to ensure integrity of the power system. Specifically, when the voltage at the point of electrical connection of a wind-generator to the transmission system drops to as low as 15% of the initial value, the wind-generator must be able to "ride-through" that condition for at least 600 ms (FERC Order No.661, July 5, 2005). This is to ensure that the transmission system can recover from such an electrical fault condition. While manufacturers of wind-turbines provide theoretical estimates of performance, these have never been validated. Hydro One has worked with a generation developer and their manufacturer to carry out full scale transmission system tests in order to validate that the particular wind-generator machine did perform consistent with the results of computer model simulation and the FERC requirements.

Hydro One continues to seek validation of other combinations of onerous operating conditions, using "scaled-down" equipment in some cases, and relying on computer simulations in other cases.

8.1.5 Electric Vehicles

As part of the province's commitment to reduce greenhouse gas emissions, the Ontario government has set a target that one in 20 passenger vehicles (5%) driven in Ontario should be electrically powered by 2020. Major automobile manufactures are continuing to make advances in Plug-in Hybrid Electric Vehicles (PHEVs) technology and many have significantly ramped up PHEV production for 2012 and beyond.

PHEVs are powered by both a gasoline engine and electric motor. PHEVs have larger battery packs than hybrid vehicles, and the batteries are rechargeable from the grid at 120 V, 240 V, or 500 V. Typical charge times for a 65 km range are 8-10 hours and 4.5 hours with 120 V and 240 V electrical receptacles respectively.

PHEVs load growth will likely cluster in urban areas, and could impact peak load assuming high PHEV adoption rates and coincident recharging of vehicles in the evening. The Ontario Ministry of Economic Development estimated the cumulative on-road electric vehicle population in Ontario between now and 2020 to be between 130,000 and 360,000, the majority of which would be PHEVs. High PHEV popularity and demand may create concerns of overloading on many transmission and distribution assets already operating close to capacity. Hydro One is mindful of the evolving PHEV market, and potential adjustments to Hydro One's load forecast.

The integration of a large number of PHEVs with variable charging patterns in the grid could also negatively affect voltage regulation, frequency regulation, and contribute to harmonic distortion.

To more effectively plan for PHEVs, Hydro One with a market research company and others, are exploring the application of demographic profiling to estimate PHEV clustering and link these geospatially. Such information could be used for developing more flexible transmission plans to accommodate PHEVs as needed.

As discussed above, there is some potential for vehicle-to-grid electricity transfer and the use of electric vehicle batteries for energy storage applications. PHEVs can act as distributed loads (i.e., grid-to-vehicle), or distributed sources of energy storage for the grid.

Hydro One continues to be a participant in an electricity industry sponsored program (along with EPRI, CEATI, and other organizations) to better understand and support the needs related to PHEVs in Hydro One's system.

8.2 Transmission System Effectiveness

While there are advances and enhancements to the existing transmission system, the primary "architecture" of the future transmission system needs to be given fuller consideration. For example, should the future transmission system continue with AC technologies; should it be HVDC (high voltage direct current); or, should it be a blend of these two technologies? Further, one needs to address specific concerns such as the addition of large amounts of renewable generation resources with intermittent and variable energy, which could significantly change the current basis for planning, building, and operating transmission systems.

Utilities world-wide, including Hydro One, are being confronted with the challenges of a surge in requests to connect many large renewable energy technology generating facilities in a very short time period. Different approaches involving alternative infrastructure or generation connection "configurations" are needed to rapidly connect the renewable energy generators to the Hydro One transmission system, and support the Ontario Government initiatives for renewable generation.

In some cases, certain advanced technologies, including those used in other industries, and business circumstances may involve step changes (compared to gradual changes) within the electricity industry, and this may alter the very nature and approach to managing the electricity transmission business. This includes electrical protection systems to ensure continued safe operations and continuity in reliable supply of electricity to customers. There are many challenges, and some people have proposed the idea of a "smarter" transmission system (compared to the less automated distribution systems) to address such concerns.

The following subsections indicate how advanced technologies could be applied to address noted challenges.

8.2.1 Flexible Alternating Current Transmission System (FACTS) & Power Quality

The expected increase in the number and capacity of renewable generators connected to Hydro One's transmission and distribution system over the next few years could result in power quality (PQ) issues due to the highly variable and intermittent nature of these resources. Load and generator customers could be impacted by PQ issues. Flexible Alternating Current Transmission System (FACTS) technologies may be appropriate to ensure that adequate power quality levels are maintained.

FACTS technologies may help address three main types of power quality issues affecting the transmission system:

- voltage variations as a result of the high variability in power output from renewable generation resources;
- harmonics (resulting in higher frequency electrical currents above 60 Hz); and
- system resonance.

FACTS technology could also have potential use in the future integration and interconnection of micro-grids with Hydro One's transmission system, (e.g., remote communities).

Voltage Control

Traditionally, voltage control in transmission systems has been carried out using capacitors and reactors together with circuit breakers. These devices provide a discrete amount of reactive power to raise and lower the voltage in the vicinity of the electrical connection point of such devices. Going forward, the use of circuit breakers will be inadequate given the switching requirements associated with large levels of connected renewable generation.

FACTS technologies offer two variable and rapid voltage control technologies:

- SVC (Static Var Compensator); and
- STATCOM (Static Compensator) which is comprised of a SVC plus a direct current (DC) source for charging a capacitor for more effective voltage control with a combination of reactive power and limited real power injection.

Both the SVC and STATCOM have capacitors and reactors which are integrated with power electronic devices to rapidly control reactive power, and hence, the voltage at the connection point in the transmission system.

The use of FACTS devices at Hydro One is not entirely new. In 2009, Hydro One installed an SVC at Lakehead TS for voltage control, replacing a failed synchronous condenser. Additional SVCs have been installed and these installations are being monitored for effectiveness.

DVR (Dynamic Voltage Restorer) is another voltage control device consisting of STATCOM in combination with a series transformer inserted into the transmission circuit.

Harmonics Management

There are two options for managing harmonics, involving either passive electrical filters or active electrical filters.

- *Passive Electrical Filters*
  Passive filters consist of a combination of capacitors and reactors to "trap" the harmonic currents. The design of these electrical filters is dependent on the transmission

system configuration, and on the connected renewable generation. These filters may not be effective during changes in system configuration, (e.g., maintenance on a transmission line or when a large portion of the renewable generation is shutdown or unavailable).

- *Active Electrical Filters*
  Active filters are comprised of STATCOM plus controls focused on suppressing harmonics. This is achieved by injecting currents of harmonic frequencies of concern with electrical current of opposite polarity. Since the power electronics controls use measured values of voltage and current conditions, these devices are not as dependent on configuration of the transmission system.

Resonance Management

Depending on the gear boxes and electrical converters, renewable energy generators can introduce electrical currents at frequencies which could be multiples of 60 Hz. At certain harmonic frequencies the combination of capacitive and inductive equipment, plus the system configuration in an AC circuit, can result in near zero effective impedance (comparable to zero resistance in a DC circuit). The result can be that the electrical current becomes very large. Such large currents can potentially damage equipment. Work is needed to identify these harmonics and mitigate these using the techniques outlined immediately above under the harmonics discussion.

The use of FACTS devices, while promising, has the potential for negative impacts on existing assets, including protection and control devices, transformers, and associated tap changers. It is recommended that Hydro One:

- carry out project-specific technical evaluations, as part of the detailed planning for distributed generation connections to address the concerns and issues noted in this section;
- carry out further research in collaboration with universities and other utilities to determine the advisability of including additional requirements for renewable generation in the TSC (Transmission System Code); and,
- consult with developers of renewable energy generation, the IESO and the OPA on the operation of FACTS to ensure a common understanding of underlying issues and solutions.

8.2.2 Wide Area Control and Phasor Measuring Unit (PMU)

Traditionally, power flow phase angles are determined by performing calculations based on various measured transmission system parameters. PMU technology combines GPS technology, signal filtering, and faster digital signal processing, to measures power flow phase angles directly. This information can be combined with information about inter-area and regional transmission system conditions and disturbances to improve system operation and flexibility and to control the power system in such a way as to reduce the likelihood of major system disturbances (e.g., blackouts).

Hydro One plans to continue participation in USDOE supported NASPI (North American Synchro Phasor Initiative) project to assess the applicability of PMU technology in Ontario.

8.2.3 Dynamic Rating of Assets

Dynamic circuit rating refers to the utilization of real-time information to develop accurate ratings of lines, cables and substation components to either increase circuit ratings above nominal ratings or to maintain transfer capacities at safe levels.

In the absence of a dynamic rating capability, circuit ratings are periodically established in a conservative fashion through the use of conservative engineering calculations that are based on an assumption of the most unfavorable conditions that could prevail. While this provides a “factor of safety”, the end result can be overly conservative, and therefore sub-optimal.

With dynamic rating, it is possible to increase the calculated allowable thermal rating of transmission assets such as lines and transformers by using calculations that are based on actual conditions prevailing at the moment (for example, conductor temperature, loading history, weather conditions, and so on). In some cases, the allowable power flows may be increased by a significant amount (e.g., 10% - 20%). The application of dynamic ratings is expected to focus on key transmission lines with rating concerns.

Dynamic circuit rating could be used to:

- increase the allowable power flow over existing static rating;
- defer the need for capital expenditures by obtaining greater capacity from existing assets;
- integrate new generation resources without costly equipment upgrades;
- avoid damage to system components and extend asset life; and
- identify actual system constraints as a focus for potential upgrades.

Some of the key challenges facing dynamic circuit rating implementation may include:

- reliably determining the conditions that affect asset ratings;
- cost and complexity of incorporating dynamic rating into day-to-day operations;
- limitations in modeling dynamic behaviour to predict circuit ratings into the future;
- the determination of the limiting power system condition

at each instant (e.g., thermal limits, transient stability limits, or voltage stability limits);
- the need to consider the ratings of all components in a circuit to ensure that the "weakest link" is considered; and,
- increases in transmission line losses.

8.2.4 Energy Hub Management System

While individual energy efficiency and renewable energy technologies continue to be developed and improved, insufficient attention is being paid to the ways in which they can be operated to maximize the benefits across a broader 'energy system'. The solution proposed can be called an 'energy hub management system', where an "energy hub" can be thought of as any concentration of load and generation, at locations such as a home, a manufacturing facility, a store, an office, or a farm.

In brief, an energy hub management system would provide an effective, integrative interface and control capability for energy producing and energy consuming devices within the hub. The energy hub management system could improve reliability and customer service by controlling generation and load devices through analysis based on customer driven heuristics and external factors such as energy prices, emission levels, and weather conditions.

As envisaged, the energy hub management system consists of three key elements.
- A central unit through which information is collected from the energy hub's devices and the external environment (for example, local electricity conditions, electricity market prices, or weather forecasts). This central unit would mathematically process that information in models developed from past device performance and user-defined decision making heuristics in order to manage energy more effectively.
- Two-way controls on all energy consuming and producing devices within the energy hub. These controls would have the ability both to record energy consumption and production data, and to direct the operation of individual devices as appropriate.
- A web-based portal, which is the interface between the energy hub's manager(s) and the central unit/device technology.

Using state-of-the-art wireless communication devices, web deployment, and various instrumentation and control technologies, the energy hub management system provides an effective, integrated interface not only among energy producing and consuming devices within a single, static location (i.e., an energy hub) but it also receives, analyzes and acts upon system-wide information (e.g., electricity prices or emissions levels). All of this is presented in a user-friendly web portal for the manager(s) of the energy hub to use locally or remotely.

8.3 Transmission System Sustainability

Hydro One recognizes the importance of the environment as it relates to the electricity transmission business. Hydro One supports the need for environmental sustainability and for actions to mitigate potential impacts of:
- transmission system losses;
- climate change, even though the transmission and distribution businesses are fractional contributors to those impacts (larger impacts result from industries which use fossil based fuels more heavily).

The following subsections indicate how advanced technologies could be applied to enhance the use of Hydro One's existing transmission assets.

8.3.1 Transmission Loss Reduction

Transmission losses on Hydro One's transmission system were approximately 3% of the total energy delivered in 2011. This represented approximately 4000 gigawatt-hours of electricity. Compared to other utilities, these system losses are relatively high, owing to the size of Hydro One's service territory, the number of very long lines in Hydro One's transmission system, and the remoteness of many generation resources.

To reduce these losses, Hydro One adopts the following approaches when planning transmission facilities.

- Specific areas with high concentration of electrical loads and high volumes of electricity transfer in transmission lines are identified and ways to reduce associated line losses are sought.
- Transmission planners consider the possibility of raising operating voltages (within existing limits). Effects on equipment capability need to be considered, as well as the effect on reducing line losses.
- The costs and effects of installing shunt capacitors to provide reactive power to raise operating voltages are considered. If shunt capacitors are installed, the associated costs need to be recovered.
- Factoring equipment/transmission line losses and the value of loss reductions into equipment specifications, bid evaluations, business case recommendations, and decisions.

The potential opportunities with respect to the first item above need to be identified in co-operation with the OPA and the IESO. Potential regulatory issues arising out of all of these approaches need to be considered.

Table 8.3 summarizes existing and other technologies to reduce transmission losses and improve the overall efficiency of the transmission system.

Table 8.3 Possible Loss Reduction Solutions

Transmission Efficiency Improving Opportunity	Demonstration Technologies
1. Reduce System Losses	1A. Voltage Upgrade/EHV AC/HVDC
	1B. Voltage Var Control Coordination
	1C. Generation Dispatch to Reduce Losses (Loss Minimization Optimization)
2. Reduce Line/Equipment Losses	2A. Advanced Conductors/ Superconductors/Low Loss Design
	2B. Low Loss/LEED* Substation Equipment & Transformers * Leadership in Energy and Environment Design (LEED)
3. Increase Line/System Utilization	3A. Dynamic Rating
	3B. Smarter Tranmission

(Based On: EPRI Information)

8.3.2 Climate Change

Weather has significant impacts on the planning, design, asset management and operating of the transmission system, especially given Ontario's large geographic area with challenging terrain and climatic conditions. Changing meteorological conditions, prticularly an increased frequency of extreme weather events, may significantly increase failures, recovery time, and overall unreliability of the transmission system. Other adverse impacts on asset management and operation can include accelerated corrosion of steel components, more rapid wood decay, wildfire hazards, mud slides, avalanches, flooding, reduced opportunity for live line maintenance, delays in recovery operations, and reduced transmission transfer capability.

It is important to understand the impacts of climate change on Hydro One's transmission system, and factor these in Hydro One's practices.

Climate Change Strategy

Climate change is any significant long-term change in the "average weather" that a given region experiences. Average weather may include average temperature, precipitation and wind patterns. There is evidence to suggest that climate change will affect the operations of Hydro One facilities.

Hydro One's approach to climate change will be: to responsibly prepare and adapt to the physical impacts that affect the electricity grid; to continually improve our internal efficiencies and processes; and, to work with key stakeholders to enable initiatives that will help Ontario reduce its overall greenhouse gas emissions.

Hydro One's Climate Change Strategy includes six key considerations. These are:

- climate change policy and regulations;
- internal energy efficiency;
- employee and customer engagement;
- physical impacts;
- investment planning;
- green energy.

Hydro One has begun to document its annual greenhouse gas inventory for some emission sources where information is readily available. Hydro One is continuing to work toward further refinement of the greenhouse gas inventory.

Transmission Planning and Operations

There is a need to examine the experience of transmission and distribution companies operating in warmer climates to determine whether Hydro One planning and operating practices need to be modified (e.g., line losses, line sag). This work should include working with other utilities through industry organizations to determine the need to consider changes in facility design parameters to better accommodate changes in weather patterns.

Hydro One should also examine whether expected increases in vegetation growth rates (e.g., deciduous forest growth and expansion of deciduous vegetation into more northerly areas) will require changes in utility vegetation/ forestry management practices. It may also be necessary to explore innovative funding recovery measures in light of an expected increase in severe weather.

Unlike in the 1970s and 1980s, Ontario's electricity consumption now peaks in the summer. With climate change this summer peaking behaviour is unlikely to change. It would therefore be advisable to examine opportunities for expanded cooperation with winter peaking jurisdictions such as Quebec, Newfoundland and Labrador, and Manitoba in order to more effectively use the available energy resource pool. Hydro One would support such initiatives with modifications or reinforcement to transmission facilities where these can be shown to benefit Ontario customers.

Settlement Patterns

In planning transmission service, Hydro One needs to factor in the impact of both global warming and measures to mitigate global warming at the location of electrical load. For instance, rising carbon emission costs may, in the future, penalize commuters and owners of large suburban homes, with the effect of driving urban intensification. This could lead to the need for additional transmission facilities in urban areas.

8.3.3 Remote Communities

Hydro One Remote Communities currently provides generation to about 20 off-system communities in Northern Ontario. The costs of doing so are currently driven mainly by the cost of delivering diesel fuel to these communities. Rising fuel oil costs and reduced availability of winter roads is increasing the cost of providing the service.

Hydro One is undertaking a pilot project at one community with a wind-fuel cell facility to reduce diesel fuel requirements. Additional opportunities for fuel substitution will need to be considered under a broader program for remote communities, preferably with renewable generation technologies (e.g., hydroelectric, wind, solar).

Connection of remote communities to the transmission system (or possibly the distribution system) may also be a possible option in some cases, noting the potential for development of more renewable generation in Northern Ontario, and the potential for electricity supply to large electrical loads for resources development in those areas.

8.3.4 Satellite Imaging

Enhanced satellite imaging could be used to complement existing conventional approaches (including air-borne LiDAR – light detection and ranging) for better gauging vegetation out-growth, improved asset condition assessment, and better estimation of operating line ratings. Reduction in air-borne LiDAR would reduce fuel use if the challenges related to satellite imaging can be addressed.

Hydro One is one of several utilities supporting work being conducted by EPRI to seek ways to provide more accurate and effective ways of applying satellite imagery for line applications. One of the challenges in using satellite imaging at present includes the fact that the resolution of images taken by satellites is currently about 300 meters, which may be inadequate for application by electricity utilities. There are indications that a resolution of 100 meters may be required for images to be useful for assessments.

8.3.5 Advanced Maintenance and Diagnostic Technologies

The development and use of advanced maintenance and diagnostic technologies offer several potential advantages, including:

- better prioritization of time-based maintenance programs;
- condition based maintenance programs;
- failure prevention programs;
- smart equipment replacement programs; and
- timely right-of-way maintenance.

Improvements in diagnosis and maintenance techniques are part of the ongoing work to provide increased system reliability and availability of transmission equipment in an effective way.

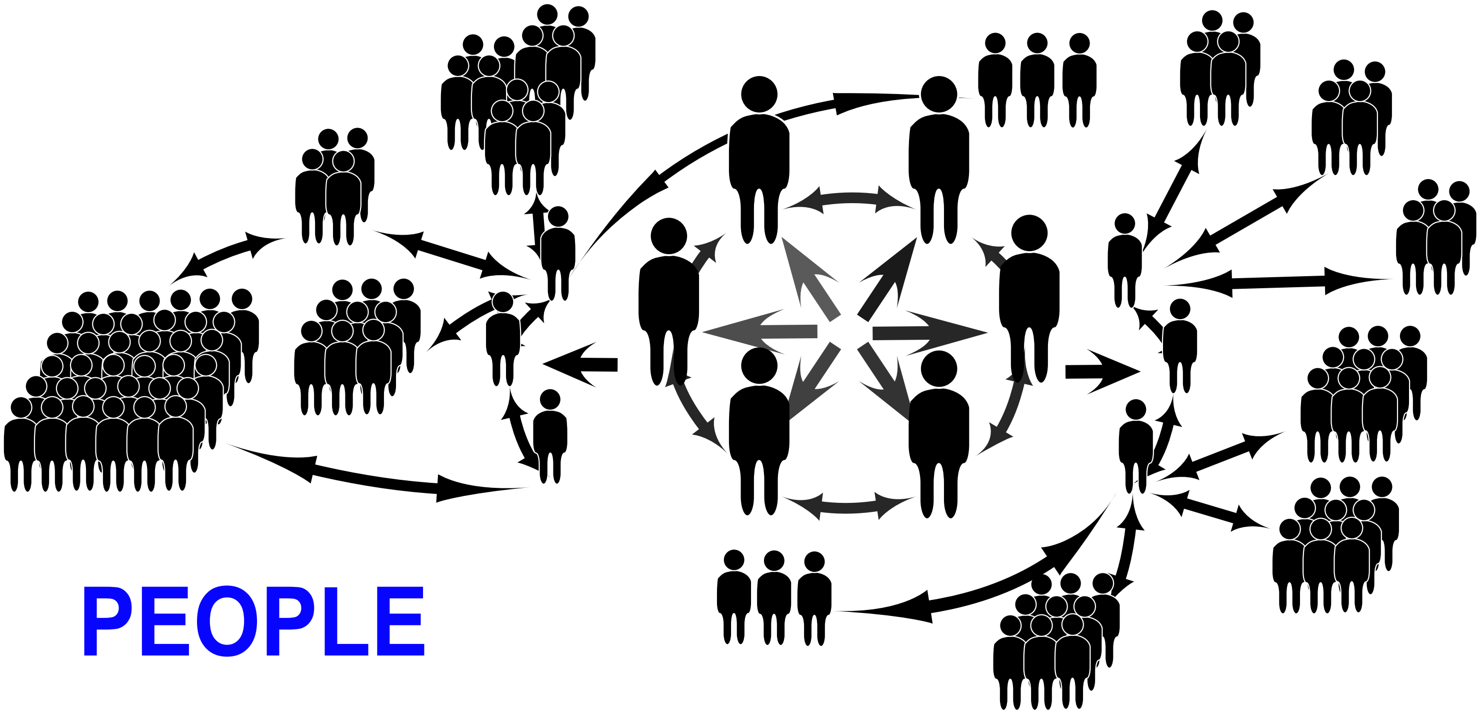
Self-Diagnosing Equipment

In order to use the existing grid infrastructure more effectively, system operators need better operation and diagnostic tools to identify developing or incipient problems. Advanced technologies include equipment capable of self-diagnoses that is able to address internal problems such as cracked bushings, contact wear and loose connections. Integrating self-diagnostic capabilities with appropriate algorithms will help asset managers replace and upgrade the existing infrastructure and reduce catastrophic failures, reduce maintenance costs and improve the overall reliability of the systems.

8.3.6 Better Use of Aging Equipment Assets

Hydro One has developed, and continues to enhance, its collection and use of asset condition information and its planning processes and tools for the purpose of making best use of aging equipment. Examples include:

- low-frequency heating for the removal of moisture from power transformer insulation;
- on-line dry-out of power transformers;
- on-line gas and moisture monitoring to support the detection of potential imminent failures of larger power transformers;
- partial discharge tests for epoxy in insulation of GIS circuit breakers to detect the potential for imminent equipment break-down/ failure;
- the use of infra-red cameras together with video cameras in helicopters to assess asset condition of overhead transmission line facilities;
- helicopter aerial steps to enable field staff to more easily and safely mount and dismount from a helicopter onto a transmission line tower;
- advanced sensors (compensating for electrical loading and ambient temperature) to detect oil leaks in underground cables together with injection of special fluids to localize leaks, (this reduces the potential for major oil spills and cuts down on potential environmental impact);
- design review of the capability of power transformers, particularly if the equipment is expected to operate under more onerous conditions in the foreseeable future; The results of this work, together with other condition information and the asset's operating history helps in formulating sustainment plans for such equipment;
- improvement of the ACA (asset condition assessment) methodology;
- frequency response analyses of transformers to estimate potential damage to the transformer during transport or damage owing to power system fault conditions.



PEOPLE

9. PEOPLE

For more than 100 years, Hydro One (and its predecessor company) has successfully sustained a safe, reliable, robust and cost-effective transmission and distribution system for the benefit of its customers. This has contributed significantly to the provincial economy and has resulted in added value to the shareholder, the Province of Ontario, its residents, and its businesses. This could not have been achieved without a dedicated, skilled and trained workforce.

As indicated in Hydro One's strategic plan, its people underpin everything that the company does. Hydro One's employees are essential to the operation and management of Hydro One's business. As a result, the company considers safety to be paramount, as reflected in the strategic objective to achieve world class standing for medical attentions, compared to other utilities.

In addition to the safety of its employees, Hydro One believes that the capability of the employees is a primary strength of the company and one which must be maintained and sustained for competitive advantage. For this reason, Hydro One's strategic plan recognizes the need to develop skills and knowledge retention in the face of changing demographics. Accordingly, Hydro One is committed to address issues of labour demographics, the development of critical core competencies, and skill and knowledge retention. Underpinning all of this is the need to achieve productivity improvements and cost reductions based on a flexible and capable workforce.

In the future, employees will play an even more critical role to ensure the continued viability and sustainability of Hydro One's transmission system as aging assets are renewed and as the Ontario generation resource mix and load patterns undergo significant changes. Concurrently, there will be a need to accommodate and enable significant numbers and amounts of distributed renewable energy generation on the transmission and distribution system.

9.1 Challenges Facing Hydro One

The electricity sector in Ontario as a whole is facing unique and unprecedented challenges with respect to the aging demographics of the current workforce combined with the limited supply of, and competition for, available replacement staff when these workers retire. There is a strong likelihood of shortfalls in available skilled and qualified workers, which will make it difficult to meet developing and anticipated workforce requirements of the electricity sector in the foreseeable future. This problem is further exacerbated for Hydro One by the need for additional staff above current staff levels in order to accomplish the projected transmission work programs outlined over the 10-year Outlook period. It is a problem that is not unique to Ontario, but is equally relevant to the electricity sector throughout Canada, North America, and even world-wide.

In the next few years, approximately 30% of Hydro One's current workforce – equivalent to about 1,600 employees – will be eligible for retirement. While it is not clear at this time how many of the eligible staff will elect to retire, it can be anticipated that there will be impacts on various parts of the organization. Furthermore, it is expected these impacts will not be uniform and some work categories and specialty disciplines may be more severely impacted than others.

Many of the new staff Hydro One needs to ensure a capable workforce going forward will be new to the transmission and distribution industry or to the workforce in general. As such, extensive training programs will be required in order to develop the requisite skills and experience in order for these staff to contribute effectively to the business.

Hydro One is contracting work out when work program requirements exceed the capabilities of the Hydro One workforce. In these situations, the work contracted out, typically greenfield (i.e., new site location) and brownfield (i.e., existing site location) projects as well as some major refurbishment projects, is completed using a combination of internal resources, engineering subcontracts, construction contracts or arrangements contracted on a fixed-price basis. As well, some types of work which require specialized skill sets which Hydro One does not have internally and which are very low volume (eg., Static Var Compensators, Series Capacitors, and some buried cable work) are normally constructed by turn-key contractors.

It can be expected that Hydro One will be facing keen competition for skilled and unskilled staff needed for the short-to-long-term technical management and business operations. To develop new staff – such as apprentices, operator-trainees, and university graduates – to sufficient competency levels requires several years of instruction and training. In most cases, the training is a minimum of six years, (e.g., new grads before they become journeyperson engineers), and it can take up to six to eight years of training to become a fully competent protection & control (P&C) engineer.

Concurrent with the issues of the aging demographics and competition for suitable replacement staff, there is also the issue of new skill sets based on new and advanced technologies that will be required to complement traditional utility skill sets. The infusion of new and advanced technologies will impose additional training requirements on Hydro One's workforce.

9.2 Human Resources Initiatives

The following are some key human resources initiatives to address the issues and challenges facing Hydro One.

9.2.1 Resource Planning and Work Capacity Challenges

This initiative is intended to:

- identify staff resourcing needs for future work programs;
- develop broad strategies and approaches to work program implementation, including the optimal use of in-house resources supplemented by contracting-out of services where appropriate, (e.g., unavailability of in-house resources, specialized resource requirements, or one-time/one-off projects); and,
- develop effective staffing programs consistent with approved strategies to acquire the appropriate level of regular staff and skill sets to support the business.

This initiative requires an understanding of available resources, now and in the future, with skills and their associated numbers that are required, to meet Hydro One's requirements. The implementation of this initiative will require:

- enhanced methods and approaches to estimate future staff resource requirements;
- identification of critical resources, their skill sets, and levels, required to sustain the business;
- factoring in current staff levels and age demographics to identify current and projected shortfalls or surpluses in critical resources (e.g., P&C resources); and,
- identification of the availability of skilled external resources to effectively and economically carry out, or assist in carrying out, identified Hydro One work programs.

9.2.2 Electricity Industry Skills Co-ordination Initiative

This initiative is intended to ensure that an adequate pool of skilled, knowledgeable and trained staff is available to Hydro One and others in the electricity industry to meet projected work requirements now and in the future.

9.2.3 Recruitment Initiative

This initiative is intended to secure adequate levels of new staff with the requisite skills or capability to meet the planned and on-going work-program needs of Hydro One.

Challenges associated with this initiative include the recruitment of new staff with unique skill sets relevant to the electricity industry and specific to Hydro One's business. As well, Hydro One faces the need to replace those staff who may retire in the next few years with staff resources that have the required skills and knowledge to manage the increased volumes and complexities of the significant amount of work ahead. As indicated, these challenges are compounded by the limited supply of new graduates in the power system sector. As well, the limited availability of experienced resources, particularly at the team lead or middle management level, is acute.

9.2.4 Training Initiative

This initiative is intended to ensure that new and existing staff have the appropriate knowledge, skills and training to effectively achieve Hydro One business objectives and related-work programs.

As indicated at the beginning of this section, Hydro One considers its people as the foundation of everything that the company does. As such, the safety of its employees is essential, as is the development of critical skills and core competencies. Hydro One is therefore committed to ensuring that these objectives are met through appropriate and intensive training programs, especially given the specialized nature of the industry, the potential hazards associated with the delivery of electricity, and the transformation of today's electricity sector.

9.2.5 Skills Transfer, Knowledge Retention and Succession Planning Initiative

This initiative is intended to ensure that valuable knowledge and skills from potential retirees are retained effectively or transferred to other staff; and to ensure effective pre-planning of potential succession of key senior management positions. This is important in light of the age demographics issue.

The graduate trainee and apprentice programs, documentation of key business processes and methods, records management, mentoring, and succession planning for key staff are all important contributors to this initiative.

9.2.6 Revitalize Educational Programs

This initiative is intended to encourage and assist educational institutions in Ontario to provide effective education and training for potential recruits for Hydro One; increase the supply of power system engineers and related disciplines for Hydro One; and promote awareness of the rich and rewarding opportunities at Hydro One.

10. Work Management

Hydro One applies widely accepted asset management principles in managing its assets. This involves optimizing and sustaining the assets over their life-cycles and factors in performance, cost, and risk. Further, the management of assets is carried out consistent with Hydro One's strategic objectives.

Balancing competing requirements for asset performance, cost and risk presents unique challenges. This section highlights some selected key business management work methods (or processes) that will be essential to the effective achievement of the objectives identified in the Outlook, thereby leading to overall improvements in business and system efficiencies and effectiveness for the benefit of Hydro One's customers and shareholder. The identified work methods are not intended to detract from the importance of other business work methods used on a daily basis to manage and operate Hydro One's transmission system and business and which have served the company well. These will still be required going forward.

10.1 Asset Management Methods Improvements

Hydro One has several initiatives for enhancing the application of asset management principles, including those described in the following sub-sections.

10.1.1 Asset Analytics Initiative

The Asset Analytics (AA) Initiative is expected to be fully operational by early 2013. This initiative builds on the success of Cornerstone Phases 1 and 2 and the "proof of concept" carried out in 2010. The asset analytics initiative leverages the data and information collected from the existing enterprise work management system (SAP) and other systems (e.g., geo-spatial systems, operations systems, performance) to guide and support the collaboration of investment planners and field staff to make strategic asset lifecycle investment decisions that best optimize cost and operational risks consistent with corporate objectives. This initiative required consistent data quality as discussed further in subsection 10.1.5.

The AA Initiative will develop asset management analytic tools and analysis to consistently provide comprehensive and cascading information views of asset risks/priorities based on demographics, condition, performance, utilization, criticality/customer, obsolescence, HS&E and other operational risks. The correlation between asset risks will be built using scientific methods and data mining techniques. This will provide reporting visualization, facilitate knowledge transfer, and improve data quality awareness for the complete lifecycle management of transmission assets in one central system.

The AA Initiative will develop the tools and analysis required for all core operational assets of Transmission Stations & Lines. This will provide end users (non-technical users) with the ability and ease of use to more efficiently extract the information they need to improve decision making, better manage Hydro One assets, continuously improve business processes, and improve data quality and data integrity on a day-to-day basis.

Specifically, the AA Initiative will deliver the following benefits.

- The analytics will facilitate the rationalization of work programs and improve productivity and cost effectiveness of investment decisions by eliminating unnecessary work that is made redundant by the analytics. Work can be concentrated and targeted (e.g., shorten vegetation management cycle) on high impact, customer critical, trouble areas. This should reduce the number of trouble calls by addressing all known defects/ issues on a radial transmission line, or feeder before they manifest themselves into a customer outage and a "higher" cost trouble call.

- This is expected to minimize the adverse effects on transmission system reliability and customer satisfaction arising out of budget reductions by targeting investments to where they provide the highest value. This will also help provide stronger rationale for planned work and make it easier to effectively demonstrate the business impacts of potential reductions in revenue requirements at forums such as OEB.

- The AA initiative will also provide a longer term view and line of sight to forecast work to allow improved work planning, bundling, and optimization which better matches the available resources and skills to planned work. This will enable Hydro One to put in place improved strategies necessary to ensure availability of the workforce and skills required into the future.

- Existing field deployed intelligent electronic devices (IEDs) are currently used, and could be further enhanced to analyze system and equipment events and relay that information to the OGCC for quicker response. Examples include online transformer condition monitoring so that units are removed from service just prior to failure and determining fault location more quickly to enable more rapid dispatch of crews to a specific location for faster outage response and restoration. Often, particularly on long lines, a significant amount of time and resources are spent on searching for the location of a fault. Knowing the fault location on the circuit, or even an approximate location, before a line crew is dispatched can reduce the time and the cost required to rectify the fault.

- AA is also expected to improve safety performance by highlighting high risk assets in need of repair or replacement (e.g., manufacturer recall, alerts/ bulletins, obsolescence notification). This will allow the workforce to better manage the safety risks of exposure.

- The AA Initiative will provide an information repository for highlighting asset needs and findings from the field. This can be used to facilitate transfer of knowledge from more senior staff resources.

10.1.2 Asset Investment Planning (AIP) Initiative

Enhancements are planned for Hydro One's risk-based investment prioritization methodology. The existing investment prioritization methodology considers potential investments which are grouped into "functionally similar" elements, such as power system equipment, which are called "investment drivers". Alternative five-year funding levels are formulated for each investment driver, with each funding level related to materially different exposure to residual risk. The residual risks are linked to Hydro One's corporate risk tolerances, which in turn are associated with Hydro One's business values and strategic objectives. Alternatives at different funding levels are ranked, based on the best economic value, (i.e., a measure of risk mitigated for each investment dollar). This allows selection of alternatives for each investment driver.

The key enhancements to be achieved in the AIP investment prioritization initiative include the following.

- Flexibility for "bottom-up" approaches for work planning (driven by assets' technical needs), and "top-down" approaches for work planning (driven by factors such as corporate constraints including available staff resources, funding, regulatory or rate impacts). The "bottom-up" technical asset needs approach compels one to consider key technical factors (such as asset condition and power system factors including reliability) and integrates with the asset analytics work described elsewhere.

- Flexibility to prioritize among investments at the level of individual items of power system equipment (e.g., investment in a specific circuit breaker compared to say a specific information technology project or investment in other pieces of power system equipment).

- Flexibility to consider planning for a 30-year or longer time horizon, recognizing the relatively long lives of major power system equipment.

- Flexibility to carry out scenario analysis (e.g., advance or defer work) to consider top-down resource or funding constraints, and estimate the impact of risks to Hydro One's business.

- Flexibility to identify "investment bundling" opportunities, noting that prioritizing investments at the individual asset level could otherwise lead to inefficiencies as assets at a common location such as a station are replaced consecutively rather than concurrently.

The AIP prioritization will be applied at the enterprise level within Hydro One's transmission and distribution system businesses. This initiative is planned to be fully operational by spring of 2013.

It will be essential to ensure effective integration of AIP and other initiatives within the enterprise work management system (SAP).

10.1.3 Collaborative Planning

Major equipment for the electricity industry can have a manufacturing lead time of up to two years, which can impact the implementation of many Hydro One projects and programs. Collaborative planning is an approach for coordinating work within Hydro One that takes advantage of strategic procurement alliances formed between Hydro One and multiple equipment manufacturers.

Collaboration requires ensuring that technical specifications for power system work covering a multi-year period are established and communicated to vendors in a timely manner, from both the functional and engineering viewpoints. During the initial stages, the collaboration emphasizes the adoption of a set of purchasing standards to optimize the use of interchangeable assets and minimize the need for strategic spare units. This approach allows equipment manufacturers to set aside manufacturing space and production time-slots to meet Hydro One's critical equipment and material needs. In addition, with the use of repeatable standards, production times can be reduced and the quality of products improved.

This collaborative planning approach has been in place since 2008, and helps ensure that Hydro One has the right major equipment and materials, at the right location, and at the right time.

10.1.4 Unit Cost Estimating

The availability of standardized cost estimates for high volume, well defined, repetitive and standardized work will help improve the quality of work planning and reduce the time needed to formulate plans. An initiative is underway to work with a number of Hydro One groups to develop unit cost estimates for as much as 70% of the annual work program. This initiative will reduce unnecessary effort, time and cost associated with the Request For Estimate approach currently applied to most of our program and standard project work.

This will also allow experienced staff to focus on high value projects where better work definition is needed for cost estimating, including new projects involving newer technologies (which have higher uncertainties in terms of scope definition and schedules).

This approach has the added benefit that it provides the means for structured knowledge transfer related to program cost estimating. Further, tracking units of work accomplished and unit costs against standardized estimates could allow one to quickly gauge effectiveness and productivity trends of these key measurements.

10.1.5 Data Quality and Integrity Management

Reliable asset information is essential if decision makers are to make appropriate asset acquisition and asset management decisions. This is particularly the case for major transmission assets which tend to be relatively capital intensive and have relatively long service life, with ongoing costs for testing, maintenance, and eventual replacement.

Both data quality and data integrity are important. Acceptable data quality requires information to be accurate, complete, timely and valid. Data integrity is the need for consistency and the absence of any unauthorized or unintended alteration in data among two or more updates of data records.

The data quality and integrity management initiative includes identifying data needs, assessing the relative importance of data, setting priorities, defining acceptable levels of data quality and integrity for different data sets, and ensuring adequacy of, or enhancing, work methods/ processes for data management. Further, it will be essential to communicate, educate and gain employee engagement to ensuring acceptable levels of data quality and integrity through understanding of the broader context of the data-driven asset management framework.

Hydro One makes use of the data repository in the enterprise work management system (SAP) as the system of record for major assets. Data security features built into SAP help ensure data integrity and the ability of staff throughout the company to access SAP will help ensure that necessary information is readily entered into the system and widely available for decision making when needed.

10.2 Standards Initiative

Standards are published documents which define characteristics of equipment, components, practices, methods and services to ensure safe, secure and reliable operation, performance, and sustainability for common and repeated use. Standards enable the consistent, efficient and effective planning, design, construction, operation, maintenance and retirement of system assets throughout the assets' life cycle.

In 2008, Hydro One embarked on a Standards Initiative to consolidate all of the standards development work across the organization. This initiative allowed for setting in place standards governance, processes work methods, a standards repository, revision cycles, and standards compliance monitoring to ensure that required standards are developed and followed. All work methods and priorities are managed through effective deployment of project management, tracking and reporting techniques.

Standards at Hydro One are corporate assets which are an integral element of the physical assets in the transmission and distribution systems.

The objectives of the standards initiative are to develop a single repository with common access for standards; to efficiently plan and manage standards development and revisions; and to implement a standard numbering and formatting system. A single process which governs standards development is in place. This process covers the work from an initial request to final approval of a standards document prior to its release and use in accordance with an established governance model. This process recognizes regulatory requirements, the need for cost-effectiveness, the benefits of modularity, and the importance of common industry practices.

Development of new standards and revision of existing standards are typically triggered by the implementation of new technologies, changes in safety and reliability requirements, or changes in regulatory and compliance requirements (e.g., IESO, OEB, OPA, ESA, NERC, NPCC, Environment Canada).

Hydro One also monitors, and is involved in, the development of emerging industry standards and requirements through its participation with other industry groups (e.g., the Canadian Standards Association [CSA], Institute of Electrical and Electronics Engineers [IEEE], International Electrotechnical Commission [IEC]).

10.3 Integrated Resource Planning (IRP)

Hydro One is considering the use of an Integrated Resource Planning (IRP) approach, to complement the traditional approach used to date for conducting area load supply studies. IRP incorporates CDM and distributed generation (DG) resources into traditional supply-side planning.

Traditional supply-side solutions have primarily focused on capital investments for new stations, transmission lines, upgrading of existing equipment, new equipment, or other modifications required in response to projected area load growth and demand. Potential solutions are then subjected to a net present value economic analysis for selection of the most economic option.

Continued use of the traditional planning approach has limitations and may not be effective in certain situations. This is because of the changing planning and operating environment in Ontario, which emphasizes the development of increased levels of renewable energy resources and the promotion of CDM consistent with government policy and direction.

The inclusion of CDM and DGs as part of an IRP approach provides additional, and potentially more optimal, planning solutions. This includes the possible deferral or reduction of capital investments because of reduced load demand from CDM measures and new electricity supply from local DGs.

The proposed IRP process to be used by Hydro One will be based on an economic analysis of resources, rather than on a technical analysis. Technical requirements, such as connections, and technical impacts on the distribution system would not be considered at the IRP stage.

The adoption of the IRP process will require close cooperation among the Ontario electricity industry participants, as it involves an integrated and forward-looking approach to area planning. It will also affect the current business planning process and may require some adjustments for the IRP process to be effective.

It is recognized, that the OEB staff paper titled *Regional Planning for Electricity Infrastructure (2011)*, calls on the electricity industry for coordinated planning on a regional basis for cost effectiveness.

11. Risk Considerations

Hydro One is required by securities law to publicly disclose risk factors relating to its business that are most likely to influence an investor's decision to purchase Hydro One's securities in order of seriousness from most serious to least serious. In addition to those risks, which are published annually in Hydro One's Annual Information Form, located at www.sedar.com, the following are key business risks specific to transmission asset management. It is recommended that for a full understanding of the risks to Hydro One, you read both this section and the Risk Factors section in Hydro One's Annual Information Form.

As indicated in Section 2, the definition of asset management in PAS 55 includes the management of the risks associated with an organization's assets and asset systems over their life cycles in order to achieve the organization's strategic plan. In this context, risk is:

"*The potential for an event, action or inaction to adversely affect Hydro One's ability to achieve its business objectives.*"

Hydro One uses an enterprise-wide approach for managing key business risks, including strategic, regulatory, operational and financial risks. This approach includes the integration of best practices in risk management into business processes, including operational management, business planning, and investment planning in order to ensure a consistent consideration of risks in the company's decision-making processes.

A systematic approach is used to determine corporate risk tolerance profiles for identified risks to the strategic objectives identified in the corporate strategy. These strategic objectives focus on:

- safety,
- customers,
- innovation,
- reliability,
- environment,
- employees,
- shareholder value, and
- productivity.

The corporate values, including Health and Safety, Stewardship, Excellence, and Innovation, are embedded in these objectives.

The determination of the risk tolerance profile associated with an identified risk involves the assessment and rating of "worst credible" risk impacts against each of the business objectives. These impact ratings are expressed as one of five levels, ranging from "minor" to "worst case".

Risk tolerance profiles for identified risks must be combined with an assessment and determination of internal controls in place to manage the identified risks. Hydro One uses a control model based on five levels, which give an indication of the strength of the internal controls in place against a particular risk. These range from the need for few controls, to partial controls, and to the highest control level – designated full controls – which require Senior Management/CEO oversight.

Finally, Hydro One evaluates the likelihood of identified risks coming to pass in the planning period and having the adverse effect identified in the above step. This likelihood assessment is done in consideration of the extent and frequency of Hydro One's exposure to the risk sources, and the strength of the aforementioned internal controls.

11.1 Context

Ontario's electricity system will be undergoing massive transformation over the next 20 to 30 years. All remaining coal fulled generation in Ontario is due to be retired by 2014. With this, and with the inevitable aging of other generation infrastructure, it is anticipated that roughly 80% of the existing generation capacity, or about 24,000 MW, will have to be replaced in the next 15 to 20 years. The nature and location of generation on the system can be expected to change dramatically (e.g., shut down of coal fuelled stations by 2014; more intermittent and variable renewable generation). As a result, the demands and risks placed on the transmission system will change.

As environmental consciousness grows, more emphasis is being placed on Conservation and Demand Management (CDM) to mitigate load requirements than ever before. Since 2005, with the advent of the *Green Energy and Green Economy Act (GEGEA)*, the province has conserved over 1,700 MW and has become a North American leader in energy conservation. By issuing a *Long-Term Energy Plan (LTEP, 2010)* and associated directives in late 2010, the Ontario Ministry of Energy has signalled that it expects energy conservation to mitigate an additional 5400 MW by 2030. This brings with it huge benefits, but also new risks that must be managed.

In addition, the government is expecting the Ontario Power Authority to submit an updated Integrated Power System Plan (IPSP) to the Ontario Energy Board. This updated IPSP is expected to result in a significant increase in the capacity contribution from renewable sources (hydroelectric, solar, bioenergy, and wind) with the contribution from solar and wind increasing by a substantial amount in the next 15 to 20 years. Much of this new generation will not be in the form of large, centralized generating facilities which the existing transmission system has been designed to handle. More distributed generation will be connected to the grid. That, plus the intermittent and variable energy output of many renewable energy options, will doubtless change the risk profile that must be managed through changes in transmission system design and operating practices.

The bulk of the new wind and hydroelectric generation will be located in rural and remote areas and will require transmission development for implementation. Furthermore, it can be anticipated that any updated IPSP issued by the OPA is likely to call for significant new transmission development to incorporate generation identified as necessary to maintain system reliability in the face of load growth, a changing generation mix, and facility retirements.

Of course, even without load growth or the need to incorporate new generation sources noted in the LTEP, existing transmission system assets will need to be maintained, refurbished, and eventually replaced as aging takes its inevitable toll. There are risks associated with these transmission system sustainment activities as well.

11.2 Key Risks

This sub-section discusses key risks facing the transmission system sustainment, development, operating, and technology advancement programs presented elsewhere in the Transmission Asset Management Outlook.

Hydro One will monitor ongoing and future developments related to these and other risks in order to better understand and quantify their potential impacts.

11.2.1 Economic and Financial Risks

Ontario has not been immune to past global economic and financial crises and it must face the prospect of possible further upheaval, particularly in light of ongoing concerns about sovereign debt in Europe and other sources of economic uncertainty. While the longer term impacts of the uncertain economic outlook are unclear, there are potential risk implications for the Hydro One Transmission business.

A prolonged economic downturn would result in lower than expected provincial electricity demand. There could be more pronounced regional effects depending on local economic factors. Conversely, a more rapid economic recovery than expected could lead to unanticipated growth in electricity demand, again with possible regional effects. Both overall and regional electricity load growth will also be affected by the rate at which Electric Vehicles (EVs) are adopted by Ontario consumers, which, amongst other things, will be influenced by general economic conditions, and potential government incentives encouraging EV use.

Hydro One runs the risk that faster or slower load growth than expected could result in work programs being potentially mismatched to actual needs. Work programs could be more aggressive than needed or could result in insufficient transmission capacity when required.

Mitigation of this risk can be achieved, to some extent, by developing work plans which are flexible and which can be implemented on an as needed basis. Economic conditions and provincial and local load growth should be carefully monitored and work programs adjusted accordingly, in consultation with key external parties such as the OPA, IESO, and Ministry of Energy.

In some cases, intentionally advancing transmission work sooner than absolutely necessary may be prudent in order to balance workloads and ensure transmission assets are in place when needed should load climb unexpectedly. Encouraging distributed generation and CDM programs can also help to mitigate the risk to the transmission system if load growth is more rapid than expected.

Revenue requirements and the corresponding rates which Hydro One can charge for its transmission services are regulated by the OEB based, in part, on projected electricity demand. Lower than expected load growth could lead to lower revenues being recovered during the period when approved transmission rates are in force.

Revenue shortfalls could require Hydro One to re-balance the relative priorities of transmission sustainment, transmission development and other work programs. Given the aging demographic profile of transmission assets and the condition of some of those assets as determined in Asset Condition Assessments (ACAs), there is a risk that transmission system reliability would be adversely affected should asset sustainment programs have to be deferred significantly.

11.2.2 Changing Nature of Generation

The nature and location of generation on the bulk power system is changing rapidly, partly as a result of the retirement of aging resources, and partly as a result of the increasing contribution of renewable resources, distributed generation, and CDM consistent with Government policy. This is likely to lead to changes in traditional power flow patterns which the existing transmission system was not designed to handle. There is a risk that transmission system reliability could suffer. Reliability effects are likely to be exacerbated by the operating characteristics of much of the renewable generation capacity, which tends to operate intermittently and somewhat unpredictably (e.g., wind and solar generation). There is also a risk that some forms of Distributed Generation could introduce effects such as harmonics, system resonance, and/or frequency variations which can adversely affect both reliability and power quality.

Furthermore, the intermittent nature of much of this new generation means relatively low capacity factors. Additional sources of reliable generation must be available at short notice to ensure reliability at times when the wind does not blow, or the sun does not shine. Such backup generation must be incorporated into the power system (requiring transmission facilities), and it must be rapidly dispatchable.

Other effects on the transmission system arising from the changing nature of generation on the system are discussed in Section 2.

Managing these effects is likely to require operational changes and could also create a need for additional transmission facilities (e.g., specialized reactive power, control systems), the nature and timing of which is somewhat uncertain as it will be dependent on the location, timing, and nature of renewable and distributed generation additions.

11.2.3 Regulatory and Approvals Risks

Rates and Revenues

Hydro One's revenue requirements and the rates it can charge customers are subject to OEB review and approval. There is a risk that the revenue and rate approvals which are approved are not adequate to pursue planned work programs. Ensuring that proposed work programs are well defined, costs are carefully controlled, performance is well managed, customer satisfaction remains high, and rate cases are carefully prepared and presented will help mitigate this risk.

Environmental Assessments

The long lead time needed to plan, gain approvals for, and build new major transmission facilities has long been recognized as problematic. Failure to gain timely approvals of transmission projects could adversely affect generation and load customers and the reliability of the transmission system. There is also the risk that major load or generation proponents could back out of proposals (thereby negating the need for the transmission facilities in question, possibly after procurement and construction has begun).

A related issue arises with respect to the numerous other approvals associated with the development of the transmission system. Risks arise because these other approvals processes further lengthen the overall timeline for project implementation. In addition, the need to pursue multiple approvals increases the chance that different approving authorities operate to different timelines, or impose requirements which are contradictory.

Hydro One continues to collaborate with potential proponents, the OEB, and other electricity sector participants (OPA, IESO, Ministry staff) to seek ways to streamline the necessary approvals processes. It may also be possible to employ innovative means of speeding transmission facility construction for faster generation incorporation. The use of "Star" connection facilities as discussed in Section 8 of this Outlook is an example.

First Nations and Métis Consultation

For Hydro One projects and activities which could potentially have significant impacts on First Nations and Métis communities, the Crown has the responsibility to consult with, and accommodate, the affected communities. The Crown may delegate certain procedural aspects of consultation to Hydro One. If these consultations are deemed inadequate, potential project delays could occur. Hydro One works to build positive working relationships with affected communities, and works toward project consultations being carried out in an appropriate manner.

Changes to Legislation and Regulations

A number of significant changes have been made or proposed to the regulatory landscape in recent years. These include the passage of the *GEGEA*, the release of the

Minister of Energy's *LTEP*, the government's expectation of OPA to submit an updated Integrated Power System Plan, the OEB's transmitter designation process, the OEB's Renewed Regulatory Framework for Electricity (RRFE), and the Drummond Report. These are expected to result in:

- increased development and implementation of renewable generation, distributed generation, and conservation and demand management (CDM) programs;
- increased participation of First Nations and Métis people in the development of renewable energy generation facilities in the Ontario electricity system;
- extended obligations on distributors and transmitters for the filing of plans and investment decisions with the OEB;
- implementation of an "Advanced Distribution System" (or "Smart Grid"), primarily in the distribution system;
- potential new electricity transmission entrants in Ontario, consistent with OEB's policy;
- further changes to OEB regulations and policies potentially affecting electricity rate mitigation, performance measures for transmitters and distributers, regional planning for the electricity system, and requirements for OEB regulatory filings; and
- encouraging operational efficiencies, major transmission strategic partnerships, and the potential for locational electricity pricing.

Each of these affects the risk profile for transmission system work plans:

- As discussed above, significantly increased generation capacity contributions from distributed generation, and renewable generation (e.g., solar and wind) are likely to require new transmission system operating paradigms and possibly additional transmission facilities in order to maintain reliability and power quality. In addition, new transmission facilities could be required in relatively short order if it is necessary to incorporate large concentrations of new renewable resources over a short time frame.
- Increased CDM could also affect transmission system operations.
- Increased consultation brings with it the possibility of adopting innovative solutions to transmission system issues, but it can also create increased risk that planned transmission solutions are delayed or denied.
- The need for extended filings creates a risk that regulatory proceedings will become longer, more complex, more uncertain, and more expensive than originally contemplated.
- Implementation of an Advanced Distribution System is likely to require careful integration with existing transmission system assets and could lead to changes in transmission system operation.
- Major transmission projects may not all be built by Hydro One.
- There will be major challenges in meeting electricity customer, government, and OEB expectations for cost containment and operational efficiencies, while, at the same time, managing aging electricity assets and connecting new generators and loads.

Renewed Regulatory Framework For Electricity

In early November of 2011, the OEB issued a set of five OEB staff discussion papers with an overarching objective of renewing the regulatory framework. These are discussed more fully in Section 3. Each of these discussion papers raises the prospect of changes to the regulatory landscape within which Hydro One must operate, and as such, each raises risks to the success of Hydro One's transmission work plans going forward. Some of these risks are:

- Possible fundamental changes to regional planning paradigms.
- Operational challenges with private sector parties owning more distribution and transmission facilities.
- Possible increased costs for filing transmission system plans and gaining approvals due to changes in the prescribed manner and schedules for filing plans.
- Possibly greater uncertainty in the extent and timing of required system expansions and reinforcement.
- Possibly increased uncertainty as to the ability to fund & carry out major work programs due to changes in cost allocation and/or cost recovery.
- Possible effects associated with the need to mitigate customer rates/total bills.
- The cost and impact of changes that need to be made to internal business and regulatory processes for consistency and improved effectiveness.

Hydro One will comply with any new requirements that arise after the OEB's stakeholdering process is complete and changes to the regulatory framework have been finalized. In some cases, Hydro One is already carrying out work consistent with the proposed approaches outlined in the OEB staff discussion papers.

Transmitter Designation Process

A 2010 OEB policy (FTPDP, 2010) identified a "designation process" which is intended to encourage new electricity transmission entrants in Ontario in order to support competition in the transmission business and drive economic efficiencies. Accordingly, transmission projects identified in this Outlook may not necessarily be built by Hydro One. This could potentially affect Hydro One's future business and related revenues.

Update to the IPSP

As part of its mandate, the OPA is required to periodically produce an updated IPSP which provides guidance as to the future of the overall bulk power system. This includes projections about the future generation mix and locations of major new generation facilities. Depending on the plans anticipated in the updated IPSP, Hydro One could be expected to maintain existing transmission facilities, or the updated IPSP could signal the need for new transmission facilities previously not contemplated. Risks to transmission system work programs will arise as the IPSP is updated, and this will need to be accommodated.

Uncertainties in the OPA's plan projections, and potential unexpected shortfalls in their IPSP, can arise for a number of reasons including: faster or slower than expected load growth, greater than anticipated private sector involvement in the energy sector, changing public attitudes towards various energy generation technologies, regional reluctance to host generation facilities, and so on. This creates a difficult to manage two-sided risk for Hydro One: work programs approved and undertaken today in light of past OPA projections may not be well matched to actual future need as it evolves. This risk is exacerbated in situations where OPA plans do not adequately anticipate Government directives or changes in policy.

The legislative and regulatory framework of the electricity sector in Ontario creates challenges for Hydro One's ability to manage uncertainties in OPA plans. Continued close cooperation with key decision makers and influencers (e.g., Government, OPA, IESO, customer advocates) will provide Hydro One with improved situational awareness and should facilitate an enhanced appreciation by third parties of some of the challenges faced when dealing with sudden, unexpected changes in circumstances or direction.

Changing Technical Standards

As a condition of its Transmitters license, Hydro One must comply with reliability standards and criteria set by NERC and the NPCC and enforced in Ontario by the IESO. New or updated reliability standards and criteria may be prescribed from time to time as needed and these could require significant changes to the way the transmission system is built or operated. Changes to mandatory standards can take place relatively quickly, certainly within a time span of a few years. This is much shorter than the lifetime of major transmission assets and is likely to be shorter than the lead time for design, approval and construction of new transmission facilities.

In some cases, where the lead time to comply with the standards is very short, Hydro One could potentially be non-compliant. To some extent this risk is mitigated by ensuring Hydro One's participation in standard setting bodies in order to gain some influence over standards development and to obtain advance knowledge of likely changes.

Hydro One is also required to comply with the Ontario Electricity Market Rules (administered by the IESO) and with the Transmission System Code (issued by the OEB). Changes to either of these could have an impact on Hydro One's transmission system work plans and the management of transmission assets. Again, monitoring of developments and participation, where possible, in the revision of rules and regulations provides a degree of risk mitigation.

11.2.4 Staffing Risks

Hydro One's staff demographics indicate that about 30% of current staff will be eligible for retirement within the next few years. While different functions within Hydro One will be affected to different extents, there is a risk that Hydro One could lose substantial amounts of transmission related institutional knowledge, experience, and capability in a relatively short time period.

In addition, there is a relative shortage of new entrants to university and trades programs which offer some of the specialized technical disciplines which Hydro One historically has relied upon.

This issue is not unique to Hydro One, but applies to the Canadian electricity sector as a whole. In a 2008 study of the Canadian electricity industry (Powering Up the Future, 2008 Labour Market Information Study – Full Report), the Electricity Sector Council stated, "The Canadian electricity sector is about to enter into the eye of the perfect storm, whereby the supply of trained workers is decreasing just at the same time that a significant proportion of the current workforce is retiring, and the demand for electricity and investment in new capital and infrastructure projects is increasing."

Staffing risks are further exacerbated by the magnitude of projected transmission asset sustainment, development, operating, and technology advancement work programs over the next ten years. Without careful management there is a risk of having insufficient experienced internal resources to fully implement future transmission asset management work plans on the timeline currently being planned. The risk will be greater if a substantial volume of near-term transmission work is deferred and a "bow-wave" of work is allowed to develop. This risk can be partially managed by ensuring that work plans are developed and implemented consistent with the concept of "work levelling".

To some extent, the risk of the evaporating intellectual capital can be mitigated by developing programs to encourage the development and mentoring of junior and new staff by experienced staff prior to the latter leaving the company. Hydro One also currently has a number of recruitment and training initiatives underway to help mitigate staffing risks. However, there is a risk that Hydro One may not be able to compete effectively for the diminishing number of suitably trained and experienced power sector workers in the future. This will be the case, particularly if prospective employees see greater opportunities in other jurisdictions or organizations

Aside from the demographic issue, Hydro One faces challenges in ensuring effective supervision of its workforce. Hydro One is having difficulty attracting qualified unionized staff into non-union supervisory positions, partly as a result of a government mandated wage freeze. This could continue to represent a challenge to Hydro One's ability to safely and efficiently complete its work programs effectively.

These staffing related issues are discussed further in Section 9 (People).

11.2.5 Supply Chain Risks

The past several years have seen marked increases in the cost of material and equipment needed to implement Hydro One's sustainment, development, and operating work programs. These increases in costs can be attributed both to general price inflation and to competing demands for equipment as other utilities in North America experience pressures to invest in aging transmission infrastructure. There is a risk that prices for essential equipment could escalate even faster than expected, particularly as the economy improves. More rapid cost escalation than expected creates a risk that the ability to proceed with work programs as originally planned would be disrupted. Work priorities would have to be reassessed accordingly.

Further, there is a risk that the lead times required to procure major power equipment could lengthen. It now requires a lead time of about two years for Hydro One to procure a power transformer which, in the past, took about a year to obtain. As the economy improves, the lead time could lengthen even more as suppliers' order books fill and competition for production line space increases. This creates a risk that the replacement of failed or failing transmission assets, or the building of new transmission facilities, could take significantly longer than anticipated. System reliability could suffer.

These risks can be mitigated by maintaining adequate equipment and parts inventories and by pre-ordering items with longer lead-times.

11.2.6 Operational Risks

Hydro One is implementing alternative and innovative solutions to address certain transmission constraints, including the installation of SVCs (Static VAR Compensators), and series capacitors. These devices enhance reactive power control and power transfer capability, and potentially defer constructing new transmission facilities. However, the long-term performance of these devices is not fully known at this time and there is, therefore, a degree of power system reliability risk associated with their increased application within the transmission system.

Similar risks arise with the introduction of any new technology. These can be mitigated by following developments elsewhere in the industry, carefully monitoring the performance of new technologies once they are implemented in the Hydro One transmission network, and limiting the degree to which new technologies are implemented before being fully proven.

Additionally, the September 11, 2001 terrorist attacks have resulted in intensified requirements for power system security, including physical security and cyber security. These security requirements are still evolving, and there will be mounting pressure for more robust security measures, noting the importance of Critical Infrastructure. There is a high likelihood that increased security requirements could complicate transmission operations. This risk is mitigated in part through representation on the standards working groups addressing issues of concern.

11.2.7 Technological Risks

Aging Assets

Hydro One carries out asset condition assessments (ACAs), to support the maintenance, refurbishment, and replacement of aging assets (i.e., sustainment work). Constraints such as the need to coordinate outages for sustainment work with customer needs and other transmission system outages, work program funding priorities, and the limited availability of adequately trained staff, all affect the ability to perform necessary sustainment work when needed. Excessively deferring the work needed to address issues associated with aging assets could affect customer load supply reliability and power system security.

Changing Power System Architecture

Several large, centralized generation facilities, particularly coal fulled generating stations, will be taken out of service in the near future. A number of large nuclear generating units will also likely become unavailable in the next few years as they are retired or placed into a prolonged maintenance shutdown for refurbishment. To make up for lost generation, new generation will need to be provided.

Government policy is ensuring that traditional forms of generation are being replaced by large quantities of renewable generation (largely wind and solar generation). Some of these new resources may be added in the form of centralized wind or solar "farms", but much will be added in the form of smaller distributed generation facilities. To add, much of the new generation (particularly renewable generation) is variable and intermittent in nature.

The transmission system will likely have to handle significantly different power flow patterns than it was originally designed to handle. The basis for planning, building, operating, and maintaining the power system must now be re-examined to address this unprecedented change.

There is a risk that the current power system architecture is not well suited to the new paradigm and substantial changes to that architecture may be needed.

In addition, it has been noted previously (Section 8) that some renewable generation sources can introduce power quality issues into the power system. The extent of this potential problem is not yet fully understood but there is a risk that it could necessitate new transmission facilities that are not currently being contemplated.

Advanced Technologies

Advanced technologies such as Static Var Compensators (SVCs), series capacitors, and other advanced technologies (see Section 8) are being considered for integration into the power system in order to enhance the capability of the existing transmission system and address some of the power quality concerns noted above. The long term impacts of these technologies, and their effect on power system reliability, is not fully known.

Improvements in wireless technologies are making it feasible to install more instrumentation to monitor conditions in more locations on the transmission system and make it available to power system operators. While this may provide greater visibility of system conditions, it also risks overwhelming the operators with information, particularly under emergency conditions when stresses are already high. A balance will need to be struck to ensure that operator response is facilitated under both normal and emergency conditions.

The use of instrumentation and controls employing internet based communication protocols (such as IPV4) is becoming increasingly widespread. Without careful design and appropriate operating practices the use of these technologies can introduce vulnerabilities which risk the secure operation of the power system.

11.2.8 Political Risks

Hydro One is required to operate within a policy framework established by the provincial Government. The Government passes legislation and/or issues policy directives to Hydro One, regulators, and/or to other electricity sector organizations as it deems necessary, to accomplish its goals. Hydro One attempts to anticipate changes in policy, and in any event, it is required to respond to them.

There is a risk that rapid policy changes could prompt the need for unanticipated transmission system work, or could reduce the value of work programs pursued under a different policy regime.

In late March, 2012, the government announced its intention to “move forward with a comprehensive review of the electricity sector and its various agencies”. This could lead to fundamental changes in the roles of various electricity sector stakeholders and the ways in which they are required to interact. Significant changes to the transmission planning, approvals, construction, and operations/maintenance processes are conceivable, and could potentially affect Hydro One’s transmission work programs.

Political risks are inherently difficult to anticipate accurately and prepare for. Aside from keeping key decision makers informed of the possible effects of policy changes which may be contemplated, the best form of mitigation probably is to monitor policy developments carefully while endeavouring to ensure that customer satisfaction levels remain high. In this context, it will be important that Hydro One considers the recommendations and implications of the Report of the Commission on the Reform of Ontario’s Public Services (the “Drummond Report”, 2012).

11.2.9 Other Risks

Public and Worker Safety

There is a risk that a public or worker safety incident could lead to pressure to revisit safety standards, work procedures, and/or transmission facility designs. This could, in turn, lead to delays in transmission system sustainment, development and operating work programs and potentially increase costs. This risk is best mitigated by a continued focus on worker training, corporate safety programs, and continual review of safety performance.

Environmental

Hydro One’s asset management activities are subject to extensive environmental regulations. Failure to comply with applicable regulations could lead to fines and other penalties. The presence or unintentional release of hazardous substances could potentially lead to stringent government orders and actions. These risks are mitigated by identifying potential hazards and proactively managing these risks as part of ongoing environmental work programs. For example, Hydro One is currently undertaking a voluntary land assessment and remediation (LAR) program covering most of Hydro One’s stations and service centres. This program involves the systematic identification of any contamination at, or from, these facilities.

Natural and Human Hazards

Hydro One faces two types of external hazards – natural and human. Natural hazards include events such as wind storms, tornados, icing, earthquakes, land slides, avalanches, wildfires, floods, and actions of animals and birds. Human hazards include cyber and physical intrusion to facilities, theft, and vandalism.

It is not possible to completely mitigate the risk associated with all natural hazards, particularly high impact- low probability (HILP) external hazards. However, Hydro One continues to enhance its practices for addressing HILP type events where practical.

For example, solar storms caused geomagnetic induced currents (GICs) to damage and disrupt the entire power system in Quebec in 1989. Similar, albeit lower intensity, solar storms occurred in March, 2012 with no significant disturbance on Hydro One's transmission system. This was due, in part, to Hydro One's development of advanced analyses, monitoring, and mitigation steps for managing GICs after the 1989 event in Quebec.

As another example, Hydro One adjusted its emergency preparedness program following a review of lessons learned after a major ice storm in 1998 resulted in transmission system damage and disrupted the electricity supply to a large number of customers in both Ontario and Quebec.

To reduce the risk associated with human created hazards, Hydro One has undertaken enhancements to transmission facilities and work practices to meet the NERC Critical Infrastructure Protection Standards. Recognizing that other, or more stringent, requirements could emerge, Hydro One actively participates in the development of industry standards to help ensure that requirements are practical, cost effective, and serve the intended purposes.

Further, Hydro One participates in industry groups such as the NPCC, CEA, and the North American Transmission Forum, to assess hazards and develop industry practices to mitigate identified threats. These include consideration of issues such as solar storms, operator training and certification, lessons learned, and event analysis.

System Performance

Lower than expected performance in terms of meeting performance targets, failure to meet service quality indicators, and or declines in customer satisfaction, particularly if repeated or prolonged, could create the risk of political or regulatory intervention, management upheaval, significant revision of work program priorities, and, with potential performance based regulation, possible revenue shortfalls. Any or all of these issues could affect the ability to pursue transmission system asset management work programs. Mitigation of this risk is provided by continually monitoring customer satisfaction and focussing on performance metrics at all levels of the company.

Labour Disruptions

Most of Hydro One's employees are represented by two labour unions. Hydro One continues to strive for flexibility in collective labour agreements, recognizing the Ontario government's call for operation efficiencies, cost management, and salary freezes. The collective agreements with the two unions expire on March 31, 2013. Hydro One faces financial and political risks if future negotiated collective agreements for wages are inconsistent with the direction set by government. Further, if there is labour disruption, Hydro One could face operational risks which could hamper its ability to provide electricity delivery service to customers and/or remain in compliance with OEB licence requirements.

A 10-Year Transmission Asset Management Outlook: 2012-2021

ACRONYMS

AA	Asset Analytics
AC	Alternating Current
ACA	Asset Condition Assessment
ADA	Advanced Distribution Automation
ADET	Area Distribution Engineering Technician
ADS	Advanced Distribution System (Smart Grid)
AECL	Atomic Energy of Canada Limited
AIP	Asset Investment Planning
AM	Asset Management
AMI	Advanced Metering Infrastructure
AVL	Automatic Vehicle Location
BES	Bulk Electric System
BLIP	Buchanan Longwood Input
BP	Business Plan
BPS	Bulk Power System
BSI	British Standards Institute
BSPS	Bruce Special Protection System
BUCC	Backup Control Centre
CAE	Capacity Allocation Exempt
CAES	Compressed Air Energy Storage
CAIDI	Customer Average Interruption Duration Index
CCRA	Connection Cost Recovery Agreement
CDM	Conservation and Demand Management
CDPP	Customer Delivery Point Performance
CEA	Canadian Electricity Association
CEATI	Center for Energy Advancement Through Technological Innovation
CELID	Customers Experiencing Long Interruption Durations
CEMI	Customers Experiencing Multiple Interruptions
CEO	Chief Executive Officer
CGS	Combined Cycle Gas Station
CHP	Combined Heat and Power
CIA	Customer Impact Assessment
CIP	Critical Infrastructure Protection
CIS	Customer Information System
CMS	Central Maintenance Services
CNP	Canadian Niagara Power Inc.
CO	Customer Operations
C-Ops	Customer Operations
COS	Conditions of Service
CSA	Canadian Standards Association
CSO	Customer System Operations
CT	Current Transformer
CTS	Central Tool Services
CVR	Conservation Voltage Reduction
CVT	Current Voltage Transformer
CVVC	Coordinated Voltage/Var Control
DA	Distribution Automation

DAT	Distribution Availability Test
DC	Direct Current
DESN	Dual Element Spot Network
DESS	Distributed Energy Storage System
DG	Distributed Generation
DGA	Dissolved Gas Analysis
DGR	Deep Geologic Repository
DMS	Distribution Management System
DOMC	Distribution Operations Management Centre
DP	Delivery Point
DPP	Delivery Point Performance
DR	Demand Response
DS	Distribution Station
DSC	Distribution System Code
DSTATCOM	Distribution Static Synchronous Compensator
DSVC	Distribution Static Var Compensator
DVAR	Dynamic Var
DVR	Dynamic Voltage Restorer
DVVC	Dynamic Variable Voltage Control
Dx	Distribution
EA	Environmental Assessment
EAM	Enterprise Asset Management
ECT	Economic Connection Test
EE	Energy Efficiency
EL	Electronic Log
EOL	End-Of-Life
EPD	Engineering & Project Delivery
EPEEC	Electric Power Engineering Education Consortium
EPRI	Electric Power Research Institute
ERA	Electronic Recording Ammeter
ERIP	Electricity Retrofit Incentive Plan
ESA	Electrical Safety Authority
ETR	Estimated Time of Restoration
EV	Electric Vehicle
FABC	Flow Away From Bruce Complex
FACDS	Flexible Alternating Current Distribution System
FACTS	Flexible Alternating Current Transmission System
FERC	The U.S. Federal Energy Regulatory Commission
FETT	Flow East To Toronto
FIT	Feed-in Tariff
FLISR	Fault Location, Isolation and Supply Restoration
FRA	Frequency Response Analyses
G/R	Generation Rejection
GEA	Green Energy Act
GEGEA	Green Energy and Green Economy Act
GEP	Green Energy Plan
GIS	Geographic Information System

GLP	Great Lakes Power
GPS	Global Positioning System
GS	Generating Station
GTA	Greater Toronto Area
GTAA	Greater Toronto Airport Authority
HAN	Home Area Network
HOI	Hydro One Inc.
HON	Hydro One Network
HONI	Hydro One Networks Inc.
HPFF	High Pressure Fluid Filled
HR	Human Resources
HS&E	Health, Safety & Environment
HST	Harmonized Sales Tax
HV	High Voltage
HVCA	High Volume Call Answering
HVDC	High Voltage Direct Current
HVDS	High Voltage Distribution System
HVT/T	High Voltage Transfer Trips
HWB	Heavy Water Board
IEC	International Electrotechnical Commission
IED	Intelligent Electronic Device
IEEE	Institute of Electrical and Electronics Engineers
IESO	Independent Electricity System Operator
IHD	In Home Display
IPSP	Integrate Power System Plan
IRP	Integrated Resource Planning
ISO	International Standards Organization
IT	Information Technology
ITMC	Integrated Telecommunication Management Center
KPI	Key Performance Indicator
KWCG	Kitchener-Waterloo-Cambridge-Guelph (area)
LDA	Large Distribution Account
LDC	Local Distribution Company
LEO	Line End Open
LFH	Low Frequency Heating
LiDAR	Light Detection And Ranging
LIRP	Local Integrated Resource Planning
LPFF	Low Pressure Fluid Filled
LS	Load Shedding
LTEP	Long Term Energy Plan
LTR	Limited Time Rating
LV	Low Voltage
MDMR	Meter Data Management Repository
MEU	Municipal Electric Utility
MOE	Ministry of the Environment
MSO	Midspan Opener
MTO	Ministry of Transportation
MTS	Maintenance Technical Services

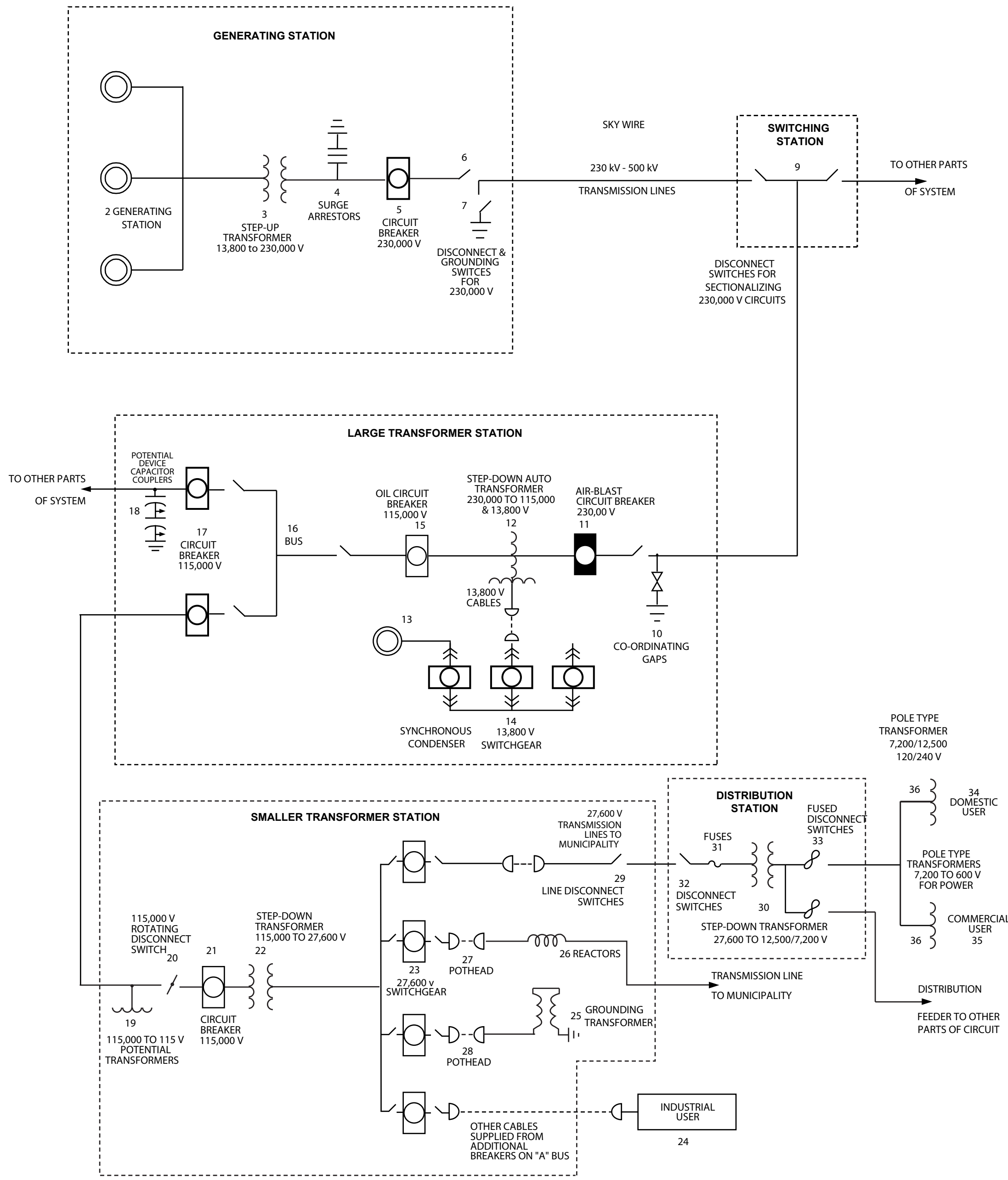
MUS	Mobile Unit Station
MUSH	Municipal, University, School and Hospital
MVAR	Mega Volt-Amperes Reactive
NAPSI	North American Synchro Phasor Initiative
NaS	Sodium-Sulphur (battery)
NBLIP	Negative Buchanan-Longwood Input
NERC	North America Electric Reliability Corporation
NGS	Nuclear Generating Station
NiMH	Nickel Metal Hydride (battery)
NIST	National Institute of Standards and Technology
NMS	Network Management System
NOD	Network Operating Division
NOMS	Network Outage Management System
NPCC	Northeast Power Coordinating Council
NYR	Northern York Region
O&M	Operating and Maintenance
OBCA	Ontario Business Corporations Act
OCE	Ontario Center for Excellence
ODP	Outlier Delivery Point
OEB	Ontario Energy Board
OEM	Original Equipment Manufacturer
OGCC	Ontario Grid Control Centre
OM&A	Operating, Maintenance and Administration
OMS	Outage Management System
OP&CS	Operating Performance and Customer Support
OPA	Ontario Power Authority
OPG	Ontario Power Generation
OPGW	Optical Ground Wire
OPUC	Office of Public Utility Counsel
ORMS	Outage Response Management System
OSI	Open Systems Interconnection
P&C	Protection and Control
PAC	Program Administrator Cost
PALC	Programmable Auxiliary Logic Controller
PAS	Publicly Available Specification
PCB	Polychlorinated Biphenyl
PCC	Power Control Center; or Point of Common Coupling
PCT	Programmable Communicating Thermostat
PCT	Protection & Control and Telecom
PDA	Personal Digital Assistant
PG&E	Pacific Gas and Electric
PGS	Pumped Generation Storage
PHEV	Plug-in Hybrid Electric Vehicle
PILs	Payments In Lieu (of Taxes)
PLCO	Provincial Lines Customer Operations
PM	Preventive Maintenance
PMO	Preventive Maintenance Optimization
PMU	Phasor Measurement Unit

PQ	Power Quality
PSB	Polysulphide Bromide Battery
PSDB	Power System Database
PSU	Process and System Upgrades
PUC	Power Utility Commission
PV	Photovoltaic
PWU	Power Workers' Union
QFW	Queenston Flow West
QNL	Quebec, Newfoundland & Labrador
R&D	Research and Development
RCM	Reliability Centered Maintenance
REI	Renewable Enabling Investment
RES	Renewable Energy Supply
RESOP	Renewable Energy Standard Offer Program
RET	Renewable Energy Technologies
RFP	Request For Proposal
ROW	Right-Of-Way
RPP	Regulated Price Plan
RRFE	Renewed Regulatory Framework for Electricity
RS	Regulating Station
RTM	Real Time Monitoring
RTNET	Real Time Network
SAIDI	System Average Interruption Duration Index
SAIFI	System Average Interruption Frequency Index
SAP	Systems, Applications and Products in Data Processing (Enterprise Work Management System)
SC	Service Centres
SCADA	Supervisory Control and Data Acquisition
SCE	Southern California Edison
SDG&E	San Diego Gas and Electric
SDO	Sustainment, Development, and Operating
SF6	Sulfur Hexafluoride (a gaseous dielectric used in high voltage electrical equipment as an insulator and/or arc quenching medium)
SG	Smart Grid
SIA	System Impact Assessment
SMES	Superconducting Magnetic Energy Storage
SONET	Synchronous Optical Network
SQI	Service Quality Indicators
SQR	Service Quality Requirements
SS	Switching Station
SST	Station Service Transformer
STATCOM	Static Synchronous Compensator
STNET	Study Network
SVC	Static Var Compensator

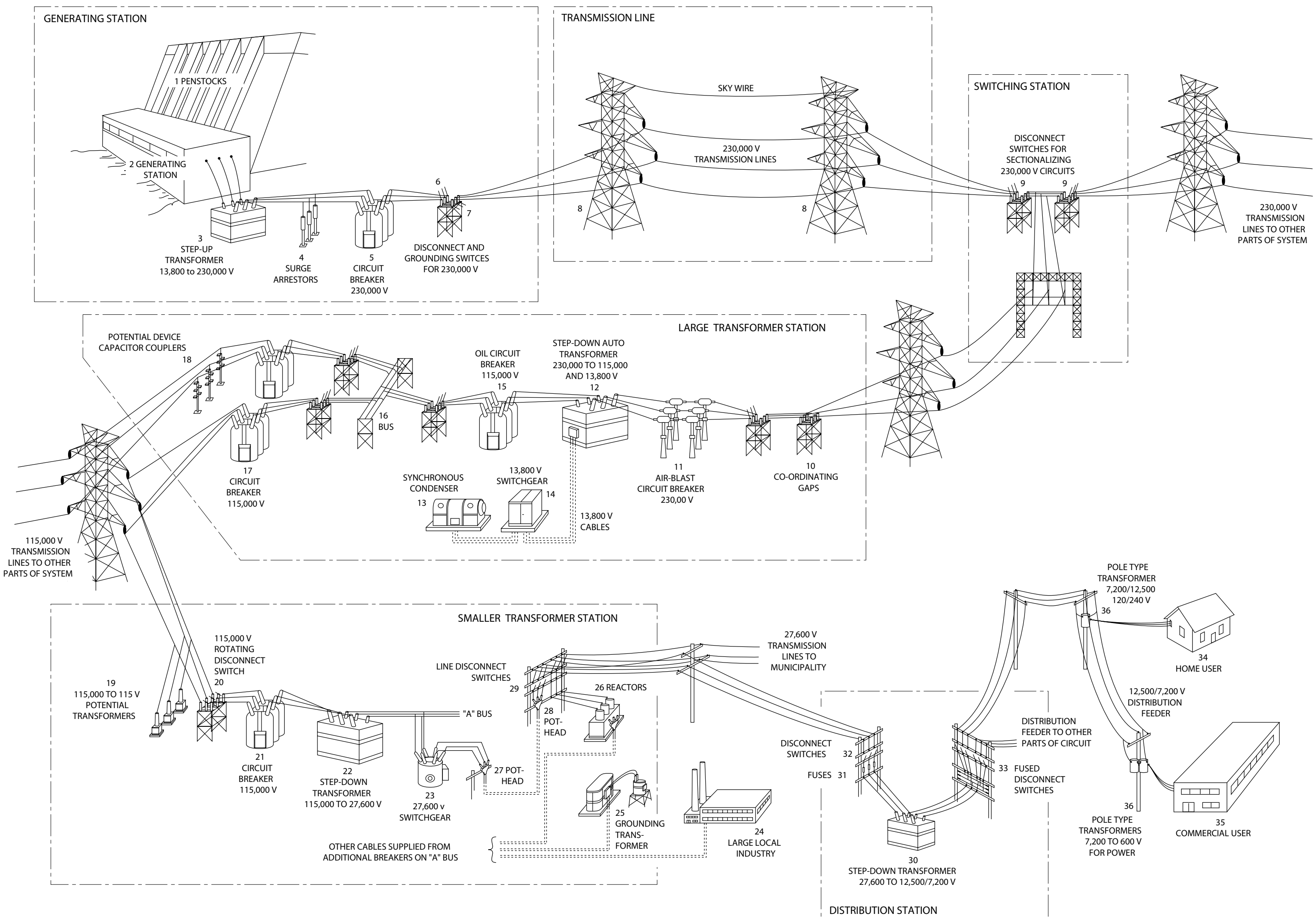
T&D	Transmission and Distribution
TAT	Transmission Availability Test
TCSC	Thyristor Controlled Series Compensation
TGS	Thermal Generating Station
THESL	Toronto Hydro Electric System Limited
TOU	Time-Of-Use
TOV	Temporary Over Voltage
TRC	Total Resource Cost
TS	Transformer Station
TSC	Transmission System Code
TWP	Township
TWPL	The Woodhouse Partnership Limited
Tx	Transmission
TXU	Texas Utilities
UFLS	Under-Frequency Load Shedding
ULTC	Under Load Tap Changer
UOIT	University of Ontario Institute of Technology
USDOE	U.S. Department of Energy
UWPC	Utility Work Protection Code
VAR	Volt-Amperes Reactive
VRB	Vanadium Redox Battery
VVO	Volt-Var Optimization
WEC	Wind Energy Centre
WSD	Work Specification Document
WSIB	Workplace Safety and Insurance Board
XLPE	Cross-Linked Polyethylene
YTD	Year-to-Date
Zn-air	Zinc-air (battery)
Zn-Br	Zinc Bromine (battery)
Zn-Cl	Zinc-Chloride (battery)


C-GHOX

SIMPLIFIED ONE-LINE SCHEMATIC DRAWING OF AN ELECTRIC POWER SYSTEM



SIMPLIFIED ILLUSTRATION OF AN ELECTRIC POWER SYSTEM



Asset Management - Asset Strategy
483 Bay Street
Toronto, Ontario
M5G 2P5
www.HydroOne.com

TRANSMISSION GREEN ENERGY PLAN

INDEX

1.0 HYDRO ONE'S GREEN ENERGY PLAN

The Hydro One Transmission Green Energy Plan for 2013 and 2014 continues to have significant investments for the integration of renewable generation in the Province of Ontario that is consistent with the *Green Energy and Green Economy Act, 2009* ("*GEGEA*") and government policies. It reflects the transmission needs of the Ontario Government's Long Term Energy Plan ("LTEP") and is based on ongoing planning work by Hydro One, the OPA and the Ministry of Energy and Infrastructure related to renewable initiatives.

A significant number of transmission projects are included in the Development Capital portion of this application (Exhibit D1, Tab 3, Schedule 3) to provide increased capacity to facilitate further planned renewable resources or to connect renewable projects. This exhibit provides an overview of these projects which form the Hydro One Green Energy Plan for this rate submission.

1.1 Background

The Green Energy Plan in Proceeding EB-2010-0002 outlined Hydro One's strategy to implement the Government of Ontario's policy objectives in the GEGEA and more specifically a letter dated September 21, 2009 from the Minister of Energy and Infrastructure to Hydro One, which is attached in Appendix A to this exhibit. The letter instructed Hydro One to immediately proceed with the planning, development and implementation of 20 large transmission projects outlined in Schedule A and also a number of shorter term Schedule B projects to facilitate distributed generation including the Hearn SS, Leaside TS and Manby TS upgrades, In-Line Circuit Breakers, Static Var Compensators ("SVC's"), enabling transformer stations, and Protection and Control ("P&C") upgrades.

On May 5, 2010 the Minister of Energy and Infrastructure sent a letter to Hydro One (attached in Appendix B to this exhibit) instructing the company to reassess its pending transmission rate application in light of the government's efforts at cost restraint and to focus the forthcoming transmission rate application on projects that "are critical to the connection of renewable generation projects that have been identified by the Ontario Power Authority as part of the government's green energy agenda". Further, on May 7, 2010 the Minister also wrote to the OPA (also attached in Appendix B to this exhibit) and instructed it to prepare an updated transmission expansion plan that would replace the September 21, 2009 instruction to Hydro One and address the needs of the Feed In Tariff ("FIT") program and the Korean Consortium. In response to these letters, Hydro One suspended all development work on the 20 Schedule A projects in May, 2010. Work continued on the Schedule B projects that were approved by the Board in the EB-2010-0002 Decision and Order.

2.0 PROJECTS TO FACILITATE GREEN ENERGY IN EB-2010-0002

In the EB-2010-0002 Decision, the Board approved several projects which at the time were also included in the list of Schedule B projects referred to above. These investments included the Hearn SS, Leaside TS and Manby TS upgrades, as well as two In-Line Circuit Breakers and P&C Facilities to Enable Distributed Generation. However, the Decision did not allow P&C upgrades for the purpose of enabling distribution connected projects to be recovered from rates. A summary of the previously approved projects is outlined below in Sections 2.1 to 2.3.

There were also several projects in the list of Schedule B projects in the previous rate submission that had capital spending in the test years, but would not be in-service in the 2011-2012 test years. These investments included two Enabling Transmission Stations, four In-Line Circuit Breakers, and a SVC to accommodate potential distributed generation from the FIT program. In the EB-2010-0002 Decision, the Board did not provide any guidance to the company with respect to these projects. However, the Board did state that the decision to withhold project approval does not inhibit the company from doing whatever it considers to be prudent in preparation for these projects; with the disclaimer that the company may need to bring the projects back to the Board for approval once more robust evidence of need is available. As Hydro One, IESO and OPA studies have not identified a specific need for any of these projects to date; no capital spending has been incurred for these projects and no investments have been included in this rate submission.

2.1 Projects to Facilitate Generation Connections to the Toronto Hydro System

In order to enable connections of new renewable and high efficiency generation facilities, the short circuit capabilities at three Stations in Toronto – Hearn SS, Leaside TS and Manby TS – needed to be increased. The short circuit levels at these stations are almost near the equipment limits and currently permit only a very limited amount of distributed small scale generation to be connected. Work to upgrade the short circuit capability at these stations is underway. This work involves replacing the end-of-life facilities at Hearn SS with a new switchyard, and largely upgrading the breakers at Leaside TS and Manby TS for higher short circuit operation. Further details of these projects are provided in Exhibit D1, Tab 3, Schedule 3 and in Exhibit D2, Tab 2, Schedule 3, ISD's # D7, D8, D9. Once this work is completed it will be possible to connect not only significantly more small scale and larger size distributed generation but also medium and large sized transmission connected generation to the central and downtown areas of Toronto.

Since the last transmission rate application, both costs and timing of these projects have been updated as shown in Exhibit D1, Tab 3, Schedule 3, Appendix A, Table 3. Overall, the costs for the three stations are slightly lower than estimated in the previous transmission rate application (EB-2010-0002, Exhibit A, Tab 11, Schedule 4, Table 3). Estimates provided at the time of the last rate submission were budgetary and only a limited amount of preliminary engineering had been completed. Since that time detailed engineering including major tenders for equipment and major land acquisition has been completed.

The current project cost for Hearn SS is higher due to increased costs for the turn-key GIS station following the tendering process and increased costs for P&C facilities. The delayed in-service date for Hearn SS from the initial forecast of December 2012 is due to a one year delay in acquiring property for the new switchyard. It was initially anticipated that the land acquisition could be completed by late Fall 2010; however, property purchase negotiations took longer than expected and the required property could not be secured until late October 2011.

The current project costs for both Leaside TS and Manby TS are lower as a result of detailed engineering work which determined that a portion of the P&C facilities did not require modifications at this time and replacement could be deferred. The delayed in-service date at Leaside TS from the initial forecast of December 2012 is due to difficulty in obtaining outages to stage the upgrade work. The Manby TS in-service date remains unchanged.

2.2 In-Line Circuit Breaker Projects

From the perspective of system protection, there is a limit to the number of generating stations or transformer stations feeding power back into the system that can be tapped to high-voltage transmission circuits. Detailed power system studies and P&C analysis are required to establish how many such stations can be tapped to any particular transmission circuit. Various factors including size, type, station design and the connection location of the generation as well as the electrical characteristics of the local system can affect the number of stations that can be tapped. In cases where a generator cannot be connected via a simple tapped arrangement, additional high voltage facilities are required to provide switching and to sectionalize (or divide) the existing circuit into more than one section. Appropriate protection can then be provided for each section.

For connections to a single circuit that requires sectionalizing, the minimal facilities to achieve this involve much more than in-line circuit breakers. New station infrastructure is required to house and support these breakers including bus work, a building for relay and communication facilities, local AC power supply, grounding, fencing, environmental mitigation and even an access road.

In the previous rate submission, Hydro One proposed that likely two in-line breaker facilities would be required by 2012 based on the information available for the projects that were awarded FIT contracts in spring 2010. Following the connection assessments of many of these projects, it was confirmed that two generation projects (Summerhaven and Port Dover) required in-line breakers by 2012.

In the EB-2010-0002 Decision, the Board approved two In-line Circuit Breaker projects at a preliminary estimated cost of $20.3M each. The expected cost for the in-line breakers for the Summerhaven and Port Dover wind farm projects are $22.7 million and $23.8 million respectively. These costs are based on detailed engineering and reflect the scope of work identified by the IESO's System Impact Assessment and Hydro One's Customer Impact Assessment.

In the current rate submission, Hydro One anticipates that one additional in-line breaker facility is required to connect the Armow wind farm by 2014. The preliminary estimate for this project is $22 million.

2.3 P&C Upgrades to Enable Distribution Connected Generation

Two major Protection and Control investments were identified at Transmission Stations to allow the connection and efficient ongoing operation of generation to distribution systems:

1. Station Protection Upgrades for Distributed Generation – This identified the various protection and control upgrades at the transmission stations which are required to ensure the reliability of supply, the protection of transmission assets and safety.
2. Enhanced Transfer Trip Facilities – This identified the need for enhanced transfer tip signaling facilities at Transmission Stations to allow transmission forced and planned outages to proceed without requiring generation connected to the distribution system to be curtailed or shut down.

In the Decision and Order in proceeding EB-2010-0002, the Board approved the Station Protection Upgrades and Transfer Trip Facilities investments. H owever, the Board concluded costs should not be recovered from rates and that the Transmission System Code prescribed user-pay approach for such facilities is appropriate.

The Station Protection Upgrades investments are essential to allow generators to connect and work is proceeding on these investments. Administrative systems are being put into place to obtain fair recovery from the generators. See Section 2.2.5 in Exhibit D1, Tab 3, Schedule 3 for more details.

The Enhanced Transfer Trip Facilities are not essential to allow generators to connect and this work has been delayed until a fair mechanism can be designed to allow all generators that benefit from their implementation to determine if they wish to contribute to the cost. A number of generators have begun to ask for these facilities as the cost of lost revenue will quickly pay-back their share of the implementation cost. As with the Station Protection Upgrades, these facilities will benefit generators in different groups. Enhanced feeder transfer trip facilities will benefit all generators connected to a "back-to-back" feeder pair during outages to the station bus or feeder breakers. Enhanced wide-area transfer trip facilities will benefit all generators connecting to a transmission station or transmission line. Mechanisms are being examined to reach out to all generators that will benefit from the installation of these facilities and determine equitable sharing of cost.

3.0 PROJECTS TO FACILITATE GREEN ENERGY

In addition to the projects discussed above, this section describes the projects in the current rate submission which will facilitate further development of green energy. Table 3 summarizes the related investments, their costs and the level of renewable generation that they potentially facilitate. These projects collectively allow for the connection of approximately 5000-6000 MW of renewable energy.

Table 3

Item #	Project	Gross ($M)	Net ($M)	Renewable Generation Facilitated (MW)
1	Reconductor the Lambton TS to Longwood TS 230kV Circuits	40.0	40.0	500
2	Installation of SVC at Milton SS	100.0	100.0	250
3	FIT Renewable Generation Connections	170.4*	0.2*	2000
4	Non-FIT Renewable Generation Connections	104.5*	22.3*	2075
5	Allanburg TS: Upgrade Short Circuit Capability	19.0	19.0	Up to 150
6	Hawthorne TS: Upgrade Short Circuit Capability	11.8	11.8	Up to 300
7	Protection and Control Upgrades to Enable Generation Connections to Distribution Systems	52.0	0.0	Up to 500
8	Protection and Control Upgrades for the Consequences of Generation already connected to Distribution Systems	13.8	13.8	0

*Estimates of capital expenditure for 2013 and 2014 only

Item #1 and #2 reflect two of the three priority projects in the Government of Ontario's LTEP that were designated to Hydro One. Hydro One received letters from the OPA to proceed with the re-conductoring work on the existing Longwood to Lambton circuits on June 30, 2011 (attached in Appendix D to Exhibit D1, Tab 3, Schedule 3) and to proceed with the addition of an SVC at Milton SS on October 3, 2011 and further supporting evidence in March, 2012 (attached in Appendix C to Exhibit D1, Tab 3, Schedule 3). Further details of these projects are provided in Table 2 of Exhibit D1, Tab 3, Schedule 3, Appendix A and ISD's # D5 and #D6 at Exhibit D2, Tab 2, Schedule 3. The third priority project in the LTEP involves a new transmission line west of the London area. Hydro One understands that further studies by the OPA are required to establish the scope and requirements of the new line. For the new line project, only minor expenditures of $1 million or less have been included in the test years to conduct studies in support of the OPA, perform conceptual level engineering and initiate preliminary approvals work.

Items #3 and #4 represent significant expenditures to connect renewable generators to the Hydro One transmission system. Capital expenditures of almost $171 million will be required to connect 37 FIT generators and approximately $105 million to connect 12 non-FIT renewable generators. Non-FIT connections include mainly renewable projects arising from other OPA procurement programs and government initiatives (Green Energy Investment Agreement) or directives (e.g. Hydro Electric Energy Supply Agreements). Generation connection work is expected to exceed $275 million over the two Test Years; however, the vast majority of this work is to be fully recovered from the generation proponents. Less than $25 million of the costs are expected to be recovered from rates. Further details of generation connections are provided in Table 5 of Exhibit D1, Tab 3, Schedule 3, Appendix A and the ISD's #D20 to #D25 at Exhibit D2, Tab 2, Schedule 3.

Item #5 a nd #6 are included to illustrate the additional benefits provided by other investments in the rate submission to facilitate renewable generation. Upgrades at both Allanburg TS and Hawthorne TS are required to address the high short circuit levels which are at or exceeding equipment capabilities. The upgrades involve mainly replacing existing oil circuit breakers with new higher rated SF6 breakers. In situations where the short circuit levels are being exceeded, interim operating measures are in place including opening bus-tie breakers. Such measures result in reduced reliability at these stations as the switchyards are now split into smaller subsystems with much less redundancy. The primary driver for the upgrade at these stations is to restore the reliability to previous levels. Further details of these investments are provided in Table 10 of Exhibit D1, Tab 3, Schedule 3, Appendix A and ISD's #D30 and #D31 at Exhibit D2, Tab 2, Schedule 3.

A secondary benefit of these upgrades is that it will provide for significantly increased capability to connect additional renewable generation. At present, the limitations at Allanburg are constraining additional generation connection in the Niagara Pennisula. Similarly limitations at Hawthorne TS are constraining the generation connections in the greater Ottawa and surrounding areas. The upgrades will allow connection of up to 150MW of additional generation in the Allanburg area and up to 300MW of additional generation in the Ottawa area.

Item #7 represents all of the P&C upgrades required to enable renewable generation connections. This includes:

- Enhanced transfer trip signalling to allow transmission outages to proceed with reduced impact to distribution connected generation
- Transmission Station P&C upgrades for distribution connected generation

Further details on these investments are provided in Exhibit D1, Tab 3, Schedule 3, Section 3.5 and Table 6 of Appendix A, and ISD's #D26 and #D27 at Exhibit D2, Tab 2, Schedule 3.

Item #8 represents all of the P&C modifications required to address the consequences of the generation already connected to the distribution systems. This includes:

- Transmission P&C modifications to mitigate the power distance limitation,
- Modifications to maintain compliance with under-frequency load shedding requirements (UFLS) and to preserve required load rejection capability,
- Other work including: expansion to the operating infrastructure required to monitor all of the new generation and associated protection systems; and systems to manage generation curtailment during outages.

Further details on these investments are provided in Exhibit D1, Tab 3, Schedule 3, Section 3.6 and Table 7 of Appendix A, and ISD's #D28 and #D29 at Exhibit D2, Tab 2, Schedule 3.

3.1 Licence Amendment to Upgrade TS's to Facilitate Renewable Generation

In addition to the projects in Table 3, Hydro One is performing work to upgrade existing transformer stations to facilitate small scale renewable generation as per the license amendment issued on March 1, 2011. The license amendment required Hydro One to upgrade up to 15 transformer stations subject to the scope and timing recommended by the OPA. On April 7, 2011, the OPA sent a letter (attached in Appendix C to this exhibit) advising Hydro One to upgrade 10 transformer stations. Upgrades were to be performed at the following stations:

1. Kingsville TS
2. Kent TS
3. Port Hope TS
4. Birch TS
5. Caledonia TS
6. Clarke TS
7. Keith TS
8. Longwood TS
9. Nebo TS
10. Goderich TS

Upon further investigation and engineering review, alternative approaches were identified for Port Hope and Birch which did not require further work to be done to accommodate the small scale generation at these stations. Subsequent to the OPA letter, transformer upgrades for increasing load connection capacity at Nebo TS was identified and therefore the originally proposed upgrades to Nebo TS would not be needed. Further details of the work at Nebo can be found in the ISD #D15 at Exhibit D2, Tab 2, Schedule 3.

Transformer upgrade work was performed at Kent TS and Goderich TS to increase reverse flow transformation capacity. Bus tie reactors were added to the Kingsville, Caledonia, Clarke, Keith, and Longwood transformer stations to increase short circuit capability at these stations. Work at Kingsville TS was completed in 2011 and the other six stations will be completed in 2012. The total cost for the seven stations is $43.5 million. Hydro One has not recovered these costs from ratepayers as per the licence amendment.

3.2 OM&A Costs related to the Green Energy Plan

Exhibit C1, Tab 3, Schedule 3 describes the Development OM&A work Hydro One plans to undertake in 2013 and 2014. The work includes R&D studies and pilot projects, the development of technical standards, and development of the Advanced Distribution System (ADS or Smart Grid). A significant amount of this work is related to accommodating the connection of renewable generation to the transmission and distribution systems in Ontario. As such, these OM&A costs are also part of the Green Energy Plan.

4.0 RECOVERY OF DEVELOPMENT COSTS FOR EARLIER GREEN ENERGY PROJECTS

In Exhibits F1, Tab 1, Schedules 1 and 3, Hydro One is requesting recovery of a deferral account for costs incurred in 2010 for OM&A development work on projects included in the EB-2010-0002 Green Energy Plan. This section provides background information to support why Hydro One should be allowed recovery of these costs.

On May 28, 2009, the Board established a deferral account for projects related to the Green Energy Act that had been identified by the OPA in the Integrated Power System Plan (IPSP). On March 25, 2010, the Board expanded the list of projects to include other green projects listed in the Minister of Energy's letter to Hydro One dated September 21, 2009 that were not already included in the deferral account.

Hydro One initiated an aggressive program of OM&A development work on certain priority projects following the Minister's letter of September 21, 2009. The letter instructed Hydro One to "immediately proceed with the planning, development and implementation of Transmission Projects outlined in the attached Schedule A." The letter required Hydro One's Chairman to return a signed copy stating "I concur." Based on this direct instruction and commitment; and based on the target in-service dates listed in Schedule A for some of the projects, work had to ramp up very quickly in order to meet the in-service dates.

In November of 2009, Hydro One began discussions with Ministry staff about its implementation plan. In accordance with the September 21, 2009 letter from the Minister, on December 29, 2009 Hydro One submitted to the Minister of Energy and Infrastructure, a status report on the Transmission and Distribution Projects in Support of Renewable Energy Projects (attached in Appendix D to this exhibit).

As part of the EB-2010-0002 Decision, the Board approved the recovery of $1.9 million incurred in 2009 in the deferral account. This was the early portion of the development work referred to above. It is important to note that the amount of $4.6 million incurred and recorded in the account in 2010 was for continuation of the same type of work as that incurred in 2009 and for continuing to implement the Plan as submitted to the Minister. These costs were incurred prior to the Board's approval of the Electricity Transmitter Designation process in EB-2010-0059 and were in direct response to the Minister's letter and instruction of September 21, 2009. The only way Hydro One could have met the in-service dates established by the Minister in Schedule A of the letter was to proceed immediately and aggressively on the development work. The development work involved a large degree of outsourcing partly to acquire the right expertise and partly to acquire enough resources to meet the very tight time frames set by the aggressive in-service dates.

As indicated in Section 1.1 above, the development work on the Schedule A projects was suspended following the Minister's letter of May 5, 2010 to Hydro One and May 7, 2010 to the Ontario Power Authority (both attached in Appendix B to this exhibit). Although not rescinded, statements made in these letters make it very clear that the September 21, 2009 instructions to Hydro One were in question. Therefore, until clear direction was received, Hydro One suspended all development work on the Schedule A projects. It was, however not appropriate for Hydro One to suspend the development work prior to the issuance of these letters as that would not have complied with the Minister's instruction. Therefore, Hydro One submits that although circumstances were changing, the development work that was charged to the deferral account until May of 2010 is entirely valid and in keeping with the Minister's and shareholder's instructions.

4.1 Prioritization of Projects

Due to the amount of time needed for consultation, approvals and construction of large transmission projects, development work had to begin immediately on the priority Green Energy projects in order to meet their target in-service dates. Hydro One selected those projects where there was an urgency to begin development work primarily based on the target in-service date and based on the following criteria:

- All the Core Transmission lines (bulk transmission upgrades) listed in Schedule A were prioritized given their wide areas of service and relatively long lead times, other than the Bowmanville x GTA 500 kV line which was deferred pending a decision on whether to add new nuclear capacity at Darlington,
- Of the Enabling Transmission lines in Schedule A, only the Goderich and Manitoulin Island Enablers were prioritized given the potential benefits and the expectation that the need would be relatively near term. Development work on all other projects was to be initiated following the OPA's Economic Connection Test process,
- The one "regional transmission" project prioritized was the Northwest Transmission line. This project was determined to be a priority given the Minister's target in-service date of 2013 and the various potential benefits including connection of new

renewable generation, service to additional gold mining in the area and to new chromite mining in the Ring of Fire.

The 7 priority projects are listed in Table 4.

4.2 Cost Breakdown

Table 4

Project Name	**Amounts incurred in 2010 ($M)**
Goderich Area Enabler	0.2
Northwest Transmission Line	1.4
Manitoulin Island Enabler Line	0.2
East-West Tie TX Development	0.4
North South Transmission Expansion	1.2
Hanmer x Mississagi	0.5
West of London TX Line Development	0.7
Total	**4.6**

The cost of $4.6 million is divided primarily between internal labour and contract work with smaller amounts for miscellaneous equipment and helicopter surveys to study route options, feasibility and determine environmental and construction issues. Internal labour includes project management and estimation, environmental engineering and design, drafting, and conceptual engineering. C ontract work included contracts awarded for detailed environmental, GIS (or mapping) and engineering work.

These costs are included in the request for recovery of the deferral account in Exhibit F1, Tab 1, Schedule 1 and Exhibit F1, Tab 1, Schedule 3.

4.3 Recovery of Costs

Hydro One submits that the Board should approve the recovery of these development costs. Hydro One acted prudently and appropriately in carrying out this development work in 2010. In particular, Hydro One notes that the Minister's letter of September 21, 2009 included a request to the company to "immediately proceed with the planning, development and implementation of the Transmission Projects outlined in the attached Schedule A." The letter included in-service dates in Schedule A that required a very aggressive pace of development work in order to complete the large number of major projects within the prescribed time frame. Furthermore, the letter required Hydro One's chairman to sign the letter under the statement "I concur" and return the letter to the Minister. The company had made a very serious commitment to the Minister to deliver on this work.

Minister of Energy and Infrastructure

Office of the Deputy Premier

4th Floor, Hearst Block
900 Bay Street
Toronto ON M7A 2E1
Tel.: 416-327-6758
Fax: 416-327-6754
www.ontario.ca/MEI

Ministre de l'Énergie et de l'Infrastructure

Bureau du vice-premier ministre

4e étage, édifice Hearst
900, rue Bay
Toronto ON M7A 2E1
Tél. : 416 327-6758
Téléc. : 416 327-6754
www.ontario.ca/MEI

Ontario

September 21, 2009

Mr. James Arnett
Chair
Hydro One Inc.
483 Bay Street
15th Floor, North Tower
Toronto ON M5G 2P5

Dear ~~Mr. Arnett~~ Jim:

As you know, our government is committed to increasing renewable energy generation across Ontario and ensuring that the necessary infrastructure is in place to enable it. To that end we have passed the *Green Energy and Green Economy Act, 2009* (GEA) providing a comprehensive framework for developing renewable energy generation in Ontario.

The GEA sets the framework for, among other things, the introduction of a feed-in tariff program for renewable energy. To accommodate the anticipated increase in renewable energy generation associated with a feed-in tariff program, it will be necessary to implement a number of major projects to upgrade the transmission and distribution systems.

In anticipation of this, I understand that the Ontario Power Authority (OPA) and Hydro One have worked together to identify areas of the province that would benefit from specific transmission and distribution upgrades to enable new renewable generation likely to be forthcoming through the feed-in tariff program. These projects are reflected in the attached Schedules. I am pleased that Hydro One has been proactive in planning for this much needed expansion of its transmission and distribution systems, in addition to planning for the development of a smarter grid infrastructure that will enable greater integration of renewables.

Given the immediate importance of the projects shown in the attached Schedules, I would ask that Hydro One complete the following activities in anticipation of the feed-in tariff program and high demand for renewable connections:

.../cont'd

1. Immediately proceed with the planning, development and implementation of Transmission Projects outlined in the attached Schedule A, including seeking approvals for the upgrades as soon as there is a reasonable basis to do so.

2. Collaborate with the OPA in defining the scope of work, including termination points, target capacity, number of lines, technical options and sequencing necessary for the Transmission Projects, as well as collaborating with the Independent Electricity System Operator on System Impact Assessments and reliability impacts.

3. Develop and implement smart grid infrastructure in accordance with upcoming government policy, including establishing novel ways of managing network infrastructure for renewables more efficiently.

4. Given the magnitude of work required to complete the Transmission Projects:
   a. Identify the commercially reasonable opportunities for entering into partnership arrangements with qualified third parties/partners for the execution of the Projects;
   b. Work with the Shareholder to identify commercially reasonable criteria that will be used to select qualified third parties/partners;
   c. Use best efforts to enter into those commercially reasonable arrangements; and,
   d. Identify projects as appropriate where the planning, development and implementation of the project would be better accomplished by a qualified third party other than Hydro One.

5. Provide opportunities for participation in the projects by potentially-affected Aboriginal peoples.

6. Immediately proceed with the planning, development and implementation of upgrades to enable distribution system connected generation, as outlined in the attached Schedule B, including collaborating with the OPA and the Independent Electricity System Operator in defining the scope of work necessary for the transmission facilities to enable distribution system connected generation.

7. Begin planning and preliminary development to explore and preserve options for longer-term, high-capacity, transmission link between Thunder Bay and the Greater Toronto Area, including associated collaboration with the OPA for planning.

8. Subject to Crown oversight, engage in consultations with and, where appropriate, accommodate Aboriginal peoples respecting their section 35 rights of the Canadian *Constitution Act*, potentially affected by transmission and distribution projects listed in the attached Schedules.

.../cont'd

To be clear, I am seeking your cooperation on these matters as a key enabler for the feed-in tariff program to be implemented under the GEA and in order to establish a more modern and reinforced electricity grid in Ontario. In no way does my request relate to the implementation or methods used to carry out the work described in this letter, including following appropriate consultation and approvals processes. In light of that, I would expect that Hydro One will develop a comprehensive implementation plan to achieve these objectives.

Furthermore, in order to be informed about Hydro One's progress toward implementing and meeting these objectives, and in keeping with the purpose of the Memorandum of Agreement between Hydro One and the Shareholder, I request that Hydro One report back to me on a semi-annual basis on planning, development and implementation activities undertaken, and progress made in connection with Transmission and Distribution Projects that will enable the feed-in-tariff program. I would appreciate receiving a first report by no later than the end of November 2009.

I am appreciative of Hydro One's continued leadership in moving towards Ontario's green energy future and look forward to seeing your progress in meeting the government's objectives on transmission and distribution system expansion.

On behalf of the Hydro One Board, would you please confirm your understanding of the above, and your concurrence with all that is contemplated, by signing in the space provided below. Thank you for your prompt attention to these matters.

Sincerely,

George Smitherman

George Smitherman
Deputy Premier, Minister

I concur,

James Arnett

James Arnett
Chair of the Board, Hydro One

Enclosures

Schedule A - Transmission Projects

Item #	Project	Key Driver	Target In-Service Year*
Core Transmission (Bulk transmission upgrades)			
1	East-West Tie: Nipigon x Wawa (230 kV)	Bulk Transmission Capability for FIT program	2015
2	North-South Tie: Sudbury Area x Barrie (500 kV)	Bulk Transmission Capability for FIT program	2015
3	Barrie x GTA (500 kV)	Bulk Transmission Capability for FIT program	2015
4	Sudbury Area x Algoma Area (Mississagi Transformer Station, 70km east of Sault Ste. Marie) (500 kV)	Bulk Transmission Capability for FIT program	2014
5	London Area x Sarnia (500 kV or 230 kV)	Bulk Transmission Capability for FIT program	2016
6	Bowmanville x GTA (500 kV)	Bulk Transmission Capability for reliability and FIT program	2016
Enabling Transmission (Local enabler connection lines for renewable clusters)			
7	Goderich Enabler	Connections in anticipation of high renewables demand	2013
8	Manitoulin Island Enabler	Connections in anticipation of high renewables demand	2014
9	Huron South Enabler (Wanstead Transformer Station)	Connections in anticipation of high renewables demand	2016
10	Pembroke Enabler	Connections in anticipation of high renewables demand	2014
11	Parry Sound Enabler	Connections in anticipation of high renewables demand	2015
12	North Bay Enabler and 230 kV Line Upgrade	Connections in anticipation of high renewables demand	2015
13	Thunder Bay Enabler	Connections in anticipation of high renewables demand	2015
Regional Transmission (Regional transmission lines for renewables)			
14	Pickle Lake x Nipigon	Renewables, Reliability, and Load Growth	2013
15	Cornwall x Ottawa	Renewables and load growth	2015
16	Belleville x Napanee (Selby Junction)	Renewables and load growth	2014
17	Chenaux x Arnprior Area (Galetta Junction)	Renewables and reliability	2014
Longer-Term (Post-2016)			
18	Sudbury North (500 kV)	Bulk Transmission Capability for FIT program	2017
19	London x Hamilton Area (500 kV)	Bulk Transmission Capability for FIT program	2020
20	Kenora x Thunder Bay	Bulk Transmission Capability for FIT program	2020

* Scope, sequencing and details of implementation subject to detailed Implementation Plan

Schedule B - Projects to Enable Distribution System Connected Generation

Item #	Project	Target In-Service Year*
Transmission Facilities to Enable Distribution-connected Generation		
1	Install 3 Static Var Compensators in Areas of high FIT Uptake	2012-2014
2	Install up to 7 Enabling Transformer Stations in Areas of High FIT Uptake	2012-2015
3	Upgrade Short Circuit Capability of Toronto Area Stations (Hearn TS, Manby TS, Leaside TS)	2012
4	Install in-line Circuit Breakers at up to 7 Locations to Enable Generation Connections	2012-2015
Distribution		
5	Targeted Dx Enhancements to Support Distributed Generation -10 New Distribution Feeders (in areas of high FIT uptake) -Other Minor Investments	2009-2012
Protection, Control, and Telecom (enabling distributed generation)		
6	DG Connection Cost Reduction -Wide Area Telecommunication Infrastructure -Wide Area Island Detection -Transmission Protection Change for Tap-Connected Generation -Stop-Gap Wireless Remote Trip -GPRS (Cellular) Telemetry -Pulse-signalling Island Detection -OGCC System Changes	2009-2012
7	Protection -Feeder Protection Replacements -Telecom to In-Line Reclosers -TS Bus Protection Replacements	
8	TS Capacity Expansion -Generation Trip and Block Scheme -Automated Generation Dispatch System -Transfer Protection Replacements -Tapchanger Control Upgrades -OGCC System Changes	
9	Product Quality -Feeder Voltage Regulator Replacement -OGCC System Changes	
10	Bulk System Reliability -Distribution Station SCADA and Protection Upgrades -OGCC System Changes -Load Rejection Systems Modifications	

* Scope, sequencing and details of implementation subject to detailed Implementation Plan

Ministry of Energy and Infrastructure

Office of the Minister

4th Floor, Hearst Block
900 Bay Street
Toronto ON M7A 2E1
Tel.: 416-327-6758
Fax: 416-327-6754
www.ontario.ca/MEI

Ministère de l'Énergie et de l'Infrastructure

Bureau du ministre

4e étage, édifice Hearst
900, rue Bay
Toronto ON M7A 2E1
Tél. : 416 327-6758
Téléc. : 416 327-6754
www.ontario.ca/MEI

Ontario

MC-2010-1609

MAY - 5 2010

Ms Laura Formusa
President and CEO
Hydro One Inc.
483 Bay Street, 15th Floor, North Tower
Toronto ON M5G 2P5

Dear ~~Ms Formusa~~ Laura:

I am writing in regards to Hydro One Networks' pending 2011–2012 transmission rates application to the Ontario Energy Board.

As you are aware, the Province of Ontario has keenly felt the impact of the recent recession, and this has been reflected in the government's 2010 budget. We are aggressively pursuing internal cost savings to meet our fiscal targets. At the same time we are committed to ensuring government agencies and Crown corporations across the public sector are equally focused on delivering cost savings that are under their control.

Bearing that in mind, I would request that Hydro One Networks carefully reassess the contents of its transmission rates application prior to filing with the Ontario Energy Board. I would like Hydro One Networks to demonstrate concerted efforts to identify cost saving opportunities and focus your forthcoming transmission rates application on those items that are essential to the safe and reliable operation of your existing assets or projects already under development and approved by the Ontario Energy Board, or are critical to the connection of renewable generation projects that have been identified by the Ontario Power Authority as part of the government's green energy agenda.

Also, as part of Hydro One's efforts to mitigate rate pressures and consistent with the government's policy on the introduction of the harmonized sales tax (HST), I would request that Hydro One commit to tracking for return to ratepayers the full cost reduction impact of input tax credits from items that were previously subject to the Retail Sales Tax (RST).

.../cont'd

I am confident that Hydro One Networks and the Ministry of Energy and Infrastructure can continue working together to provide good value to Ontario electricity customers.

Sincerely,

Brad Duguid
Minister

Ministry of Energy and Infrastructure

Office of the Minister

4th Floor, Hearst Block
900 Bay Street
Toronto ON M7A 2E1
Tel.: 416-327-6758
Fax: 416-327-6754
www.ontario.ca/MEI

Ministère de l'Énergie et de l'Infrastructure

Bureau du ministre

4e étage, édifice Hearst
900, rue Bay
Toronto ON M7A 2E1
Tél. : 416 327-6758
Téléc. : 416 327-6754
www.ontario.ca/MEI

MAY 07 2010

Ontario

MAY - 7 2010

Mr. Colin Andersen
Chief Executive Officer
Ontario Power Authority
1600–120 Adelaide Street West
Toronto ON M5H 1T1

Dear Mr. ~~Andersen~~: Colin

I would like to take this opportunity to express my appreciation for the hard work performed to-date by the Ontario Power Authority (OPA) on the Feed-in-Tariff (FIT) program and associated power system planning, which has been crucial to the progress achieved in implementing the *Green Energy Act*. I am pleased to see the tremendous interest across the province in developing new renewable energy projects since the FIT program has been launched.

Given this interest, it is clear that timely, well-planned and co-ordinated transmission infrastructure is a critical enabler for both the *Green Energy Act* and FIT program. In September 2009, my predecessor instructed Hydro One to begin the planning, development and implementation of 20 major transmission projects across the province in anticipation of the FIT program launch in October 2009.

Since the time of the instruction to Hydro One, there have been a number of developments in the electricity sector, including an unprecedented response to the FIT program, as well as an historic agreement with a Korean Consortium to develop 2,500 MW of renewable energy projects and to bring wind and solar manufacturing jobs to Ontario.

These developments have underlined the need for co-ordinated transmission planning to account for the many factors and timelines involved. As such, I am writing, pursuant to my authority under subsection 25.26(1) of the *Electricity Act*, to require that the OPA develop and submit to me an updated transmission expansion plan updating the September 2009 instruction to Hydro One and considering the sequencing necessary to meet the needs of the FIT program and the Korean Consortium.

. . . /cont'd

I would expect that the plan will contain recommendations for development sequencing of priority transmission projects and an implementation approach that would ensure that key government commitments are met. I also understand that such advice can only be provided in anticipation of the economic connection test, which is currently being established as part of the FIT program.

A key element of the instruction to Hydro One was to work with the OPA in defining the scope of work, including the sequencing necessary for the implementation of the projects. I understand that Ministry staff have been working extensively with the OPA and Hydro One toward this end. I would expect that your report will continue to build on these extensive efforts to-date, and ask that you provide your advice by June 11, 2010.

Thank you for your prompt attention to this issue, and I look forward to receiving your report.

Sincerely,

Brad Duguid
Minister

ONTARIO POWER AUTHORITY

120 Adelaide Street West
Suite 1600
Toronto, Ontario M5H 1T1

T 416-967-7474
F 416-967-1947
www.powerauthority.on.ca

April 7, 2011

Mr. Mike Penstone
Vice President, Transmission Project Development
Hydro One
483 Bay Street
Toronto, Ontario M5G 2P5

Dear Mike:

List of 10 Priority Transmission Stations for Upgrading to Facilitate the Connection of Small-Scale Renewable Energy Generation Facilities

In its Decision and Order dated February 28, 2011, the Ontario Energy Board amended the transmission licence of Hydro One Networks Inc. (Hydro One) in accordance with the Minister's Directive, dated February 17, 2011, to the Ontario Energy Board. The transmission license amendment includes, among other things, a requirement that Hydro One increase short circuit and/or transformer capability at up to 15 stations to enable the connection of small-scale renewable energy generation facilities during the 48 month period commencing on the date of the licence amendment. The Directive further stated that Hydro One was to "immediately work in co-operation with the Ontario Power Authority (OPA) to establish the scope and timing on the projects identified…", and that "the scope and timing of the projects shall be in accordance with the recommendations of the OPA".

The purpose of this letter is to provide you an initial list of 10 transmission stations for upgrading to enable the connection of currently constrained small-scale renewable generation facilities. For the purposes of this letter, as per the February 17, 2011 Ministerial Directive to the Ontario Energy Board, small scale-renewable generation facilities are defined as capacity allocation exempt small embedded generation facilities or micro-embedded generation facilities as defined in the Board's Distribution System Code.

The OPA has worked closely with Hydro One's staff over the past few weeks to identify the stations which should be upgraded for this purpose. The following list achieves the government's immediate objective of enabling the constrained generation facilities, and the connection of future renewables. The investments will also support reliability and allow smart grid approaches to distributed generation. The OPA and Hydro One identified the Hydro One transmission stations which have a high level of constrained small-scale renewable energy generation projects. These stations were then evaluated to identify the cost and timing requirements of accelerating the necessary improvements, with end of life of facilities at the stations also taken into consideration in this analysis.

The 10 transmission stations identified for upgrading through this process are listed in the following table:

Station Name	Capital Cost ($M)	Time for Completion (Months)
Kingsville TS	3.0	4-5
Kent TS (in Chatham-Kent)	15.0	4-6
Port Hope TS	2.0	9
Birch TS (in Thunder Bay)	4.0	12
Caledonia TS	2.5	12
Clarke TS (in London)	2.5	12
Keith TS (in Windsor)	2.5	12
Longwood TS (near London)	2.5	12
Nebo TS (in Hamilton)	2.5	12
Goderich TS	13 (4*)	15
Total Capital Cost	50	

* Cost considering the end-of-life of facilities at the station

Overall, the capital cost for these station improvements, based on Hydro One's estimates, totals approximately $50 Million, with project in-service dates ranging from August 2011 to June 2012, all within the 48 month requirement stated in the February 17, 2011 Directive.

It should be noted that improvements at these stations will not result in the removal of all connection limitations affecting small-scale renewable generation facilities. Some projects may also be subject to distribution constraints, and in that regard it could be useful for Hydro One to examine how connection issues at the distribution level could be addressed. For the purposes of this recommendation, our assumption is that any constraints that do exist do not affect the relative rankings of the transmission upgrades.

The OPA and Hydro One will continue to work to identify further upgrades, up to an additional 5 transmission stations consistent with the February 17, 2011 Directive, where small-scale renewable generation facilities are currently constrained, or where significant future constraints are anticipated.

We appreciate the ongoing cooperation of Hydro One's staff on this matter. We will continue to provide you our support and assistance throughout the implementation of these upgrade projects. If you have any questions, please contact Bob Chow, Jim Lee or Charlene de Boer.

Regards,

Amir Shalaby
Vice President
Power System Planning

Hydro One Inc.
483 Bay Street
North Tower, 15th Floor
Toronto, Ontario M5G 2P5
www.HydroOne.com

Tel: (416) 345 6306
Fax: (416) 345 6054

Laura I. Formusa
President & CEO

hydro One

December 29, 2009

The Honourable Gerry Phillips
Minister of Energy and Infrastructure
4th Floor, Hearst Block
900 Bay Street
Toronto, Ontario M7A 2E1

Dear Minister:

Status Report – Transmission and Distribution Projects in Support of Renewable Energy Projects

On September 21, 2009, the former Minister of Energy and Infrastructure and Deputy Premier, George Smitherman, wrote to our Chair, James Arnett, asking Hydro One to immediately proceed with the planning, development, and implementation of transmission projects and distribution system upgrades in anticipation of the Feed-in Tariff program and the associated high demand for renewable connections. We subsequently confirmed our understanding of the letter's intent and concurred with what was asked by the Minister.

We have developed a Green Energy Implementation Plan, which provides a comprehensive framework for accomplishing the Transmission and Distribution projects outlined in the September 21st letter. The Plan includes an assessment of the necessary actions and processes associated with obtaining approvals for the transmission projects. This Plan was shared with Ministry staff in November and will continue to be updated to reflect the status of the renewable energy projects.

Eight priority transmission projects in northern and southwestern Ontario have been identified, in consultation with the OPA. The development work for seven of these projects is well underway and work on others will be initiated early in 2010. Our progress on these projects is a reflection of our expertise and commitment to the timely expansion of Hydro One's transmission and distribution networks to accommodate renewable generation.

The remaining suite of projects will be initiated once the results of the Feed-in Tariff program and the need for new transmission are confirmed by the OPA. It is important that we continuously review and re-align our plans to be consistent with the location of renewable generation applications throughout the Province.

The development work to obtain approvals involves a number of inter-related processes which most often require three years and beyond to complete. Our recent experience with major transmission projects has provided us with an extensive understanding of these existing processes and has positioned us well to undertake the projects outlined in the Minister's letter.

Our experience also shows that extensive coordination and timely actions are required from not only Hydro One but the OPA, IESO, and government ministries including the MEI, MOE and MNR, to support the need for these projects and to meet our ambitious project timelines. Furthermore, regulatory clarity is important in understanding how the OEB will test the prudence of the green transmission and distribution projects in light of its new statutory object to "promote the use and generation of electricity from renewable energy sources in a manner consistent with the policies of the Government of Ontario, which includes the timely expansion or reinforcement of transmission systems and distribution systems to accommodate the connection of renewable generation facilities". In this regard, we are working closely with all affected agencies, ministries and our regulator.

Hydro One fully understands the importance to the Province of Ontario of the *Green Energy and Green Economy Act* and the Feed-in-Tariff (FIT) Program. The projects have been given a high priority within our business plan and are fully supported at an internal working level. The unprecedented response to the FIT Program will require some re-alignment of our plans in order to ensure we are giving the right priority to our transmission and distribution projects. We are also continuing to examine and discuss potential partnership models, including partnerships with First Nation communities.

We will continue to provide regular briefings to Ministry staff. Should you require further details at any time on the activities and progress associated with the green projects, please contact me or Mike Penstone, Vice President of Major Project Coordination and External Relations at (416) 345-5444.

Sincerely,

L Formusa

Laura Formusa
President and CEO
Hydro One Inc.

cc: James Arnett, Chair, Hydro One Inc.
Saäd Rafi, Deputy Minister, Ministry of Energy and Infrastructure

ECONOMIC INDICATORS

1.0 INTRODUCTION

Appendix A of Exhibit A, Tab 13, Schedule 1 provides the costing assumptions underlying the 2012 Business Plan. This exhibit provides additional background with respect to these assumptions.

2.0 ECONOMIC INDICATORS

2.1 Transmission Cost Escalation for Construction, Operations and Maintenance

The Transmission Cost Escalation for Construction, Operations & Maintenance provides a broad average measure of the industry-wide yearly price changes by tracking a representative basket of equipment and labour for these areas of business. This basket of goods is comprised of the following types of equipment and labour:

- Operation;
- Supervision and Engineering;
- Load Dispatching;
- Station Expenses;
- Lines;
- Meters;
- Customer Installations;
- Maintenance;
- Structures;
- Station Equipment;
- Overhead Lines;

- Underground Lines;
- Line Transformers; and
- Miscellaneous.

The data in Table 1 was provided by Global Insight's February 2012 forecast.

Table 1

	Historic			Bridge	Test	
	2009	2010	2011	2012	2013	2014
Transmission Cost Escalation for Construction (%)	-2.6	1.9	4.4	4.3	2.0	2.0
Transmission Cost Escalation for Operations & Maintenance (%)	-0.1	1.6	3.7	1.9	2.4	2.8

The Transmission Cost Escalation for Construction, Operations & Maintenance is used as a planning tool to predict expenditure level changes for Transmission materials and services, where better project specific information is not available.

2.2 Consumer Price Index

The Consumer Price Index ("CPI") provides a broad measure of the cost of living. Through the monthly CPI, Statistics Canada tracks the change in retail price of a representative shopping basket of about 600 goods and services from an average household's expenditure: food, housing, transportation, furniture, clothing, and recreation.

Hydro One Transmission operates wholly in the Province of Ontario, Canada. As a result, the CPI–Ontario exhibits the inflationary environment in which Hydro One Transmission operates. The CPI forecast is from Global Insight's January 2012 forecast and can be found in Table 2.

Table 2

	Historic			Bridge	Test	
	2009	**2010**	**2011**	**2012**	**2013**	**2014**
CPI – Ontario (%)	0.4	2.4	3.1	2.0	2.1	2.0

The CPI is used as a planning tool to forecast expenditure level changes for items such as fleet and sundry costs, where better work-specific information is not available.

2.3 Exchange Rate (CDN$ per US$)

The historic rates in Table 3 are the average exchange rates for 2009, 2010 and 2011 from the Bank of Canada. The exchange rate forecast for 2012 was based on the average of the 3-month out (December 2011) and 12 month out (September 2012) forecasts from September 2011 Consensus Forecasts and for 2013 and 2014 was based on the Global Insight June 2011 Long-Term Forecast and Analysis.

Table 3

	Historic			Bridge	Test	
	2009	**2010**	**2011**	**2012**	**2013**	**2014**
Exchange Rate (CDN$ per US$)	1.142	1.030	0.989	0.984	1.034	1.079

While the exchange rate forecast is not directly used to forecast costs or other variables, it is an important variable affecting the performance of the Canadian and Ontario economies.

3.0 INTEREST RATES

Interest rate forecasts are used to determine the cost of capital for Hydro One Transmission as described in Exhibit B1, Tab 1, Schedule 1. Please refer to Exhibit B1, Tab 1, Schedule 1 for historical and forecast deemed short term debt rates and to Exhibit B1, Tab 2, Schedule 1 for historical and forecast long term debt rates.

3.1 Allowance for Funds Used During Construction

For construction work in progress (CWIP), Hydro One Transmission capitalizes interest at the All Corporate Mid-Term Average Weighted Bond Yield as per the methodology approved by the Board in its letter dated November 28, 2006 in proceeding EB-2006-0117.

The 10-year Government of Canada bond yield forecast for 2012 is based on the average of the 3-month out (December 2011) and 12 month out (September 2012) forecasts from September 2011 Consensus Forecasts, and for 2013 and 2014 is based on the Consensus Forecasts October 2011 Long-term forecasts. The All Corporate Mid-Term Bond Spread is based on the August 15, 2011 to September 15, 2011 spread between the average actual 10-year Government of Canada bond yield and the average DEX Mid Term Corporate Bond Index - Yield inferred from the graph on www.pcbond.com.

Table 6

	Bridge	Test	
	2012	**2013**	**2014**
10-year Government of Canada %	2.75	3.30	4.30
All Corporate Mid-Term Bond Spread	1.43	1.43	1.43
CWIP Account Rate %	4.18	4.73	5.73

4.0 INCOME AND CAPITAL TAX RATES

Please refer to Exhibit C1, Tab 9, Schedule 1 for the historical and forecast tax rates.

5.0 LABOUR ESCALATION RATES

Appendix A of Exhibit A, Tab 13, Schedule 1 provides the labour rate escalation assumptions for Hydro One Transmission’s three compensation categories: the Society of

Energy Professionals ("Society"), the Power Workers Union ("PWU") and Management Compensation Plan ("MCP") staff.

For Management Compensation employees, escalation factors were provided by Hydro One senior management. Details regarding management compensation are provided in Exhibit C1, Tab 5, Schedule 2.

Escalation factors for PWU and Society staff reflect the current collective agreements, (PWU effective April 1, 2011 and Society effective March 31, 2013).

6.0 COST RATES FOR BENEFITS

Appendix A of Exhibit A, Tab 13, Schedule 1 provides the benefit cost rates or payroll burden assumptions incorporated in the 2012 Business Plan. These rates are applied to the forecast labour rates.

The "burden rate," expressed as a percentage, estimates employee current and future cost rates for benefits which are attributable to labour in the current period, and allocates such costs across Hydro One legal entities. The benefit costs include:

a) Other post-retirement benefits ("OPRB"), such as future health and dental costs;
b) Other post-employment benefits ("OPEB"), such as long-term disability;
c) Supplementary pension plan ("SPP");
d) Pension (funding) contributions;
e) Employee benefit costs during active employment; and
f) Statutory benefit payments, such as CPP, EI, etc.

Cost items (a) through (d) are actuarially determined by Hydro One Inc.'s external actuaries, Mercer Consulting Inc., using assumptions recommended by the actuaries and accepted by Hydro One Inc.'s management. Assumptions are determined with reference to past experience and industry norms.

Cost item (e) is based on estimates from Mercer, and from Hydro One Inc.'s insurance provider Great West Life, as anticipated escalation factors of health and dental costs. These estimates are compared to past experience.

Cost item (f) is based on government schedules of premium rates for CPP, EI, etc.

BUSINESS LOAD FORECAST AND METHODOLOGY

1.0 INTRODUCTION

This Exhibit discusses Hydro One Transmission system load forecast and the related methodology. The key load forecast supporting Hydro One Networks' Transmission rate case is the hourly demand load forecast by customer delivery point. This forecast is used to prepare the charge determinant forecast for the following rate categories: network pool, line connection pool, and transformation connection pool. The load forecast in support of this application was prepared in February, 2012 using economic and forecast information that was available in January, 2012.

Hydro One Transmission forecast of average 12-month peak load for 2013 and 2014 for Ontario as a whole and for its three rate categories are shown in Table 1 below. The impacts of conservation and demand management (CDM) and embedded generation (EG) are included.

Table 1
Hydro One's Load Forecast
(12-Month Average Peak in MW)

	Ontario Demand	Hydro One Rate Categories (Charge Determinants)		
		Network Connection	Line Connection	Transformation Connection
2013	20,319	20,023	19,406	16,759
2014	19,841	19,553	18,990	16,400

This Exhibit also addresses a directive from the Board's December 23, 2010 Decision on Hydro One Networks' Transmission Proceeding (EB-2010-0002) requiring Hydro One to work with the OPA in devising a robust, effective and accurate means of measuring the expected impacts of CDM programs promulgated by the OPA. Hydro One worked with the

OPA and used their latest CDM assumptions in preparing the load forecast in this rate application. A detailed report was prepared and is provided as Attachment 1 to this Exhibit and the summary results are discussed in Section 3.6.

2.0 A SUMMARY OF HYDRO ONE'S LOAD FORECAST METHODOLOGY AND ASSUMPTIONS

Hydro One Transmission uses a number of methods, such as econometric models, end-use models, customer forecast surveys and hourly load shape analyses to produce the forecasts required for its transmission business. This is the same load forecast methodology used and approved by the Board in previous Hydro One Networks' Transmission rate cases (EB-2006-0501, EB-2008-0272, and EB-2010-0002). All forecasts presented in this Exhibit are weather-normal, that is, abnormal weather effects are removed from the base year for load forecasting purposes so that the forecast assumes typical weather conditions based on the average of the last 31 years.

All forecasts produced are internally consistent. This means that the forecasts for all customer delivery points are calibrated to add up to the total for the entire customer base served by Hydro One Transmission's system.

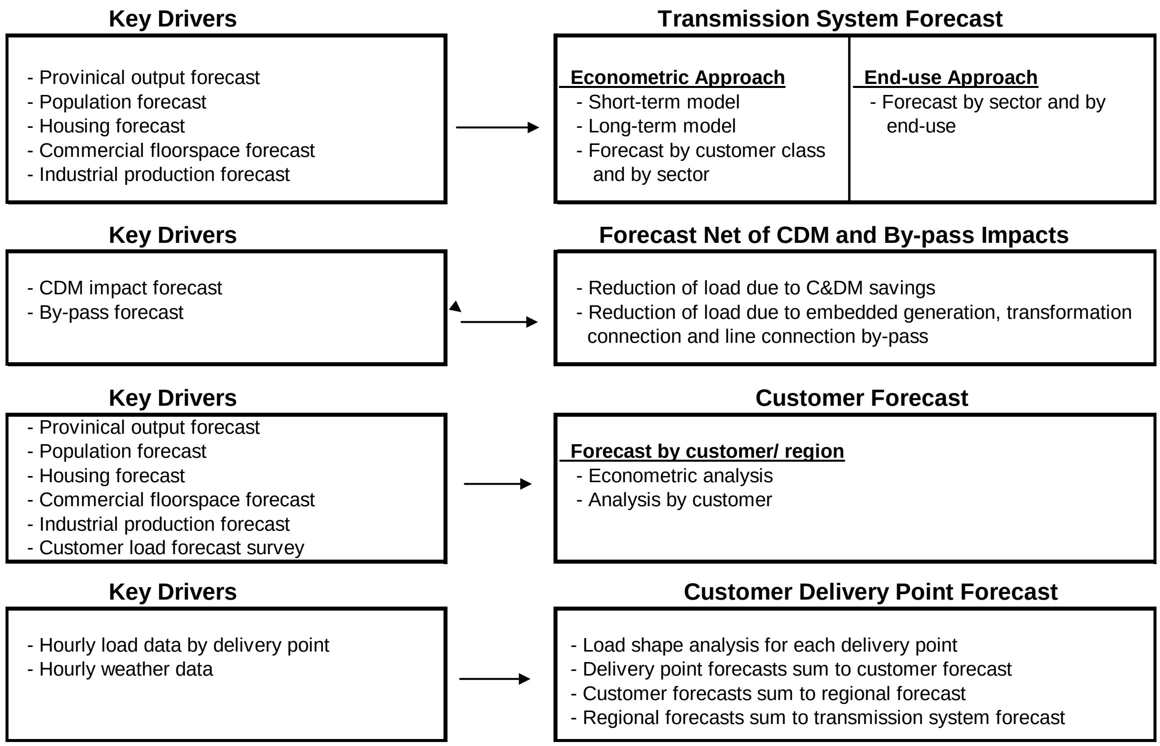
The forecasts presented in this Exhibit also are consistent with the economic assumptions used in the business planning process and described in Exhibit A, Tab 15, Schedule 1. Section 3 discusses in detail, the various economic inputs taken into consideration when applying the methodology for deriving the load forecasts. Hydro One Transmission's forecasting methodology comprises a combination of elements that include consensus input, updates to changes in economic forecasts, energy prices, population and household trends, industrial development and production, residential and commercial building activities, and efficiency improvement standards. Economic inputs are based on analyses prepared by major economic establishments in the country, such as HIS Global Insight, the Conference Board of Canada, the Centre for Spatial Economics and the University of Toronto. Efficiency standard assumptions used in the end-use models are based on discussions with the OPA staff. Specific customer development is based on forecast survey results from major customers. Inputs from these entities form the economic database (referred to henceforth as the economic forecast) that is used to establish Hydro One Transmission's load forecast.

3.0 KEY ASSUMPTIONS THAT INFLUENCE HYDRO ONE NETWORKS' LOAD FORECASTS

This Section discusses some of the key assumptions that must be taken into account in the process of developing load forecasts and in the application of forecasting methodologies. T he elements of the forecasting process used by Hydro One Transmission are for the most part based on the knowledge of how the major economic drivers that affect the usage of electricity demand are likely to evolve over the forecast period of 2013 and 2014. Consequently for the purpose of this Application, the focus is on the short term and the load forecast will reflect those impacts that are likely to have a major effect in this respect. The key assumptions used in the analysis are summarized in Figure 1 below.

Figure 1

Key Assumptions Used in the Forecast



Key information used in the analysis includes Ontario GDP, provincial demographic, industrial production and commercial floor space forecasts and regional analysis included in the economic forecast. Also taken into consideration are the provincial CDM plans and by-pass risks, which have a direct impact on Networks' system energy demands.

3.1 Provincial GDP Forecast

The provincial GDP forecast is a key driver for the load forecast. The high Canadian dollar and the recent recession had an adverse impact on the provincial manufacturing sector. Industries that were negatively affected in recent years include the pulp and paper, chemical and auto-related industries. Rising oil prices, slow recovery of the U.S. economy and the financial crisis in the European Union also contributed negatively to

Ontario growth. The provincial GDP declined by 3.8 percent in 2009, followed by 3.0 percent growth in 2010 and 2.0 percent growth in 2011. Based on the consensus forecast, the Ontario GDP is expected to grow by 1.8 percent in 2012, 2.4 percent in 2013 and 2.7 percent in 2014 as the economy recovers. Appendix E is attached and provides the details of the consensus forecast for Ontario GDP.

3.2 Provincial Population Forecast

The Ontario population grew 1.0 percent in 2009, 1.1 percent in 2010, and 1.2 percent in 2011. Population growth in Ontario is forecast to grow at about the same pace as the nation in the forecast period. The economic forecast indicates that the Ontario population is expected to grow at about 1.0 percent per year between 2012 and 2014. Steady population growth contributes positively to the load forecast.

3.3 Provincial Housing Forecast

Housing starts slowed down in 2009 due to the recession. Helped by population growth and low interest rates, housing demand in Ontario rebounded during the past two years. Housing starts statistics showed growth of 50,000 houses in 2009, 61,000 in 2010 and 69,000 in 2011. The consensus forecast calls for 63,000 housing starts in 2012, 64,000 in 2013, and 70,000 in 2014. Appendix E is attached and provides the details of the consensus forecast for Ontario housing starts.

3.4 Commercial Floor Space Forecast

With the help of low interest rates, commercial construction activities remained relatively strong in Ontario, averaged about 1.3 percent per year between 2008 and 2011. The economic forecast shows commercial floor space growth of about 0.6 percent in 2012, 1.0 percent in 2013, and 1.3 percent in 2014. The forecast for commercial floor space additions is an important contributor to the commercial sector load forecast.

3.5 Industrial Production Forecast

The manufacturing sector in Ontario experienced a substantial decline (almost 30 percent) between the years 2006 to 2009, primarily due to the impact of higher Canadian exchange rate and economic downturn. Industries that were hit hardest included transportation equipment, mining, primary metals and forestry products. The industrial production declined by 15.8 percent in 2009, and rebounded by 8.7 percent in 2010 and 7.0 percent in 2011. The economic forecast calls for a continuation of growth of 6.0 percent in 2012, 4.2 percent 2013 and 4.6 percent growth in 2014. The industrial production forecast is an important contributor to the industrial sector load forecast but it is also prone to economic cycles.

3.6 Conservation and Demand Management Forecast

The Board in its Decision with Reasons released on December 23, 2010 for Hydro One Networks' Transmission rate application (EB-2010-0002) directed Hydro One to:

> "Work with the OPA in devising a robust, effective and accurate means of measuring the expected impacts of CDM programs promulgated by the OPA. It is important that the terms of reference for the development of this methodology should, to the extent possible, be devised with input from and consultation with a sufficiently broad range of stakeholders so as to ensure that the resulting product has credibility within the sector." [1]

[1] EB-2010-0002 Decision with Reasons, December 23, 2010, pg. 6 and 7

During the consultation process in February 2011, stakeholders made the following recommendations:

- A third party study on CDM impacts was not required. Stakeholders determined that an internal study by Hydro One would be appropriate.
- Hydro One should undertake a review of utilities/entities in other jurisdictions to determine what categories are incorporated into their load forecasts. A review of British Columbia, New York and California was requested.
- CDM categories should be chosen so that they are comprehensive and can be tracked.
- Hydro One should work closely with the OPA to better define and measure CDM impacts for use in its load forecast and rate applications submitted to the OEB.
- In its next transmission rate application, Hydro One should provide detailed documentation on how the province-wide CDM impacts, provided by the OPA, are used to derive CDM deductions by charge determinant.

Hydro One worked with stakeholders and listened to and addressed their concerns. The study undertook by Hydro One Networks was completed and is provided as Attachment 1 of this Exhibit. The study focuses on 2 objectives:

1. Propose a methodology to incorporate CDM impacts into the load forecast; and
2. Work with the OPA to derive CDM impacts for use by Hydro One in this rate application.

To satisfy these objectives, Hydro One completed the following activities:

- A literature review of utilities in other jurisdictions to better understand the CDM categories incorporated into their load forecast.
- A web-based survey to confirm the findings of the literature review. Hydro One received responses from 41 organizations.
- A comparative analysis of 3 approaches commonly used by electric utilities in North American to incorporate CDM impacts into the load forecast.

Hydro One worked with the OPA and obtained their current CDM forecast for use in this rate application. The following CDM categories are incorporated in Hydro One's transmission load forecast:

- Programs (those initiated by the OPA and Other Influences)
- Codes and Standards
- Pricing

The OPA provided Hydro One with province-wide annual energy and peak savings by sector, by resource type (Demand Response, Energy Efficiency, and Customer-Based Generation), and by three policy instruments (CDM categories) including Programs, Codes and Standards, and Pricing. Details of the information provided by the OPA and the methodology used by Hydro One to derive the CDM impacts for the 3 c harge determinants are documented in Attachment 1 of this Exhibit.

Table 2 summarizes the CDM peak impacts assumed in Hydro One Transmission's system load forecast for 2006 to 2015. These CDM peak impacts are consistent with the Long-Term Energy Plan (LTEP) released by the Ontario Government in November 2010 with a provincial target of achieving peak savings of 4,550 MW by 2015 and 7,100 MW by 2030.

Table 2
Load Impact of CDM on Ontario Demand (MW)

Year	Cumulative CDM Impact on Peak Demand *	Cumulative CDM Impact on 12-month Average Peak Demand **
2006	608	396
2007	1490	982
2008	1583	1051
2009	1650	1115
2010	1751	1196
2011	2351	1605
2012	2749	1890
2013	3292	2147
2014	4186	2899
2015	4590	3223

* The figures represent the load impact of CDM on summer peaks.
** The figures represent the load impact of CDM on monthly peaks, averaged over 12 months in the year.

3.7 By-Pass Forecast

Hydro One Transmission collects its transmission revenue through four types of Board-approved transmission charges (networks, line connection, transformation connection, and wholesale meter) for customers using its transmission system. When Hydro One Transmission's customers get power from their own embedded generation (instead of buying power through the IESO controlled transmission system) or building their own transformation station or line connections to their distribution system, Hydro One Transmission loses transmission revenue. The following summarizes the by-pass forecast assumptions used in the test years:

Embedded Generation By-pass

A total of 346 MW of embedded generation were assumed to be in place in 2011. An additional 121 MW in 2012, 71 MW in 2013, and 31 MW in 2014 of new embedded generation were assumed in the load forecast, which reflects renewable energy projects initiated by the OPA.

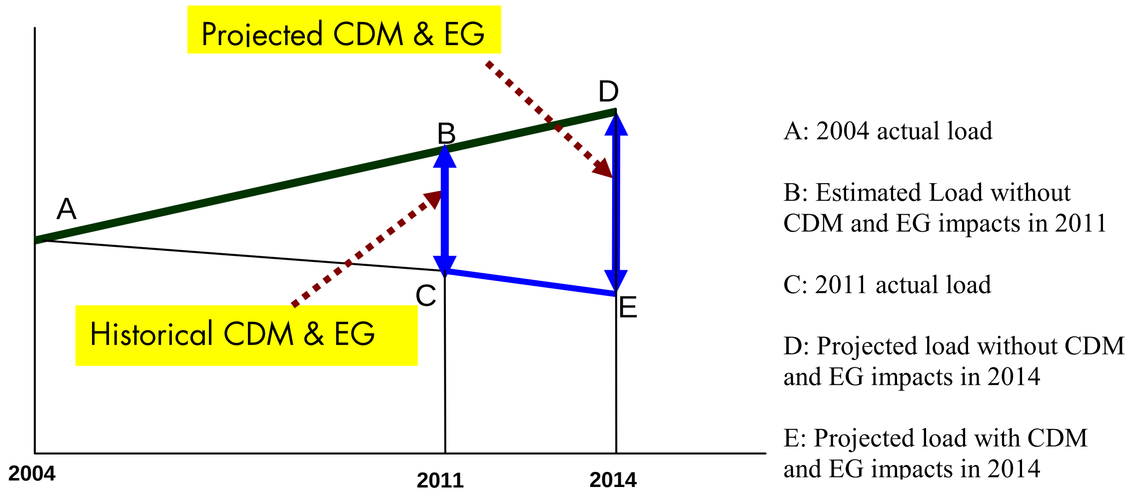
Transformation and Line Connection By-pass

No transformation and line connection by-pass is assumed in the load forecast in this rate application.

4.0 LOAD FORECASTING METHODOLOGY

Hydro One Transmission's system load forecast is developed using both econometric and end-use approaches. The forecast base year is corrected for abnormal weather conditions and the forecast growth rates are applied to the normalized base year value. The load impacts of CDM and EG are added back to the historical values during the modeling process (see Figure 2 below).

Figure 2
Incorporation of CDM and EG in the Load Forecast



Section 4.1 addresses Hydro One Transmission's weather correction process. Section 4.2 describes Hydro One Transmission's load forecast methodologies. The derivation of each of the Customer Forecast and the Customer Delivery Point Forecast is then addressed in Sections 4.3 and 4.4, respectively.

4.1 Weather Correction Analysis

Weather correction analysis removes the abnormal or extreme weather effects from the load data to yield average conditions that reflect the more normal or expected weather that is used in the forecast. This is essential because the volatility of abnormal or extreme weather conditions would likely adversely impact the provision of a consistent and meaningful forecast for load growth. H ourly load data and hourly weather data of various weather stations across the province are used in the analysis.

4.1.1 Hydro One Networks' Weather Correction Methodology

This section discusses the weather correction methodology used by Hydro One Transmission. Hydro One Transmission's weather correction methodology was originally developed by the forecasting and meteorology staff of the former Ontario Hydro. This weather correction method was used to forecast the total system load since 1988 and for forecasting local electric utility load since 1994. The weather correction methodology used by Hydro One Transmission is a proven technique that has performed well in the past years. The same methodology was reviewed and approved by the Board in previous Hydro One Networks' Transmission rate cases (EB-2006-0501, EB-2008-0272, and EB-2010-0002).

Weather correction is a statistical process designed to remove the impact of abnormal or extreme weather conditions from historical load data. Normal weather data is defined to be data that is based on the average weather conditions experienced over the last 31 years. This methodology is consistent with the approach used by the IESO and the OPA. A weather-normal load forecast is a forecast of load assuming normal weather conditions with a weather-corrected base year.

Hydro One Transmission's weather correction methodology uses four years of daily load and weather data to establish a sound statistical relationship between weather and load at the applicable transformer station or delivery point used to supply customer demand. Weather variables used in the analysis include temperature, wind speed, cloud cover and humidity. The estimated weather effects are then aggregated up to the required time interval. Past experience shows that weather correction should best be done on a daily basis, rather than weekly, monthly or annual basis.

Daily weather correction is preferred because the timing of extreme temperatures combined with wind speed and humidity can have a substantial impact on load that would otherwise not be captured by averages over a longer period of time. In particular, when abnormal weather conditions continue for several days, the cumulative impact is much greater than any single day's impact.

The loads that are most impacted by changes in weather conditions are electric space heating and cooling in residential and commercial buildings. Across Ontario, the penetration rate of such loads varies widely, which means the weather sensitivity of load supplied from one transformer station or delivery point may differ quite significantly from that of load supplied from another transformer station or delivery point, even in the same climate zone. The climate in Ontario varies considerably from the Niagara Peninsula to Thunder Bay, so it is important to use data from the appropriate weather stations that are in close proximity to the transformer station or the customer delivery point when correcting for weather effects.

4.1.2 Weather Correction Practices in Other Jurisdictions

Hydro One Transmission completed a study on weather normalization practices by surveying over 50 utilities in North America in 2008. The study was submitted to the Board for review in the transmission rate case (EB-2008-0272). Major findings of the study are summarized below:

- Most utilities use long term weather data to calculate the weather normal conditions; about 75% of utilities are currently using 20 years or more for weather normalization.
- The most commonly used period for weather normalization is at least 30 years; no utilities use less than 10 years of weather data to do weather normalization.
- Weather normalization surveys undertaken by Edison Electric Institute, BC Hydro and ITRON show similar results as Hydro One Transmission's survey.
- Most utilities update their weather data set and weather normalization analysis on an annual basis.
- Very few utilities have changed their weather normalization practices in recent years in response to global warming or other reasons.
- The survey results were supportive of Hydro One Transmission's weather-normalization methodology, which is based on the use of 31 years of weather data to define normal weather conditions.

The above study confirms that the weather normalization methodology used by Hydro One Transmission is appropriate. In light of the increased volatility on peak in recent years, the energy to peak relationships are reviewed and updated on an on-going basis, and has been done for this application.

Figures 3 and 4 below present the maximum and minimum daily temperature since 1953 as a measure of peak-generating weather conditions during summer and winter respectively.

Figure 3. Toronto Pearson International Airport: Maximum of Average Daily Temperature

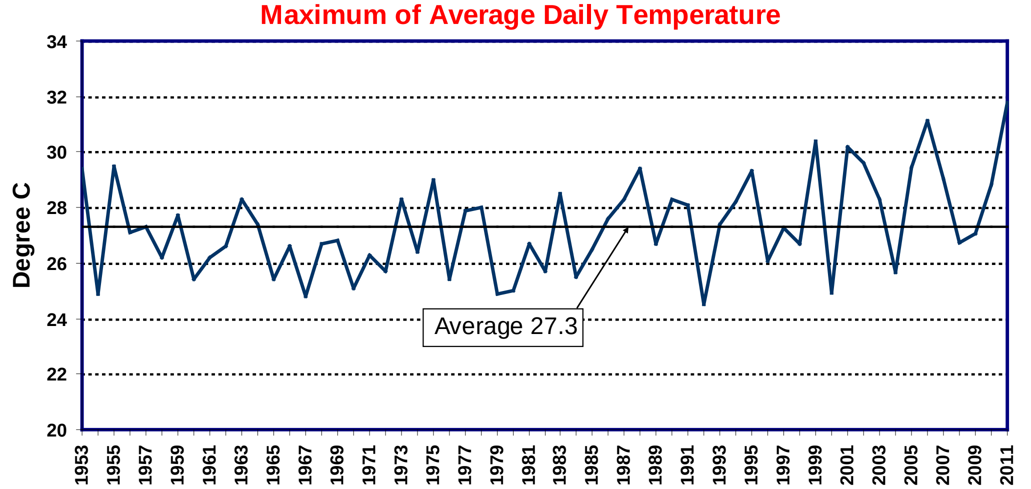
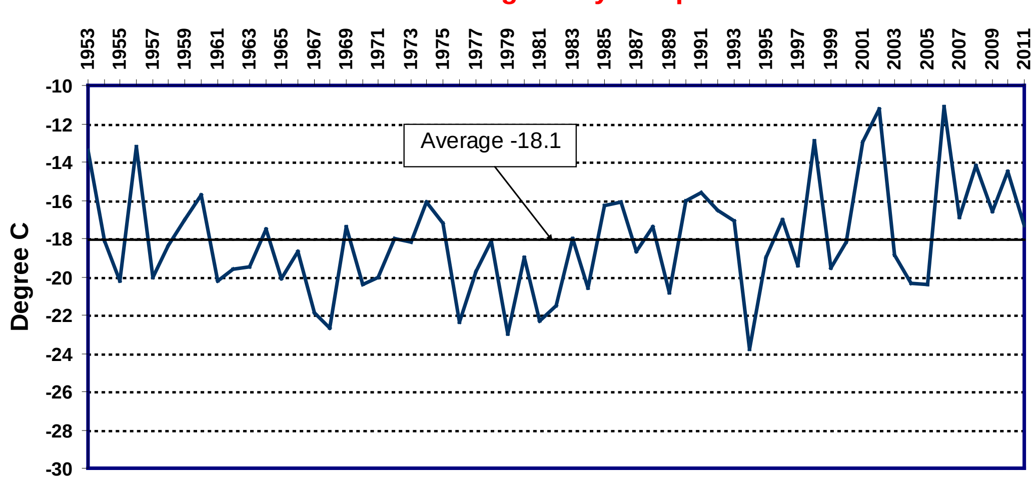


Figure 4: Toronto Pearson International Airport: Minimum of Average Daily Temperature



4.2 Hydro One Transmission Forecasting Methodology

Hydro One Transmission uses econometric (top-down) and end-use (bottom-up) models to forecast the transmission system load. For the top-down approach, both monthly and annual econometric models are used. For the bottom-up approach, end-use models are used to analyse the transmission system load by sector (i.e. residential. commercial and industrial customers). Key information used in the analysis includes economic, demographic, industrial production and commercial floorspace forecast provided in the economic forecast. The purpose of using both the econometric and end-use forecast models is to arrive at a balanced forecast that represents a consistent set when looked at from macro (econometric) and micro (end-use) perspectives. The forecasting methodology used here was reviewed and approved by the Board in previous Hydro One Networks' Transmission rate cases (EB-2006-0501, EB-2008-0272, and EB-2010-0002).

4.2.1 Monthly Econometric Model

The monthly econometric model uses a multivariate time series approach to develop the monthly forecast for the total transmission system load. The model links monthly energy consumption to Ontario GDP and residential building permits, taking into account the August, 2003 blackout. The load impacts of CDM and embedded generation are added back to the historical data set during the modelling process. The transmission system load used in the model is weather-normal, that is, corrected for abnormal weather effects. Appendix A is attached and provides the detailed regression equations and definitions.

4.2.2 Annual Econometric Model

The annual econometric models cover five sectors of the economy: residential, commercial, industrial, agriculture, and transportation. Appendix B is attached and provides the detailed regression equations and definitions.

The residential sector is modelled as a two-equation system for saturation and usage of electric equipment. Explanatory variables used include energy prices, personal disposable income per household and weather conditions as measured by heating degree days. As in monthly and end-use models, the load impact of CDM and embedded generation is added back to historical figures.

The commercial sector links energy usage to electricity price, commercial GDP and weather conditions as measured by heating and cooling degree days.

The industrial model consists of an equation for total energy and a two-equation model to determine shares of electricity usage. Total energy is modelled as a function of energy price and industrial GDP. Energy shares are linked to relative energy prices. Dummy variables are used to capture unusual changes in energy growth in the 70's and early 80's and to measure the impact of technical change on energy shares.

The agricultural sector is modelled in relation to electricity price and income, while accounting for cyclical and trend changes.

The transportation sector, which consists mainly of pipeline and road transport, is modelled by an equation relating electricity usage to income, electricity price, and a dummy variable to capture a change in load pattern since 1997.

4.2.3 End-Use Models

The end-use models cover the residential, commercial, industrial, agricultural and transportation sectors. As in the monthly and annual econometric models discussed above, the load impact of CDM and embedded generation is added back to historical figures. Appendix C is attached and provides details of the methodology used in the end-use analyses.

In the residential sector, the end-uses analysed include space heating, water heating, air conditioning, and base load. The forecast of each end-use is based on the number of households having that end-use and unit energy consumption of the equipment.

The commercial model analyses energy use by building type. Key drivers used in the analysis are the commercial sector floor space and the intensity of end-use demand per unit of floor space.

The industrial forecast is based on analysis for each major industrial segment, energy intensity and expected economic growth.

The agricultural and transportation sector models are based on base year electricity consumption and the expected growth rates for each sector and segment.

4.3 Methodology for Customer Forecast

This section discusses the load forecasting methodology used for deriving the customer forecast. Both econometric and customer analyses based on survey results from the customers, when available, are used in the forecast. This is supplemented by the economic data provided in the economic forecast.

In January 2012, Hydro One Transmission conducted a customer load forecast survey with customers having more than 5 MW of load. The survey also covered the station service load requirements of generating stations when they are not producing electricity. In addition to questions relating to the total load of the customer, information at each of the delivery points was also collected. The customer survey results are used in preparing the customer forecast.

In addition to the information contained in the customer survey, a number of forecasting techniques are used to prepare the load forecast by customer. For large utility customers, each customer is modeled individually using the econometric approach. The drivers used in these models include provincial economic variables such as Ontario GDP, population, number of household, energy prices, as well as local demographic and economic variables such as population and related industrial and commercial loads. Th e load impact of weather conditions is also taken into account. The best subset of the drivers is selected on the basis of regression criteria.

For industrial customers, several information sources are used to prepare the forecast. They include:

- historical load profile of the customer,
- knowledge of the customer through industry monitoring,
- forecast provided by customer through the survey,
- company information through Hydro One Transmission account executives, industry and company forecasts from industry associations and government agencies, and
- production and industry forecasts provided in the economic forecast.

4.4 Methodology for Customer Delivery Point Forecast

This section discusses the forecasting methodology for the customer delivery point forecast. Electricity Power Research Institute (EPRI)'s Hourly Electric Load Model (HELM) is used to normalize the hourly load for each of the transmission customer delivery points, removing abnormal weather effects and abnormal load patterns. Key information used in analyzing the load shape for each delivery point includes hourly load and weather data. The load growth for each delivery point is linked to the customer forecast discussed above. The forecasts for all customer delivery points are calibrated to add up to the regional and the total transmission system forecast.

The most updated customer totalization table is used to retrieve hourly peak electricity demand data for each of the customer delivery points connected to the transmission system. The totalization table reflects the latest records from Hydro One Transmission and the IESO. For each customer delivery point, at least one full year of hourly data is retrieved and checked for data quality. Hourly weather data is also retrieved to prepare weather sensitivity analysis. Weather data analyzed include temperature, wind speed, cloud cover and humidity. Data for five weather stations across Ontario are used in the analysis. They include Toronto, Windsor, Ottawa, North Bay and Thunder Bay. Each delivery point is linked to the closest weather station.

In preparing the database for the load shape analysis, missing values are estimated by load on a similar day and hour during the same month. For weather-sensitive load, local weather conditions are also taken into account in estimating the missing values

EPRI's HELM is used to prepare the hourly weather response analysis by each delivery point. The model takes into account differences in load depending upon time of use (that is weekdays, weekends and holidays) and weather conditions. Load of industrial customers is assumed to be insensitive to weather and as such are forecast in relation to load on a similar day and hour during the historical period. The customer forecast is used to drive the customer delivery point forecast. The resulting customer delivery point forecast is therefore consistent with the customer load forecast and the total transmission forecast as discussed above. The charge determinant forecasts at the delivery point level add up to the total charge determinant forecasts presented in Table 4 in the next section. The customer delivery point forecast uses the latest customer totalization table that shows which customers pay Network, Line Connection and Transformation Connection service to determine the charge determinant forecast for each transmission service tariff. The basis for determining the transmission charges applicable to each customer delivery point is further discussed in Exhibit H1, Tab 3, Schedule 1.

5.0 LOAD FORECAST FOR 2013 AND 2014

As described in the previous section, Hydro One Transmission's charge determinant forecast is derived from the Ontario peak demand forecast, which in turn was based on the econometric, end-use, and customer forecasts. Before deducting the load impact of CDM and embedded generation, the 12-month average charge determinant forecasts grow from 2011 in a manner consistent with the growth of the 12-month average peak for Ontario. Table 3 of this exhibit presents the forecast before and after deducting the load impacts attributed to embedded generation and CDM for the 2011-2014. The charge determinant forecast is based on the methodology approved by the OEB in its decisions for EB-2006-0501, EB-2008-0272 and EB-2010-0002. Appendix D is attached and provides the historical actual and weather-corrected charge determinant data for 2002-2011.

Before deducting for the load impacts of embedded generation and CDM, Hydro One Transmission is forecast to deliver an average of 22,696 MW in 2012 (12-month average peak), rising to 23,003 MW in 2013, and 23,309 MW in 2014.

After deducting the load impacts of embedded generation and CDM, Hydro One Transmission is forecast to deliver an average of 20,339 MW in 2012 (12-month average peak), lowering to 20,319 MW in 2013, and 19,841 MW in 2014.

The forecast is weather-normal and the actual load could be below or above the forecast depending on the weather conditions and/or a different economic growth pattern. Table 4 of this Exhibit presents the upper and lower bands of one standard deviation for the charge determinant forecast. Based on historical data, there is a two in three chance that the actual load in 2012, 2013, and 2014 will fall within the upper and lower bands. The bands are derived using Monte Carlo simulation technique relating variations in load to variations in Ontario GDP and weather.

Table 3
Load Forecast Before and After Embedded Generation and CDM
(12-Month Average Peak in MW)

		Charge Determinant		
Year	Ontario Demand (MW)	Network Connection (MW)	Line Connection (MW)	Transformation Connection (MW)
Load Forecast before Deducting Impacts of Embedded Generation and CDM				
2011	22,498	22,164	20,944	18,089
2012	22,696	22,359	21,128	18,248
2013	23,003	22,662	21,415	18,495
2014	23,309	22,963	21,699	18,741
Load Impact of Embedded Generation				
2011	346	337	10	10
2012	467	455	10	10
2013	538	524	10	10
2014	568	554	10	10
Load Impact of CDM				
2011	1,605	1,582	1,517	1,310
2012	1,890	1,862	1,760	1,520
2013	2,147	2,115	1,998	1,726
2014	2,899	2,856	2,699	2,331
Load Forecast after Deducting Embedded Generation and CDM				
2011 Actual	20,547	20,245	19,417	16,769
2012	20,339	20,042	19,359	16,718
2013	20,319	20,023	19,406	16,759
2014	19,841	19,553	18,990	16,400

Note. All figures are weather-normal.

Table 4
One Standard Deviation Uncertainty Bands for Hydro One Transmission's Charge Determinants (Using Current Rates) (MW)

Year	Lower Band	Forecast	Upper Band
Network Connection			
2011 (Actual)	20,245	20,245	20,245
2012	19,688	20,042	20,398
2013	19,556	20,023	20,491
2014	19,044	19,553	20,061
Line Connection			
2011 (Actual)	19,417	19,417	19,417
2012	19,017	19,359	19,702
2013	18,954	19,406	19,860
2014	18,497	18,990	19,484
Transformation Connection			
2011 (Actual)	16,769	16,769	16,769
2012	16,423	16,718	17,015
2013	16,368	16,759	17,151
2014	15,973	16,400	16,826

Note: All figures are weather-normal.

6.0 VARIABILITY OF HYDRO ONE'S LOAD FORECASTS

Hydro One Transmission's load forecasting team has significant expertise in preparing Provincial electricity demand forecasts as well as hourly load shape analysis. As part of the load research work associated with EB-2005-0317, Hydro One prepared the load shape analysis for over 80 LDCs in Ontario for use in their distribution rate applications to the Board. The performance of Hydro One Transmission's system load forecast, since Hydro One Transmission's separation from the former Ontario Hydro, has been fairly consistent as shown in Table 5 below.

Table 5
Comparison of Average Monthly Transmission Peak Demand Forecast with Actual
(Variance of forecast as percentage of actual on weather corrected basis)

Forecast made In Year	Forecast for current year	Forecast for 2nd Year	Forecast for 3rd Year
1999	-0.92%	-2.22%	-2.30%
2000	0.18%	0.26%	0.22%
2001	-0.14%	-0.29%	0.41%
2002	0.15%	0.36%	-0.14%
2003	0.25%	0.09%	0.83%
2004	0.08%	0.59%	0.89%
2005	0.17%	0.36%	0.97%
2006	-0.69%	0.41%	0.15%
2007	0.93%	0.18%	0.70%
2008	-0.38%	0.24%	0.24%.
2009	-0.23%	-0.88%	0.83%
2010	1.00%	0.32%	n.a.
2011	0.40%	n.a.	n.a.
Mean	0.00%	-0.05%	0.10%
One standard deviation (+/-)	1.77%	2.33%	2.60%

Note. The forecasts are net of the load impact of CDM and embedded generation and are compared to the weather corrected actual.

Between 1999 and 2011, the average variance of the transmission peak demand forecast compared to the weather corrected actual peak is well within one standard deviation of the forecast. One standard deviation means there is a one-in-three chance that the actual will be outside the plus or minus range (alternatively, there is a two-in-three chance that the actual will fall within the plus or minus range). The use of the one standard deviation as a measure of forecasting accuracy is an accepted standard in the utility industry.

Forecast accuracy for previous Board-approved forecasts of charge determinants are presented in Table 6 below. The figures reflect the percent deviation of forecast for each charge determinant over the forecast period compared to the historical actual on a weather corrected basis. The 2006-2008 forecasts were approved by the Board in EB-

2006-0501. Similarly, the 2008-2010 forecasts were approved in EB-2008-0272 and 2010-2012 in EB-2010-0002. Detailed comparison of forecasts for each forecast year separately is provided in the attached Appendix F and Tables 6a to 6c.

Table 6
Historical Board Approved Forecasts
vs. Historical Actual-Weather Corrected

	Difference from Actual-Weather Corrected (%) *			
Type of Connection	EB-2006-0501 Forecast	EB-2008-0272 Forecast	EB-2010-0002 Forecast	**Average**
Network	-0.49	-0.45	-0.03	**-0.33**
Line	-0.71	0.79	1.06	**0.38**
Transformation	-1.02	0.16	0.72	**-0.05**
Average	**-0.74**	**0.17**	**0.58**	**0.00**
One Standard Deviation (+/-) **	2.23	2.23	2.05	

* A negative (positive) variance shows that the forecast was below (above) actual.
** Reflects expected deviation of forecast from actual-weather corrected based on historical variations. For EB-2006-0501 and EB-2008-0272, 3-year standard deviation is shown, and for EB-2010-0002, 2-year standard deviation. All forecasts are within one standard deviation

As shown in Table 6, the deviations of previous Board-approved charge determinant forecasts from historical actuals on a weather-corrected basis are all within one standard deviation of errors, and the average deviation over the past 3 Board-approved forecasts (EB-2006-0501, EB-2008-0272 and EB-2010-0002) is close to zero.

APPENDIX A

MONTHLY ECONOMETRIC MODEL

The monthly econometric model uses the State-Space Approach in the regression equation, where the left-hand side of the equation represents the energy estimates, and the right-hand side contains the explanatory variables including the dummy variables that are used to capture special events that could affect the energy estimates because these events would likely cause variations in the load. The dummy variables are used to minimize the variability of the energy estimates around the forecast.

LWCTSE = f (LGDPONT, LBPONT, D0803)

where:

LWCTSE = logarithm of Networks' load,
- Based on hourly figures for Ontario Demand from IESO

LGDPONT = logarithm of Ontario GDP in chained 2002 dollars,
- History is based on quarterly figures in Ontario Economic Accounts published by Ontario Ministry of Finance
- Forecast is based on annual consensus forecast for Ontario GDP as presented in Appendix 5

LBPONT = logarithm of Ontario residential building permits in constant dollar,
- History is based on monthly value of Ontario residential building permits from Statistics Canada
- Forecast is based on consensus forecast of housing starts as presented in Appendix 5

D0803 = dummy variable for the August 2003 Blackout, equals 1 in that month and zero elsewhere.

The output parameters from the model are presented below. The State-Space (SS) estimated parameters are not associated with standard error and t-ratios (statistical relevance test).

State-Seasonal Factors	Space (SS) parameters:
A[1]	0.143643
K[1]	-0.51614
Non-Seasonal Factors SS	parameters:
A[1]	0.609212

K[1]	-0.25137
GDPONT	0.200174
BPONT[-9]	0.002432
D0803	-0.00505

R-squared = 0.996, R-squared corrected for mean = 0.996, Durbin-Watson Statistics = 2.3

The goodness of fit, or the extent to which variability in the energy estimates is captured in the forecast, is measured in terms of R-squared (adjusted for mean), which in this case is close to 1. This result reflects statistical significance of the explanatory variables that are used to explain for the variations in load. The regression results show that the fit is very good and there is confidence that the forecast will produce outcomes that are within the expected range of variability.

Using the forecast values for GDP, building permits and dummy variables, the above parameters are used in the monthly regression equation described above to generate the forecast for the transmission system load.

APPENDIX B

ANNUAL ECONOMETRIC MODEL

Residential Model

Residential sector equations consist of a saturation equation and a use equation. Saturation at year t is measured as sum of penetration of household equipment i at year t, Ei (t) – which is measured as the percentage of households using that equipment - multiplied by the annual electricity usage of equipment i in 2009 (Ui); normalized to be 1 in 2009:

Saturation (t) = (Σ Ei (t) * Ui) / (Σ Ei (2009) * Ui)

Usage at year t is measured as the ratio of per capita residential consumption to saturation in that year, again normalized to be 1 in 2009.

Usage (t) = [(per capita consumption (t))/ Saturation (t)] /
[per capita consumption (2009) / Saturation (2009)]

Ontario residential electricity consumption can then be calculated as:

Total residential electricity consumption = Saturation (t) * Usage (t) * N(t)
where N(t) is a normalizing factor to account for the number of households in Ontario.

Saturation is modelled as a function of energy prices, income per household in Ontario, lagged value of saturation and a dummy variable:

LELSAT = C(1)*(LPELRES+LPELRES(-1))/2+C(2)*LPLIQRES+C(3)*LYPDPHH +
C(4)*LELSAT (-1) +C(5)*LELSAT(-2)+ C(6)* D81

LELUSE = C(7)*(LPELRES+LPELRES(-1))/2+C(8)*LPLIQRES(-1)
+C(9)* LYPDPHH+C(10)*LHDD+(1+C(11)+C(12))*LELUSE(-1)+C(11)*LELSAT
+C(12)*LELSAT(-1)-C(10)*(1+C(11)+C(12))*LHDD(-1)

where:

LELSAT = logarithm of residential electricity saturation in Ontario,

- History is constructed from residential load, number of households and Survey of Household Spending by Statistics Canada, and associated load impact of CDM

LPELRES = logarithm of electricity price in Ontario residential sector,

- History is from Statistics Canada
- Forecast is prepared by Hydro One Networks

LPLIQRES = logarithm of liquid-fuel price in Ontario residential sector,

- History is from Statistics Canada
- Forecast is prepared by Hydro One Networks

LYPDPHH = logarithm of Ontario personal disposable income per household in constant $,

- Disposable income history is based on quarterly figures in Ontario Economic Accounts published by Ontario Ministry of Finance and Ontario population history is from Statistics Canada, deflated by CPI from Statistics Canada
- Forecast is based on forecasts of disposable income from C4SE, CPI from IHS Global Insight, and population from IHS Global Insight and C4SE

D81 = dummy variable to account for an outlier, equals 1 in 1981, 0 elsewhere,

LELUSE = logarithm of residential electricity usage in Ontario,

- History is constructed from residential load, number of households and Survey of Household Spending by Statistics Canada, and associated load impact of CDM

LHDD = logarithm of heating-degree-days for Pearson International Airport,

- History is from Environment Canada
- Forecast is 31-year average of historical annual HDD figures

c(1) to c(12) = variable coefficients.

The equations are estimated simultaneously using 3-Stage Least Squares, as presented below:

	Coefficient	Std. Error	t-Statistic	Prob.
C(1)	-0.068596	0.018379	-3.732221	0.0004
C(2)	0.017043	0.01751	0.973326	0.3334
C(3)	0.141638	0.053274	2.658668	0.0095
C(4)	0.633129	0.131626	4.810065	0
C(5)	0.24768	0.122048	2.029365	0.0458
C(6)	-0.028004	0.02121	-1.320328	0.1906
C(7)	-0.065427	0.010839	-6.036476	0
C(8)	0.016343	0.016619	0.983408	0.3284
C(9)	0.251848	0.059564	4.228194	0.0001
C(10)	0.153808	0.044284	3.47324	0.0008
C(11)	-1.658548	0.194524	-8.526173	0
C(12)	1.464042	0.187857	7.793376	0

Saturation Model Fit:

R-squared =0.966, Adjusted R-squared = 0.961, Durbin-Watson Statistics =2.16

Usage Model Fit:
R-squared =0.844, Adjusted R-squared = 0.824, Durbin-Watson Statistics =2.05

The regression results show the goodness of fit of the above model, as measured by (Adjusted) R-square, is good. The t-ratios also show that most of the factors used to explain the variations in load are statistically significant. Using the forecast values for personal disposable income, energy prices, heating degree days and dummy variables, the above parameters are used in the annual regression equation to generate the forecast for the residential load.

<u>Commercial Model</u>

The commercial model uses price of electricity, commercial GDP and, cooling and heating degree days to forecast the commercial load. The commercial model can be represented by the following equation:

LELCOM = C(1) +C(2)*(0.1*LPELCOM+0.2*LPELCOM(-1)+0.3
*LPELCOM(-2)+0.4*LPELCOM(-3))+C(3)*(0.1*LGDPCOM+0.2
*LGDPCOM(-1)+0.3*LGDPCOM(-2)+0.4*LGDPCOM(-3))+(1
-C(3))*LELCOM(-1) +C(4)*LCDD+C(5)*LHDD-(1-C(3))*(C(4)
*LCDD(-1)+C(5)*LHDD(-1))

where
LELCOM = logarithm of electricity consumption in Ontario commercial sector,
- History is based on commercial load from Statistics Canada, and associated load impact of CDM

LPELCOM = logarithm of price of electricity in the commercial sector,
- History is from Statistics Canada
- Forecast is prepared by Hydro One Networks

LPGDPCOM = logarithm of Ontario commercial GDP in 2002 $,
- History is from Statistics Canada figures for GDP by industry
- Forecast is prepared by Hydro One Networks in a manner consistent with consensus forecast as presented in Appendix 5

LHDD = logarithm of heating-degree-days for Pearson International Airport,
- History is from Environment Canada.
- Forecast is 31-year average of historical annual HDD figures

LCDD = logarithm of cooling-degree-days for Pearson International Airport.
- History is from Environment Canada
- Forecast is 31-year average of historical annual CDD figures

The estimated equation is presented as follows:

	Coefficient	Std. Error	t-Statistic	Prob.
C(1)	0.461302	0.343702	1.342157	0.1871
C(2)	-0.068961	0.022	-3.134549	0.0032
C(3)	0.108982	0.039957	2.7275	0.0094
C(4)	0.032668	0.009466	3.450957	0.0013
C(5)	0.12367	0.059711	2.071138	0.0448

R-squared =0.998, Adjusted R-squared = 0.998, Durbin-Watson Statistics =1.26

The regression results reflect a high goodness fit and statistical significance for most estimates.

<u>Industrial Model</u>

The industrial load is modelled as one source of energy in the industrial sector of Ontario economy. The model consists of an equation for total energy and a 2-equation model to determine share of electricity usage out of the total energy.

The total energy model is represented by the following equation:

LENIND=C(1)+C(2)*LGDPIND+C(3)*LGDPIND(-1)
+C(4)*LOG(ENIND(-1))+C(5)*(LOG(PENIND)+LOG(PENIND(-1)))/2

where
LENIND = logarithm of electricity consumption in Ontario industrial sector,
- History is based on energy series from Statistics Canada, and associated load impact of CDM

PENIND = logarithm of price of energy in the industrial sector, defined as the weighted average of price of electricity, liquid fuel and coal in that sector,
- History is from Statistics Canada
- Forecast is prepared by Hydro One Networks

LGDPIND = logarithm of Ontario industrial GDP in 2002 $.
- History is from Statistics Canada figures for GDP by industry
- Forecast is prepared by Hydro One Networks in a manner consistent with consensus forecast as presented in Appendix 5

The estimated model is presented below:

	Coefficient	Std. Error	t-Statistic	Prob.

C(1)	0.815718	0.711877	1.14587	0.2585
C(2)	0.683102	0.102942	6.635768	0
C(3)	-0.659219	0.105878	-6.226217	0
C(4)	0.93447	0.063546	14.70551	0
C(5)	-0.029976	0.033986	-0.882015	0.3829

R-squared =0.865, Adjusted R-squared = 0.852, Durbin-Watson Statistics =2.23

The regression results show a strong correlation between energy consumption and explanatory variables noted above, despite higher variability in the industrial sector compared to the residential and commercial sectors in Ontario.

The equations for determining the share of electricity in total energy (LW13 and LW23) are presented below:

LW13=C(1)-(W2S*C(12)+(W1S+W3S)*C(13))*LP13+(C(12)
-C(23))*W2S*LP23+C(5)*LT+[AR(1)=C(60)]

LW23=C(2)-(W1S*C(12)+(W2S+W3S)*C(23))*LP23+(C(12)
-C(13))*W1S*LP13+C(6)*LT+C(7)*DG+[AR(1)=C(60)]

where
LW13 = logarithm of electricity cost relative to coal in Ontario industrial sector,
LW23 = logarithm of liquid-fuel cost relative to coal in Ontario industrial sector,
W1, W2, W3 = quantity share of electricity, liquid fuel and coal in total energy in Ontario, respectively,
- History of all cost shares are based on energy series and associated energy prices from Statistics Canada

LP12 = logarithm of price of electricity relative to liquid fuel in Ontario industrial sector,
LP23 = logarithm of price of liquid fuel relative to coal in Ontario industrial sector,
LP13 = logarithm of price of electricity relative to coal in Ontario industrial sector,
- History for all price series is from Statistics Canada
- Forecast is prepared by Hydro One Networks

DG = dummy variable to account for abnormal changes in energy growth between 1969 and 1982, equals 0.5 in 1969 to 1970, 1 in 1971 to 1982, and 0 elsewhere,
LT = logarithm of a trend variable equals 1 in 1963, increasing by 1 each year thereafter. This would pick up impact of technical change on energy shares apart from movements in relative energy prices.

The equations are estimated using the Seemingly Unrelated Equations (SUR) method. The estimated model is presented as follows:

	Coefficient	Std. Error	t-Statistic	Prob.
C(1)	-2.013222	0.12287	-16.38499	0
C(12)	-0.988795	0.075507	-13.09547	0
C(13)	-1.301881	0.086246	-15.09505	0
C(23)	-0.71395	0.094628	-7.544824	0
C(5)	0.520585	0.030058	17.31958	0
C(60)	0.515553	0.070744	7.287599	0
C(2)	-0.692699	0.125964	-5.499208	0
C(6)	0.430056	0.032187	13.36126	0
C(7)	0.22003	0.036939	5.956638	0

LW13 Model Fit:

R-squared =0.990, Adjusted R-squared = 0.989, Durbin-Watson Statistics =2.12

LW23 Model Fit:

R-squared =0.987, Adjusted R-squared = 0.985, Durbin-Watson Statistics =1.70

The regression results show the model has a good fit with historical values and all the model parameters are statistically significant.

<u>Agricultural Model</u>

The agricultural electricity consumption is affected by income, electricity prices as well as trend and cyclical variations. The agricultural electricity model therefore includes trend and moving average terms in addition to income and price variables, as follows:

ELAGR = C(1)+C(2)*D(LYPD(-1))+C(3)*D(RPELRES(-1))+C(4)*TREND
+C(5)*LELAGR(-2) +C(6)*D08+MA(4)

where
ELAGR = electricity consumption in Ontario agricultural sector,

- History is based on commercial load from Statistics Canada, and associated load impact of CDM.

YPD = logarithm of Ontario personal disposable income in 2002 $,

- History is based on quarterly figures in Ontario Economic Accounts published by Ontario Ministry of Finance History, deflated by CPI from Statistics Canada
- Forecast is based on forecasts of disposable income from C4SE, and CPI from IHS Global Insight

RPELRES = electricity price in Ontario residential sector divided by liquid-fuel price in Ontario residential sector,

- History is from Statistics Canada
- Forecast is prepared by Hydro One Networks

TREND = a trend variable, equals 1 in 1961 and increase by 1 per year thereafter,
D08 = dummy variable to account for an outlier, equals 1 in 2008, 0 elsewhere,
MA(4) = a moving average error term of order 4.

Variable	Coefficient	Std. Error	t-Statistic	Prob.
C	2396.939	1351.553	1.773471	0.0979
D(YPD(-1))	0.005514	0.009117	0.604827	0.555
D(RPELRES(-1))	-11.26598	82.52296	-0.136519	0.8934
TREND	-29.1885	17.92446	-1.628417	0.1257
ELAGR(-2)	0.476259	0.269808	1.76518	0.0993
D08	470.6368	80.00627	5.882499	0
MA(4)	-0.990019	4.80E-06	-206107.3	0

R-squared =0.927, Adjusted R-squared = 0.896, Durbin-Watson Statistics =1.31

The regression results show the model captures most of the variations in the agricultural load in Ontario despite a great volatility in the data series. Not all the model parameters are statistically significant due to correlation between the variables included in the model. However, the inclusion of all the variables was warranted due to theoretical considerations.

<u>Transportation Model</u>

The transportation model is represented by an equation basically relating electricity usage to income and price variables.

LTRANS=C(1)+C(2)*LYPDPHH+C(3)*(LPELRES+LPELRES(-1)
+LPELRES(-2)+LPELRES(-3))/4+C(4)*D98ON(-1)

where
LTRANS = logarithm of electricity consumption in Ontario transportation sector,

- History is based on agricultural load from Statistics Canada, and associated load impact of CDM

LPELRES = logarithm of electricity price in Ontario residential sector,

- History is from Statistics Canada
- Forecast is prepared by Hydro One Networks

LYPDPHH = logarithm of Ontario personal disposable income per household in 2002 $,

- Disposable income history is based on quarterly figures in Ontario Economic Accounts published by Ontario Ministry of Finance and Ontario population history is from Statistics Canada, deflated by CPI from Statistics Canada
- Forecast is based on forecasts of disposable income from C4SE, CPI from IHS Global Insight, and population from IHS Global Insight and C4SE

D98ON = a dummy variable to capture change in load pattern since 1998, equals zero prior to 1998 and 1 elsewhere.

	Coefficient	Std. Error	t-Statistic	Prob.
C(1)	0.488323	4.402512	0.110919	0.9126
C(2)	1.090338	0.800534	1.362014	0.1853
C(3)	0.125946	0.186804	0.674214	0.5064
C(4)	0.23707	0.082858	2.861167	0.0084

R-squared =0.688, Adjusted R-squared = 0.650, Durbin-Watson Statistics =1.50

The model fit is not as good as that in other sectors described above given extreme volatility in the transportation electricity consumption in Ontario. However, transportation load is less that 0.5 percent of Ontario electricity usage and, as such, its volatility does not significantly affect the forecast accuracy of total load.

APPENDIX C

END-USE MODEL

Residential Sector

The end-uses considered in the residential sector include space heating, water heating, air conditioning and base load (lighting and appliances). The forecast of each of the end-use is based on the following equation:

kWh = number of households * end-use share * end-use UEC

where:

- end-use share refers to the fraction of houses with the particular end-use considered,
- UEC (unit energy consumption) refers to the annual energy consumption of that end-use per household.

The following section describes each component of the equation in detail.

- The base-year number of households were taken from Ontario residential household information from Statistics Canada;
- The base year end-use shares (space heating, water heating and air conditioning) information and fuel switching (space/water heating) information are based on Statistics Canada residential appliance survey results;
- The trends for end-use shares and fuel switching over the forecasting period are based on historical time series from Statistics Canada residential appliance surveys;
- The base year end-use UEC's were estimated based on Statistics Canada Ontario residential electricity consumption data (CANSIM DATA) and Statistics Canada residential appliance survey results.

Commercial Sector

The commercial forecast for the total transmission system is developed using the COMMEND (Commercial end-use planning system). The model uses an end-use framework to provide estimates of energy use by building type. The 12 building types including office, elementary and secondary school, college and universities, health, public service, retail, grocery, accommodation, recreation, religious/cultural, warehouse, commercial miscellaneous. Non-building related segments, such as transportation, communication and utilities etc, were prepared outside the model using spreadsheet analysis. The forecast is the product of the commercial sector building floor space and the intensity of end-use demand per unit floor space.

Industrial Sector

Industrial sector analysis includes large industrial customers with monthly demand >5 MW and general service customers with demand <5 MW. The forecast is based on detailed analysis of each major industrial sub-sector. Various segments are considered in this analysis including abrasives, motor vehicle assembly, vehicle parts, nonmetallic minerals, electronic products, fabricated metal products, foods & beverage, glass, industrial chemicals, iron and steel, lime, smelting & mining, petroleum refining, pulp & paper, rubber & plastics, clothing & textiles, and miscellaneous manufacturing. The forecast for industrial customers is based on customer level data and the effect of the economy on their production prospects. Pattern in energy intensity are considered in relation to technological change.

Agricultural and Transportation Sectors

Transportation sector is comprised mainly of pipeline transport and road transport. The forecast for agricultural and transportation sectors is based on the following equation:

kWh = base year consumption * expected annual growth rates

For each component of this equation, data are gathered from:

- The base year consumption by segment is taken from the Statistics Canada;
- Expected annual growth rates are based on the economic forecast by sector and segment.

APPENDIX D

HISTORICAL ONTARIO DEMAND AND CHARGE DETERMINANT DATA

This Appendix provides the historical actual and weather corrected Ontario dem and and Hydro One charge determinants for 2002-2011.

Actual Ontario Demand and Hydro One Charge Determinants
(MW)

	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
2002												
Ontario Demand					20,068	23,578	25,226	25,414	25,062	21,216	21,862	23,334
Network Connection					19,991	23,336	25,295	24,803	24,547	20,880	21,376	22,730
Line Connection					19,182	22,104	24,081	23,462	23,081	20,149	20,139	21,361
Transformation Connection					16,397	19,162	21,030	20,415	19,993	17,288	17,264	18,591
2003												
Ontario Demand	24,158	23,469	23,117	21,010	18,741	24,753	23,175	23,891	20,700	20,408	21,584	22,798
Network Connection	23,620	22,903	22,694	20,813	18,700	24,427	23,151	23,758	19,668	20,528	20,950	21,960
Line Connection	21,925	21,550	21,125	19,714	18,196	22,958	22,005	22,178	19,401	18,721	19,930	20,826
Transformation Connection	19,156	18,838	18,351	16,813	15,273	19,921	19,140	19,328	16,487	15,976	17,153	18,231
2004												
Ontario Demand	24,937	22,608	21,634	19,911	20,327	23,163	23,976	23,159	21,911	19,829	22,066	24,979
Network Connection	24,166	21,860	20,990	19,448	20,034	22,752	22,304	22,687	21,435	19,454	21,055	24,299
Line Connection	22,297	20,643	20,014	18,770	19,241	21,611	20,890	21,361	20,388	18,868	19,963	22,337
Transformation Connection	19,795	18,091	17,211	16,110	16,344	18,573	18,060	18,481	17,472	15,992	17,068	19,570
2005												
Ontario Demand	24,362	22,322	22,724	19,343	19,007	26,157	26,160	25,816	23,914	20,752	22,564	23,766
Network Connection	23,713	21,684	22,075	18,899	18,739	25,520	25,447	25,023	23,305	20,611	22,072	23,000
Line Connection	22,237	20,712	20,581	18,424	18,328	24,163	24,123	23,507	21,807	19,937	20,672	21,651
Transformation Connection	19,351	17,846	17,818	15,466	15,314	20,806	20,945	20,311	18,747	17,008	17,800	18,854
2006												
Ontario Demand	23,052	22,321	21,772	19,582	24,857	23,349	26,092	27,005	19,976	19,590	21,267	22,941
Network Connection	22,083	21,562	21,028	19,073	24,272	22,491	25,405	26,292	19,692	19,372	20,726	22,343
Line Connection	20,821	20,727	19,900	18,415	22,909	21,519	24,198	24,732	19,214	18,919	19,666	20,870
Transformation Connection	18,017	17,964	17,170	15,649	19,748	18,337	20,911	21,371	16,285	15,999	16,822	18,098
2007												
Ontario Demand	23,537	23,935	22,969	20,016	21,490	25,737	24,561	25,584	24,046	19,233	21,814	22,935
Network Connection	22,766	23,278	22,406	19,614	21,020	24,926	23,864	24,951	23,277	18,909	21,539	22,220
Line Connection	21,370	21,872	21,126	19,181	20,358	23,572	23,126	23,620	22,239	19,197	20,466	21,190
Transformation Connection	18,550	19,078	18,291	16,205	17,203	20,433	20,040	20,638	19,253	16,464	17,720	18,567
2008												
Ontario Demand	22,782	23,054	20,990	19,512	18,650	24,195	23,787	22,707	22,975	19,366	21,279	22,541
Network Connection	22,112	22,227	20,395	19,114	18,260	23,502	23,302	22,182	22,502	19,183	20,740	22,169
Line Connection	21,148	21,065	19,719	18,564	17,836	22,514	22,414	21,218	21,255	18,390	19,574	20,940
Transformation Connection	18,500	18,472	17,093	15,912	15,057	19,316	19,368	18,269	18,263	15,717	16,953	18,418
2009												
Ontario Demand	22,983	22,110	21,466	18,744	17,560	22,540	20,011	24,380	19,731	18,420	19,710	21,921
Network Connection	22,414	21,446	21,194	18,461	17,647	22,053	20,089	23,705	19,343	18,011	19,413	21,146
Line Connection	21,084	20,175	20,262	17,799	17,170	20,795	19,042	22,244	18,520	17,249	18,160	19,968
Transformation Connection	18,568	17,898	17,701	15,481	14,705	18,166	16,687	19,622	16,182	15,118	16,009	17,856
2010												
Ontario Demand	22,045	21,367	19,393	17,398	22,904	21,527	25,075	24,917	24,444	17,704	19,970	22,114
Network Connection	21,656	20,845	18,931	17,360	22,162	21,181	24,903	24,227	24,108	17,640	19,477	21,868
Line Connection	20,381	19,594	18,280	17,049	21,143	20,338	23,589	22,945	22,527	17,174	18,607	20,312
Transformation Connection	18,106	17,268	15,747	14,533	18,394	17,698	20,736	19,991	19,601	14,732	15,969	17,841
2011												
Ontario Demand	22,733	21,871	20,667	17,945	20,870	22,765	25,450	22,051	21,552	18,234	19,673	20,204
Network Connection	21,844	21,184	20,115	17,737	20,647	22,661	25,395	21,831	21,398	18,104	19,450	19,964
Line Connection	20,629	19,927	19,023	17,396	19,764	21,620	24,252	21,411	20,551	17,569	18,576	19,331
Transformation Connection	18,115	17,394	16,433	14,811	16,858	18,582	21,077	18,454	17,671	15,006	16,057	16,827

Note. Charge determinant values are proxy numbers calculated based on actual data.

Weather Corrected Ontario Demand and Hydro One Charge Determinants
(MW)

	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
2002												
Ontario Demand					18,966	22,376	22,755	22,570	21,222	20,312	22,444	23,466
Network Connection					18,893	22,146	22,817	22,028	20,786	19,991	21,945	22,858
Line Connection					18,129	20,977	21,722	20,836	19,544	19,291	20,675	21,481
Transformation Connection					15,497	18,186	18,970	18,131	16,930	16,552	17,724	18,696
2003												
Ontario Demand	23,612	23,392	21,807	19,758	19,233	22,367	22,955	22,842	21,294	20,062	22,387	23,629
Network Connection	23,086	22,827	21,408	19,572	19,191	22,072	22,931	22,715	20,232	20,181	21,729	22,760
Line Connection	21,429	21,480	19,928	18,539	18,674	20,744	21,795	21,205	19,958	18,404	20,672	21,585
Transformation Connection	18,723	18,776	17,311	15,811	15,675	18,000	18,958	18,480	16,960	15,706	17,792	18,896
2004												
Ontario Demand	23,676	23,560	22,128	20,016	19,373	22,658	23,187	23,008	21,524	20,199	22,822	23,824
Network Connection	22,944	22,781	21,469	19,551	19,094	22,256	21,570	22,539	21,056	19,817	21,776	23,175
Line Connection	21,170	21,513	20,471	18,869	18,337	21,139	20,203	21,222	20,028	19,220	20,647	21,304
Transformation Connection	18,794	18,853	17,603	16,195	15,576	18,168	17,465	18,361	17,164	16,290	17,653	18,665
2005												
Ontario Demand	23,877	23,685	22,187	20,209	19,407	22,951	23,476	23,395	21,746	20,118	22,276	23,632
Network Connection	23,241	23,008	21,553	19,745	19,133	22,393	22,836	22,676	21,193	19,982	21,790	22,871
Line Connection	21,794	21,976	20,094	19,249	18,714	21,202	21,648	21,303	19,830	19,328	20,408	21,529
Transformation Connection	18,966	18,935	17,397	16,158	15,637	18,256	18,796	18,407	17,048	16,488	17,573	18,748
2006												
Ontario Demand	23,899	23,218	22,006	19,966	19,351	22,826	23,119	22,927	20,510	19,816	21,746	23,160
Network Connection	22,895	22,429	21,254	19,448	18,896	21,988	22,510	22,322	20,219	19,596	21,192	22,555
Line Connection	21,585	21,560	20,114	18,777	17,834	21,037	21,441	20,997	19,728	19,138	20,109	21,069
Transformation Connection	18,679	18,686	17,354	15,956	15,373	17,926	18,528	18,144	16,721	16,184	17,201	18,270
2007												
Ontario Demand	23,229	22,715	20,536	19,539	18,656	22,022	22,369	22,401	20,543	19,755	22,459	23,487
Network Connection	22,469	22,092	20,032	19,147	18,248	21,328	21,734	21,848	19,887	19,422	22,175	22,755
Line Connection	21,091	20,757	18,888	18,724	17,673	20,169	21,062	20,682	19,000	19,717	21,071	21,701
Transformation Connection	18,307	18,105	16,353	15,819	14,935	17,483	18,252	18,070	16,448	16,910	18,244	19,014
2008												
Ontario Demand	23,409	23,058	21,009	19,967	18,559	22,677	22,847	22,848	20,436	19,562	21,577	22,937
Network Connection	22,721	22,231	20,414	19,559	18,171	22,027	22,381	22,319	20,015	19,377	21,030	22,558
Line Connection	21,728	21,067	19,736	18,996	17,748	21,099	21,527	21,348	18,904	18,575	19,846	21,305
Transformation Connection	19,005	18,471	17,105	16,279	14,980	18,100	18,599	18,378	16,241	15,872	17,186	18,737
2009												
Ontario Demand	22,639	22,128	21,246	18,635	18,943	22,935	23,575	23,639	20,224	19,466	20,671	21,977
Network Connection	22,078	21,464	20,977	18,353	19,037	22,439	22,668	22,984	19,827	19,034	20,360	21,199
Line Connection	20,768	20,191	20,054	17,696	18,522	21,159	21,322	21,568	18,983	18,229	19,045	20,019
Transformation Connection	18,290	17,913	17,520	15,391	15,863	18,485	18,259	19,026	16,587	15,976	16,789	17,901
2010												
Ontario Demand	21,817	21,551	20,413	18,082	18,373	21,760	23,144	22,299	20,901	18,275	19,881	21,709
Network Connection	21,432	21,025	19,927	18,042	17,778	21,411	22,986	21,681	20,614	18,209	19,389	21,467
Line Connection	20,170	19,763	19,242	17,719	16,960	20,558	21,773	20,535	19,262	17,728	18,524	19,940
Transformation Connection	17,919	17,417	16,575	15,104	14,755	17,890	19,140	17,891	16,760	15,207	15,898	17,514
2011												
Ontario Demand	21,964	21,734	20,621	18,062	18,114	21,349	22,728	21,671	20,655	18,262	19,977	21,427
Network Connection	21,104	21,052	20,070	17,853	17,920	21,252	22,679	21,454	20,508	18,131	19,750	21,173
Line Connection	19,931	19,803	18,980	17,509	17,153	20,275	21,658	21,042	19,696	17,596	18,864	20,501
Transformation Connection	17,502	17,285	16,397	14,908	14,632	17,426	18,823	18,136	16,936	15,029	16,305	17,846

Note. Charge determinant values are proxy numbers calculated based on actual data.

APPENDIX E

CONSENSUS FORECAST FOR ONTARIO GDP AND HOUSING STARTS

This Appendix provides the consensus forecast details for Ontario GDP and Ontario housing starts undertaken by Hydro One in January, 2012 for 2012-2014.

Survey of Ontario GDP Forecast (annual growth rate in %)

	2012	2013	2014
Global Insight (Nov 2011)	1.7	2.6	2.7
Conference Board (Nov 2011)	2.2	3.3	2.7
U of T (Dec 2011)	1.5	2.9	3.2
C4SE (Jan 2012)	2.1	2.4	2.2
CIBC (Dec 2011)	1.9	2.0	
BMO (Dec 2011)	1.9	2.4	
RBC (Dec 2011)	2.3	2.3	
Scotia (Jan 2012)	1.6	2.1	
TD (Dec 2011)	1.9	2.3	
Desjardins (Dec 2011)	1.9	2.4	
Central 1 (Nov 2011)	1.8	2.6	
National Bank (Dec 2011)	1.5		
Laurentian Bank (Dec 2011)	1.4	1.6	
Average	**1.8**	**2.4**	**2.7**

Survey of Ontario Housing Starts Forecast (in 000's)

	2012	2013	2014
Global Insight (August 2011)	62.5	58.7	59.2
Conference Board (Nov 2011)	68.5	82.6	88.4
U of T (Oct 2011)	67.8	67.8	68.8
C4SE (Jan 2012)	59.4	66.3	62.0
CIBC WM (August 2011)	65.2	61.1	
BMO (Dec 2011)	64.0	65.0	
RBC (Dec 2011)	57.5	56.0	
Scotia (Jan 2012)	63.0	60.0	
TD (Dec 2011)	65.5	55.3	
Desjardins (Dec 2011)	62.0	65.0	
Central 1 (Nov 2011)	63.3	70.4	
National Bank (Dec 2011)	62.0		
Laurentian Bank (Dec 2011)	61.2	54.0	
Average	**63.2**	**63.5**	**69.6**

Updated January 9, 2012

APPENDIX F

FORECAST ACCURACY

Tables 6a to 6c present the forecast accuracy of the Board-approved forecasts of the 3 charge determinants on a weather-corrected basis for the past 3 rate applications (EB-2006-0501, EB-2008-0272, and EB-2010-0002).

All forecasts are weather-normal and compared with weather-corrected actuals. In all tables, a negative (positive) percent deviation indicates that the forecast was below (above) actual-weather corrected.

Table 6a
Historical Board Approved for Network Connection Forecast
vs. Historical Actual and Historical Actual-Weather Normalized

Year	12-Month Average in MW					Difference from Actual Weather Corrected (%)		
	EB-2006-0501 Forecast (1)	EB-2008-0272 Forecast (2)	EB-2010-0002 Forecast (3)	Actual: Weather Corrected	Actual	EB-2006-0501 Forecast	EB-2008-0272 Forecast	EB-2010-0002 Forecast
2005	21,704			21,702	22,507	0.01		
2006	21,259			21,275	22,028	-0.08		
2007	20,827	20,928		20,928	22,398	-0.48	0.00	
2008	20,872	20,943		21,067	21,307	-0.92	-0.59	
2009		20,842	20,868	20,868	20,410		-0.13	0.00
2010		20,199	20,414	20,330	21,196		-0.64	0.41
2011			20,150	20,245	20,861			-0.47
Average Excluding First Year (Actual) (4)						-0.49	-0.45	-0.03

(1) EB-2006-0501; Ex A; T14; S3; P 19 of 20.
(2) EB-2008-0272; Ex A; T14; S 3; P 22 of 24.
(3) EB-2010-0002; Ex A; T14; S 3; P 19 of 21.
(4) Compares actual-weather corrected with forecast (3 years of forecast for EB-2006-0501and EB-2008-0272 forecasts and 2 years for EB-2010-0002 forecast).

Table 6b
Historical Board Approved for Line Connection Forecast
vs. Historical Actual and Historical Actual-Weather Normalized

Year	12-Month Average in MW: EB-2006-0501 Forecast (1)	EB-2008-0272 Forecast (2)	EB-2010-0002 Forecast (3)	Actual: Weather Corrected	Actual	Difference from Actual Weather Corrected (%): EB-2006-0501 Forecast	EB-2008-0272 Forecast	EB-2010-0002 Forecast
2005	20,590			20,590	21,345	0.00		
2006	20,242			20,282	20,991	-0.20		
2007	19,875	20,044		20,044	21,443	-0.84	0.00	
2008	19,940	20,111		20,156	20,386	-1.07	-0.23	
2009		20,100	19,796	19,796	19,372		1.53	0.00
2010		19,555	19,674	19,348	20,162		1.07	1.69
2011			19,500	19,417	20,004			0.42
Average Excluding First Year (Actual) (4)						-0.71	0.79	1.06

(1) EB-2006-0501; Ex A; T14; S3; P 19 of 20.
(2) EB-2008-0272; Ex A; T14; S 3; P 22 of 24.
(3) EB-2010-0002; Ex A; T14; S 3; P 19 of 21.
(4) Compares actual-weather corrected with forecast (3 years of forecast for EB-2006-0501and EB-2008-0272 forecasts and 2 years for EB-2010-0002 forecast).

Table 6c
Historical Board Approved for Transforer Connection Forecast
vs. Historical Actual and Historical Actual-Weather Corrected

Year	12-Month Average in MW: EB-2006-0501 Forecast (1)	EB-2008-0272 Forecast (2)	EB-2010-0002 Forecast (3)	Actual: Weather Corrected	Actual	Difference from Actual Weather Corrected (%): EB-2006-0501 Forecast	EB-2008-0272 Forecast	EB-2010-0002 Forecast
2005	17,702			17,701	18,355	0.01		
2006	17,401			17,419	18,031	-0.10		
2007	17,086	17,329		17,329	18,537	-1.40	0.00	
2008	17,142	17,386		17,413	17,611	-1.56	-0.16	
2009		17,376	17,333	17,333	16,999		0.25	0.00
2010		16,905	16,999	16,839	17,551		0.39	0.95
2011			16,850	16,769	17,274			0.48
Average Excluding First Year (Actual) (4)						-1.02	0.16	0.72

(1) EB-2006-0501; Ex A; T14; S3; P 19 of 20.
(2) EB-2008-0272; Ex A; T14; S 3; P 22 of 24.
(3) EB-2010-0002; Ex A; T14; S 3; P 19 of 21.
(4) Compares actual-weather corrected with forecast (3 years of forecast for EB-2006-0501and EB-2008-0272 forecasts and 2 years for EB-2010-0002 forecast).

Incorporating Conservation and Demand Management Impacts in the Load Forecast

Hydro One Networks Inc.

March 2012

EXECUTIVE SUMMARY

This study was initiated in response to directions from the Ontario Energy Board (OEB or "the Board"), requiring Hydro One Networks Inc. ("Hydro One" or "the Company") to work with the Ontario Power Authority (OPA) in devising a robust, effective and accurate means of measuring the expected impacts of Conservation and Demand Management (CDM) programs promulgated by the OPA. The Board also noted that Hydro One should consult with stakeholders in devising the terms of reference for this study.[1]

Stakeholders recommended that the study be completed by Hydro One without support from a third-party consultant. Hydro One worked with stakeholders and listened to and addressed their concerns.

The study focuses on two objectives: (i) propose a methodology to incorporate CDM impacts into the load forecast; and (ii) derive CDM impacts for use in Hydro One's transmission load forecast.

Objective 1: Propose a methodology to incorporate CDM impacts into the load forecast

To satisfy this objective, Hydro One, with input from stakeholders, designed a set of activities. These activities included a literature review and a survey of other utilities in North America and a comparative analysis of the methodologies used to incorporate CDM impacts into the load forecast.

It is difficult to determine the methods used by other utilities/entities to incorporate CDM in the load forecast based solely on a literature review, as publically available documents often do not have adequate information to determine the methodology used. Therefore, the literature review concentrated on the assessment of CDM categories, while the survey focused on the methodology to incorporate CDM impacts into the load forecast.

Approximately 100 surveys were sent out to the members of the North American Electric Reliability Corporation (NERC) and Edison Electric Institute (EEI), as well as to the utilities previously surveyed by Hydro One. An excellent response rate of about 41% was achieved.

The survey responses identified three main methodologies: 1) use actual load for forecasting purposes, 2) use CDM as an explanatory variable on the right-hand side of the econometric equation, and 3) add the historical CDM savings back to the actual load and then use this gross load for forecasting.

[1] EB-2010-0002 Decision with Reasons, December 23, 2010, pg. 6, 7 and EB-2007-0681 Decision with Reasons, December 18, 2008, pg. 8.

In order to make an informed decision, Hydro One undertook a comparative analysis of the three methods. Hydro One has selected Method 3 as it is the most robust method for incorporating CDM impacts into the load forecast. Method 3 also addresses the OEB directive to apply a methodology that is less primitive and provides more acuity. It also is the same approach as used by the OPA.

Objective 2: Derive CDM impacts for use in Hydro One's transmission load forecast

The following CDM categories are incorporated in Hydro One's transmission load forecast:

- Programs (those initiated by the OPA and "Other Influences")
- Codes and Standards
- Pricing

The literature review and the survey conducted by Hydro One confirm that the CDM categories mentioned above are consistent with those used by utilities in other North American jurisdictions.

The OPA provided Hydro One with province-wide annual energy and peak savings by sector, by resource type (Demand Response, Energy Efficiency, and Customer-Based Generation), and by three policy instruments (CDM categories) including Programs, Codes and Standards, and Pricing. The OPA also provided key assumptions used to derive these savings.

Figure ES 1 illustrates how the information provided by the OPA was used to derive CDM impacts by charge determinant.

Table ES 1 shows CDM impacts by the three charge determinants used in this rate application.

Figure ES 1: Process of deriving CDM deductions by charge determinant

Step 1	Obtain the OPA's CDM savings and assumptions: • Total annual savings • Hourly profiles by program type • Key assumptions
Step 2	Estimate annual CDM savings by sector, customer type and program type.
Step 3	Estimate monthly CDM savings by sector and customer type.
Step 4	Produce gross load forecast for Ontario demand and Hydro One charge determinants.
Step 5	Estimate CDM impacts for Ontario demand and Hydro One charge determinants.

Table ES 1: Annual CDM impacts by charge determinant (12-month avg peak MW)

		Charge determinant		
Year	Ontario Demand (MW)	Network Connection (MW)	Line Connection (MW)	Transformation Connection (MW)
2012	1,890	1,862	1,760	1,520
2013	2,147	2,115	1,998	1,726
2014	2,899	2,856	2,699	2,331

All figures are at wholesale purchase level

TABLE OF CONTENTS

LIST OF FIGURES

LIST OF TABLES

1 Introduction

This study was initiated in response to directions from the OEB, requiring Hydro One to work with the OPA in devising a robust, effective and accurate means of measuring the expected impacts of CDM programs promulgated by the OPA.

This report contains four sections including this introduction.

- Section 1 provides background and context;
- Section 2 is a summary of the actions taken to determine appropriate CDM categories and methodologies to incorporate CDM in the load forecast;
- Section 3 discusses how the information provided by the OPA was used to derive CDM impacts for Hydro One's transmission load forecast; and
- Section 4 contains concluding remarks.

1.1 Objectives

The following are the two objectives of this study:

- **Objective 1:** Propose a methodology to incorporate CDM impacts into the load forecast.
- **Objective 2:** Derive CDM impacts for use in Hydro One's transmission load forecast.

1.2 Ontario Energy Board Directives

The Board, in its decision on Hydro One's 2008 distribution rates proceeding (EB-2007-0681), directed Hydro One to come forward with a proposal to incorporate CDM into its load forecast.

"Accordingly, the Board finds that the effects of CDM activities not attributable to the company's actions must be accounted for and requires Hydro One to come forward in its next rate case with a detailed proposal to incorporate the impacts of CDM into its load forecast, both those attributable to its own actions and those not attributable to the Company's actions."[2]

The Board further directed Hydro One in its latest transmission rates proceeding (EB-2010-0002) to:

"Work with the OPA in devising a robust, effective and accurate means of measuring the expected impacts of CDM programs promulgated by the OPA. It is important that the terms of reference for the development of this methodology should, to the extent possible, be devised with

[2] EB-2007-0681 Decision with Reasons, December 18, 2008, pg. 8

input from and consultation with a sufficiently broad range of stakeholders so as to ensure that the resulting product has credibility within the sector." [3]

Below is a summary of the Board's requirements:

- Propose a methodology to incorporate CDM impacts into the load forecast.
- Consult with stakeholders to devise terms of reference for this study.
- Work with the OPA to derive expected impacts from CDM.

1.3 Stakeholder Consultations

In response to the Board's direction, Hydro One held consultation sessions in February and March 2011 to seek input from stakeholders. Representatives from over 15 organizations were in attendance to provide valuable contributions in the design of this study.

In the February consultation session, Hydro One presented the Board's directives to stakeholders and explored various options to meet the Board's requirements.

Several key messages were brought forward by stakeholders during the first consultation session:

- A third party study on CDM impacts was not required. Stakeholders determined that an internal study by Hydro One would be appropriate.

- Hydro One should undertake a review of utilities/entities in other jurisdictions to determine what categories are incorporated into their load forecasts. A review of British Columbia, New York and California was requested.

- CDM categories should be chosen so that they are comprehensive and can be tracked.

- Hydro One should work closely with the OPA to better define and measure CDM impacts for use in its load forecast and rate applications submitted to the OEB.

- In its next transmission rate application, Hydro One should provide detailed documentation on how the province-wide CDM impacts, provided by the OPA, are used to derive CDM impacts by charge determinant.

At the March consultation session, Hydro One worked with the stakeholders to design a set of activities that it would undertake to complete this study.

Based on the input from the stakeholders, Hydro One proposed the following activities:

[3] EB-2010-0002 Decision with Reasons, December 23, 2010, pg. 6 and 7

- Review CDM categories and methodologies used by other utilities in North America.
    - This would include review of the publically available load forecast related documents for British Columbia, New York and California, as well as a survey of other North American Utilities.
- Work closely with the OPA to better understand the assumptions used to derive their conservation forecast.
- Use the information gathered from the OPA to derive CDM impacts for Hydro One's transmission load forecast.
- Document the process used to derive CDM deductions by charge determinant.
- Propose a methodology to incorporate these CDM impacts into Hydro One's load forecast.

Stakeholders agreed that this approach is appropriate to complete the CDM study. The presentations and notes from the stakeholder sessions are available online from Hydro One website[4].

The remainder of this report discusses the methodologies and results of these activities.

1.4 Study Approach

Based on the above outlined recommendations from stakeholders, Hydro One developed the following framework to study the impacts of CDM on its load forecast.

- A literature review of selected North American electric utilities was undertaken in the spring of 2011, to determine which methodologies and CDM categories are commonly in use in North America. Publicly available utility load forecasts and other pertinent documents were collected by a general web search. Where possible, direct communication with the utility via phone or e-mail was undertaken to gain further understanding. As requested by stakeholders, Hydro One conducted a literature review of British Columbia, New York and California. The review was expanded to include some of the other major utilities with knowledge and experience in the CDM area. This review was useful in determining industry practices regarding CDM categories, however there was not enough information available to fully understand the methodologies used to incorporate CDM in the load forecast.
- Hydro One also developed a web-based survey which was launched in April 2011 to the members of Edison Electric Institute (EEI) and North American Electric Reliability Corporation (NERC) load forecasting working group, as well as to other

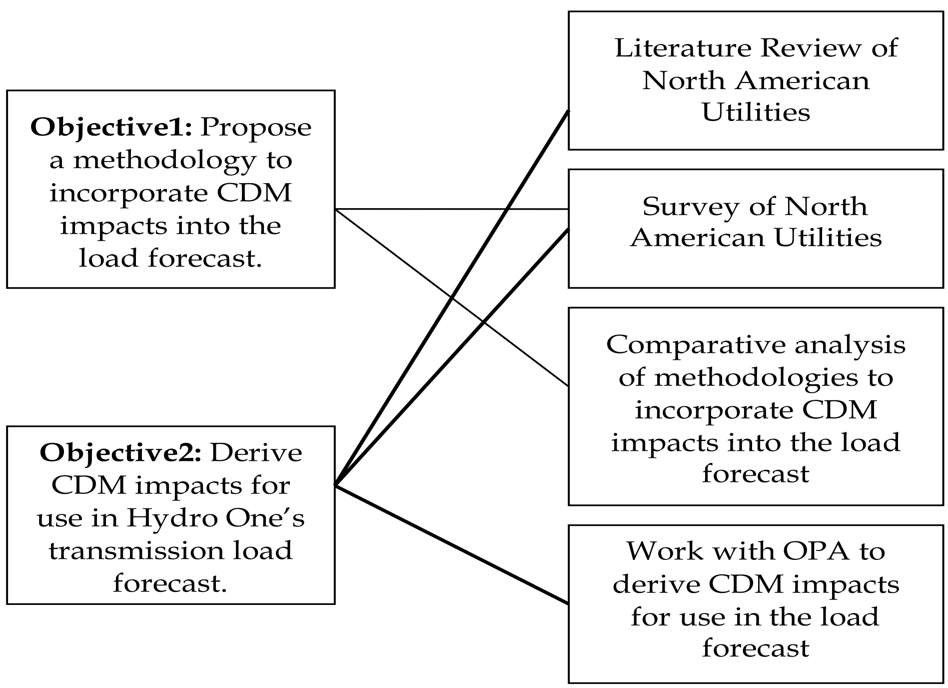
[4] http://www.hydroone.com/RegulatoryAffairs/Pages/DxRates.aspx

utilities that have participated in previous Hydro One surveys. Approximately 100 surveys were sent and responses from 41 organizations were received. This survey gave further insight into the CDM categories in use across North America. It also allowed Hydro One to ask specific questions regarding methodologies used to incorporate CDM in the load forecast.

- In light of the results of the literature review and survey, a comparative analysis was undertaken to examine the advantages and challenges associated with different methodologies to incorporate CDM in the load forecast. This review took into consideration the forecasting requirements specific to Hydro One.

After the February 2011 stakeholder session, Hydro One met with the OPA to discuss OEB requirements and stakeholder expectations. Hydro One worked closely with the OPA to better understand their CDM categories and methodology to incorporate CDM impacts in the load forecast. Detailed savings assumptions from the OPA were used to align Hydro One's CDM forecast with that of the OPA. Figure 1 illustrates, in a flow diagram, how this process addresses the two objectives.

Figure 1: Study approach flow diagram



2 Exploring CDM Categories and Forecast Methodologies

The study approach described in Section 1 outlines the four main activities undertaken by Hydro One to satisfy the objectives of this study. This approach was designed to afford Hydro One a comprehensive view of commonly used CDM categories and existing methodologies in order to explore which categories and methods are appropriate for Hydro One to adopt. This section describes each of these four activities and explains how the results of these activities were used to develop appropriate CDM categories and methodology to incorporate CDM impacts into Hydro One's transmission load forecast.

2.1 Literature Review

In the spring of 2011, Hydro One carried out a literature review to explore various CDM categories and methodologies to incorporate CDM impacts into the load forecast used by electric utilities/entities in North American jurisdictions.

As per stakeholders' recommendation, utilities/entities in British Columbia, New York, and California were reviewed. The review was extended to include some of the major electric utilities/entities, in other North American jurisdictions, with significant experience with CDM. The utilities/entities reviewed are:

- British Columbia Hydro (BC Hydro)
- Manitoba Hydro
- New Brunswick Power (NB Power)
- Nova Scotia Power Inc. (NSPI)
- California Energy Commission (CEC)
- Consolidated Edison Company of New York (CECONY)
- Consumers Energy
- Independent System Operator – New England (ISO-NE)
- Long Island Power Authority (LIPA)
- New York Independent System Operator (NYISO)
- Wisconsin Public Service Corporation (WPS)

The process started with reviewing publically available documents on utilities' load forecasting methodologies and other documents that were of relevance. These documents were obtained either through a general web-search or from the utility's revenue requirement filings with its regulator. Where possible, Hydro One staff contacted the utility/entity (via phone or e-mail) for further clarifications and information.

Some of the key findings of the review are:

- It is difficult to determine the methods used by other utilities/entities to incorporate CDM in the load forecast based solely on a literature review, as publically available documents often do not have adequate information to determine the methodology used. The literature review concentrated on the assessment of CDM categories.

- CDM categories included in the load forecast vary widely from one utility/entity to another.

- Similarly, the definitions of CDM categories may be different for different utilities. For example, some utilities may consider impacts of building codes and appliance efficiency standards under "Federal/Provincial Programs" while others may define it as a separate category.

- Most utilities/entities reviewed, account for CDM programs in their load forecast.

- Most utilities/entities account for impacts of building codes and/or appliance efficiency standards in their load forecast.

The results of this review confirmed that the CDM categories used by Hydro One in its transmission load forecast (Programs, Codes and Standards, and Pricing) are consistent with those used by utilities in other jurisdictions. Complete report on this literature review can be found in Appendix C.

It should be noted that this report only reflects information available during the review period (i.e., Spring 2011).

2.2 CDM Load Forecast Survey

In addition to the literature review, Hydro One also developed a web-based survey which was sent to approximately 100 North American utilities. The survey was launched in April 2011 to the members of the Edison Electric Institute (EEI), the North American Electric Reliability Corporation (NERC) load forecasting working group, and to other utilities who participated in a previous Hydro One survey. Forty-One organizations from jurisdictions within Ontario, other Canadian provinces, and across the United States, responded to this survey.

The survey questionnaire was designed to gain insight into the CDM categories used by other North American utilities and to learn more about the methods used to incorporate CDM in the load forecast.

The results of the survey and the survey questionnaire can be found in Appendix D.

CDM Categories

To determine commonly used CDM categories, the survey provided a list of categories and asked whether the utility/entity accounts for the impacts due to that category. The categories listed in the questionnaire were:

- Energy efficiency programs
- Appliance and lighting efficiency standards
- Building codes
- Demand management programs
- Time-of-Use prices or dynamic pricing
- Customers' conservation actions (not captured by specific programs)

There was also an option to say none of the above and to list any additional categories that are considered by the utility.

The results of the survey confirmed the findings from the literature review in terms of the CDM categories that are used by utilities/entities in North America. Each utility/entity has its own categories; however none of the respondents indicated they consider a unique category not listed in the questionnaire. Each of these categories was recognized by multiple respondents.

Incorporating CDM in the Load Forecast

The survey also asked which methodology (if any) they use to incorporate CDM into their load forecast. There are two types of methodologies commonly in use in North America. The first is an implicit methodology where actual load data is used to generate the forecast with past conservation impacts embedded in it, then future incremental CDM savings are subtracted from the forecast. The second is an explicit methodology where the historical CDM savings are first added back to the actual load then all past and future efficiency savings are subtracted from the forecast. More details on each of these methods can be found in the next section.

Seventy-five percent of respondents said they use an implicit methodology while twenty percent said they use an explicit methodology. Five percent responded that CDM is not reflected in their load forecast. For those who said they use an implicit methodology, only 45 percent said that they use that method because it is the best available. Rather, they use this method because it is either recommended by their regulator or it is the most practical. On the other hand, for those who use an explicit methodology, 75 percent said they do so because it is the best methodology available.

Hydro One undertook a comparative analysis of the implicit and explicit methodologies to evaluate the advantages and challenges associated with each method and to determine which is the most appropriate for Hydro One. The next section describes the results of this analysis.

2.3 Alternatives for Incorporating CDM Impacts into Load Forecast

Since 2005, the Ontario Government has set specific Conservation and Demand Management (CDM) targets to be achieved in the province. Over the past several years, significant progress has been made in delivering various CDM programs across the province. The latest Long Term Energy Plan (November 2010) and the Supply Mix Directive (February 2011) issued by the government call for CDM savings of 4,550 MW and 13 TWh by 2015. Over the 2011-2014 period, Local Distribution Companies (LDCs) are mandated to meet the CDM target of 1,330 MW and 6 TWh. In order to achieve acceptable load forecasting accuracy, CDM impacts have to be handled appropriately in the modeling process.

Incorporating CDM into the load forecast is a challenge facing utilities across North America. As already discussed, Hydro One examined the methodologies for incorporating CDM into the load forecast, used by other utilities and organizations through a survey. The results of this Hydro One survey, two other similar surveys (one launched by the North American Electric Reliability Corporation (NERC) in 2007 and the other by Duke Energy in 2010), as well as a white paper published by Itron Inc. (2010) show that there are three different methods widely being used by various North American utilities.

This section compares these three most commonly used methodologies and provides justification for the method adopted by Hydro One. A detailed description of each method can be found in Appendix E.

<u>Method 1: Use Actual Load without CDM Adjustments (Implicit Method 1)</u>

In this method, no CDM adjustments are made during the modeling process so that the actual load (which is net of CDM) is linked to the economy, demography, prices and weather variables. Over the forecast period, incremental CDM (over and above the historical period) is usually deducted from the forecast.

This method has several challenges which make it less than desirable for Hydro One:

- The load during the historical period is already affected by CDM between 2005 and 2011, and hence, this data will not be consistent with the rest of the load data prior to 2005.
- The model linking load to explanatory variables does not acknowledge that, in addition to economic/demographic factors, the load has also been affected by CDM.
- Having ignored the CDM impacts, the estimated coefficients of the model will likely be biased, because the impacts of CDM will now go to the error term. As a

result, the error-term variance is inflated by the CDM impacts which are not explicitly accounted for in the model.

- This method does not provide details regarding various CDM impacts accounted for in the load forecast, and hence, fails to meet the Board's requirement of a more detailed and transparent process for incorporating CDM impacts into the load forecast.

Method 2: Use CDM Impacts as an Explanatory Variable (Implicit Method 2)

In this method, CDM impacts are used as an explanatory variable on the right-hand-side of the econometric equation, together with other economic/demographic variables. The model is then used to forecast the load net of CDM.

Some of the challenges with using this method are as follows:

- The CDM series may be correlated with other variables on the right-hand-side of the equation (e.g., income). In this case, not only the CDM coefficient, but some other coefficients in the model may diverge from their true value.
- If there are missing explanatory variables that are not included in the equation, then the estimated CDM coefficient is biased and it would probably diverge significantly from its true value.

These challenges along with the fact that the OEB has recognized the issues with this method (such as multicollinearity and heteroskedasticity between economic activity/income and the CDM variables)[5] lead to conclusion that this methodology is not the most suitable for Hydro One.

Method 3: Add Historical CDM Impacts Back to the Actual Load (Explicit Method)

This method can be used to account for CDM impacts for both historical and forecast periods. This method employs the following steps:

- The historical CDM impacts are added back to the actual load reconstituting consistent load data over time, which is gross of CDM impacts.
- The gross load data is then used to forecast the load using an econometric model. This requires linking gross load to explanatory variables, namely, weather, economic/demographic factors (e.g., GDP, income, population, number of households, etc.) as well as prices.
- Finally, estimated CDM impacts for the forecast period is deducted from the gross load forecast to arrive at the load forecast net of CDM.

The advantage of this method is that it explicitly accounts for historical and forecast CDM impacts.

[5] EB-2010-0131 Decision with Reasons, July 7, 2011

The challenge with this method is that it relies on accurate estimates of historical CDM impacts. If the actual impact of CDM is not properly measured, then projecting future CDM savings will be difficult.

Despite the challenges involved in using the implicit methodologies, the survey conducted by Hydro One indicated that 75 percent of respondents use either Method 1 or Method 2. This may be due to lack of data availability necessary to use the explicit methodology. It may also be because, unlike Ontario, many jurisdictions do not have aggressive CDM targets that require robust, bottom-up forecasts.

According to the Board's directives, Hydro One is required to use a methodology that provides detailed explanations for various CDM impacts incorporated in the load forecast. The comparison of the three methods (provided in Appendix E) showed that Method 3 is technically sound and efficient and effectively takes into account CDM impacts during the historical and forecast periods. Based on Hydro One's experience, this method has resulted in accurate load forecasts over past several years. For these reasons, Method 3 was considered to be the most appropriate for use by Hydro One.

3 Deriving CDM Impacts for Hydro One's Transmission Load Forecast

The OEB and stakeholders requested that Hydro One work closely with the OPA to better define and forecast impacts for various CDM categories. Based on numerous consultations with the OPA, Hydro One has adopted the OPA's province-wide conservation forecast and is using similar methodology to incorporate these CDM impacts into the load forecast.

While the OPA provided total CDM impacts for the province, it did not provide this information by LDC or by charge determinant. Hydro One derived CDM impacts by charge determinant to support its load forecasts. This process is discussed in the following sections.

3.1 CDM Categories

For its transmission load forecast, Hydro One adopted three CDM categories (policy instruments) that are consistent with the OPA: Programs, Codes and Standards, and Pricing. Each of these categories is described in more detail below.

1. Programs

- *OPA province-wide CDM Programs*: Province-wide CDM programs designed by the OPA and made available to LDCs to help achieve CDM targets specified by the Board.

- *Other Influences*: CDM programs offered by other agencies such as the federal and provincial governments, gas companies, various associations and communities in Ontario.

2. Building Codes and Appliance Efficiency Standards ("Codes & Standards")[6]

Codes and Standards are an effective means of achieving lasting conservation as they lock in the savings by raising the baseline of efficiency available to customers. They are also very cost-effective from a ratepayer perspective since they require no program investment to be achieved. Customers, however, may incur cost in that they must invest in the more efficient equipment required by the regulation.

The Green Energy Act (2009) of Ontario outlines the intent to make energy efficiency a key purpose of the Ontario Building Code and signals aggressive equipment standards development.

6 http://www.powerauthority.on.ca/sites/default/files/page/IPSP%202011%20Conservation%20Handout%202%20-%20Codes%20and%20Standards%20Summary.pdf

3. Pricing

Under the Regulated Price Plan, the Board has set Time-of-Use (TOU) electricity prices for eligible consumers that have smart meters. TOU prices are designed to give consumers an incentive to shift their electricity use from "on-peak" periods, when the price of electricity is the highest, to "mid-peak" or "off-peak" periods when electricity prices are relatively lower.

3.2 Derivation of CDM impacts by charge determinant

Figure 2 illustrates the overall process used to derive forecast for CDM impacts by charge determinant.

Figure 2: Process of deriving CDM impacts by charge determinant

Step 1	Obtain the OPA's CDM savings and assumptions: • Total annual savings • Hourly profiles by program type • Key assumptions
Step 2	Estimate annual CDM savings by sector, customer type and program type.
Step 3	Estimate monthly CDM savings by sector and customer type.
Step 4	Produce gross load forecast for Ontario demand and Hydro One charge determinants.
Step 5	Estimate CDM impacts for Ontario demand and Hydro One charge determinants.

Step 1: Data collection

Hydro One worked closely with OPA and collected the following information as a first step to forecast the CDM impacts for its transmission business:

i) Province-wide annual CDM savings[7]

The OPA provided Hydro One with province-wide annual peak and energy savings by policy instrument (Programs, Codes & Standards and Pricing), by sector (Residential, Commercial and Industrial), and by resource type (Demand Response (DR), Energy Efficiency (EE), and Customer-Based Generation).

This information is provided in Appendix A.

ii) Key savings assumptions[8]

In addition to the province-wide annual savings, the OPA also provided key assumptions for each CDM program included in their conservation forecast. This included sector, customer type (transmission (TX)-connected large industrial customers and LDCs) and program type (DR, EE and TOU pricing).

iii) Hourly load profiles

The OPA also provided hourly savings profile for each program type for the forecast period.

Step 2: Estimate annual energy and peak demand savings by customer type

The OPA did not provide total annual CDM savings by customer type. Hydro One used total annual province-wide CDM impacts and program assumptions provided by the OPA to estimate annual CDM savings by customer type.

Table 1 summarizes the annual peak and energy savings estimated for TX-connected industrial customers and LDCs.

Table 1: Annual CDM impacts by customer type

	Peak (MW)			Energy (MWh)		
	2012	**2013**	**2014**	**2012**	**2013**	**2014**
TX-connected industrial customers	456	565	653	151,236	491,440	1,073,643
LDCs	2,133	2,536	3,288	6,824,809	7,829,373	9,448,111

All figures are at end-use level.

[7] The annual CDM impacts provided by the OPA are at generation level (that is, including transmission and distribution losses).

[8] The savings assumptions provided by the OPA are at end-use level (that is, excluding transmission and distribution losses).

Step 3: Estimate monthly CDM savings by sector and by customer type

Monthly CDM savings were estimated by applying hourly savings profile for each program type (EE, DR and TOU) to the annual CDM savings by sector and by customer type. Detailed monthly CDM savings are provided in Appendix B.

Step 4: Estimate gross load forecast by charge determinant

Hydro One produced the gross load forecast, using its load forecasting models, by adding back the monthly CDM and embedded generation impacts to the actual load and then forecasting forward[9]. Charge determinant load forecasts were then generated by using the Ontario demand growth rate in the forecast period (see Table 2).

Table 2: Gross load forecast by charge determinant (12-month average peak MW)

Year	Ontario Demand (MW)	Charge determinant		
		Network Connection (MW)	Line Connection (MW)	Transformation Connection (MW)
2012	22,696	22,359	21,128	18,248
2013	23,003	22,662	21,415	18,495
2014	23,309	22,963	21,699	18,741

All figures are at wholesale purchase level

Step 5: Estimate 12-month average peak demand savings by charge determinant

CDM impacts for the three charge determinants were calculated by multiplying the monthly CDM savings for Ontario with the ratio of gross forecast for charge determinant and Ontario demand. The annual CDM impacts by charge determinant were calculated using the 12-month average of the monthly savings (see Table 3).

Table 3: Annual CDM impacts by charge determinant (12-month average peak MW)

Year	Ontario Demand (MW)	Charge determinant		
		Network Connection (MW)	Line Connection (MW)	Transformation Connection (MW)
2012	1,890	1,862	1,760	1,520
2013	2,147	2,115	1,998	1,726
2014	2,899	2,856	2,699	2,331

All figures are at wholesale purchase level

[9] The methodology for incorporating CDM impacts into the load forecast used by Hydro One is discussed in Section 2.3 of this report (Method 3).

4 Concluding Remarks

As outlined in Section 1.1, the objectives of this study were to i) propose a methodology to incorporate CDM impacts into the load forecast; and (ii) derive CDM impacts for use in Hydro One's transmission load forecast.

With input from stakeholders, Hydro One developed a study approach consisting of four main activities to satisfy the above mentioned objectives:

1. Literature review – Hydro One performed a literature review of major utilities, with extensive experience in CDM area, in North America. The results of this review provided Hydro One with a list of well-defined and comprehensive categories to use in forecasting the CDM impacts.

2. Survey – Hydro One launched a web-based survey to approximately 100 utilities across North America. The results of the survey confirmed the findings from the literature review in terms of the CDM categories that are used by utilities/entities in North America. The survey results also showed that there are three most commonly used methods to incorporate CDM impacts into load forecast. Majority of the utilities/entities use the method where actual historical load (with CDM embedded in it) is used to forecast the future load.

3. Comparative analysis of the forecast methodologies – Hydro One undertook a comparative analysis of the three forecast methods commonly used to incorporate CDM impacts into the load forecast. The research performed by Hydro One suggested that adding historical CDM impacts back to the actual load and then deriving a gross forecast is the most appropriate method for Hydro One.

4. Deriving forecast of CDM impacts by charge determinant – As directed by the Board and recommended by the stakeholders, Hydro One worked closely with the OPA throughout the course of this study. OPA provided province-wide conservation savings by policy instrument (CDM categories). Hydro One used the methodology discussed in Section 3 to derive CDM impacts by charge determinant.

In completing these activities, Hydro One explored options to forecast the CDM impacts and incorporate these impacts into the load forecast. The results of this research show that the methodology adopted by Hydro One is appropriate. Hydro One has spent significant time and effort in completing this study, and as a result, has produced very detailed analysis that not only incorporates stakeholders' recommendations, but also meets all of the Board's requirements listed in Section 1.2.

Appendix A

Information Provided by the OPA

A.1 Province-wide annual demand and energy savings[10]

Table 4: Province-wide annual demand savings by policy instrument (MW)

	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015
Programs	608	1,472	1,543	1,583	1,633	2,019	2,224	2,606	3,332	3,576
Codes & Standards	0	18	40	67	107	284	437	550	671	792
Pricing	0	0	0	0	10	48	89	137	184	221
Total	**608**	**1,490**	**1,583**	**1,650**	**1,751**	**2,351**	**2,749**	**3,292**	**4,186**	**4,590**

Table 5: Province-wide annual energy savings by policy instrument (TWh)

	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015
Programs	1.6	3.4	3.9	4.6	4.8	5.3	5.9	6.7	8.5	10.0
Codes & Standards	0.0	0.1	0.2	0.3	0.5	1.0	1.6	2.2	2.8	3.3
Pricing	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Total	**1.6**	**3.5**	**4.0**	**4.9**	**5.2**	**6.3**	**7.5**	**8.9**	**11.2**	**13.3**

Table 6: Province-wide annual demand savings by sector (MW)

	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015
Residential	192	344	407	481	576	787	972	1134	1429	1451
Comemrcial/Institutional	121	418	483	583	680	888	963	1190	1638	1798
Industrial	296	727	693	586	495	676	814	967	1119	1340
Total	**608**	**1,490**	**1,583**	**1,650**	**1,751**	**2,351**	**2,749**	**3,292**	**4,186**	**4,590**

Table 7: Province-wide annual energy savings by sector (TWh)

	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015
Residential	1.2	1.7	2.0	2.2	2.1	2.5	2.9	3.3	4.0	4.3
Comemrcial/Institutional	0.4	1.1	1.4	1.9	2.4	3.0	3.5	4.0	4.9	6.0
Industrial	0.1	0.7	0.7	0.8	0.7	0.8	1.0	1.5	2.3	3.1
Total	**1.6**	**3.5**	**4.0**	**4.9**	**5.2**	**6.3**	**7.5**	**8.9**	**11.2**	**13.3**

[10] All figures in are at generation level (including both, transmission and distribution losses).

Table 8: Province-wide annual demand savings by resource type (MW)

	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015
Customer-Based Generation	0	3	12	12	12	12	12	12	12	12
Energy Efficiency	289	778	893	997	1167	1518	1753	2126	2884	3263
Demand Response	319	710	678	641	572	821	984	1153	1290	1314
Total	**608**	**1,490**	**1,583**	**1,650**	**1,751**	**2,351**	**2,749**	**3,292**	**4,186**	**4,590**

Table 9: Province-wide annual energy savings by resource type (TWh)

	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015
Customer-Based Generation	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Energy Efficiency	1.6	3.5	4.0	4.7	5.2	6.2	7.3	8.6	10.8	12.9
Demand Response	0.0	0.0	0.0	0.1	0.0	0.0	0.1	0.2	0.3	0.3
Total	**1.6**	**3.5**	**4.0**	**4.9**	**5.2**	**6.3**	**7.5**	**8.9**	**11.2**	**13.3**

Appendix B

Monthly CDM Impacts (at end-use level)

Table 10: Monthly demand savings by sector (MW)

Sector	Month	2012	2013	2014
Residential	1	668	739	901
	2	513	553	695
	3	484	524	658
	4	536	528	895
	5	583	566	952
	6	859	1,011	1,275
	7	908	1,061	1,336
	8	860	1,005	1,264
	9	663	762	959
	10	480	527	670
	11	562	620	878
	12	658	735	909
Commercial/Institutional	1	666	755	996
	2	612	697	944
	3	570	651	882
	4	550	662	964
	5	610	711	1,044
	6	828	1,031	1,422
	7	900	1,113	1,532
	8	830	1,022	1,403
	9	725	887	1,217
	10	559	647	889
	11	604	687	950
	12	647	744	1,004
Industrial	1	530	569	683
	2	194	215	293
	3	188	216	279
	4	376	343	716
	5	385	352	734
	6	769	881	1,048
	7	780	927	1,073
	8	769	879	1,044
	9	403	453	574
	10	186	205	280
	11	345	381	678
	12	534	572	690

Table 11: Monthly energy savings by sector (MWh)

Sector	Month	2012	2013	2014
Residential	1	248,514	289,341	348,912
	2	198,435	216,350	252,122
	3	202,790	220,366	256,844
	4	197,813	217,967	268,705
	5	200,214	221,953	278,360
	6	259,369	311,485	356,803
	7	315,153	384,622	479,481
	8	255,000	292,296	352,195
	9	224,188	253,893	303,418
	10	205,018	228,136	270,833
	11	204,131	222,999	283,078
	12	236,412	271,089	305,329
Commercial/Institutional	1	279,036	314,992	382,498
	2	244,771	276,456	335,996
	3	253,804	287,466	350,637
	4	240,495	275,583	339,565
	5	245,745	284,350	352,690
	6	296,872	346,662	429,617
	7	339,289	396,812	492,198
	8	307,029	357,681	443,569
	9	271,353	315,023	390,267
	10	250,144	287,107	354,671
	11	254,696	289,066	354,012
	12	265,784	300,898	366,970
Industrial	1	84,657	123,617	181,412
	2	73,496	107,682	158,699
	3	76,092	111,871	165,538
	4	72,324	107,392	160,552
	5	73,828	110,745	166,750
	6	89,872	135,896	203,335
	7	103,445	156,162	233,810
	8	92,429	139,588	209,742
	9	81,642	122,863	184,460
	10	75,197	111,905	167,576
	11	76,384	112,524	167,419
	12	80,625	117,972	173,691

Table 12: Monthly demand savings by customer type (MW)

Customer Type	Month	2012	2013	2014
LDCs	1	1,557	1,734	2,165
	2	1,236	1,368	1,774
	3	1,160	1,287	1,667
	4	1,251	1,305	2,137
	5	1,366	1,397	2,283
	6	2,002	2,394	3,104
	7	2,133	2,536	3,288
	8	2,004	2,377	3,072
	9	1,576	1,858	2,415
	10	1,143	1,286	1,687
	11	1,326	1,479	2,092
	12	1,529	1,720	2,183
TX Connected Large Industrial Customers	1	306	328	415
	2	83	96	159
	3	82	103	152
	4	211	229	438
	5	212	232	447
	6	455	529	641
	7	456	565	653
	8	455	529	639
	9	215	243	334
	10	82	93	152
	11	186	209	414
	12	310	331	420

Table 13: Monthly energy savings by customer type (MWh)

Customer Type	Month	2012	2013	2014
LDCs	1	598,896	686,098	823,124
	2	505,527	564,316	668,447
	3	521,175	582,159	691,283
	4	499,579	564,850	689,511
	5	508,542	579,852	715,429
	6	632,078	748,086	889,280
	7	741,367	884,573	1,089,828
	8	640,285	742,581	901,895
	9	564,687	650,451	787,034
	10	518,881	589,532	710,317
	11	523,643	586,815	721,802
	12	570,149	650,058	760,162
TX Connected Large Industrial Customers	1	13,312	41,852	89,698
	2	11,175	36,172	78,370
	3	11,511	37,544	81,736
	4	11,053	36,092	79,311
	5	11,245	37,196	82,371
	6	14,034	45,957	100,475
	7	16,520	53,023	115,661
	8	14,174	46,984	103,612
	9	12,496	41,328	91,111
	10	11,477	37,617	82,762
	11	11,567	37,774	82,708
	12	12,672	39,901	85,828

Appendix C

Review of Conservation and Demand Management (CDM) Categories

EXECUTIVE SUMMARY

In the first quarter of 2011, Hydro One Networks Inc. ("Hydro One") hosted two consultation sessions with the stakeholders to define the terms of reference for development of a methodology to effectively and accurately measure the expected impacts of Conservation and Demand Management (CDM) initiatives.

Stakeholders recommended that, as part of this study, it would be useful to review what CDM categories are accounted for in the load forecast by utilities in British Columbia, New York, and California. In response, Hydro One initiated a review process for the jurisdictions recommended by stakeholders. The review was extended to include some of the major electric utilities/entities, in other North American jurisdictions, with significant experience with CDM.

Below are some of the observations made during the review process:

- It is difficult to determine the methods used by other utilities/entities to incorporate CDM in the load forecast based solely on a literature review, as publically available documents often do not have adequate information to determine the methodology used. The literature review concentrated on the assessment of CDM categories.

- CDM categories included in the load forecast vary widely from one utility/entity to another.

- The definitions of CDM categories may be different. For example, some utilities may consider impacts of building codes and appliance efficiency standards under "Federal/Provincial Programs" while others may define it as a separate category.

- Most utilities/entities reviewed, account for CDM programs in their load forecast.

- Most utilities/entities account for impacts of building codes and/or appliance efficiency standards in their load forecast (either modeled implicitly or accounted for explicitly in the load forecast).

C.1 Introduction

At one of the consultation sessions held by Hydro One, the stakeholders recommended that it will be useful to look at what CDM categories are used by utilities in jurisdictions such as British Columbia, California, and New York.

To address this concern, Hydro One initiated a review process to better understand various CDM categories incorporated in the load forecast. In addition to the three jurisdictions recommended by the stakeholders, the review included major utilities in Manitoba, New Brunswick, Nova Scotia, Michigan, New England States (Connecticut, Maine, Massachusetts, New Hampshire, Rhode Island, and Vermont), and Wisconsin.

The review process started with reviewing publically available documents on utilities' load forecasting methodologies and other documents that were of relevance. These documents were obtained either through a general web-search or from the utility's revenue requirement filings with its regulator. Where possible, Hydro One staff contacted the utility (via phone or e-mail) for further clarifications/information.

It should be noted that this report only reflects information available during the review period (i.e., Spring 2011).

C.2 Review Findings

C.2.1 Canada

C.2.1.1 BC Hydro[11]

BC Hydro is a crown corporation, owned by the province of British Columbia, and a vertically integrated electric utility. It is the largest electric utility in British Columbia, serving approximately 1.8 million customers.

BC Hydro's electric load forecast is published annually and is based on several end-use and econometric models.

Based on the review of BC Hydro's latest load forecast document, BC Hydro accounts for the following CDM categories into its load forecast:

- Impacts of codes and standards
- Impacts of pricing (rate structure) (Inclining Block Rate)
    - BC Hydro refers to the conservation induced by general rate increases as "natural conservation" and the incremental conservation induced by changing elements of the rate structure from one year to the next as "rate structure conservation". In the BC Hydro's load forecast, "natural conservation" is included in the before-CDM load forecast, and "rate structure conservation" is included in the estimates of CDM savings.
- Impacts of BC Hydro's energy efficiency and conservation programs

C.2.1.2 Manitoba Hydro[12]

Manitoba Hydro is a crown corporation and a major energy utility in Manitoba. It serves over 500,000 electric customers and exports electricity to over 30 electric utilities through four wholesale markets in Canada and the mid-western United States.

---

[11] BC Hydro Electric Load Forecast 2010/11 to 2030/31
http://www.bchydro.com/etc/medialib/internet/documents/planning_regulatory/iep_ltap/2011q1/electric_load_forecast.Par.0001.File.Electric-Load-Forecast-2010-march-24.pdf

[12] Manitoba Hydro Electric Load Forecast 2010/11 to 2030/31
http://www.hydro.mb.ca/regulatory_affairs/electric/gra_2010_2012/Appendix_62.pdf

MB Hydro 2010/11 and 2011/12 General Rate Application Filing, Information Requests from the Manitoba Public Utilities Board
http://www.hydro.mb.ca/regulatory_affairs/electric/gra_2010_2012/PUB.pdf

In addition to reviewing Manitoba Hydro's load forecast related documents, the utility was also contacted through e-mail. Following observations were made based on the review of Manitoba Hydro's latest load forecast and the e-mail correspondence with the market forecast personnel at Manitoba Hydro:

- The load forecast contains future CDM savings at the minimum level of CDM services and activity that Manitoba Hydro will provide to customers in the future and savings due to changes to codes and standards.
    - This is termed as the Basic Customer Information and Service in Manitoba Hydro's load forecast. The individual provincial/federal standards are not included on program by program basis; rather they are grouped into savings by end-use.
- The electricity savings due to CDM programs (energy efficiency and demand response) funded by Manitoba Hydro are treated as supply-side option, and hence, are not included in their load forecast.
- Eco-Energy, the federal government funded program, is integrated in Manitoba Hydro's overall CDM initiative (Power Smart), which implies that the savings associated with this category are considered as a supply-side resource.
- Manitoba Hydro offers a curtailable rate program to its customers. When calculating the net total peak, the curtailments are added back to create a consistent hourly integrated load profile.

C.2.1.3 New Brunswick Power (NB Power)[13]

NB Power is a Crown Corporation, wholly owned by the Government of New Brunswick and consists of a holding company and four operating companies: NB Power Generation, NB Power Nuclear, NB Power Transmission, and NB Power Distribution and Customer Service which serves over 370,000 customers in the province.

In its 10-year load forecast produced in 2009, NB Power included the following CDM categories:

- Naturally occurring efficiency
    - In addition to the naturally occurring conservation, which is embedded in the historical trend, this includes efficiency due to thermal shell improvements in the residential sector.

[13] NB Power 3% rate increase investigation 2009, Responses to Written Questions, Appendix B: Load Forecast 2009-2019
http://156.34.203.123/Documents/Electricity%20Info/Responses_May_19_2009.pdf

- Natural Gas conversions (Fuel Switching)
- Efficiency New Brunswick's programs
    - In New Brunswick, Efficiency New Brunswick is responsible for promoting efficiency measures, and for developing and delivering efficiency programs. The savings estimates from these programs (based on discussions and information from Efficiency New Brunswick staff) are included in the base load forecast.
- Appliance and lighting standards (embedded in the model)

C.2.1.4 Nova Scotia Power Inc. (NSPI)[14]

NSPI provides 95 percent of generation, transmission, and distribution of electricity in the province of Nova Scotia and serves about 490,000 residential, commercial, and industrial customers.

NSPI's load forecast accounts for savings from CDM programs in the province and codes and standards (embedded in the model).

In addition, NSPI offers optional Time-of-Use (TOU) pricing to its residential customers. As the customers on time-of-use prices do not yet constitute a large enough portion of the sector, impacts of the TOU prices are also assumed to be captured in historical trends.

C.2.2 Unites States of America

C.2.2.1 California Energy Commission (CEC)[15]

CEC is California's primary energy policy and planning agency. One of its major responsibilities is to forecast future energy needs and keep track of historical energy data.

CEC produces a 10-year load forecast, for California as a whole and for each major utility planning area, on an annual basis.

During CEC's 2007 Integrated Energy Policy Report process (IEPR), utilities and stakeholders expressed concern regarding the lack of transparency in methods that account for efficiency program impacts in CEC's demand forecast. To address this

---

[14] E-mail correspondence with sales forecasting personnel at NSPI.

[15] California Energy Demand 2010-2020 Adopted Forecast
http://www.energy.ca.gov/2009publications/CEC-200-2009-012/CEC-200-2009-012-CMF.PDF

concern, the 2007 IEPR process required CEC to examine these methods in public process in 2009 and beyond.

CEC initiated a major effort to improve the measurement and attribution of efficiency impacts in energy demand forecast, and as a result, starting 2009, the Commission's electricity demand forecast documents provide more details on the impact of energy efficiency programs.

Below are the various CDM categories accounted for in CEC's load forecast for 2010-2020:

- Investor-owned utility programs
- Public agency programs
- Building codes and appliance standards (before 2006, excludes future standards)
- Naturally occurring savings
    - Impacts of rate changes, certain market trends, and other changes in consumption not directly associated with standards or efficiency programs.
    - There are other consumption trends leading to reduced energy that could be included in this category.

In addition to these "committed" savings, CEC is also working with Itron Inc. to estimate the incremental impacts from future efficiency programs and standards reasonably expected to occur but not yet committed.

C.2.2.2 Consolidated Edison Company of New York (CECONY)[16]

CECONY is a subsidiary of Consolidated Edison, Inc., one of the US's largest investor-owned energy companies. It is a regulated utility that provides electric service to approximately 3.3 million customers in New York City (except for a small area of Queens), and Westchester County.

Based on e-mail communication with the energy-efficiency programs personnel, CECONY captures savings from programs administered by the utility, as well as programs administered by the New York State Research and Development Authority

[16] Electric System Long Range Plan: Assessment Documents
http://www.coned.com/publicissues/PDF/ESLRP%20Assessment%20Documents%20December%202010%20Final.pdf

E-mail correspondence with energy efficiency programs personnel at CECONY.

(NYSERDA), existing codes and standards in its forecasted savings. CECONY is also working towards incorporating savings from programs administered by other utilities and future codes and standards into its load forecast.

C.2.2.3 Consumers Energy Company[17]

Consumers Energy is Michigan's second largest electric and natural gas utility, serving 1.8 million electricity customers and 1.7 million natural gas customers.

In its 2011-2015 official forecasts of electric deliveries, generation requirements, and peak demand produced in 2010, Consumers Energy included:

- Electricity savings due to energy efficiency programs from the utility's Energy Optimization Plan
- Peak demand reductions from direct load management programs
- Peak demand reductions from dynamic peak pricing programs (starting in 2013)
- National appliance efficiency standards (starting 2012)

C.2.2.4 Independent System Operator-New England (ISO-NE)[18]

ISO-NE is a regional transmission organization, serving Connecticut, Maine, Massachusetts, New Hampshire, Rhode Island and Vermont. Its primary responsibilities are ensuring the day-to-day reliable operation of New England's bulk power generation and transmission system, overseeing and ensuring fair administration of the region's wholesale electricity markets, and managing comprehensive, regional planning processes.

Between 1980 and 2006, ISO-NE's load forecast methodology was to add back the historical CDM savings, forecast the load and then subtract forecasted CDM reductions. Starting 2007, demand resources (including energy efficiency) are treated as a supply resource. The load forecast is adjusted for:

---

[17] Application of Consumers Energy Company for Approval of a Power Supply Cost Recovery Plan and for Authorization of Monthly Power Supply Cost Recovery Factors for the Year 2011 http://efile.mpsc.state.mi.us/efile/docs/16432/0001.pdf

[18] Presentation on "Addressing the Evolving Role of Energy Efficiency" by Mr. Eric Wilkinson http://neep.org/uploads/EMV%20Forum/Eric%20Wilkinson%20ISO%20NE%20Presentation.pdf

Presentation on "ISO-NE Load Forecast Methodology" by Mr. David Ehrlich http://www.iso-ne.com/committees/comm_wkgrps/inactive/reei/mtrls/load_forecast_method.pdf

- Historical energy efficiency savings, and
- Federal appliance efficiency standards

However, recently, ISO-NE stakeholders have been urging for greater inclusion of energy efficiency information in ISO-NE load forecasting.

C.2.2.5 Long Island Power Authority (LIPA)[19]

LIPA is a non-profit municipal electricity provider and is the second largest municipal electric utility in the US in terms of electric revenue. It provides electric service to more than 1.1 million customers in Nassau and Suffolk counties and the Rockaway Peninsula in Queens.

In addition to the savings due to its own energy efficiency programs, LIPA also accounts for building codes and appliance efficiency standards in the load forecast.

C.2.2.6 New York Independent System Operator (NYISO)[20]

The NYISO operates the high-voltage transmission network, administers and monitors the wholesale electricity markets, and planning for the New York state's energy future.

NYISO accounts for the following CDM categories in its load forecast:

- New NYSERDA and utility programs that have been approved by the Public Utilities Commission
- Appliance efficiency standards

[19] E-mail correspondence with load forecasting personnel at LIPA.

[20] E-Source response to the member inquiry submitted by Hydro One's load forecast staff. The responses were primarily secured from a principal analyst in electric load forecasting department at National Grid and load forecasting personnel at ISO-NE.

C.2.2.7 Wisconsin Public Service (WPS) Corporation[21]

WPS Corporation is a subsidiary of Integrys Energy Group, Inc. and operates as a regulated electric and natural gas utility. It serves electricity to more than 437,000 customers in northeast and central Wisconsin and an adjacent portion of Upper Michigan.

WPS' electricity sales for 2011 test year are projected to be significantly lower as compared to their approved sales for the 2009 test year. According to the written testimony of David Clabots (Manager, Sales and Revenue Forecasting), one of the major reasons for this decrease in sales is increased energy efficiency efforts by the customers. These include the impacts of:

- Wisconsin's Focus on Energy (which partners with utilities) programs and rebates
- Federal energy efficiency mandates
- Federal tax credits on energy efficient appliances
- Retailers promoting energy efficient equipments and appliances
- Increasing energy costs
- Economy driven need to conserve

When contacted through e-mail, Mr. Clabots mentioned that they did not specifically model each of the areas mentioned in his testimony. Rather, his testimony implied that the forecasts include impacts based on Energy Information Administration (EIA) forecasts (specifically the Energy Independence and Security Act of 2007) and other areas that are driving energy efficiency in the forecast. Some of the impacts are picked up in the EIA forecast and some are picked up from the utility's historical data that gets used in the regression models.

---

[21] Application of Wisconsin Public Service Corporation for Authority to Adjust Electric and Natural Gas Rates, Direct Testimony of David W. Clabots (Manager, Sales and Revenue Forecasting)
http://www.wisconsinpublicservice.com/company/rate_case/07_Clabots_Direct_Test_Final.pdf

E-mail correspondence with Mr. David Clabots.

C.3 Conclusions

The review of utilities in other jurisdictions helped Hydro One to better understand the industry practice of what CDM categories are accounted for in the load forecast. Below are some of the key findings of the review:

- It is difficult to determine the methods used by other utilities/entities to incorporate CDM in the load forecast based solely on a literature review, as publically available documents often do not have adequate information to determine the methodology used. The literature review concentrated on the assessment of CDM categories.

- CDM categories included in the load forecast vary widely from one utility/entity to another.

- The definitions of CDM categories may be different. For example, some utilities may consider impacts of building codes and appliance efficiency standards under "Federal/Provincial Programs" while others may define it as a separate category.

- Most utilities/entities reviewed, account for savings from CDM programs initiated by the utility/entity in their load forecast.

- Most utilities/entities reviewed, account for savings from building codes and/or appliance efficiency standards in their load forecast (either modeled implicitly or accounted for explicitly in the load forecast).

The results of this review confirmed that the CDM categories used by Hydro One in its transmission load forecast are consistent with those used by utilities in other jurisdictions.

Appendix D

CDM Load forecasting Survey Results and Questionnaire

Survey Results

EXECUTIVE SUMMARY

In April 2011, Hydro One launched a web-based survey to selected North American electricity utilities to better understand the methodologies used to incorporate Conservation & Demand Management (CDM), also known as Demand Side Management (DSM) in the USA, into load forecasting.

A total of 41 organizations responded to this survey. An excellent response rate of about 41% was achieved with responses were received from jurisdictions within Ontario, from several other Canadian provinces, and from across the United States.

The following is a summary of the survey findings:

- Respondents were primarily Integrated Utilities and Distributors.
- The majority of respondents (~ 60 percent) reported a peak demand of less than 10,000 MW in 2010.
- 20 percent of respondents said that they use an explicit methodology to incorporate CDM/DSM in their load forecast. 75 percent of these said that it was the best methodology available.
- 75 percent said that CDM/DSM is incorporated in the load forecast using an implicit methodology. 45 percent of these said that it was the best methodology available.
- The most common mechanism to recover lost revenue due to CDM/DSM was cost of service.
- The current CDM/DSM categories currently used by Hydro One (energy efficiency programs, appliance and lighting standards, building codes, demand response, time-of-use or dynamic pricing, and customer conservation actions) were commonly recognized among the respondents, regardless of forecasting methodology.
- The methods used to forecast these methodologies varied by category and by utility.
- Spillover and free-driver effects, free-rider effects, and persistence of savings were all commonly accounted for in the load forecast.
- The majority of respondents (59 percent) said that natural conservation was taken into account in their load forecast methodology. The definitions given for natural conservation suggested that the definition of this term varies among the respondents.
- Those who said they did not incorporate natural conservation commonly said that it was already embedded in the historical data.

D.1 Introduction

In an effort to better understand the methodologies by which North American electric utilities incorporate CDM/DSM into their load forecasting, Hydro One developed a short, web-based survey. The survey was launched in April 2011 to selected companies across North America.

The main objectives of the survey were to determine the methodologies used by other utilities to incorporate CDM/DSM into the load forecast and to also better understand which categories of CDM/DSM are incorporated via this methodology. There are two methodologies commonly in use in North America. The first is an implicit methodology where by data is used to generate the load forecast with past conservation impacts embedded, then future incremental efficiency program savings are subtracted from the forecast. The second is an explicit methodology where the historical efficiency program savings are first added back to the actual load then all past and future efficiency savings are subtracted from the forecast. Hydro One currently uses an explicit methodology to incorporate CDM/DSM in its load forecast.

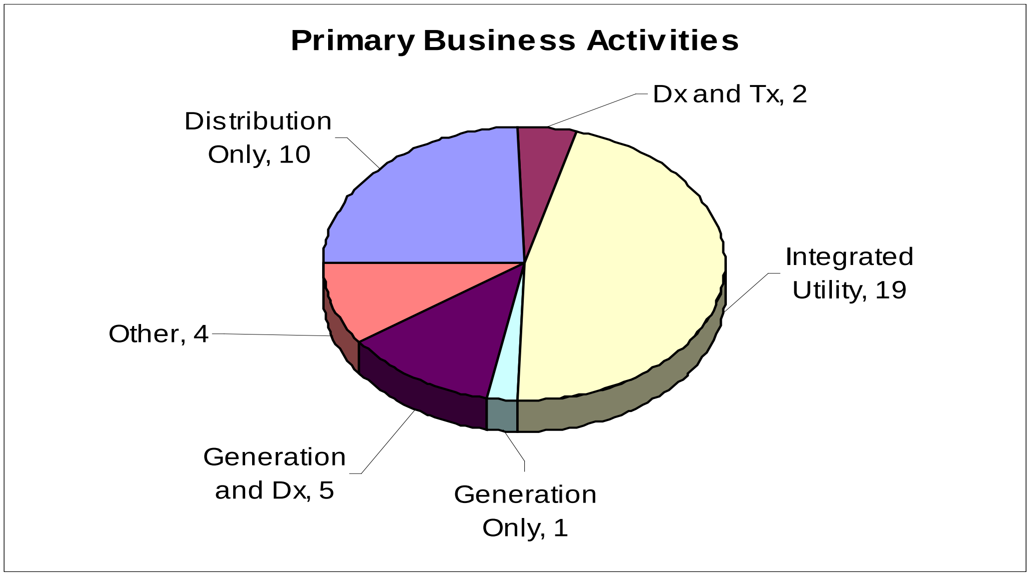
A total of 41 organizations responded to this survey. Responses were received from jurisdictions within Ontario, from several other Canadian provinces, and from across the United States.

D.2 Results

What are your primary business activities?

There were 41responses to this question.

- 46% of respondents were from integrated utilities (generation, distribution and transmission services)
- 24% of respondents were from distribution companies



What were your total electricity sales (in MWh) in 2010?

There were 34 responses to this question.

- Answers ranged from 30,485 MWh to 196,592,052 MWh.

What was your customers' or company's total peak demand (in MW) in 2010?

There were 37 responses to this question.

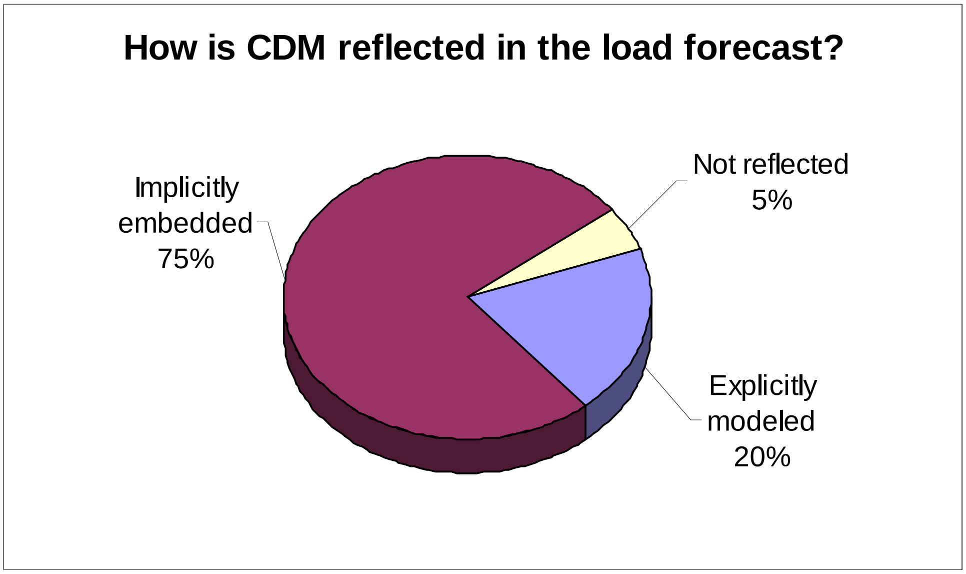
- Answers ranged from 707 MW to 47,500 MW.
- About 60% of respondents had peak demand of less than 10,000 MW in 2010.

	Definition	Number
Small	Less than 10,000 MW	22
Medium	10,000 to 20,000 MW	5
Large	More than 20,000 MW	9
No Answer	N/A	5

How is the impact of CDM/DSM reflected in your load forecasting?

There were 41 responses to this question.

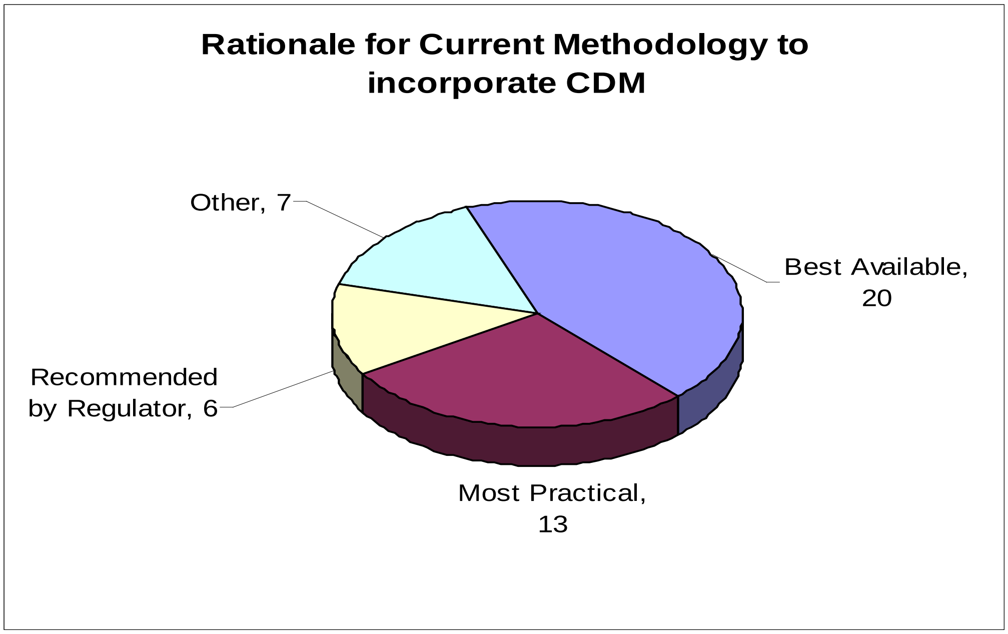
- 75% of respondents said that CDM was reflected in the load forecast using and implicit methodology.
- 20% said that CDM was explicitly modeled in the load forecast.
- 5% of respondents said they did not reflect CDM in their load forecast.



What is the rationale for the current methodology used to incorporate CDM/DSM in the load forecast?

There were 39 responses to this question. Respondents were able to respond to this question with more than one answer so as a result the numbers in the graph add up to more than 39.

- 20 respondents said that the current methodology was the best available.
- 13 respondents said that it was the most practical.
- 6 respondents said that it was the method recommended by their Regulator.



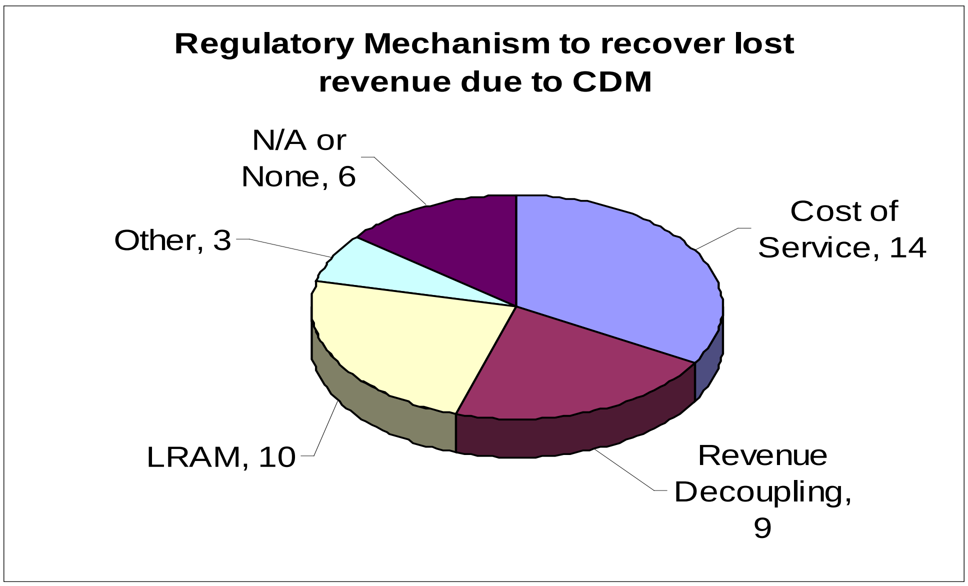
Additional notes:

- Of respondents using an explicit methodology, 75% said it was the best method available.
- Of respondents using an implicit methodology, 45% said it was the best method available.

What are the regulatory mechanisms for your company to recover lost revenue due to CDM/DSM **programs?**

There were 37 responses to this question. Respondents were able to respond to this question with more than one answer.

- 14 respondents said they use cost of service to recover lost revenue due to CDM/DSM programs.
- 10 respondents use a Lost Revenue Adjustment Mechanism (LRAM).
- 9 respondents use revenue decoupling.



Additional notes:

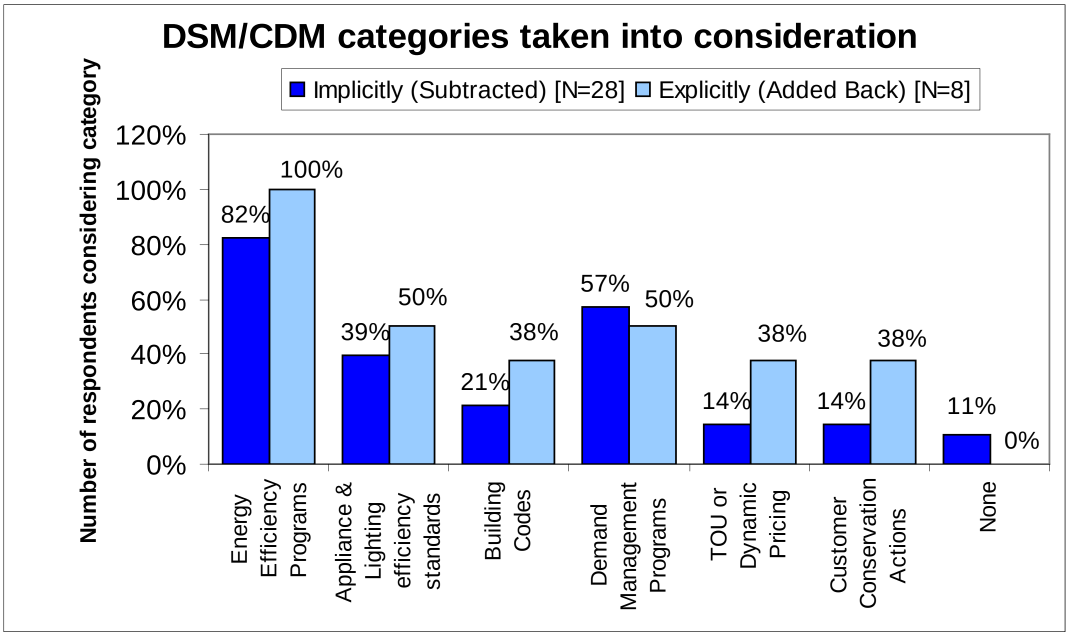
- 2 respondents used both cost of service and revenue decoupling.
- 1 respondent used cost of service, revenue decoupling and LRAM.

What DSM/CDM Categories are taken into consideration in the load forecast?

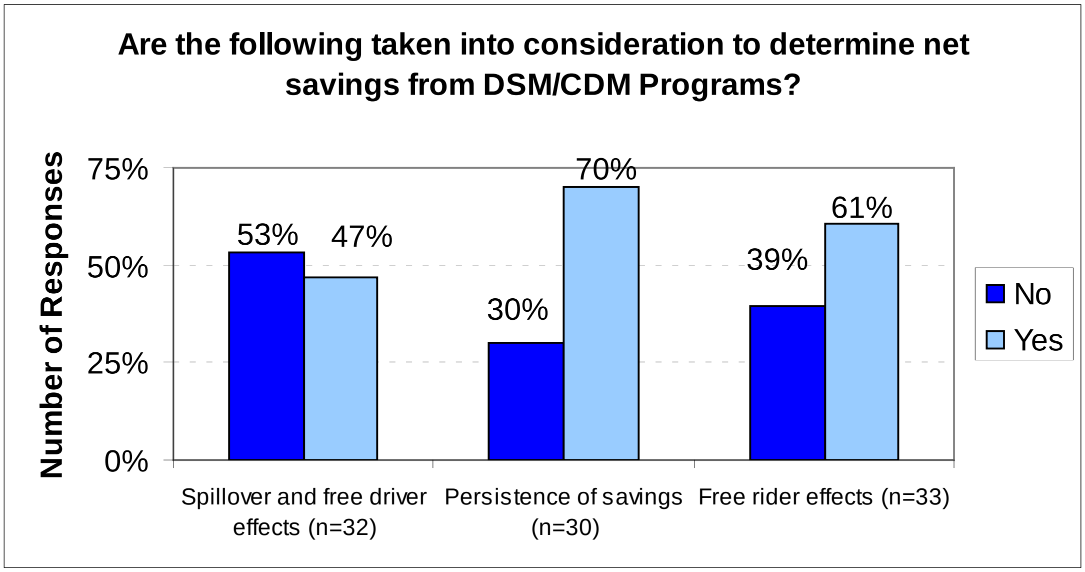
There were 36 responses to this question. Respondents were asked to select all that apply.

- All categories seem to be commonly recognized, regardless of forecasting methodology.
- The most common category considered was Energy Efficient Programs (82% of implicit and 100% of explicit considered this category)

- Demand Management Programs (57% of implicit and 50% of explicit) and Appliance & Lighting Efficiency Standards (39% of implicit and 50% of explicit) were also very commonly considered.



How do you determine net savings from CDM/DSM programs?



1. Spillover and Free-Driver Effects

    - 32 respondents answered this question.
    - 53% said that they take spillover and free-driver effects into consideration when determining net savings from CDM/DSM programs.
    - Estimation methods given included econometrics, surveys, billing analysis, and estimates by consultants.
    - Rationale given for estimation methods included best judgment and internal decisions.

2. Persistence of Savings

    - 30 respondents answered this question.
    - 70% said that they take persistence of savings into consideration when determining net savings from CDM/DSM programs.
    - Estimation methods given included econometrics, surveys, engineering calculations and equipment life assumptions.
    - Rationale given for estimation methods included best judgment, internal decisions, and regulator recommendation.

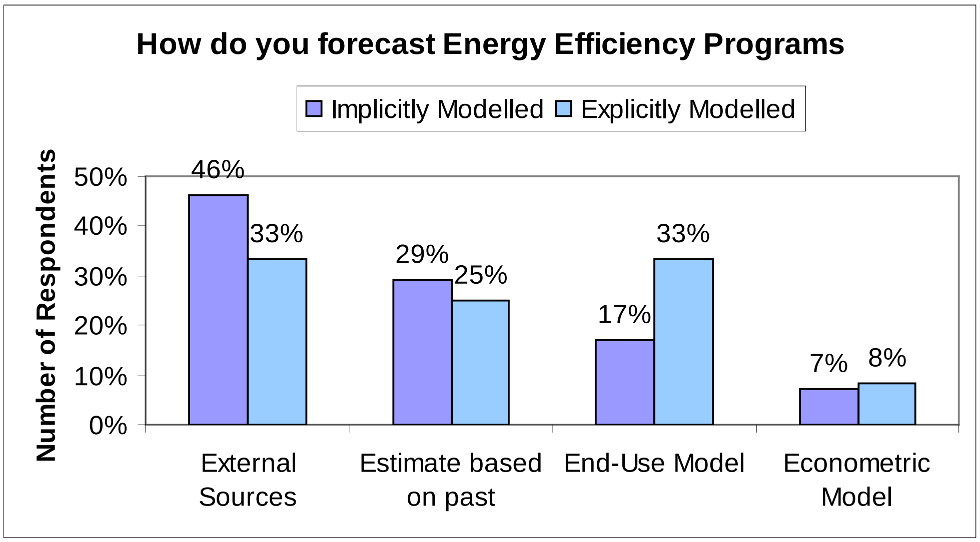
3. Free Rider Effects

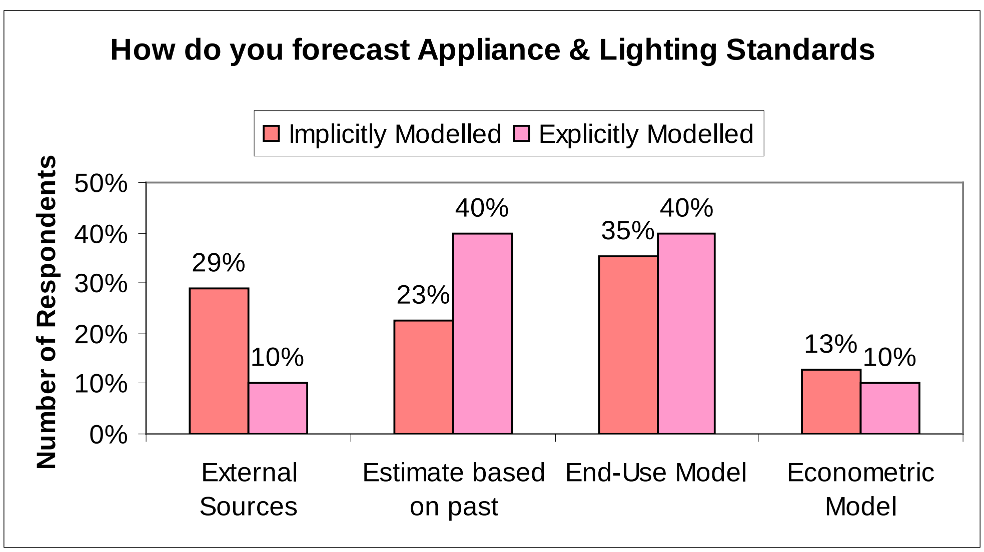
    - 33 respondents answered this question.
    - 61% said that they take free-rider effects into consideration when determining net savings from CDM/DSM programs.

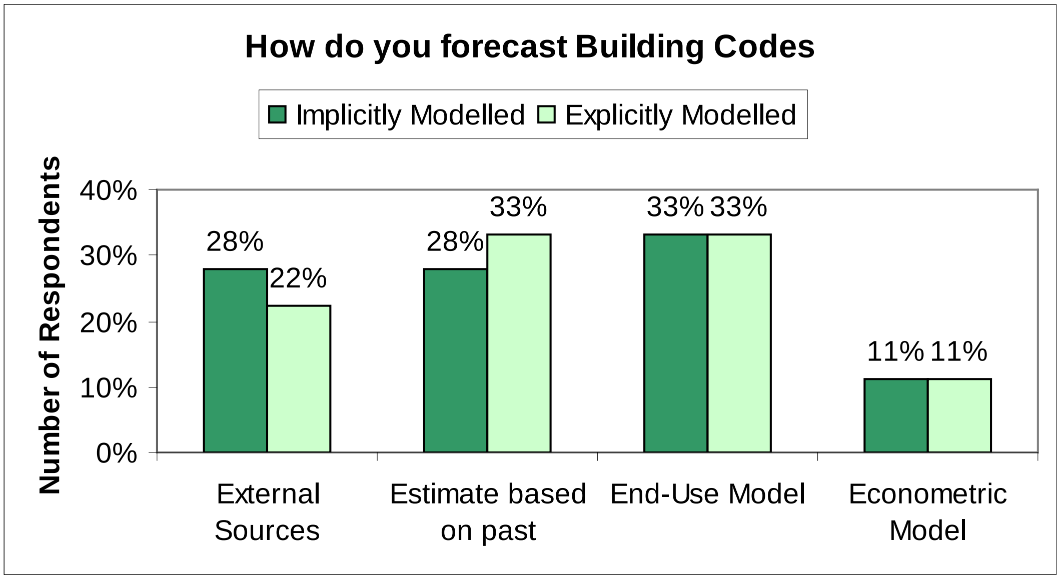
- Estimation methods given included econometrics, surveys, EM&V, program participation and past experience.
- Rationale given for estimation methods included best judgment, internal decisions, and regulator recommendation.

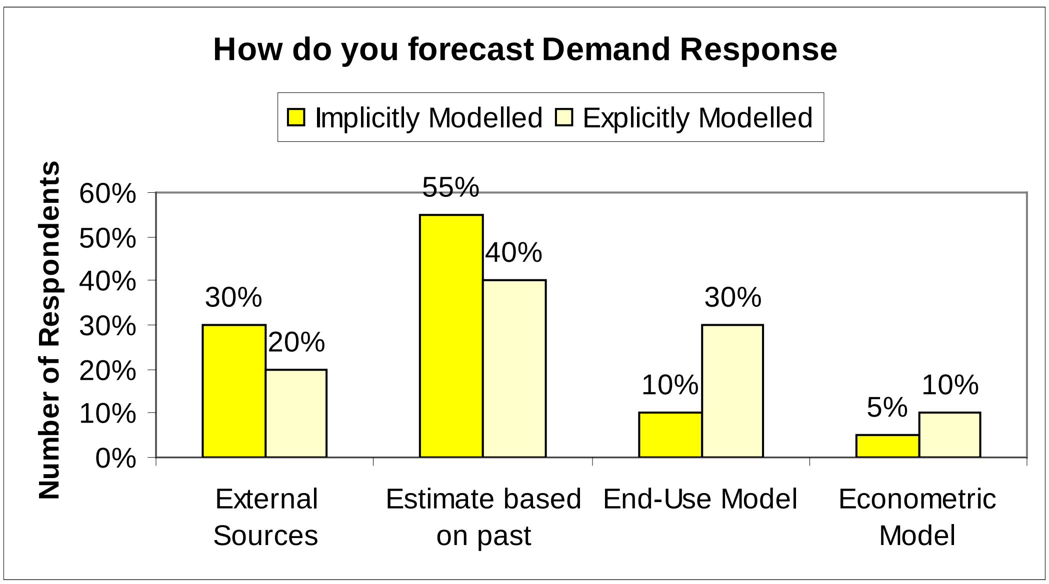
What are your methods used to FORECAST the following CDM/DSM categories?

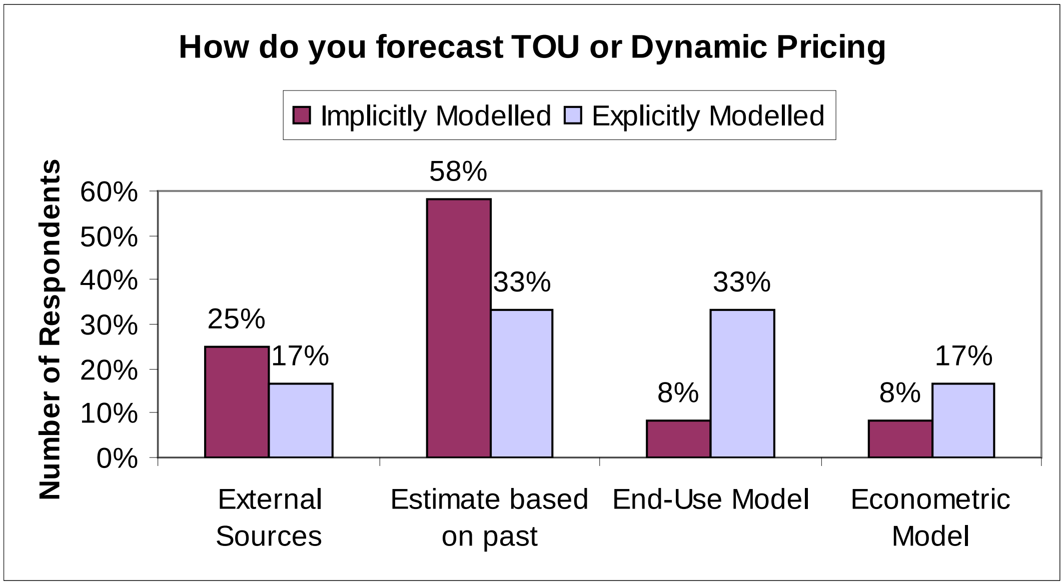
This question was asked to both implicit and explicit methodologies. The methods used varied across methodology and category.

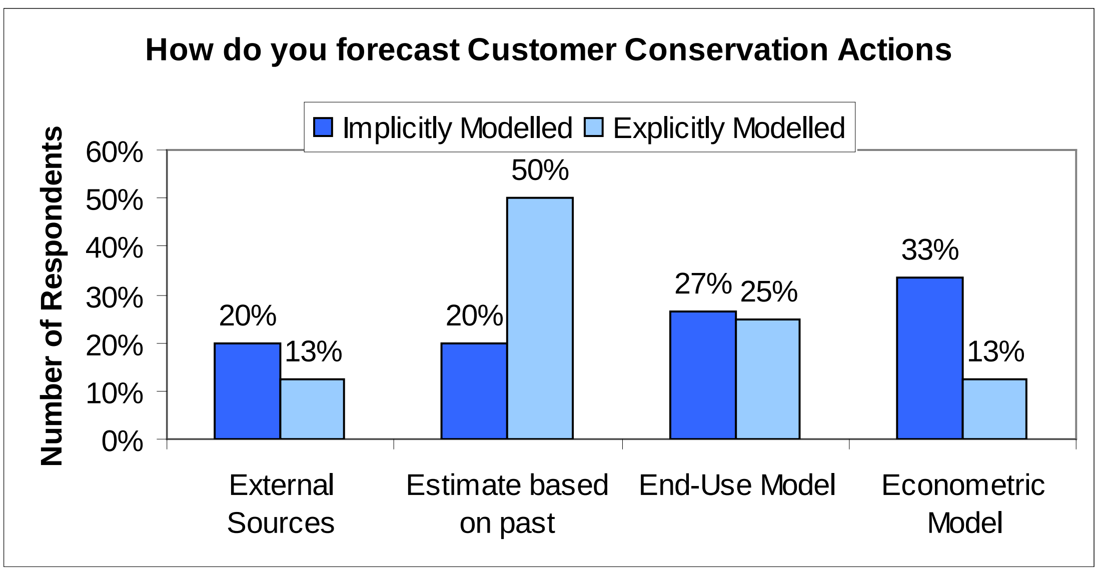





How do you forecast Building Codes
Implicitly Modelled
Explicitly Modelled
Number of Respondents
40%
30%
20%
10%
0%
28%
22%
28%
33%
33%
33%
11%
11%
External Sources
Estimate based on past
End-Use Model
Econometric Model


How do you forecast Demand Response
Implicitly Modelled
Explicitly Modelled
Number of Respondents
60%
50%
40%
30%
20%
10%
0%
30%
20%
55%
40%
10%
30%
5%
10%
External Sources
Estimate based on past
End-Use Model
Econometric Model

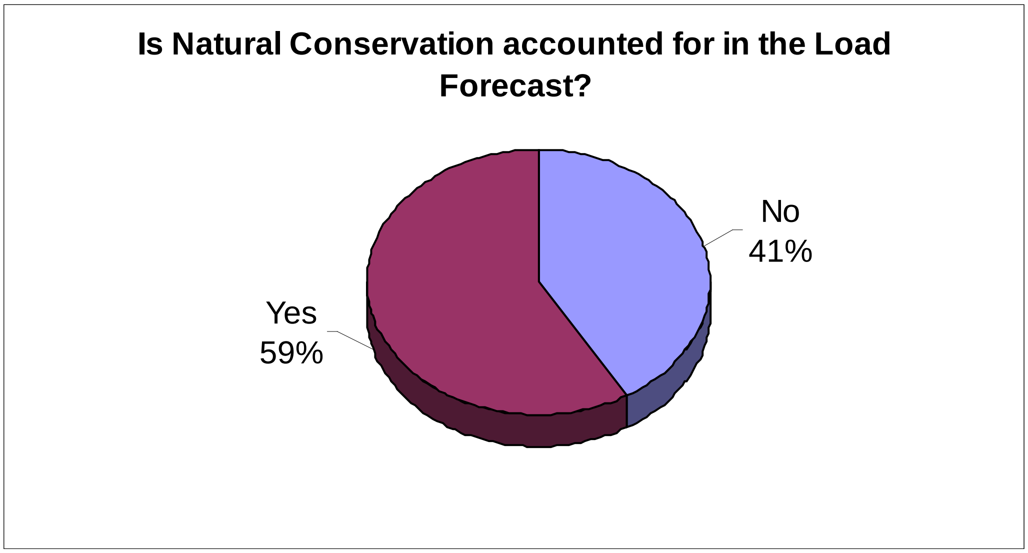

How do you forecast TOU or Dynamic Pricing
Implicitly Modelled
Explicitly Modelled
Number of Respondents
60%
50%
40%
30%
20%
10%
0%
25%
17%
58%
33%
8%
33%
8%
17%
External Sources
Estimate based on past
End-Use Model
Econometric Model


How do you forecast Customer Conservation Actions
Implicitly Modelled
Explicitly Modelled
Number of Respondents
60%
50%
40%
30%
20%
10%
0%
20%
13%
20%
50%
27%
25%
33%
13%
External Sources
Estimate based on past
End-Use Model
Econometric Model

Is Natural Conservation accounted for in your load forecasting?

There were 41 responses to this question.

- 59% of respondents said that natural conservation was accounted for in their load forecast.



Please explain your definition of "natural conservation" and the estimation methods used in your forecasting.

There were 30 responses to this question. There was a variety of answers received demonstrating that the definition of this term is not common among all respondents.

Some typical answers are shown below:

- Natural conservation is the behavior of customers to reduce energy usage without any utility or government incentive to do so. It is embedded in the historical trends.
- Natural conservation is assumed to be driven by future codes and standards and is based on some judgmental trend in future unit energy consumption by end -use.
- These are the reasonably expected improvements in efficiencies within the end-uses that we forecast.
- Natural conservation is non-program incentivized conservation due to prices, technology changes (i.e., unavailability of less efficient equipment in the market) and social, political and personal restraints. Natural conservation is embedded in the historical data.

Please tell us any other assumption that may be used in your load forecasting methodology.

There were 17 responses to this question. Listed below are a few responses:

- The impact of renewable distributed generation has become the most rapidly growing aspect of customers' conservation efforts in our territory. Data is obtained from applications filed with the utility and assumptions about operating hours, etc. from historical experience are used to develop impacts that are added back to historical data then removed and future impacts subtracted from the forecast.
- We use SAE (Statistically Adjusted End Use modeling)--Heating, cooling and other index
- Utilities must be careful to clearly distinguish between CDM/DSM savings and natural conservation in netting off CDM/DSM from load forecasts. This should be done with a detailed end use by end use accounting.
- CDM/DSM measures such as energy efficiency, demand response, and conservation are implicitly assumed to occur at the same rate as historical trends.

D.3 Comparison of Survey Results

Duke Energy conducted a survey in January 2011 to members of the Edison Electric Institute (EEI) to explore the various methods used to incorporate the load reductions due to energy efficiency programs into load forecasts.[1] While this survey asked specifically about energy efficiency programs and the load forecast, the results are similar to those from Hydro One's survey in terms of forecasting methodology. The survey had 23 respondents with 3 stating they use an explicit model to incorporate the impacts from energy efficiency programs and another considering using the methodology. Three said they do not make reductions for energy efficient programs. The remainder used different variations of an implicit methodology. The survey found that, in general, utilities either subtract energy efficiency program impacts directly from the load forecast or they are captured through the econometric model.

Table 14: Comparison of the survey results

Methodology to Incorporate DSM/CDM in Load Forecast	**Hydro One Survey** **April 2011**	**Duke Energy Survey** **January 2011**
Implicit methodology	75%	74%
Explicit methodology	20%	13%
Do not incorporate	5%	13%

D.4 Conclusions

Based on the results of 41 survey responses from North American electric utilities, the current methodology used by Hydro One to incorporate CDM/DSM into the load forecast is commonly used. The CDM categories used by Hydro One (energy efficiency programs, appliance and lighting standards, building codes, demand response, time-of-use or dynamic pricing, and customer conservation actions) were recognized by the majority of respondents regardless of the methodology for incorporating the category in the load forecast.

Survey Questionnaire

1. What are your primary business activities? (Please check one)

☐ Electricity Generation

☐ Electricity Transmission

☐ Electricity Distribution

☐ Integrated Utility (Generation, transmission, distribution)

☐ ISO/ IESO

☐ Commission or Government Agency

☐ Other

Please explain in more detail where necessary.

2. What were your total electricity sales (in GWh) in 2010?

3. What was your customer's or company's total peak demand (in MW) in 2010?

4. How is the impact of DSM/CDM reflected in your load forecasting? (Please check one)

A. Explicitly modeled in the load forecast (e.g., add historical efficiency program savings back to actual load and then deduct all past and future efficiency savings from the forecast).

B. Implicitly embedded in the load forecast (e.g., data used to generate the forecast has past conservation impacts embedded, subtract future incremental efficiency program savings from the forecast).

C. Not reflected in the load forecast

D. Other (please specify):

5. What is the rationale for the current methodology used to incorporate DSM/CDM in the load forecast? (Check all that apply)

❑ Recommended/approved by Commission/Government Agency/Regulator

❑ Believe that it is the best methodology to prepare an accurate load forecast

❑ It is the most practical method for our utility even though it may not be the best one.

❑ Other (please specify):

6. What are the regulatory mechanisms for your company to recover lost revenue due to DSM/CDM programs?

☐ Cost of service

☐ Revenue Decoupling

☐ Lost Revenue Adjustment Mechanism (LRAM)

Targets)

☐ Other (please specify):

If SELECT "A " FOR QUESTION 4, THEN CONTINUE Q7, Q8, Q9, Q13, Q14, Q15, Q16

7. What DSM/CDM savings are added back to the historical load to generate the gross load with DSM/CDM? (Check all that apply)

☐Energy efficiency programs

☐ Appliance and lighting efficiency standards

☐ Building codes

☐Demand response

☐Time-of-Use prices or Dynamic Pricing

☐Customer conservation actions (not captured by specific programs, such as turning off lights when it is not in use, turn down thermostat etc.)

☐Other [please specify]

8. What are the methods used to measure the ACTUAL IMPACT for the following DSM/CDM categories? (Check all that apply)

☐Energy efficiency programs

☐ Appliance and lighting efficiency standards

☐ Building codes

☐Demand response

☐Time-of-Use prices or Dynamic Pricing

☐Customer conservation actions (not captured by specific programs, such as turning off lights when it is not in use, turn down thermostat etc.)

☐Other [please specify]

EACH OPTION HAS THE FOLLOWING DROP DOWN LIST

EMV (Evaluation, measurement and verification)
End use model
Econometric model
Other (please specify)

9. What are the methods used to FORECAST the following DSM/CDM categories? (Check all that apply)

☐Energy efficiency programs

☐ Appliance and lighting efficiency standards

☐ Building codes

☐Demand response

☐Time-of-Use prices or Dynamic Pricing

☐Customer conservation actions (not captured by specific programs, such as turning off lights when it is not in use, turn down thermostat etc.)

☐Other [please specify]

EACH OPTION HAS THE FOLLOWING DROP DOWN LIST

External sources (such as State/provincial/utility DSM/CDM Target)
Estimate based on past experience, similar programs or customer base
End use model
Econometric model
Other (please specify)

If SELECT "B" FOR QUESTION 4, THEN CONTINUE Q10, Q11, Q13, Q14, Q15, Q16

10. What DSM/CDM savings are subtracted from the load forecast? (Check all that apply)

☐Energy efficiency programs

☐ Appliance and lighting efficiency standards

☐ Building codes

☐Demand response

☐Time-of-Use prices or Dynamic Pricing

☐Customer conservation actions (not captured by specific programs, such as turning off lights when it is not in use, turn down thermostat etc.)

☐Other [please specify]

11. What are the methods used to FORECAST the following DSM/CDM categories? (Check all that apply)

☐Energy efficiency programs

☐ Appliance and lighting efficiency standards

☐ Building codes

☐Demand response

☐Time-of-Use prices or Dynamic Pricing

☐Customer conservation actions (not captured by specific programs, such as turning off lights when it is not in use, turn down thermostat etc.)

☐Other [please specify]

EACH OPTION HAS THE FOLLOWING DROP DOWN LIST

External sources (ie. State/provincial/utility DSM/CDM Target)
Estimate based on past experience, similar programs or customer base
End use model
Econometric model
Other (please specify)

If SELECT "C " or "D" FOR QUESTION 4, THEN CONTINUE Q12, Q13, Q14, , Q15, Q16

12. How do you account for the DSM/CDM impacts in the load forecast?

13. Natural Conservation

Is natural conservation accounted for in the load forecast?	☐ YES ☐NO
Your definition of natural conservation	**Specify**
Estimation method of natural conservation	**Specify**

14. How do you determine net savings from DSM/CDM programs?

	Is it addressed?	**Estimation methods (i.e. survey, billing analysis etc)**	**Rationale for the estimation methodology (ie, recommended by regulator, commission etc)**
Free rider effect	☐ YES ☐NO	**Specify:**	
Spillover and free driver effects	☐ YES ☐NO	**Specify:**	
Persistence of saving	☐ YES ☐NO	**Specify:**	

15. Are there any documents related to the method of incorporating DSM/CDM impact in the load forecast or DSM/CDM assumptions you can share with us? **(UPLOAD FILE OR LINKS)**

____

16. Would you like to receive the results of this survey?

- ❑ Yes
- ❑ No

17. Please provide your contact information:

Last Name: _____________

First Name:_______________

Company:________________

Email:_____________________

Phone:_____________________

Thank you for participating in this survey.

Appendix E

Methodologies Used to Incorporate Conservation and Demand Management Impacts in the Load Forecast

EXECUTIVE SUMMARY

Since 2005, the Ontario Government has set specific Conservation and Demand Management (CDM) targets to be achieved in the province. Over the past several years, significant progress has been made in delivering various CDM programs across the province. The latest Long Term Energy Plan (November 2010) and the Supply Mix Directive (February 2011) issued by the government call for CDM savings of 4,550 MW and 13 TWh in 2015. Over the 2011-2014 period, Local Distribution Companies (LDCs) in Ontario are mandated to meet the CDM target of 1,330 MW and 6,000 GWh. In order to achieve good load forecasting accuracy, CDM impacts have to be handled properly in the modeling process.

Hydro One undertook a methodology review of how CDM impacts are incorporated in the load forecast modeling process. The results of the review show that there are 3 methods commonly used by electric utilities in North America. All methods take into account projected CDM impacts for the forecast period. However, major differences exist in how the CDM impacts are used in the modeling process. These methods range from using the actual load without CDM adjustments, using historical CDM impacts as an explanatory variable, to adding back historical CDM impacts to the actual load. Advantages and challenges of these methods are discussed in detail in this report.

Hydro One has adopted the third method in its load forecast modeling process. The review results show that this method effectively takes into account CDM impacts during the historical and forecast periods. It is also shown that this method is technically sound and efficient.

E.1 Introduction

Since 2005, the Ontario Government has set specific Conservation and Demand Management (CDM) targets to be achieved in the province. Over the past several years, significant progress has been made in delivering various CDM programs across the province. The latest Long Term Energy Plan (November 2010) and the Supply Mix Directive (February 2011) issued by the government call for CDM savings of 4,550 MW and 13 TWh in 2015. Over the 2011-2014 period, local distribution companies (LDCs) are mandated to meet the CDM target of 1,330 MW and 6,000 GWh. In order to achieve good load forecasting accuracy, CDM impacts have to be handled appropriately in the modeling process.

As explained in most economic textbooks, electric load forecasting models take into account economic, demographic, prices and other factors that affect the load. However, CDM does not behave like economic factors because it is determined as policy targets. As a result, economic theory would not be able to "model" CDM nor predict its impacts for the simple fact that it is set by policies. This does not change the fact that CDM affects the load and, as such, it should be taken into account in load forecast modeling process.

In addition to the survey carried out to better understand the methodologies to incorporate CDM in their modeling process, commonly used by other utilities in North America, Hydro One also undertook a review to compare these methodologies and better understand the issues surrounding this topic.

During this review process, Hydro One found that other entities have also done some research in this area. The results of this research are briefly summarized as follows:

- In 2007, North American Electric Reliability Corporation (NERC) Load Forecasting Working Group undertook a load forecasting survey among its members and concluded that there is insufficient consistency in forecasting methodologies used across the regions. It identified two key methodologies to model the impacts of historical and/or future conservation and efficiency improvements in the forecast, including explicit (e.g., directly modeling conservation impacts) and implicit (e.g., data used for base forecast has past conservation impacts embedded) models.[22]

- In 2010, Itron Inc., a US consulting firm, published a white paper on "Incorporating DSM into the load forecast"[23]. The document discusses three

[22] http://www.nerc.com/docs/docs/pubs/NERC_Load_Forecasting_Survey_LFWG_Report_111907.pdf

[23] https://itron.com/na/PublishedContent/Incorporating%20DSM%20into%20the%20Load%20Forecast.pdf

main econometric methods that may be used to account for CDM in the forecast period.

- In 2010, Duke Energy conducted a survey of Edison Electric Institute (EEI) member utilities in North America to gain an insight of the methods used to incorporate projected energy efficiency impacts into the load forecast.

The results of Hydro One's research show that there are three methods, commonly used by electric utilities in North America, to incorporate the impacts of CDM into the load forecast. All methods take into account projected CDM impacts for the forecast period. However, major differences exist in how the historical CDM impacts are being used in the modeling process. Sections E.2 to E.4 discuss these three methods in detail. Advantages and challenges of these methods are discussed in Section E.5 of this report.

E.2 Method 1: Use Actual Load without CDM Adjustments

In this method, no CDM adjustments are made during the modeling process so that the actual load (which is net of CDM) is linked to the economy, demography, prices and weather variables. Over the forecast period, incremental CDM (over and above the historical period) is usually deducted from the forecast. This method is considered the most simple among the three methods discussed in this report.

However, this modeling approach has the following challenges:

- Since the actual load during the historical period is affected by CDM between 2005 and 2010 (with CDM programs), this data will not be consistent with the rest of the historical load data prior to 2005 (without CDM programs).

- The model linking the actual load to various explanatory variables does not recognize that, in addition to the economic and demographic factors, the load has been affected by CDM. As a result, the estimated coefficients of the model will likely be biased as the impact of CDM will now go to the error term, and thereby affecting the coefficient estimates.

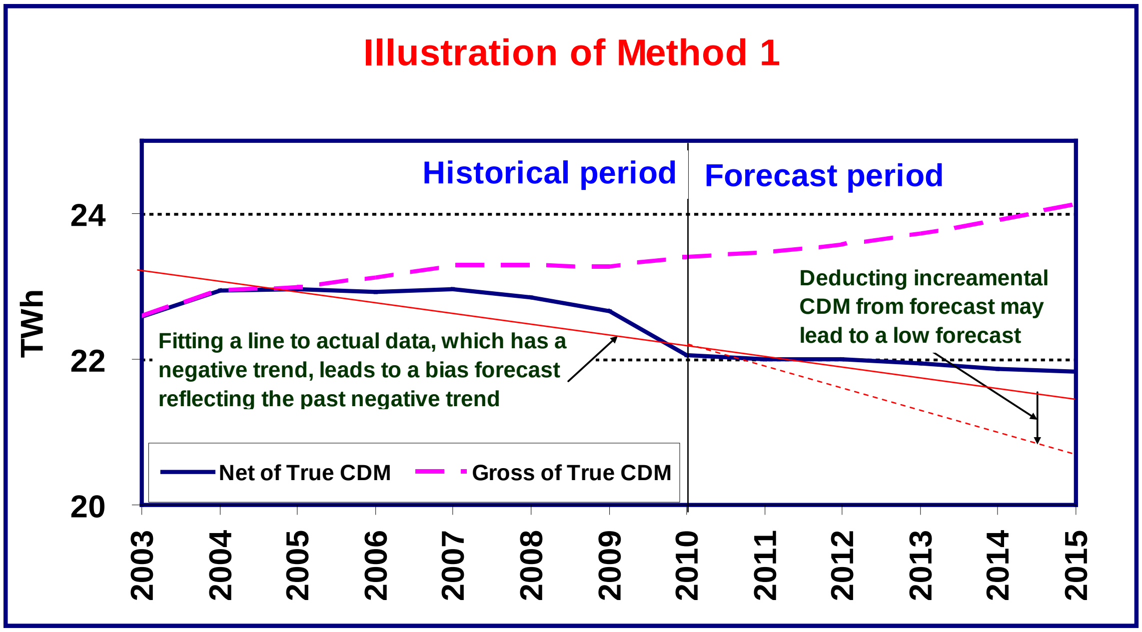
- Consequently, the forecast based on this model is biased. Due to CDM impacts, the forecasted load will likely grow less rapidly than it should for the same set of economic and demographic conditions. For example, estimated Gross Domestic Product (GDP) or income elasticity may be lower than its true value leading to a lower than normal forecast over the forecast period. GDP and income elasticity estimates will likely be negative, which is in contrast to their true positive impact to the load.

- Both the estimates of coefficients and the forecasts are inefficient because the error-term variance is inflated by the CDM impacts, which are not explicitly accounted for in the model.

Since the forecast is biased and most likely in a downward direction, it is difficult to determine how much incremental CDM should be deducted from the forecast. If the full incremental CDM impact during the forecast period is deducted from the forecast, there would potentially be double-counting issues because the forecast is already lower than it should be. Ignoring CDM during the forecast period is not a solution either because it is difficult to determine whether the bias embedded in the forecast will be completely offset by the error during the forecast period.

There is no systematic solution to generate an unbiased forecast using this method. The forecaster will likely be forced to make a judgment call on how much CDM is already "embedded" in the forecast due to the bias in the historical load data used, and how much "incremental CDM" should be deducted from the forecast.

Figure 3: Illustration of Method 1



In short, the estimated coefficients and the forecast using this method will likely be biased and inefficient. There is also a possibility for double-counting the CDM impacts, leading to a lower forecast as illustrated in Figure 3. Consequently, if a regression line is fitted to the actual data, the line will likely pick up the negative trend in data.

E.3 Method 2: Use CDM impacts as an explanatory variable

In this method, CDM impacts are used as an explanatory variable on the right-hand-side of the econometric equation, together with other economic variables. The model is then used to forecast the load net of CDM. For example, consider the following simple linear equation:

Load = a * CDM + b * Income + c * Electricity Price + d * CDD + e * HDD + Error Term

Where a, b, c, d and e are model coefficients to be estimated using data series on load and explanatory variables (i.e., income, prices, cooling degree days (CDD), heating degree days (HDD)). In this equation, the error term represents the balancing series consisting of random factors that could not be explained by any explanatory variable(s).

The CDM variable can be represented as KWh, KW or dollars value. In this example, the CDM variable is assumed to be using KWh. The CDM coefficient (a) in the forecasting model equals to -1 on *a priori* basis but because it is allowed to be estimated, its estimate may be different from -1.

This method has the following challenges:

- The CDM series may be correlated with other variables used in the equation (e.g., income). In this case, not only the CDM coefficient but some other coefficients in the model (e.g., b) may diverge from their true value.

- The error term in the equation potentially causes estimated coefficients to diverge from their true value. The larger the error, the higher the probability that the divergence would be substantial.

- If there are missing explanatory variables that are not included in the equation, then the estimated CDM coefficient is biased and it would probably diverge significantly from its true value (-1).

- This method has limitations for modeling in a log-linear form because it is difficult to take logarithm of a series (in this case CDM) if it has zero values (and CDM was zero prior to 2005).

All these could be avoided if the CDM coefficient (a) is set to equal to -1 so that CDM could be brought to the left-hand-side of the equation and be added to the actual load (which is Method 3 as discussed in this report).

The correlation between the CDM series and other variables used in Method 2 potentially leads to increases in variance of the estimated coefficients in the model so that the estimates are less efficient compared to Method 3. Efficiency is important because efficient estimates are more robust in case of small changes in data and potential equation errors.

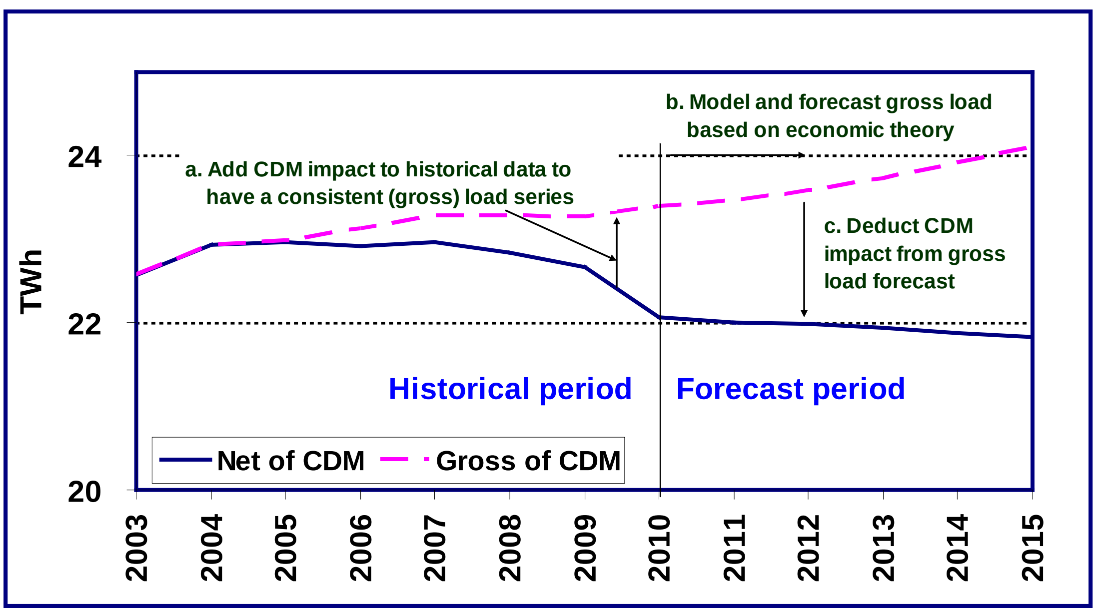
Some utilities in Ontario have used similar regression models as Method 2. The general approach is to regress monthly kWhs based on economic activity, days in the month, HDD, CDD, Spring/Fall binary "flag", CDM (in KWh value) and other variables as appropriate. The Ontario Energy Board (OEB) recognized the modeling issues associated with this method in its recent Decisions for Horizon Utilities' 2011 Cost of Service Rates Application (EB-2010-0131) and suggested that using more sophisticated econometric modeling approaches is required to deal with the multicollinearity issues associated with Method 2.

E.4 Method 3: Add back historical CDM impacts to actual load

In this method, the load impact of CDM is fully taken into account during the historical and forecast periods. This method employs the following steps as illustrated in Figure 4:

- The load impact of CDM is added back to the actual yielding a consistent data set (gross of CDM) over time for modeling.
- The adjusted (gross) load data is then used to model and forecast the load using appropriate explanatory variables (e.g., Gross Domestic Product (GDP), income, population, number of households, etc.) as well as prices in a manner consistent with economic theory. Having used consistent data and having accounted for all influential factors affecting the load, the model does not suffer from structural change due to CDM. As a result, both estimated model coefficients (elasticity) and forecasts are unbiased and efficient.
- Finally, the historical CDM impacts and CDM impacts during the forecast period are deducted from the gross load forecast to arrive at the load forecast net of CDM.

Figure 4: Illustration of Method 3



E.5 Comparison of the three methods

Each method discussed above has advantages and challenges. Hydro One has assessed all three methods and has selected Method 3 as the best method to generate accurate and efficient forecast. Table 15 compares the three methods for incorporating CDM in the modeling and forecasting process.

Table 15: Comparison of the three methods

Method	Advantages	Challenges
Method 1	• Estimates of historical CDM impacts are not required. • Modeling is simple without the need to adjust any right-hand-side or left-hand-side variables for CDM.	• Assume historical CDM impacts grow at the same rate over time, while it may not be true for all cases. • Historical efficiency savings embedded in the actual load data may influence the forecasted trend. • Subtracting additional CDM impacts for the forecast period may result in "double counting".
Method 2	• CDM is used as an explanatory variable to explain the declining trend of actual load.	• Requires estimates for CDM impacts for historical and forecast periods. • Need substantial historical CDM impacts to generate statistically significant parameter. • If CDM variable is in KWh or KW value, the regression model has potential multicollinearity issues.
Method 3	• Explicitly account for historical and forecasted CDM impacts. • Reconstitutes consistent load data to develop forecast in the model.	• Requires estimates for CDM impacts for historical and forecast periods. • If historical CDM impacts are not accurately measured, projecting future CDM impacts based on past results may affect forecast accuracy.

E.6 Conclusion

In this document, alternative methods for incorporating CDM impacts in load forecast modeling process were discussed and compared. Hydro One has adopted Method 3 in its load forecast modeling process. The comparison of the three methods in Section E.5 shows that this method effectively takes into account CDM impacts during the historical and forecast periods. It is also shown that this method is technically sound and efficient. Based on Hydro One's experience, this method has resulted in accurate load forecasts for Hydro One over past several years. Recognizing the fact that factors affecting the load forecast may change over time, Hydro One will continue to assess and adopt appropriate methods that produce accurate load forecasts.

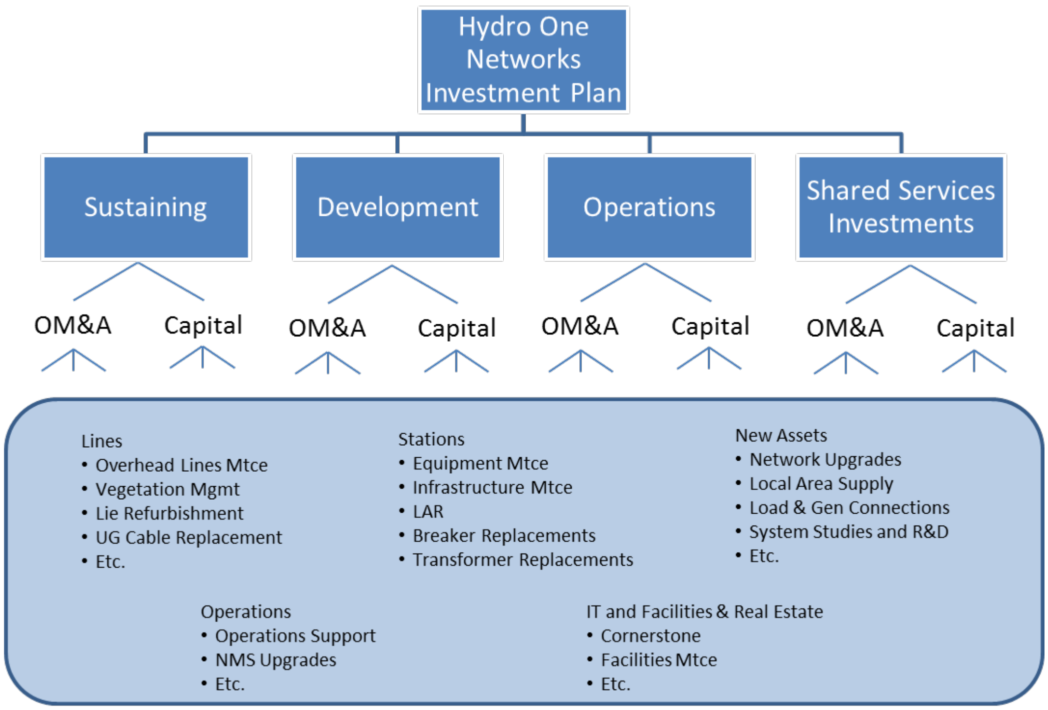
INVESTMENT PLAN DEVELOPMENT

1.0 OVERVIEW

Hydro One Transmission has four major investment categories: Sustaining, Development, Operations, and Shared Services Investments. Sustaining work is performed to maintain the existing capability of the transmission system so that it continues to function as originally designed. Development activities extend the capability of the transmission system, primarily to meet the demands of load and generator customers including the need for network transfer capability to enable load to access sources of supply. The Operations activities manage the transmission assets in real time on a continuous basis. Shared Services Investments (SSI) are a subset of the Shared Services costs and include the expenditures for MFA, Service Equipment, Projects and Programs for Facilities and Real Estate (e.g. improvements to field service centre facilities), IT projects (e.g. Cornerstone, WAN) and Customer Care (meter reading, billing, Vertex costs). These SSI projects can be common to both Transmission and Distribution or be specific to one or the other. SSI does not include the ongoing day to day process costs for the Shared Services units, such as the reporting activities performed by Finance, the HR payroll function, Cost of Sales to external parties, etc.

All of these investment categories share a common investment plan process, but with specific elements modified to address those aspects that are distinct to a particular investment category. This is explained further in sections 2, 3 and 4 of this schedule. The investments pyramid up to an overall Investment Plan for Hydro One Transmission as shown in Figure 1 below.

Figure 1
Investment Plan Process



As discussed in Exhibit A, Tab 13, Schedule 1, the investment plan process is part of Hydro One Transmission's corporate business planning process. During the investment planning phase of the business planning process information is collected, needs are assessed, and potential investments are identified for the four major investment categories. The individual investments are then evaluated taking into consideration the other investments within a category. The proposed levels of investment for each category are submitted for further evaluation against all other investments proposed, using the prioritization process described in Exhibit A, Tab 15, Schedule 4.

The prioritization process results in a portfolio of individual investments across all work categories that together make up a preliminary Investment Plan for Hydro One Networks. The preliminary Investment Plan is then reviewed by Senior Management who may further modify it based on consideration of the impact on customer rates, the ability to accomplish all of the proposed work in light of known constraints (e.g. labour, material, engineering resources, system outage availability, contract resources etc), the financial health of the company, and the impact of changes in investment levels on residual risk to business objectives.

The end result of this process is a prioritized Investment Plan proposal that meets the Company's business objectives and represents a balance among customer and transmission system needs, costs, and risks. The proposed Investment Plan is then recommended to the Hydro One Board of Directors for approval as part of the Corporation's business plan (see Exhibit A, Tab 13, Schedule 1).

The process for developing the investments for each of the Sustaining, Development and Operations investment categories is discussed in Sections 2.0, 3.0 and 4.0 respectively. Investments for Shared Services are developed using a similar process as shown in Figure 2, taking into account the requirements of Hydro One Inc. and its subsidiaries, which include both the transmission and distribution businesses. Some Shared Services are received from affiliate companies and the cost of services to and from affiliate companies are covered by Service Level Agreements, which are described in Exhibit A, Tab 8, Schedule 3.

2.0 SUSTAINING ASSET INVESTMENTS

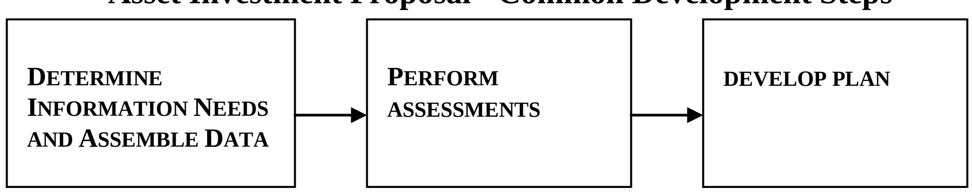
Sustaining asset investments are grouped into two categories:

- Stations, which funds the work required to maintain, refurbish or replace existing assets located within transmission stations, including protection and control and telecommunications facilities; and
- Lines, which funds the work required to maintain, refurbish or replace overhead transmission lines and underground cables, including vegetation control on transmission line rights-of-way.

Please refer to Exhibit C1, Tab 2, Schedules 1 and 2, for a full and detailed discussion on the extensive and thorough effort devoted to Sustaining asset investment in Hydro One. The next few pages provide a high level synopsis thereof.

Figure 2 shows the three basic common steps in developing asset investments.

Figure 2
Asset Investment Proposal - Common Development Steps



The particulars for each step in developing Sustaining asset investments are described below.

2.1 Determine Information Needs and Assemble Data

Hydro One Transmission has developed asset condition assessment and testing procedures for its transmission assets. Asset condition data is a key input to the assessment of possible investments as assets are essentially consumed over the course of their active duty. The scope of data collected depends on the criticality of the asset category. Data is collected in various ways, such as visual inspection by field maintenance crews, results from various testing procedures on assets (e.g. pole tests, transformer oil tests), and monitored reliability performance. Other considerations such as technical obsolescence and the level of manufacturer's support are included in the data set for assessing the investment needs. The data is compiled for each specific asset and may be grouped with the data of other assets of the same asset family for the purpose of developing component replacement programs. Data is verified and validated for accuracy.

2.2 Perform Assessment(s)

The assessment process focuses on risk mitigation and the two components that make up risk: Likelihood of Asset Failure or loss of design functionality and Consequences of Asset Failure.

Likelihood of Asset Failure or Loss of Design Functionality

The likelihood of failure or poor performance is determined through:

- Health Indices: A Health Index is generally available for assets that have on-going preventive maintenance applied against them. The results of the maintenance tests are scored and weighted to create a numerical score which indicates the relative health of an individual asset within its asset base.
- Asset Condition Assessments (ACA): These are proactive condition assessments specific to the various asset classes. The assessment results in a condition rating for each asset class which is a leading indicator of risk of failure and unacceptable

performance and the need for mitigating action in the form of revised maintenance procedures or asset replacement.

- Assessing the asset demographics: Assets entering mid or end-of-life are expected to require increased attention to maintain satisfactory level of performance. Maintenance costs of an asset in these periods can increase significantly and the likelihood of needing to refurbish or replace the asset will increase as well. Inspections and testing of such assets are undertaken to assess these needs. The demographic analysis includes a greater planning scope (up to 30 years) to facilitate an understanding of the bow wave of potential future costs. It provides a tangible understanding of the need to ramp up some of our programs to get ahead of and smooth out the future costs of our system to ratepayers.
- Evaluating component performance and reliability: Equipment failure rates are lagging measures which Hydro One Transmission monitors as critical signals of asset deterioration. These measures are used to validate the condition ratings and identify the need for immediate corrective action. Poor performance of a particular component is also assessed to determine if there is a need to be concerned about the health of other like units in the system.
- Equipment Utilization and Operating Environment: The usage of a component and the environment it operates in can also affect its performance and probability of failure. Assets wear out more quickly if operated near or above their normal ratings, or if operated in harsh environments. Thus utilization assessment(s) are done on specific assets where there is a risk that usage will have affected the life of the equipment.
- Other Assessments and Studies: Hydro One also relies on external expert opinion for assessing the condition of its assets to supplement information gathered through maintenance activities and internal studies. Other factors considered may include design issues that have manifested themselves as problematic over time.

Consequence of Failure or Loss of Design Functionality

The second aspect that is assessed is the consequence of a failure or particular unacceptable event. Consequences that are considered include:

- Safety and Environment: Hydro One strives for an injury-free workplace and to maintain public safety, as well as working to protect and sustain the environment for future generations.
- System Reliability: Hydro One makes investments to ensure reliable performance of Ontario's transmission system. Capital and OM&A investments are made to improve element and system reliability. E xternal bodies to Hydro One also provide a reliability framework to work within, including the IESO and NPCC.
- Customer Impact and Satisfaction: Hydro One evaluates the need for investment to mitigate the impact customers may face resulting from a loss of supply, as well as making investments that benefit our customers with the goal of continued improvement of customer satisfaction.
- Financial / Competitiveness: Hydro One looks to build and maintain a cost-effective transmission system for Ontario. Investment and design decisions are made to achieve OM&A and/or capex savings due to improved and/or lower priced process/equipment including moving to standardized modular designs, therefore helping to mitigate rate pressures.
- Regulatory/Legal: Hydro One makes investments in order to comply with all regulatory and legal requirements and satisfy the requirements of our transmission license.
- Reputation: Hydro One also evaluates the consequences of asset failure on the reputation of the company to preserve shareholder value.

Investments address the risk associated with the most consequential assets first. Consequential assets with higher probabilities of failure would be mitigated before those with lower probabilities of failure.

2.3 Develop Plan

Developing the plan for individual projects or programs involves the initial step of developing a recommended investment action for each asset based on the assessment discussed above. As noted in section 2.1, additional factors such as technical obsolescence and the level of manufacturer's support are taken into full consideration. Initial individual investments are developed and prioritized based on criteria aligned with corporate objectives and business values. Various levels of sustainment effort are defined for each asset, and the cost and risk is determined for each level of investment.

The planning process also involves reviewing the potential investments and "bundling" of work where there are synergies and efficiencies to be realized and it is practical to do so. For example, there may be a situation where transformers need to be replaced at a particular Transmission Station (TS) and there is also work to be done on the breakers at the same TS. This work would be scheduled together if there are efficiencies to be realized with respect to mobilization of crews to do the work and timing of outages that need to be taken. In some cases, it may also be efficient to make best use of resources and outages by advancing other sustainment work at the same TS, which would normally have occurred later. Work bundling is discussed in detail in Work Execution Strategy, Exhibit A, Tab 15, Schedule 6.

The three step process described above is essentially the same for all sustaining investments. However, there are some differences in terms of the condition data collected, assignment of criticality of assets, the assessment performed and the prioritization of investments. The results of the application of this process to determine Hydro One Transmission's proposed sustaining OM&A and capital programs and their expenditure levels for the test years are described in Exhibit C1, Tab 3, Schedule 2 and Exhibit D1, Tab 3, Schedule 2 respectively. As noted earlier, the detailed decision making processes of sustainment work programs are outlined in greater detail in Exhibit C1, Tab 2, Schedules 1 and 2.

3.0 DEVELOPMENT ASSET INVESTMENTS

Development asset investments are established using a process largely consistent with that shown in Figure 2 of Section 2.0, Sustainment Asset Investments, but with some distinct differences appropriate to the Development Capital and Development OM&A categories of work. Sections 3.1 and 3.2 discuss the specific process for developing the investment plan proposal for Development OM&A and Development Capital respectively.

3.1 Development OM&A

Development OM&A activities enable Hydro One Transmission to identify and implement Research and Development projects that investigate the use of new technologies and/or practices that, if proven feasible, may be utilized by Hydro One Transmission to improve sustainment and/or development of its transmission system. Implementation of new products and technologies is also facilitated by this program's funding of development of Standards that reflect construction needs, and legal and regulatory requirements. Development OM&A programs also include projects that will facilitate greater integration of renewable energy generation in the province and provide enhanced control and protection of the transmission system resulting in improved reliability.

Each year prospective OM&A projects and programs are identified by the business. These proposals are assessed and prioritized for funding consistent with business and program objectives.

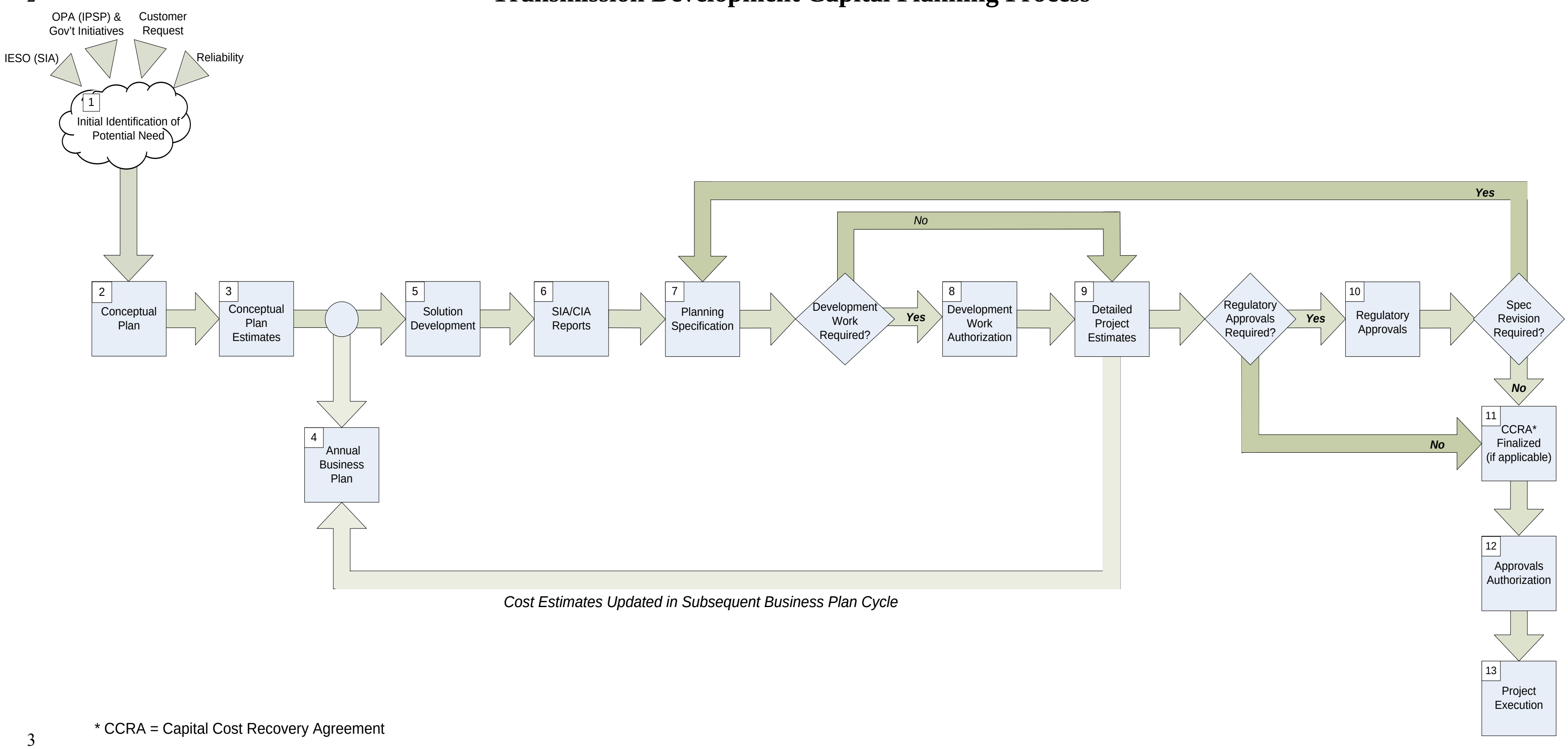
Application of this process to determine Hydro One Transmission's development OM&A programs and expenditure levels is described in Exhibit C1, Tab 3, Schedule 3.

3.2 Development Capital

The process for Development Capital investments provides the means by which the myriad of needs identified by a variety of stakeholders are addressed in a consistent manner. The process described below ensures that the transmission system is planned in a way that balances the expectations of customers, regulators, asset owners, the Ontario Power Authority (OPA), the Independent Electricity System Operator (IESO), affected communities and the general public interest.

The need for development investments is driven by requirements such as connecting new customers (Load Connection, Generation Connection), upgrading existing delivery capability to meet customer demand (Local Area Supply, Performance Enhancement and Risk Mitigation), and increasing network transfer capability to enable electricity consumers to access supply (Network Upgrades). The Development Capital planning process for all of these investments broadly consists of the thirteen steps shown in Figure 3 and described below.

Figure 3
Transmission Development Capital Planning Process



* CCRA = Capital Cost Recovery Agreement

3.2.1 Need Identification

Under the electricity industry structure in Ontario, the OPA or Hydro One Transmission may identify the need for new power system facilities or system enhancements.

The OPA identifies major transmission facilities for Inter-area Network Transfer Capability and Local Area Supply Adequacy that may be required in the long term.

For the Inter-area Network Transfer Capability and Local Area Supply Adequacy projects that require in-service in either the short term or medium term, Hydro One Transmission works cooperatively with the OPA in identifying the need of the projects.

For Inter-area Network Transfer Capability projects required to support government policies, such as for the development of renewable resources, the OPA normally consults with Hydro One Transmission, where it owns the transmission facilities in the area, as to the feasibility of solutions before recommending that specific projects be commenced, taking into acount requirements for any external approvals.

Depending on the urgency of the need to meet the requirements for in-service date for short term and medium term projects, Hydro One Transmission will initiate work on the pre-engineering, design, approvals, and construction to implement these projects. Board approvals for the projects will be obtained through the Section 92 "Leave to Construct" process.

In some cases, the need for Inter-area Network Transfer Capability and Local Area Supply Adequacy projects is identified by Hydro One Transmission on the basis of the System Impact Assessment (SIA) that is carried out by the IESO for other projects, for example for load or generation connection projects. Another potential driver for some projects is the operating and maintenance experience of Ontario Grid Control centre

(OGCC), including concerns about complexities associated with planned and forced outages of equipment. With regards to dedicated connection facilities, the need for Development projects can also result from requirements of load customers or generation customers.

The investment plan is produced at a point in time with the best currently available information. The plan is subject to subsequent changes by customers and additional needs identified by government directives, OPA procurement programs and OPA regional studies. These subsequent changes will be managed through the redirection process described in Exhibit A, Tab 15, Schedule, 4.

3.2.2 Conceptual Plan

A Conceptual or Reference Plan to satisfy the need is first developed to provide potential transmission solution(s). Typically, this Conceptual Plan is based on engineering judgment and the experience of the Hydro One Transmission planners. The plan is revised and fine-tuned as the planning process for the project moves forward as described below.

3.2.3 Conceptual Plan Estimates

Budgetary cost estimates are prepared based on the high level functional requirements of the Conceptual Plan described above. The Conceptual Plan Estimates are used for the annual business planning process if detailed cost estimates are not yet available.

3.2.4 Annual Business Plan

Business Planning is an annual process that focuses on the development of an Investment Plan based on the Corporate Planning Process (Exhibit A, Tab 13, Schedule 1) and involves the prioritization of projects using the process described in detail in Exhibit A, Tab 15, Schedule 4. The cost of plans included in the Business Plan are based on conceptual plan estimates or, if the plan has advanced to a relatively more detailed stage as described below, on more detailed project estimates as available at the time of preparing the Business Plan.

3.2.5 Solution Development

Detailed planning studies (i.e. load flow study, short circuit study, transient stability study, etc. - as required) are undertaken to assess and compare the alternatives in order to identify a transmission solution for implementation. Joint studies with the OPA and/or Local Distribution Companies (LDCs) may also be conducted to assess alternatives. For Development projects where a solution is recommended by the OPA, for example to incorporate renewable resources as per government directive(s), Hydro One Transmission commences activities to implement the OPA's recommended solution.

3.2.6 System Impact Assessment / Customer Impact Assessment

The proposals for transmission development projects are required to follow the IESO's Connection Assessment and Approval (CAA) process. The CAA process requires that a System Impact Assessment (SIA) be conducted by the IESO. The criterion used for SIA is outlined by the IESO in the "Ontario Resource and Transmission Assessment Criteria" document. A Customer Impact Assessment (CIA), where applicable, is also required to be conducted by Hydro One Transmission in accordance with the requirements of the TSC.

Hydro One Transmission and the IESO have made the processes for conducting SIAs and CIAs more efficient. For example, proponents of load or generation connections may now submit a common application for both the SIA and CIA. Under this more efficient process, proponents will need to submit technical data for SIA and CIA assessments only once, compared to the previous process wherein the proponents had to submit such data separately to the IESO and Hydro One Transmission.

3.2.7 Planning Specification

Detailed technical requirements for the preferred transmission solution are identified and documented in a Planning Specification. These planning specifications evolve as detailed requirements are identified on t he basis of SIA/CIA report findings and as the Development Work proceeds as described below.

3.2.8 Development Work Authorization

If required, authorization for project development work is sought, in accordance with Hydro One Transmission's Organization Authority Register (OAR), in order to initiate preliminary engineering work required to obtain regulatory approvals under the Environmental Assessment Act and/or under Section 92 'Leave to Construct' of the OEB Act.

3.2.9 Detailed Project Estimates

Detailed release estimates are prepared based on the project's Planning Specifications which are updated, if required, as the aforementioned Development Work proceeds. These updated estimates are used in the preparation of subsequent Annual Business Plans and for work related to Regulatory approvals described below.

3.2.10 Regulatory Approvals

There are two major types of regulatory approvals that may be required for transmission development projects. The first type of regulatory approval that may be required is the "Leave to Construct" approval (under Section 92 of the Ontario Energy Board Act, 1998) which is required for transmission lines greater in length than two kilometres. The second type of the regulatory approval that may be required arises from the Environmental Assessment (EA) Act. Under this Act, relatively smaller projects may require a Class EA while major projects may require an Individual EA. The transmission projects that would require an Individual EA would typically fall under one of the following categories: (i) 500kV transmission lines which are greater in length than two km, (ii) 115kV or 230kV transmission lines that are greater than or equal in length to 50km or (iii) transformer stations that are greater than 500kV.

Additional iterations of solution development and planning specifications may be required based on conditions or constraints identified through the approval processes, and the project cost estimates are revised accordingly.

3.2.11 Capital Cost Recovery Agreement

If required, a Capital Cost Recovery Agreement (CCRA) is finalized in accordance with the TSC.

3.2.12 Approvals Authorization

Internal approval as described in Exhibit A, Tab 15, Schedule 5 is sought for commitment of the plan, or parts of the plan, in accordance with the Organization Authority Register (OAR) described in Exhibit A, Tab 8, Schedule 2.

3.2.13 Project Execution

The plan, or parts of the plan, is released to the Engineering and Construction Services for execution.

Further details on the planning required for each type of investment (Load Connection, Local Area Supply, Generation Connection, Enabling Facilities, Station Equipment Upgrades & Additions to Facilitate Renewables, Protection and Control for Enablement of Distribution Connected Generation, Network Upgrades, Performance Enhancement, Risk Mitigation and Advanced Distribution System (Smart Grid) are provided as part of Exhibit D1, Tab 3, Schedule 3.

4.0 OPERATIONS ASSET INVESTMENTS

The Operations function manages Hydro One Transmission's assets in real time on a continuous basis, using Grid Operating Control Facilities. The facilities are typically information and control systems and tools that enable monitoring and control of transmission assets, coordinating and scheduling planned maintenance outages, and monitoring and reporting on the performance of the transmission system.

Asset investments may be either OM&A or Capital in nature. Capital investments are required to fund major enhancements and end of life replacement of the existing facilities. OM&A asset investments are required to maintain the operational readiness and reliability of the facilities and to support, manage and produce minor modifications to existing facilities.

In determining appropriate Operations asset investments, the same steps as for developing Sustaining asset investments apply, that is: 1) Determine Information Needs and Assemble Data, 2) Perform Assessments, and 3) Develop Plans.

The application of each of these steps for Operations investments is described further below.

4.1 Development of Operations OM&A Investments

Operations OM&A is required to support and maintain Grid Operating Facilities (information and control systems and tools) so that they continue to meet asset and business needs. Operations OM&A also funds incident management, system fixes and minor modifications to existing facilities.

4.1.1 Determine Information Needs and Assemble Data

The lifecycle of operating facilities and asset condition assessments are used as an input to developing investments. These expenditures fund the operation of Hydro One's transmission system consistent with good utility practice and within the requirements established by the reliability authorities, operating agreements and the market rules. The scope of the OM&A work is defined using a work specification, which is subject to annual review by stakeholders and service providers.

4.1.2 Perform Assessment(s)

Hydro One Transmission performs assessments to determine the level of effort required to support operating facilities, including control facilities, infrastructure, telecommunications and administrative and engineering tools. T he criticality of the various components is a key determinant of support requirements. The complexity of the various facilities is also an important factor in determining support requirements. For example, as information and regulatory requirements increase, the numbers of key components such as servers typically expands from year to year, leading to increased support requirements.

4.1.3 Develop Plans

Based on the assessment of criticality of the facilities and their complexity, the Operations OM&A plan is developed to meet business and technical requirements. The plan includes severity level definitions, required trouble call responses and corrective maintenance measures.

Application of the process outlined above to determine Hydro One Transmission's Operations OM&A programs and expenditure levels is described in Exhibit C1, Tab 3, Schedule 4.

4.2 Development of Operations Capital Investments

Operations Capital funds investments to sustain and enhance the computer tools and facilities that support the Control Room and back office transmission operating functions at the OGCC and the back-up Control Centre. Given the size and scope of transmission operating facilities, capital investments are typically required to provide end of life replacements and major upgrades. The work is required to maintain or enhance the functionality of existing facilities, and to meet the market and regulatory requirements for monitoring, control and reporting capability.

The following principles are used to define investment strategies with respect to centralized operating facilities:

- Fully exploit commercial-off-the-shelf software products that have been shown as "the best of breed" in the electrical utility industry.
- Enhance and extend existing applications using continuous improvement, thereby taking full advantage of enhanced capabilities inherent in the existing tool set.

- Maximize asset utilization factors and useable lifespan of Hydro One Transmission assets.
- Maximize the utilization of operating data and increase data accuracy, thereby improving business efficiency, safety provided to Hydro One staff and the public, and the reporting of performance analysis and assessment of asset investment decisions.
- Optimally replace and upgrade hardware and software platforms according to industry best practice, i.e. prior to withdrawal of vendor support or according to recommended End of Life (EOL) schedules.

4.2.1 Determine Information Needs and Assemble Date

The need for asset investments are determined using information collected from a number of sources including: operating strategies, asset conditions assessments, business objectives, lifecycle analysis, criticality of assets, benchmarking, business process requirements, market and regulatory compliance requirements, and Federal or Provincial initiatives.

4.2.2 Perform Assessment(s)

Depending on the assessment of the factors noted above, operating facilities, most of which are mission critical, are maintained or replaced entirely, depending on the most cost-effective solution. As required new facilities are also developed.

4.2.3 Develop Plans

Detailed plans are developed in order to determine the scope, timing and funding levels of investments. These investments must then be prioritized. The prioritization must strike a balance between sustaining existing operating facilities and developing new facilities. Software and hardware components have heavy sustainment needs, since they have relatively short lifecycles compared with other transmission assets, and they require support on a continuous basis. At the same time, development of new facilities is critical to implementing improvements to business processes and operational strategies, as well as maintaining regulatory compliance.

Application of the process outlined above to determine Hydro One Transmission's Operations capital programs and investment levels is described in Exhibit D1, Tab 3, Schedule 4.

INVESTMENT PRIORITIZATION PROCESS

1.0 OVERVIEW

The investment prioritization process is part of the overall company risk-based planning process (see Exhibit A, Tab 13, Schedule 1). The prioritization process converts Hydro One Transmission business values and key performance indicators shown in Table 1 into investment criteria and guidelines that are used for managing risk and facilitating trade-offs between investments. At the core of the process is a multi-criteria analysis, which is used by the company to understand and quantify business risks and uncertainties, so that objective decisions can be made respecting priorities. This process requires several iterations to achieve the best portfolio of investments that achieves the optimal balance of the constraints and criteria imposed. The objective of this exercise is to identify work that mitigates the most risk per dollar within the constraints defined.

Capital and OM&A investments are prioritized annually within a five-year planning period but within the context of an overall 20-30 year investment horizon. The output of the prioritization process is an Investment Plan Proposal (IPP). The IPP is composed of a list of prioritized investments, both capital and OM&A, developed in response to asset, customer and business needs. The process incorporates risk tolerances consistent with corporate objectives and also considers resource, material, outage availability and other constraints. Once approved, within the corporate Business Plan, the IPP sets the company's direction with respect to the work programs going forward.

The implementation of the IPP is subject to adjustments as new risks and/or opportunities emerge, changes in asset condition are identified or there may be a shift in corporate priorities throughout the year. A redirection process described in Section 2.5 of this exhibit enables the approval and implementation of such modifications.

2.0 INVESTMENT PRIORITIZATION PROCESS

The investment prioritization process was first implemented in 2001. This process responds to factors such as aging infrastructure, customer demand for higher reliability, changing regulations, funding pressures, etc. Since 2001, the process has seen continuous improvements using the experience gained each year. In 2011, Hydro One clarified the naming convention of its levels of investment to improve clarity. The prioritization methodology has remained the same and still addresses the broad scope of investment areas required to expand, operate and maintain the Transmission System. Also, work execution considerations such as resources, materials and outage availability, and effective work bundling are accounted for in the development of the proposed expenditures, which result in investment proposals that balance the company's asset needs with the various implementation constraints.

The prioritization process considers risk mitigation against an array of business values to select the proposed levels of investment leading to the IPP. This annual process consists of the following steps:

- Refine/validate business values in line with the corporate strategy;
- Develop multiple levels of investments to incrementally mitigate risks;
- Determine and evaluate the cost, benefits and risks for each level;
- Prioritize the levels across all functional areas of the corporation; and
- Assess the results and build the Investment Plan Proposal.

These steps are described in the remainder of this exhibit.

2.1 Business Values

Business Values ("BVs") are designed by Hydro One to enable the achievement of the Company's strategic goals, by forming the criteria against which: investments are developed; risks are managed; and trade-offs are facilitated between investments. The Business Values are measured by a set of key performance indicators (KPIs). The BVs represent the objectives that are to be factored into the decision-making process, while the KPIs represent how the impact on the BVs is to be measured.

Table 1 below, shows the BVs and KPIs used in 2011 in the establishment of the 2012 - 2016 Investment Plan Proposal.

Table 1
2011 Business Values and Key Performance Indicators

Business Value	Measure/Key Performance Indicator
Safety	• Employee/contractor workforce health and safety • Public safety
Customers	• OEB service quality index • Customer satisfaction: large and mid-size customers (industrials, LDCs and Tx /Dx generators) • Customer satisfaction: residential and small business customers • Public profile and confidence: effective stewardship of assets
Reliability	• Reliable delivery of electricity • System security
Environment	• Environmental performance
Employees	• Employee skills: developing, retaining, attracting and competencies
Shareholder Value	• Shareholder confidence • Meet license conditions and maintain credibility with regulators • Get required approvals from regulators • Net income • Credit worthiness • Value of the enterprise
Productivity	• Productivity • Work Program accomplishment, including Tx plan short-term initiatives

The KPIs form the basis of the multi-criteria analysis used to prioritize investments by providing the dimensions for consideration when assessing the degrees of risk and the risk mitigation that each proposed investment level provides against each of the BVs.

The process incorporates a probability and severity-of-outcome risk matrix to determine the impact ratings for each BV. The Probability scale ranges from Remote to Very Likely and Severity of Outcome scale ranges from Minor to Worst case.

2.2 Multiple Investment Levels

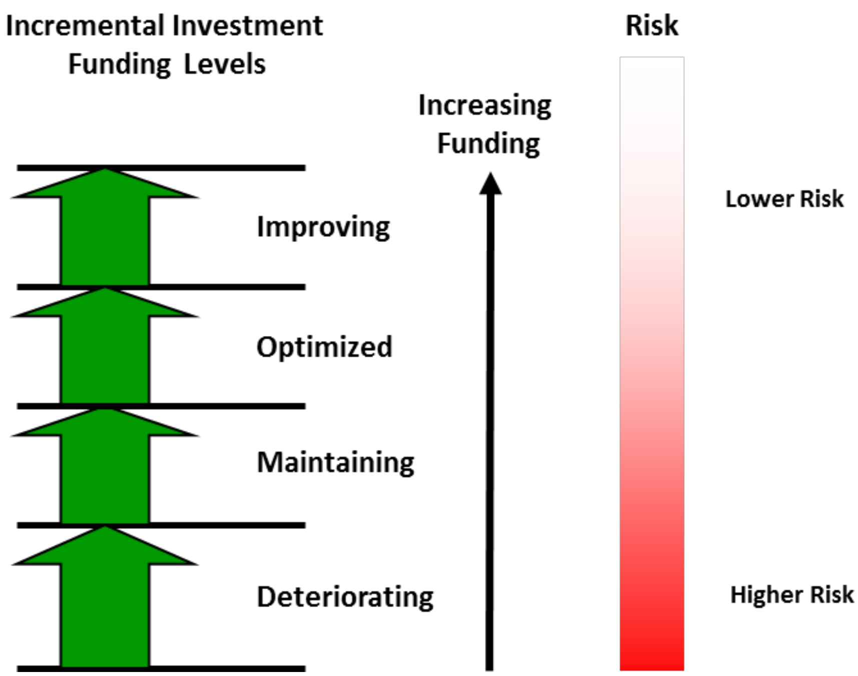
Customer, asset and business needs, risks and objectives guide the ongoing planning activities. Investment proposals are developed to address these needs, risks and objectives, and then are incorporated into the prioritization process. The scope and levels of the investment - and the accomplishments those levels of investment deliver - varies depending on the level of risk mitigated.

Hydro One's investment prioritization process is based on a risk mitigation approach and begins with the output from the Investment Plan Development process. A description of Hydro One Transmission Investment Plan Development is provided in Exhibit A, Tab 15, Schedule 3.

This Investment Prioritization Process has been consistently utilized since 2001 and has been examined in a number of recent proceedings before the OEB.

The approach is illustrated in Figure 1 below.

Figure 1
Accomplishment Levels versus Risk



The accomplishment levels are established and evaluated for a period of five years but within a longer-term view (of up to 30 years) of asset demographics, particularly in Sustainment, to ensure the appropriate trajectory is put forward to allow for, among other things, to manage the overall life cycle requirements of resources. However, short-term constraints, such as scheduling of skilled staff, availability of materials, or availability of outages, are also considered when establishing the levels of work that are actually undertaken.

"Deteriorating" investment level (previously entitled Minimum level) – This level of investment ensures compliance however asset performance will deteriorate over time. This level of investment cannot be continued beyond the planning period without the residual risk increasing to an unacceptable level. This level includes non-discretionary investments required to meet service obligations as mandated by customer connection requirements, government directives and compliance to all applicable standards and regulations.

"Maintaining" investment level – This level of investment represents a level of funding that maintains asset performance and risk at current levels. Effectiveness of executing the work program may deteriorate. For Development investments, this level would include discretionary investments, for example those designed to increase operational flexibility or enhance restoration efforts.

"Optimize" investment level – This level of investment will preserve asset performance, residual risk and operational effectiveness at optimum levels.

"Improving" investment level – This is a higher level of investment designed to increase operational effectiveness toward cost minimization over time. Asset performance will increase and residual risk will decrease. Investments are done opportunistically to enhance value to customers. Given the current state of the assets, investments may need to increase over the long term to arrive at an efficient state

Considerations of risk and risk mitigation are probabilistic in nature. Risk is the product of the probability of the worst credible scenario occurring and the impact on each business value.

The following example for the Power Transformer capital replacement program is provided for illustrative purposes only; it does not include units planned for replacement under Station Reinvestment projects.

Hydro One Transmission manages a fleet of 719 large power transformers; currently 21% of the fleet (151 transformers) are older than 50 years, which is the typical expected service life for transformers. Over the next five years, an additional 47 units will reach 50 years old. Approximately 10% of the transformers are currently in poor or very poor condition, and a further 10% are in fair condition as determined by industry standard diagnostic practices. Age and condition are both leading indicators of future transformer performance. As a greater proportion of the fleet reaches end-of-life, overall condition is forecasted to deteriorate further resulting in an increased failure rate. Transformer failures can have significant reliability impact to local customers, or in the case of autotransformers, a broader system wide impact. There are also environmental and safety concerns associated with managing a fleet of aged transformers.

To address the risks associated with current and projected transformer demographics and condition, incremental levels of accomplishment are developed for the five-year plan. Table 2 below, illustrates the transformer example above.

Table 2
Power Transformer Replacement Program – Proposed Levels

	# Replaced per year	# Replaced (over 5 yr plan)	# Beyond EOL (in 5 years)	Risk		Effectiveness
Deteriorating	4	20	178	↑	- Significant Reliability degradation impacting Customer through increased failure rates and increased forced outages. - Increased risk of environmental impact due to oil leaks and spills.	- Corrective Maintenance costs and effort expected to increase as the fleet ages
Maintaining	8	40	158	→	- This level will maintain the failure rate and number of forced outages which are currently below the CEA average. - Maintain environmental impact as a result of oil leaks and spills.	- Continued levels of OM&A required to maintain the transformer fleet.
Improving	15	75	123	↓	- Reliability will improve due to reduced failure rates and forced outages. The number of transformers beyond the expected service life will decrease. - Decreased risk of environmental impact due to oil leaks and spills	- Reduced OM&A expenses to maintain the transformer fleet and increased deployment of modern technology i.e. improved monitoring, oil filtration, etc.

The Improving level is currently being proposed as it allows Hydro One to get ahead of the bow wave of replacements, and reduce the number of transformers beyond their expected service life to roughly 123. At this level the failure rate is expected to improve minimizing the impact on reliability, decreasing the number of customer complaints. The exposure to spills is minimized, and the number of forced outages should be reduced from current levels.

Considering the demographics of the fleet, continuing at the historic rate of replacement (8-10 units/year) it is anticipated that major failures increase by a factor of 3-4 times by 2020 and delivery point performance is expected to drop.

Prolonged funding at the Deteriorating level is not sustainable and does not conform to good utility practice as replacements do not keep pace with units in need of replacement. The risk-based prioritization process is used by Hydro One to quantify risks, and to identify the appropriate sustainable level of investments that will ensure the achievement of the Company's strategic goals.

In the absence of any specific risk tied to a shorter timeframe within the five year planning horizon, specific investments may be rescheduled from one time period to another within the five-year planning horizon. Hydro One Transmission would do so in response to drivers such as execution constraints comprising critical resource limitations or availability of outages and with due care that such a rescheduling would limit any material deterioration of associated risk. If investments are assigned the lowest level of funding, redirection and work bundling becomes much more challenging as only the critical assets that pose significant risk to the company are being targeted, therefore inefficiencies are recognized.

2.3 Investment Costs, Benefits and Risks

Total funding requirements to carry out the accomplishments established for each level of investment are determined using current year costs as the basis for comparison. Where appropriate, linkages between particular investment areas are taken into consideration.

The benefits of each investment are determined by its ability to mitigate risk to the business values (BV). The KPIs provide a common set of criteria to measure the impact, or consequence, of the investment for each of the BVs. However, risk is the product of the consequence and the probability of occurrence, so this probability of occurrence also has to be established. BV risk is identified in a two-dimensional table as shown in Table 3. Using this approach, the change in risk for each BV as a result of the investment is established.

Table 3
Business Value Evaluation Matrix

	Minor	Moderate	Major	Severe	Worst Case
Very Likely (>95%)					
Likely (65 to 95%)					**Unacceptable Risk Zone**
Medium (25 to 65%)			Decreasing Risk		
Unlikely (5 to 25%)					
Remote (< 5%)					

2.4 Investment Prioritization

The needs, objectives, accomplishments, costs, and risk assessment for each level of accomplishment are documented. This information is then reviewed by technical experts, business analysts and other stakeholders within Hydro One. The quality control review ensures the full integration of the numerous investments and consistency in the use of the risk assessment model. Particular attention and challenge is given to the Deteriorating level of investment given its significance.

The information provides the necessary cost and risk mitigation data required to conduct the risk based prioritization process. The prioritization process selects one of several levels of investment for each investment area based on that level's ability to mitigate risk to the BVs. The aggregation of work programs that define the various selected levels yields the Preliminary IPP.

The Preliminary IPP is reviewed by Senior Management before the final Investment Plan and associated funding requirements are established. Senior Management's review takes into consideration the associated impacts on customer rates, the ability to accomplish the proposed work in light of known constraints (e.g. labour, material, engineering resources), the financial health of the company, as well as the residual risk to the business (i.e. the risk to the BVs that remains after the investments are made).

The end product of the Business Planning process is an Investment Plan that represents an effective balance between these considerations.

2.5 Investment Plan and Redirection

While the Investment Plan is the product of extensive planning and analysis, implementation of the plan must be done in a manner that is dynamic and flexible.

Redirection of approved investments may be required for a number of reasons, including changing customer needs, changing asset priorities based on new information, changing external requirements and major events (e.g. extensive storms and equipment failures).

This redirection of work allows appropriate and prudent adjustments to be made to the work originally identified in the Investment Plan. As an example, transmission line emergency restoration work required to repair damage caused by storms or equipment failures can be significant in a given year and may necessitate the redirection of funds and field resources from other investment areas to correct the unexpected and significant damage. On a monthly basis the changes from plan are identified and corrective action is recommended for approval to senior management; they in turn balance the emerging needs, financial impacts, resource impacts and the changing risk profile, when making a decision to approve the changes to plan.

PROJECT AND PROGRAM APPROVAL & CONTROL

1.0 INTRODUCTION

As described in Exhibit A, Tab 13, Schedule 1, there are a number of key steps within the overall business planning cycle which are typically completed prior to the development of the detailed project and program assessments. These prerequisite steps include: needs identification, project/program prioritization and the development of preliminary work programs, based on estimates of project and program costs and benefits. Once the preliminary plans have gone through the investment prioritization process described in Exhibit A, Tab 15, Schedule 4, a detailed analysis of the preferred alternatives and costs is completed for individual projects and business cases based on the detailed analysis and cost estimates are prepared for review and approval.

2.0 PROJECT AND PROGRAM APPROVAL

Once the overall investment plan has been prioritized and reviewed and the business plan is approved, individual project proposals are developed and assessed. Such factors as the need for the investment including the implications of not doing the work, the anticipated results and the recommended solution and its cost are all considered. In determining the recommended solution, alternative approaches and project risks are considered. The proposals are then reviewed in a series of steps at the senior management and executive levels, depending on the dollar limit and the significance of the investment. The proposals are then approved consistent with the provisions of the Organizational Authority Register ("OAR") described in Exhibit A, Tab 8, Schedule 2. For programs this analysis and approval is completed as part of the investment planning process. Strategic investments are reviewed and approved by the Hydro One Board of Directors. The Investment

Summary Documents provided in Exhibit D2, Tab 2, Schedule 3 summarize the proposed projects exceeding $3 million in the test years and programs with expenditures exceeding $3 million in either of the test years.

3.0 MONITORING AND CONTROL

Each month, management monitors year-to-date expenditures and accomplishments as well as projected year-end expenditures and work accomplishments. Deviations from plan are identified and the Redirection process is followed to ensure the appropriate corrective action taken. This process is described in Exhibit A, Tab 15, Schedule 4.

In the event that the total project costs are forecast to be materially different from the amount originally approved, an Interim Review of Variance ("IROV") is prepared. An IROV is essentially an amended business case that is reviewed and approved based on the revised set of circumstances (cost, scope and schedule). The IROV approval is in accordance with the limits set out in the Organizational Authority Register (OAR). Projects which cannot be re-justified are either scaled back, cancelled or otherwise adjusted to conform to the new situation.

WORK EXECUTION STRATEGY

1.0 BACKGROUND

Hydro One Transmission's Work Execution Strategy provides increased work execution capacity and necessary flexibility to accommodate additional changes in future years. This is necessary in order to address the required increases in planned transmission work programs over the coming years and the continuing global business changes such as the uncertainty regarding material availability and qualified personnel to undertake the work. A focus on efficiency continues throughout Hydro One's work planning and execution activities and processes.

Transmission system projects and programs continue to be more complex to plan and execute than in past years due to an increase in the total volume of work required, limited system outage availability, long lead times required to obtain key materials and equipment, and increased constraints from environmental regulation compliance. Each of these items is discussed in greater detail below.

The 2013 and 2014 work program is increasing to accommodate the expanded work necessary to meet Hydro One's Sustaining program (i.e. infrastructure renewal/re-investment) needs. Although there is a shift in asset investment from Development to Sustainment, this work execution strategy positions Hydro One well to complete the work in the test years. Hydro One has a long history of being a nimble work execution organization that can accommodate changes in investment needs. This was demonstrated with the Development program ramp up in recent years, a good example of which is the construction of the Bruce to Milton high voltage line. 2012 is a transition year allowing Hydro One to change focus towards a higher Sustainment investment plan. As described in Exhibit A, Tab 16, Schedule 1, despite the increasing work programs in the past few years Hydro One has been able to maintain reliability and improve safety performance; a strong focus continues on these two areas into the test years and beyond.

The following sections discuss the factors impacting the work programs as well as the work execution plan.

2.0 MAJOR FACTORS IMPACTING FUTURE WORK PROGRAMS

Major capital work on the transmission system has steadily risen from approximately $350 million per year in the middle of the last decade to expenditures of over $1.0 billion per year in 2013 and 2014 as summarized below. A full discussion of test year capital expenditure requirements is provided in the schedules found in Exhibit D1, Tab 3.

Aging system – An increasing percentage of the system has reached, or is approaching its end of service life (typically 40 or 50 years) and now requires or will soon require replacement. This vital need for infrastructure re-investment will continue to increase substantially throughout the decade as discussed further in Exhibit C1, Tab 2, Schedule 2.

System Expansion and Growth – Over the past few years, significant transmission investments in the addition or substantive upgrade of major lines and stations have been required due to the changes and system needs resulting from the retirement of coal-fired generation, the significant addition of new generation sources including gas-fired and renewable resources, and the load growth in a number of regions in Ontario. The size and number of major transmission projects over the last five years has been unprecedented in recent decades as they must be completed over a relatively short period due to the volume and urgency of meeting the various supply needs. For example, in 2012 the Bruce to Milton project will be placed into service while numerous other major projects approved by the OEB in previous decisions are being undertaken. The overall gross spend for transmission Development capital projects for 2013 and 2014 is comparable to expenditure levels of the last five years, however the overall net spend is lower as large amounts of generation work is mostly recoverable from generators. A complete discussion of these projects can be found in Exhibit D1, Tab 3, Schedule 3.

Introduction of New Technology – The original protection and control systems used to monitor and manage the transmission system have been replaced by new modern technologies. As a result, what a few years ago would have been a simple like-for-like replacement, now often requires a fundamental redesign and replacement of the complete system at a location. This renewal work began several years ago and continues through the test years at a higher level. Concurrent to this, Hydro One will also leverage knowledge gained from the Owen Sound smart grid pilot project which will be completed in 2012. Not only are efficiency gains seen during the capital installation phase, which utilizes more efficient designs, the new designs use modern computer-based P&C equipment that require less ongoing maintenance. Hydro One has also introduced new technologies during heavy construction work. For example new pole setting machines, vibrohammers and foundation jacks have improved efficiencies and enhanced safety.

Increasing Compliance Needs – As a result of failures over the past decade in the North American transmission grid and similar occurrences in other countries, transmission design and operations are subject to continued increasing compliance requirements. NERC plays a large role in defining the requirements. Similarly environmental legislation has increased levels of regulation requiring compliance. Vegetation management staff are having increased interaction with regulators to negotiate work restrictions. New training and field work plans have been put in place to deal with the requirements. These incremental increases in compliance work continually add new items to the existing work program and increase the level of verification and quality assurance activities on established work.

Green Energy & Green Economy Act 2009 (GEGEA) – The GEGEA has resulted in large amounts of renewable generation being planned, developed or constructed throughout the province of Ontario since its introduction in 2009 and the required transmission system investment discussed earlier. The government's Long Term Energy Plan (LTEP) has identified three transmission projects designated to Hydro One to increase the transfer capabilities in primarily southwestern Ontario to facilitate the connection of higher levels of renewable generation. T hese and other projects that facilitate renewable generation are described further in the Hydro One Transmission Green Energy Plan in the Exhibit A, Tab 14, Schedule 1 a nd in the Transmission Development Capital Exhibit D1, Tab 3, Schedule 3.

3.0 IMPLEMENTATION OF WORK EXECUTION STRATEGY FOR THE 2013 - 2014 WORK PROGRAM

Hydro One Transmission has taken a number of actions to increase the volume of work the Company can complete in future years. Hydro One Transmission is now using fully integrated work planning methods that balance and optimize the use of internal and external resources, costs, system outages, customer needs and material availability. These include:

3.1 Increased Work Bundling and Outage Optimization

Many of the transmission projects and work programs require parts of the system to be electrically isolated while the work is being performed. Getting the required planned outages is increasingly difficult as each year the transmission system grows larger and more complex as new generators are added, additional customers are connected and supplied loads increase. All of these factors limit the number and duration of outages that are approved by the IESO for Hydro One Transmission to complete its work programs.

In addition, planned outages are susceptible to being cancelled. Cancellation can be due to storm activity, customer demands, system constraints as dictated by the IESO, etc. When planned outages are cancelled due to system constraints or severe weather, crews have to be demobilized and the work and its required outages rescheduled for some future date. Outage cancellations increase project costs and limit work accomplishment.

Hydro One has made a number of improvements to outage planning to mitigate the risk of not being able to do the work. Often when work is required on a line section or in a station, there is other work planned for the same assets but at some other time. By bundling of this work Hydro One can reduce the number of outages and take advantage of efficiencies derived from the combination of several pieces of work into a single work package. Hydro One has defined outage zones, called Transmission Station Outage Groups (TSOGs), to allow for this bundling. For example, during a circuit outage, the following work would be done at the same time: deficiency reports, line maintenance including power washing; insulator replacement; protection system maintenance; transformer station line disconnect and ground switch maintenance; and line capacitive voltage transformer maintenance. Similarly, during a transformer outage the following maintenance work can be done at the same time: transformer mechanical and electrical; transformer protection systems; transformer spill containment; surge arrester; potential and current transformer; transformer low voltage bus; and disconnect switches.

In addition, Hydro One has implemented a long term balancing of the preventive maintenance programs for switches, transformers and instrument transformers. This means that the work programs have been aligned into integrated and optimized maintenance frequencies and plan dates to minimize outages. For example, this allows for all switch maintenance on a given circuit to be planned for the same year, with a single outage requirement.

Completing more bundled work at common locations enables Sustainment work and Development work to be planned and executed in an integrated manner under a common work plan. This reduces the number of system outages required, utilizes resources more efficiently, increases the total volume of work that can be executed, and positively impacts customer satisfaction. Fewer planned outages reduce risk to system reliability where circuit redundancy exists, and reduces customers out of power on radial circuits.

Optimized outages and bundled work directly reduces both switching time requirements as well as crew windshield time. Reduction in these activities helps reduce the risk of injury to workers and reduces greenhouse gas emissions.

The more advanced planning that is done, and the better visibility crews have to the work, the better Hydro One is able to optimize work execution. A recent example is the work in Hurkett Swamp on the high voltage lines A6P rebuild and A7L tower foundation repair. Both activities were completed, not only sharing the outage windows, but also sharing the winter roads.

There will always be a need to cancel or reschedule outages due to changing system, customer or business requirements. However, minimizing cancelled or rescheduled outages directly improves work efficiency. The volume of planned equipment outages processed annually from 2006 to 2011 has increased by 63%, while through the use of improved outage planning tools and processes, as discussed in the following section, the number of cancelled outages has only increased by six percent.

3.2 Operations Processes and Tools

The outage planning process has been developed based on timelines and outage impact. In general, equipment outages which tend to have a major impact on the power system and or customers are identified well in advance to ensure this work can be accommodated with minimal impact. Equipment outages which have little or no direct impact to the power system or customers are typically identified and planned on a shorter time schedule realizing that this work can easily be fit around the larger more impactive equipment outages. Hydro One meets with customers to jointly select the best opportunities and dates for the equipment for the following year. An optimized and bundled outage schedule for the following year is developed for the most efficient use of workforce and equipment while striving to minimize impact on the power system and affected customers.

The Network Outage Management System (NOMS) is the operational system used to plan, schedule, communicate and track planned equipment outages. This system was originally placed in service in 2002 based on both technology and business requirements at that time. A new version of the NOMS tool was released in late 2010. This version incorporated new functionality and work flow to improve outage throughput. Key enhancements included functionality such as outage conflict identification, outage bundling identification, web based user interface for customers, integration with the corporate reporting tool, work flow with the ability to assign and send e-mail notifications both to internal and external customers and improved metrics. These tools have improved the efficiency of the outage planning and scheduling process recognizing the high volume of the work programs.

3.3 Standards and Repeatable Designs

All of the transmission lines work is based on a catalogue of standardized components. Line engineers select the towers, the insulators, the hardware, the conductors, and even the foundations from the catalogue. In the stations environment, Hydro One now has developed many standard building blocks which are used on a repeatable basis. Examples include “Protection, Control and Telecom (PCT) in a box” whereby the entire protection and control and telecommunications system for a station is manufactured and delivered to the site by a manufacturer who works from standard design drawings. This approach is more cost effective and simpler from the perspectives both of design and staging into service to replace the entire relay building using this standard design rather than replace individual components. Replacements using standard PCT building design result in savings of about 15% when compared to replacements of individual components of protection and control systems. As well, it is an effective means for best utilization of resources.

Another example is standardised Distributed Generation (DG) connection equipment and standardized commissioning and inspection work modules. F urther examples would include low profile transformer station design, modular oil-water separators, transformer foundation and spill containment designs for all standard transformers ranging from the smallest to the largest, station service systems and modular distribution stations. New stations are being designed in 3D CADD using standard library components. On smaller Dual Element Stop Network (DESN) stations the application of this methodology has reduced the design time from six months to one month.

During the commissioning phase of an asset's life, field crews must validate correct functionality and also apply protection and equipment calibration settings. The standard designs allow for common commissioning processes and procedures to be developed. This is vitally important at a time where Sustainment work is high since these programs cover many locations across the province touching many different field crews. Common approaches used by crews are an important part of Hydro One's work execution strategy.

Hydro One continuously adds to the list of standards and repeatable designs that are used to minimize the design effort and maximize the opportunities for strategic sourcing savings. This is discussed further in section 3.5 Strategic Sourcing of this exhibit.

3.4 Work Programs Releases

There is a direct correlation between quality upfront planning and the ability of service groups to effectively and efficiently execute the work. Asset Management continues to improve the project definitions and timeliness by which work is released. Earlier releases allow the services groups to more efficiently plan and execute work. Construction productivity is enhanced since there is sufficient time in the schedule to order materials in such a way that they arrive at the jobsite when required according to a logic-driven work schedule, thus reducing the lost efficiency and additional costs associated with workarounds caused by missing materials. Early release of the programs leads to efficiency in that the work can be better planned and therefore scheduled when site conditions are optimal. For example crews take advantage of frozen conditions when access may be an issue.

Early and multi year work releases for Sustainment capital programs are particularly beneficial for the field execution and commissioning teams as this type of work involves considerable planning for outages, materials, staff skills, and coordination with other capital or maintenance work. In addition, new equipment usually means new technology and therefore new commissioning and maintenance documents need to be written. The early and multi year release of the work better prepares the field teams for the higher Sustainment program in the test years.

3.5 Strategic Sourcing

New materials and equipment incorporated into each capital project account for approximately 35 to 40% of the total cost of the project. Much of this material and equipment is unique to the needs of high voltage transmission systems and is manufactured by a small number of specialized global businesses. A s a result of globalization, most Hydro One suppliers of specialized equipment are located outside of Ontario, and many outside of North America.

Growth in other parts of the world coupled with very large government infrastructure programs in Europe and North America is resulting in a rebound of the global electrical equipment market from the 2008 – 2010 down turn. Manufacturing plants for specialized equipment are starting to reach full capacity. Through Hydro One's collaborative planning and strategic sourcing programs, contracts are in place and long lead time materials are being effectively managed to mitigate any potential impacts on executing Hydro One programs due to material delays. An "open orders" status report has been established to monitor the order placement status of essential project materials and equipment. This report ensures material delivery delays are minimized and expedited where possible. This report is used as a pro-active indicator that contributes to ensuring project materials will be delivered on time and enables greater work accomplishments.

Strategic sourcing is a fundamental component of the work execution strategy. Bulk purchasing has also been more broadly facilitated by the use of standardized designs discussed earlier. Materials must arrive when scheduled so that work execution can be done efficiently. The improvements made in this area have reduced the need to reschedule crews and outages. This becomes very important with Hydro One's Sustainment program where high volumes of similar work are executed across the province. As such, delayed delivery of material can have far reaching impact on many crews and outages.

Strategic sourcing has generated significant savings over traditional spot purchasing on a project by project basis. This is discussed in Exhibit D1, Tab 4, Schedule 3. Its success is based on having a good understanding of longer-term investment plans and priorities.

Strategic sourcing including bulk purchasing is a significant contributor to Hydro One's cost savings initiatives and the Company's ability to complete the work programs.

For example, a review of the entire fleet of high voltage power transformers revealed many non-standard transformers existed across the system. Many were reaching end of life and needed to be replaced. A design review was undertaken and a transformer standard was established. Contracts have been established and power transformers are being purchased in a bulk manner to meet future work program needs. Significant savings of $24 million between 2009 and 2011 have been realized in the form of lower overall purchasing costs, as well as benefits associated with greater conformity and standardization of power transformer designs; a further savings of about $25 million is expected to be realized between 2012 and 2014.

Standardized designs have also resulted in unit price reductions for bare conductor and standard switches, resulting in estimated savings of $9M over 2012-2014. Hydro One is currently evaluating bulk purchasing for other long-lead commodities. The primary focus is to strategically source all products and services (where possible) and ensure they are under contract to mitigate long lead times, ascertain favourable prices and ensure Hydro One remains agile in reacting to business plan changes.

Through Hydro One's strategic sourcing program critical materials and services, contracts and contracting are being proactively managed to ensure work execution needs are being met.

3.6 Logistics Support

An important element of the Work Execution Strategy is optimizing the material stocked in the Company's warehouse. Hydro One has embarked on a Logistics approach to support the need for project and program timelines. The strategy provisions core materials from stock rather than waiting to purchase these materials only after projects have received final approval. The materials lead times are therefore reduced. Materials are staged from a central warehouse and deployed as soon as they are needed on the work site. The result is that materials bottlenecks associated with vendor lead times have been largely eliminated.

3.7 Resource Planning and Management

Transmission system work programs are completed on a project-by-project basis by Hydro One resources, by external resources or in combination. Internal work capacity represents a challenge to work execution. A significant wave of retirements has begun and is expected to continue over the next decade. In addition, specialist power sector engineers have been more difficult to recruit than in the past, due to competing needs from other organizations in Ontario, Alberta and from international organizations recruiting to satisfy major global expansions in China, India and other rapidly expanding locations. A full discussion of all the human resource challenges are provided in Exhibit C1, Tab 5, Schedule 1.

By assessing the long term planned work, Hydro One Transmission identifies any developing gaps between the supply and demand for key resources well in advance of their need. This information is used to create resourcing plans that are directly tied to the specific needs of the work program and to identify in advance work that will be outsourced.

For example, to handle project changes a resource model is maintained that enables Hydro One to quickly evaluate what additional work can be undertaken at any time and to evaluate the impact of a proposed change in priority or redirection of effort due to some system event. This model is integrated with Hydro One's resource plans for each of the projects in progress, enabling the Company to assess the loading across resource categories. Traditional project management focuses on the critical path of each individual project separately, thus ignoring the conflicts between individual projects and project managers arising from conflicting reliance on the same scarce resources. The resource model also focuses on identifying the critical resource allocation conflicts and schedules their priorities amongst the competing projects in order to optimize the overall performance of the work program.

3.8 Outsourcing

When the work program requirements exceed the capabilities of the Hydro One workforce, additional work is contracted out. Although the Hydro One construction workforce is scalable to match the work program needs, there is a practical limit to its size defined by the volume of work that can be safely and efficiently planned and managed by internal staff. The work contracted out, typically greenfield and brownfield projects as well as some major refurbishment projects, is completed using a combination of internal resources, engineering subcontracts, construction contracts or arrangements contracted on a fixed-price basis. As well, certain types of work which require specialized skill sets Hydro One does not have internally and are very low volume such as Static VAR Compensators, Series Capacitors and some buried cables, are normally constructed by “turnkey” contractors. The work execution strategy also recognizes that the work must be completed without workplace injuries, be of high quality, on time and at a competitive cost. Hydro One continues to monitor and analyze similar projects which were executed internally and externally in order to drive internal continuous improvement initiatives and to focus contracting on areas which are most cost effective. This approach fosters competitiveness within both internal staff and external contractors. Having a highly skilled internal workforce means the Company has options and can pick the best one for the circumstance.

In addition, Hydro One utilizes engineering contractors where necessary to ensure the efficient execution of the work program allowing the Company to manage the significant increases in the program and the ongoing variation in requirements for specific skills on a weekly basis. Union purchased services agreements somewhat hamper Hydro One's ability to use contractors in some areas. However, several initiatives involving contractors have been undertaken. For instance, one significant initiative has been the migration to three dimensional computer-aided design (3-D CAD) and software that automatically generates wiring diagrams (Autowiring), which will result in fewer drawings being required and the elimination of drawings completely in some circumstances.

Outsourcing of all or a portion of a project continues through the test years. This is illustrated in the following table. Examples of major projects with significant outsourcing components include the replacement of high voltage cables in Toronto, the Milton Static Var Compensator, the new Orleans Transformer Station in Ottawa and the new Clarington Transformer Station in Oshawa.

$ millions	**2010**	**2011**	**2012**	**2013**	**2014**
Outsource Total	132	108	123	317	348

As the total work program grows, Hydro One's outsourcing strategy ensures that sufficient resources are available to execute the work in the test years.

3.9 Resources and Enhanced Expertise

Over the past few years, Hydro One staff with accountability for work program execution, have increased their critical resources to accommodate the growing work program and to offset growing staff demographic attrition. The strategy in the near-term is to continue ramping up delivery on the work accomplishments identified over the test years but to do so while maintaining regular staff levels at 2012 levels. This will be accomplished through the increased utilization of casual workers and temporary employees, and by the prudent use of overtime.

A key component of the work execution strategy is the optimal deployment of Hydro One expert internal resources. The Company possesses what is arguably one of the finest engineering teams anywhere in the high-voltage transmission sector. Optimal deployment of internal resources to maximize work program execution has been implemented to allow a fairly small group of highly skilled senior engineers to oversee the accomplishment of several tasks being done by several teams, instead of overseeing one task executed by one team.

Casual Trades continue to be a source of seasonal resources for significant programs such as brush control. See Exhibit C1, Tab 5, Schedule 1 for headcount details. Extensive training programs are deployed annually to ensure these types of staff are qualified to do the work.

Hydro One prides itself on its highly flexible Construction workforce giving the ability to meet the demands of the work program. Through a combination of regular staff, Casual Trades, temporary, and overtime, both skill sets and cost are optimized.

Efforts also continue to enhance the skills and on-the-job effectiveness and efficiency of Hydro One's new grad hires through continuously refined and improved internal training programs. Similar efforts continue with respect to Hydro One's trades apprenticeship programs as well as its co-op student programs. Hydro One has also partnered with universities and colleges to develop curricula to educate students specific to the Company's industry. Hydro One is certified by the Ministry of Training, Colleges and Universities to deliver its own apprentice training and also provide this service under contract with other utilities. Please refer to Exhibit C1, Tab 5, Schedule 1 for further details.

At the same time that Hydro One must deal with an expanding work program, it must also deal with a workforce demographic that will see a significant number of experts retire within the next few years, so programs have been initiated to preserve essential know-how for the next generation. For example, Hydro One has had good success using line crews with a large apprentice component under the guidance of just a few tradesmen to quickly learn the required skills and become very productive. This fast tracking of skills development allows the project to be efficiently delivered while ensuring qualified resource succession.

The focus on maintaining high employee engagement continues which positively influences workers commitment. This is discussed in more detail in Exhibit C1, Tab 5, Schedule 1.

Many of the efficiencies described above will be facilitated by the Cornerstone project. The specific efficiencies and expected savings are described in Exhibit D1, Tab 4, Schedule 3.

3.10 Monitor and Engage Regulators on Environmental Regulations

Environmental legislation and implementation of regulations associated with legislation such as “Species At Risk Act” and “Migratory Birds Convention Act” has increased, impacting project timelines. Hydro One has increased the levels of interaction with regulating authorities such as Ministry of Natural Resources to negotiate practical measures that balance the needs of species or environmental concerns and the work requirements of the company’s maintenance and construction projects. In fact, the Bruce x Milton biodiversity initiative has positioned Hydro One as a partner on this issue with the Ministry of Natural Resources as well as Conservation Authorities.

Hydro One has cooperated with the Ministry of the Environment on their approvals streamlining initiative. A new Environmental Compliance Approval (ECA) process under the Environmental Protection Act has replaced Certificates of Approval under the EPA and the Ontario Water Resources Act. As part of this process, Hydro One provided feedback on the types of facilities that are subject to ECA approvals and implemented changes internally to facilitate those applications. Efficiencies have been gained on both sides. Hydro One has also been cooperating on the implementation of the Renewable Energy Approvals (REA) process for generation projects. Hydro One has provided input to the Ministry of Energy Guidance Document (for generators) and shared experience with the connection of Distributed Generators (DG's). Hydro One has also been meeting with DG's to educate them on approval requirements. This customer focused dialogue has worked very well and has reduced the risks that Hydro One's connection requirements would impact in-service dates for the DG's.

Hydro One participates on an Environmental Assessment (EA) Proponents Group and Provincial EA Advisory Committee building positive relationships with Provincial Ministries and agencies (eg Go Transit, Ministry of Natural Resources, Conservation Ontario, etc).

Hydro One has developed some work practices to ensure its operations minimize impacts and continues to engage the regulators at both local and policy level as well as through the CEA to find practical solutions to environmental regulations.

In the context of Hydro One’s brush control programs, some local and municipal government agencies seek to implement controls beyond the Pesticides Act that would restrict or seek to prohibit the use of herbicides for selective brush control. Hydro One continues to work with these bodies to mitigate the risk of not accomplishing its work programs.

Environmental stewardship is a core element of Hydro One's strategic plan. Working closely with government regulators is a fundamental part of the work execution strategy.

4.0 SUMMARY

There are many factors changing the volume and characteristics of the future work program as well as the key enablers for successful completion of this work. The past few years had a large component of Development work whereas the test years transition to a greater proportion of Sustainment programs. As compared to Development work, the Sustainment programs are characterized by different complexities in both the planning and execution phases with generally more outages and a greater variety of materials required for completion. As such, 2012 is a year of transition in which the foundation is laid in terms of people, processes and tools to adjust to this new paradigm of Sustainment work. Hydro One has developed a comprehensive strategy to maximize the work execution capacity. Together with the items outlined in this exhibit, there are numerous incremental efficiency initiatives recently undertaken and planned in 2013 and 2014 throughout the business as discussed in Exhibit A, Tab 17, Schedule 1. Hydro One's work execution strategy meets its customer's needs, improves overall system performance and accommodates the expanded work program necessary to meet the Company's Sustainment and Development program needs.

TRANSMISSION BUSINESS PERFORMANCE

1.0 INTRODUCTION

Hydro One is focused on the strategic goals and performance targets in the area of safety, customer satisfaction, reliability, shareholder value, and productivity. This Exhibit illustrates the historical business performance of Hydro One's Transmission Business in these areas with the exception of Productivity, which is addressed separately in Exhibit A, Tab 17, Schedule 2. Additionally, utility performance assessment also involves comparisons with other utilities which is a priority of the Board and stakeholder community. Accordingly, this Exhibit includes a brief discussion of the issues with such comparisons and provides a comparison to other utilities, where information is available. These comparisons focus on the established Canadian Electric Association (CEA) composite performance which is the aggregate performance of CEA participating utilities. Other comparison perspectives that are evolving within the industry, on a North American scale, are also presented within this Exhibit.

2.0 PERFORMANCE MEASUREMENT PROCESS

The first approach to establish Hydro One Transmission's performance levels entails monitoring actual performance over time. The remainder of this Exhibit provides Hydro One's performance on its targeted areas, utilizing historical data drawn from Hydro One's own records.

The second approach involves comparison with other transmission utilities, particularly for reliability performance. This is a much more complex undertaking that requires careful consideration of:

- measurement definition,
- data collection processes which impact on the consistency and accuracy of the reported measures, and
- variations such as climate, operating environment and system infrastructure between transmission companies that can influence the absolute performance of their transmission systems.

A way to reduce the effect of these factors is to observe year-over-year performance using consistent and precise measurement definitions.

Although transmitters each have a slightly different approach when measuring their own reliability performance, the Canadian Electricity Association (CEA) has had success in creating reliability performance definitions of sufficient precision and consistency over the years to permit some degree of multi-jurisdictional transmission performance comparisons. The data, however, are not audited and the comparisons are used only to help identify opportunities for business improvement. This Exhibit presents Hydro One's performance relative to a C EA composite performance where available. In addition, Hydro One is participating in performance comparison studies as these evolve in the U.S.

3.0 SAFETY PERFORMANCE

Hydro One's number one priority is safety. Hydro One has implemented a managed system allowing the effective management of safety within the work environment. The managed system assesses activities, risks and the effectiveness of control, sets safety objectives and puts in place appropriate programs to manage the risks. The managed system has enabled the implementation of health and safety work programs to ensure employee health and safety training is appropriate and current and for coaching of field supervisors to ensure they understand their role as well as health and safety expectations.

In addition, Hydro One has implemented its Journey to Zero initiative to continue to engage employees by:

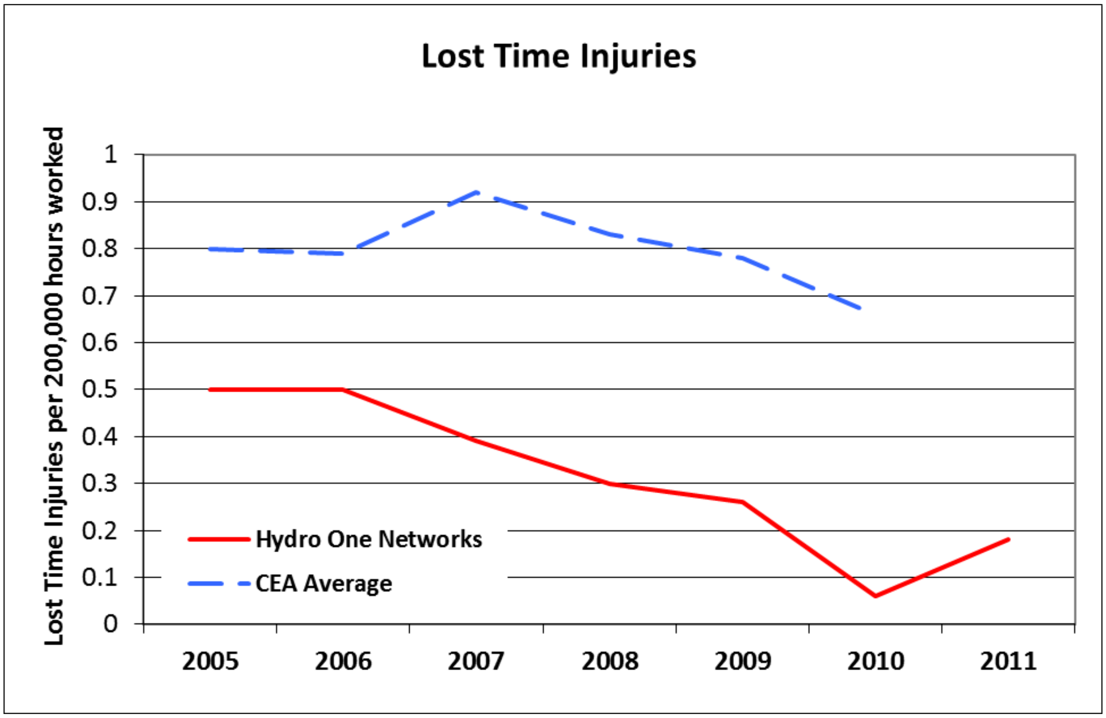
- Removing administrative tasks from supervisors so they can have more time engaging with their employees in the field.
- Improving the content and relevance of safety meetings for employees.
- Implementing the Musculoskeletal Disorder prevention recommendations.
- Delivering a new Hydro One Document System (HODS) to provide easier, more efficient access to work procedure documents.
- Developing a key set of Health and Safety leadership activities that support the Craft of Management and visible leadership in the field (See Exhibit C1, Tab 5, Schedule 1 for further information on Craft of Management).

The Hydro One executive and senior management continue to demonstrate visible leadership to reinforce our health and safety vision through site visits and face-to-face discussions with employees.

Since the Hydro One safety program encompasses the entire company, safety performance is tracked throughout the company and performance measure results are not divided between the transmission and distribution businesses. The results presented in this evidence are for all of Hydro One.

As part of its safety program, Hydro One tracks a number of measures. Historically, the focus was on the Lost Time Injury measure. Lost Time Injuries are those injuries that result in Hydro One employees having to take time off to recover before they can return to work. Recent results have been included in Figure 1 to provide continuity to past results reported in previous rate filings. However, the Lost Time Injury measure has now been replaced by the Medical Attentions measure as the primary measure of safety performance.

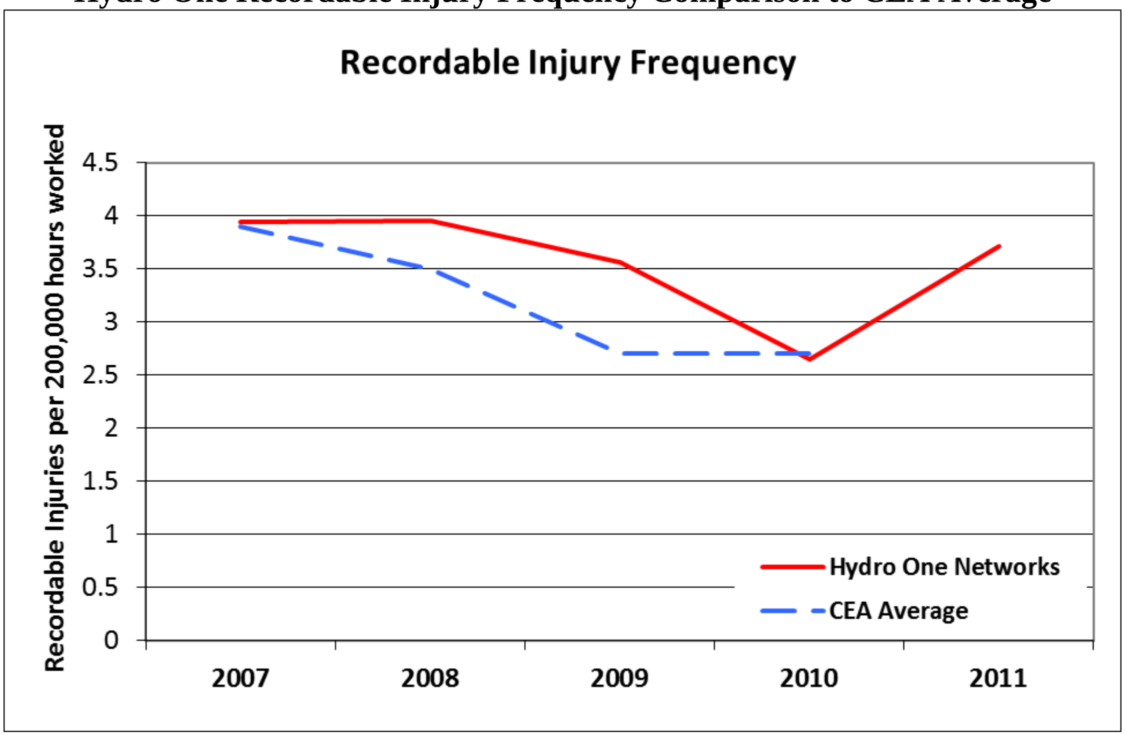
Figure 1
Lost Time Injury Frequency Rate



In recent years, Hydro One has implemented the Medical Attentions measure in favour of the Lost Time Injury (LTI) metric as its primary Health and Safety performance measure. The Medical Attentions metric measures the number of injuries that require treatment by a medical practitioner (i.e. beyond first aid). The frequency of the LTI type measure occurrences is low and does not provide the best measure upon which to base Hydro One's improvement initiatives. The Medical Attentions measure captures a broader number of occurrences than LTI and in so doing, provides more opportunities to identify potential injury situations and their avoidance as part of the objective of having an injury-free workplace. T his Medical Attentions metric will measure the impact that our planned improvement initiatives will have on the prevention of injuries that are more serious than requiring basic first aid.

The Medical Attention metric is aligned with the Canadian Electricity Association (CEA) recordable injury metric and the US Occupational Safety and Health Administration (OSHA) recordable metric. Hydro One can compare its performance with other Canadian utilities using the frequency of the recordable injury metric as shown in Figure 2.

Figure 2
Hydro One Recordable Injury Frequency Comparison to CEA Average



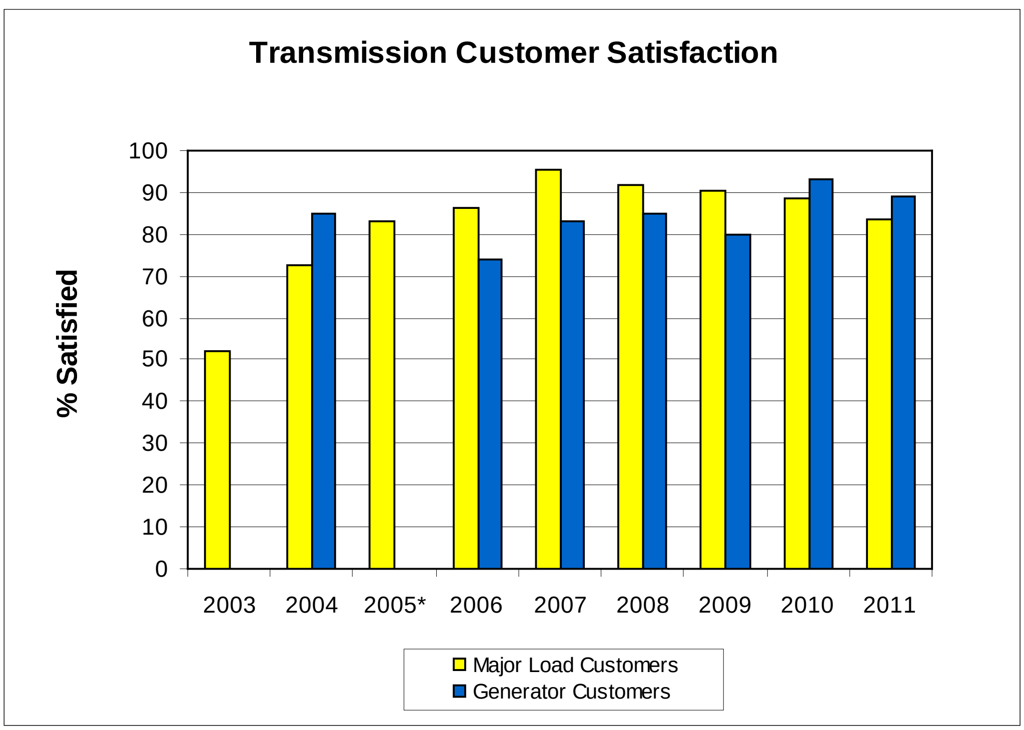
The causes for the change in result from 2010 to 2011 are still being researched by our safety experts. In 2012, weekly measurement of medical attention results will be cascaded down to the local manager level with senior management review and appropriate action plans will be formulated to address opportunities for performance improvement. Hydro One's goal is to achieve world-class performance level determined as 1.2 recordable injuries per 200,000 hours worked.

Hydro One continues to build on the strength of its achievements and focus on safety through its health and safety management program and Journey to Zero to achieve an injury-free workplace.

4.0 CUSTOMER SERVICE PERFORMANCE

Hydro One is in business to serve its customers and as such, customer satisfaction is a high priority for the company. To gauge satisfaction, the company surveys customers on their satisfaction with the service that they have been receiving. Surveys are administered to both major load and generator customers, and survey questions are focused on areas of importance to customers such as reliability, communications, relationships, and responsiveness. Figure 3 illustrates the overall results from surveys that have been conducted in recent years.

Figure 3
Customer Satisfaction



* Note: In 2005 there was no satisfaction survey carried out of the Generator Customers due to the Hydro One labour disruption.

As evidenced by the results in Figure 3, Hydro One's major load customers have indicated a relatively high satisfaction during the past several years, though a gradual decline in customer satisfaction in the major load customer sector since 2007 has been noted. This segment includes industrial customers and Local Distribution Companies (LDCs). Hydro One is actively addressing these results. For example, industrial customers have indicated that they want Hydro One to play a more active role in helping them to reduce their costs by reducing and/or better coordinating planned outages to assist them to improve their productivity through a more reliable service. Efforts to bundle work programs on transformers and circuits to minimize transmission related outages are incorporated in the Hydro One's business plans going forward. Also, LDCs are expressing concern over Hydro One's aging infrastructure and related reliability and the speed at which our work programs are addressing their concerns. Transformer and breaker replacement programs top the list of immediate concerns. Transformer capacity constraints in southern and eastern portions of the province are adding to the LDC stress, and a higher level of frustration was voiced by LDCs in the south at the inability to connect renewable generation projects within their service territories. Continual measurement of customer satisfaction and follow-up actions are examples of Hydro One's customer focus to meet and/or exceed customer expectations.

For generator customers, overall satisfaction with Hydro One is fairly stable from the first survey conducted in 2004 through to including the latest 2011 survey results. Hydro One staff are following up with those customers that indicated that they were either neutral or dissatisfied in order to gain specific feedback that will lead to ways of improving performance.

Of note, Hydro One was honoured by the E Source Review as ranking third in Canada among electric and gas utilities in delivering positive customer experience through its automated phone system - interactive voice response system. Additionally, Hydro One received the Canadian Electricity Association's Sustainable Electricity Social

Responsibility Award in recognition of its leadership in engaging its stakeholders. One of the projects recognized by this award is Hydro One's outreach at fairs across the province to deliver the "Understanding Your Power" event to customers and stakeholders.

5.0 RELIABILITY PERFORMANCE

5.1 Transmission Reliability

Hydro One measures and actively monitors its transmission reliability using two principle perspectives, namely: equipment reliability and delivery reliability. The equipment reliability perspective enables Hydro One to assess the operational performance of the components of its transmission system, ensuring that the major components are functioning effectively according to their design. The delivery perspective establishes a measure of how reliably electricity is delivered to customers of the transmission system such as Local Distribution Companies, Direct Connect Companies, in addition to the Hydro One distribution system. Being a customer focused organization, Hydro One considers delivery of electricity an important measure of transmission reliability and it strives to achieve a high level of performance in this area.

Transmission reliability is determined primarily using measures developed collaboratively with other transmission utilities across Canada at the Canadian Electricity Association (CEA). These measures have had success since they are well defined and understood by the participating member utilities and the definitions are of sufficient precision and consistency over the years to permit a degree of multi-jurisdictional transmission performance comparisons.

5.2 Transmission Reliability Measures

Hydro One's service quality includes a set of measures related to reliability for the delivery of electricity to its customers and major transmission system equipment performance. These measures are listed in Table 1.

Delivery reliability is measured using measures: Transmission Frequency of Delivery Point Interruptions and Transmission Duration of Delivery Point Interruptions. These measures are presented in this evidence at the all system perspective that includes all delivery points.

A summary of delivery point performance according to the Hydro One Customer Delivery Point Performance (CDPP) Standards is discussed below. This standard is described in a document previously filed with the OEB: Customer Delivery Point Performance (CDPP) Standard, EB-2002-0424. The document is included in Appendix A of this Exhibit for reference.

Table 1
Transmission Reliability Measures

Reliability Perspective	Reliability Measure	Description
Reliability of Delivery of Electricity to Customers	*Frequency of Delivery Point Interruptions* (average # of interruptions per delivery point)	The average number of interruptions experienced at customer delivery points
	Duration of Delivery Point Interruptions (average # of minutes of interruptions per delivery point)	The average duration of interruptions experienced at customer delivery points
	Unsupplied Energy (system minutes of energy not supplied)	Energy not supplied to customers as a result of interruptions
Major Transmission Equipment Reliability	*Transmission Unavailability* (Percentage of system not available)	The extent to which transmission equipments are not available for use by market participants due to forced outages on the transmission system

Delivery Points are the interface points between Hydro One's transmission system and its load customers. They consist of all (a) Hydro One owned step-down transformer stations' low voltage buses, and (b) stations owned by end use transmission customers, including Local Distribution Companies, and other transmitters interfacing at the 115 kV voltage level and above.

Hydro One uses these measures because:

- These are commonly used transmission industry measures. As a group, the measures address transmission service quality perspectives important to customers and stakeholders.
- Most of the measures have been in place for over 10 years making historical data available for assessing performance trends and setting targets.
- The number of measures keeps tracking and reporting requirements at a manageable and cost-effective level while still covering a broad spectrum of performance relevant to reliable performance.

Appendix B includes details on the reliability measures. Appendix C includes historical performance of the four reliability measures listed in Table 1.

5.3 Performance in Canada

Using data collected by the CEA, Hydro One is able to compare the reliability performance of its system against the composite performance of other transmission utilities in Canada that participate in CEA programs.

Results of reliability relating to the delivery of electricity to customers are presented below at the system perspective that involves all delivery points. Hydro One also tracks these measures relating to 115/230KV Network[1] System (multi-circuit supplied Delivery Points). This perspective provides an assessment of the reinforced part of Hydro One's transmission system that can be benchmarked with comparable utilities in Canada. In its efforts to achieve high performance, Hydro One establishes targets for these measures so that it maintains a first quartile ranking relative to comparable utilities in Canada, through the Canadian Electricity Associate (CEA) reliability program assessments. Performance targets set by Hydro One are more stringent than the CEA composite first quartile threshold.

Hydro One's comparative reliability performance at the system level (all delivery points taken into account) is illustrated in the following Figures 4, 5 and 6 for frequency of momentary interruptions, frequency of forced sustained interruptions and duration of forced sustained interruptions respectively.

[1] Network is defined as the portion of the system that has multi-circuit supplied delivery points. This provides assessment of the reinforced part of the transmission system. Includes Force Majeure events to enable CEA benchmark comparisons.

Hydro One data in Figures 4 through 8 exclude the impact of the 2003 blackout.

Figure 4
Performance of Frequency of Momentary Interruptions

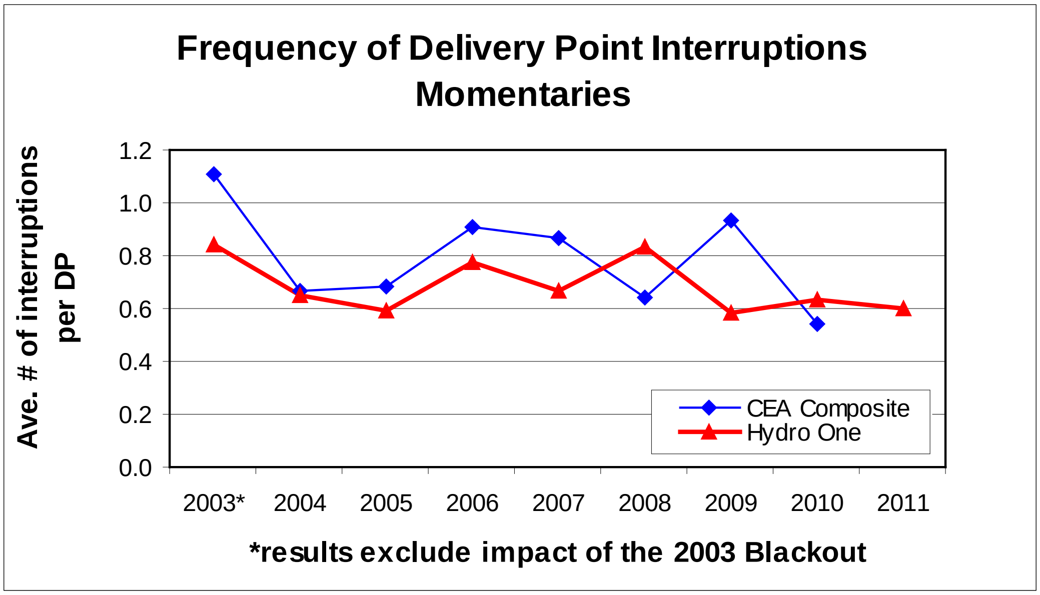
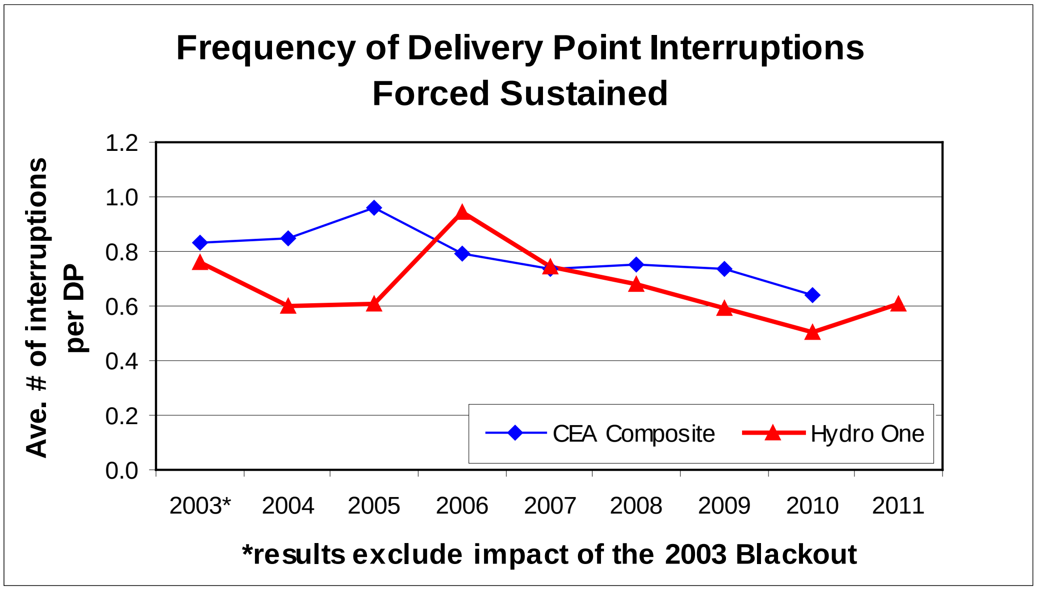
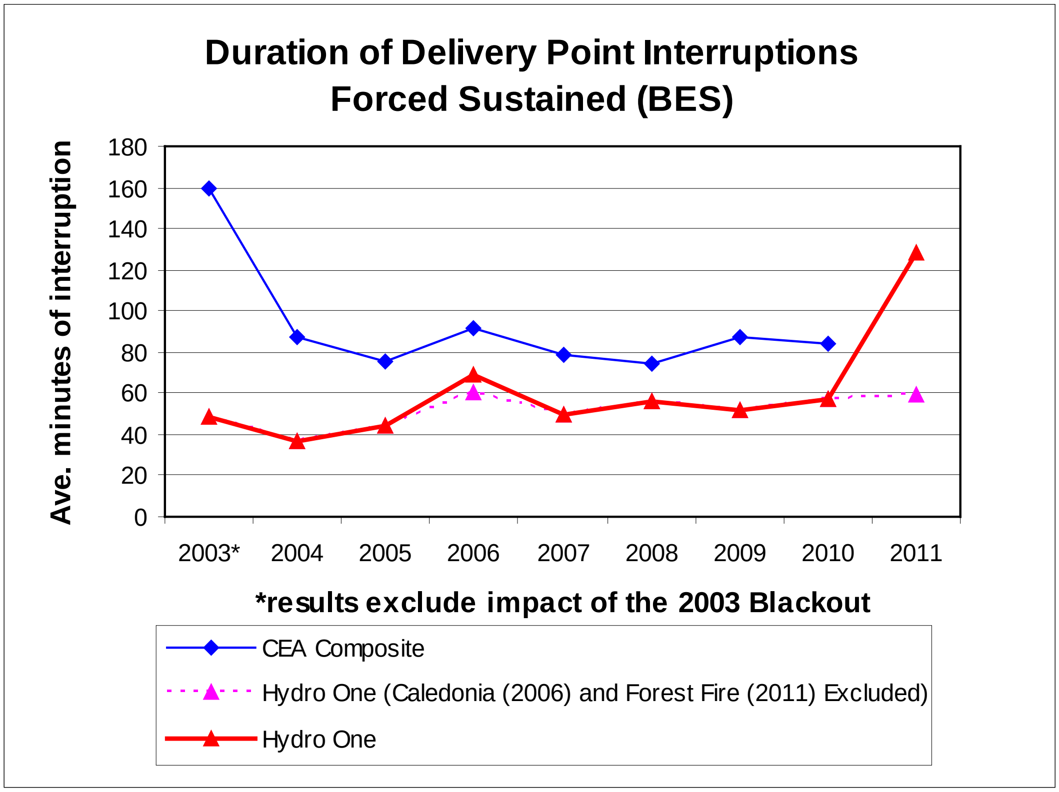


Figure 5
Performance of Frequency of Forced Sustained Interruptions



In 2006, ice storms and electric storms significantly impacted the performance of the Hydro One grid. These events contributed to the reliability measures as follows, the frequency of delivery point interruptions of forced sustained would be 0.72 interruptions per delivery point (Figure 5). The duration of delivery point interruptions of forced sustained (BES) would be at 61.1 minutes per delivery point (Figure 6).

Figure 6
Performance of Duration of Forced Sustained Interruptions



Note: The Caledonia Event in 2006 contributed 8.5 minutes to the Duration of Delivery Point Interruption measure as shown in Figure 5 above. In July of 2011 a forest fire in Northern Ontario caused damage to over 80 wood pole structures and transmission line equipment. A total of 628 customers were affected during the outage and there was 16MW of load loss. In total, this forest fire event contributed 70 minutes to T-SAIDI; 54% of the total average of interruption duration in 2011.

The following charts in Figures 7 and 8 illustrate historical performance pertaining System Unavailability of Transmission Lines and Major Transmission Station Equipment. These measures reflect system level performance of major transmission equipment such as transmission lines, power transformers, circuit breakers and capacitor banks.

Performance from an equipment perspective is considered to be a leading indicator of system performance. By the time that system performance has measurably degraded, there would be a significant increase in required asset level investment to return to historical reliability levels. Sustainment investments are made in part to preserve performance of critical asset groups by investments at the individual asset level. This approach helps preserve overall system performance.

Performance of transmission line equipment and major station equipment are summarized below in Figures 7 and 8 respectively.

The Unavailability measure represents the extent to which the major transmission equipment are not available for use within the system. The detailed description of this measure is provided in Appendix A for both Major Transmission Station Equipment and All Transmission Lines.

Figure 7 illustrates a slight increase in the Unavailability measure in 2009 for all transmission lines although unavailability levels are comparable to CEA All Canada levels.

Figure 7
Unavailability of Transmission Lines

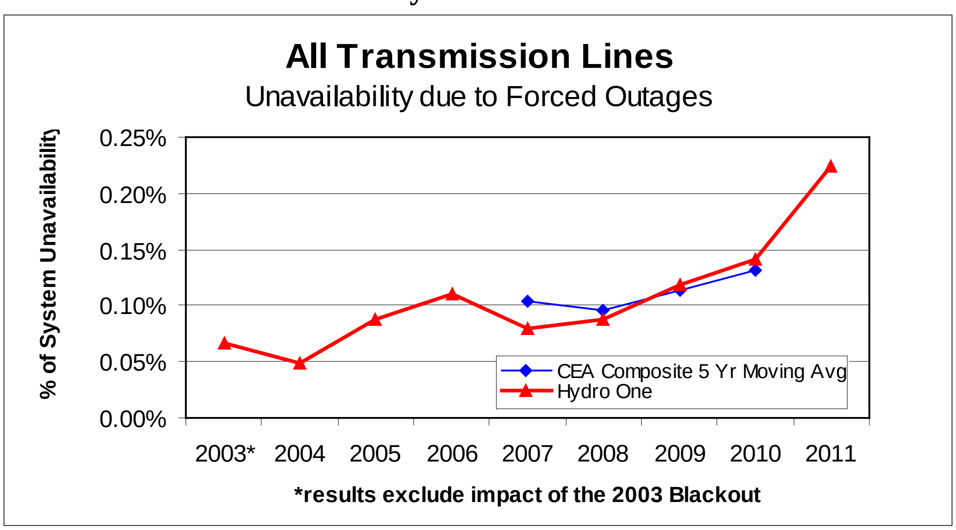
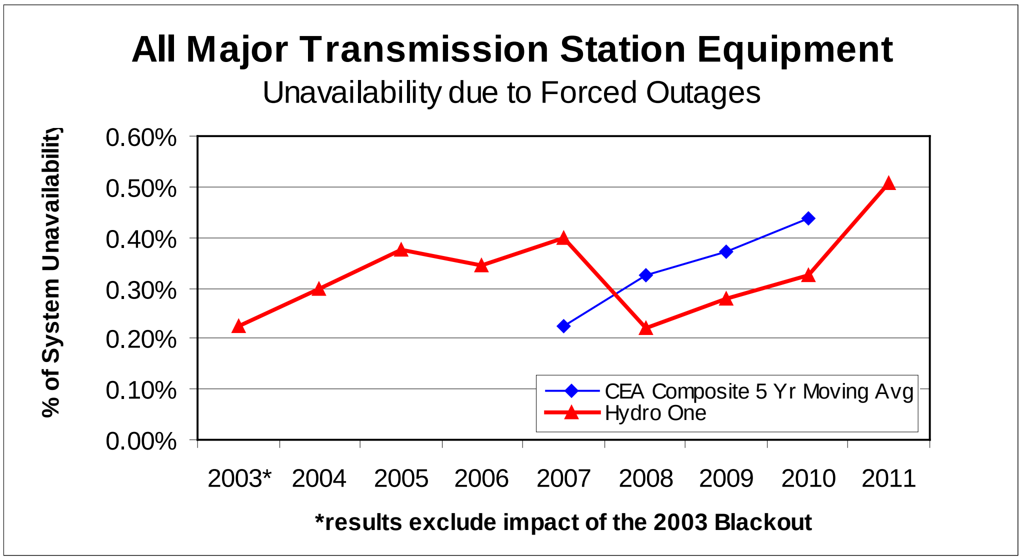


Figure 8 also illustrates overall unavailability levels comparable to CEA All Canada levels.

Figure 8
Unavailability of Major Transmission Station Equipment



Hydro One undertakes an annual detailed assessment of the performance of all the above mentioned measures. This assessment is taken into account along with other factors such as asset condition when establishing and prioritizing operating, maintenance and capital programs.

5.4 Performance Relative to Utilities in the USA

In order to provide additional reliability comparison perspectives, Hydro One also participates in a statistical and comparative study of transmission reliability in the U.S., administered by SGS, a utility consultancy. Hydro One's performance relating to frequency and duration of interruptions are illustrated in Figures 9 and 10 below. The graphs show Hydro One's relative quartile performance of delivery point reliability compared to other transmission companies that participated in the SGS study. Although there are some inconsistencies in both definitions and reporting practices within the study, the results are considered accurate enough for broad, system performance comparisons. The measures are system averages for frequency and duration and include forced interruptions to transmission delivery points. T he study includes delivery point interruptions by transmission line outages only. Results are normalized by line length to facilitate the measurement comparison. Other transmission system failures at the sub-station level affecting delivery points are not included in the study results.

Figure 9
Delivery Point Outages per 100 miles for Delivery Points Served by ≥ 230kV
From SGS Transmission Reliability Benchmarking Study Results

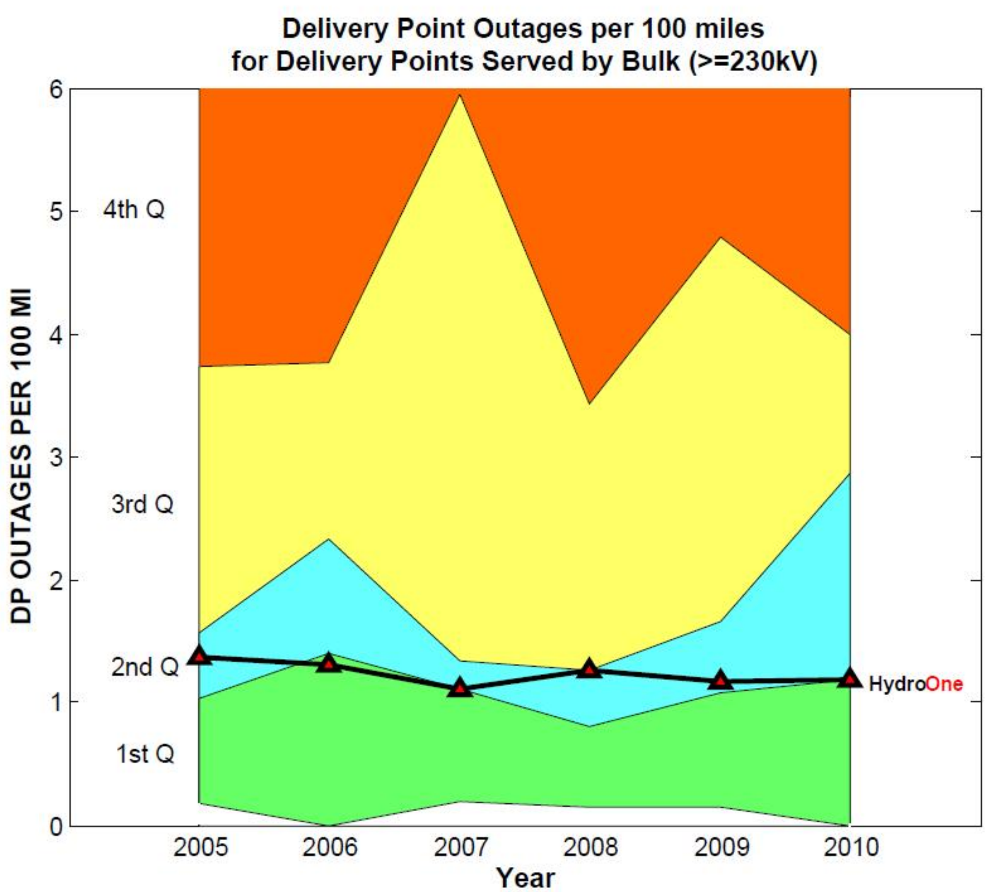
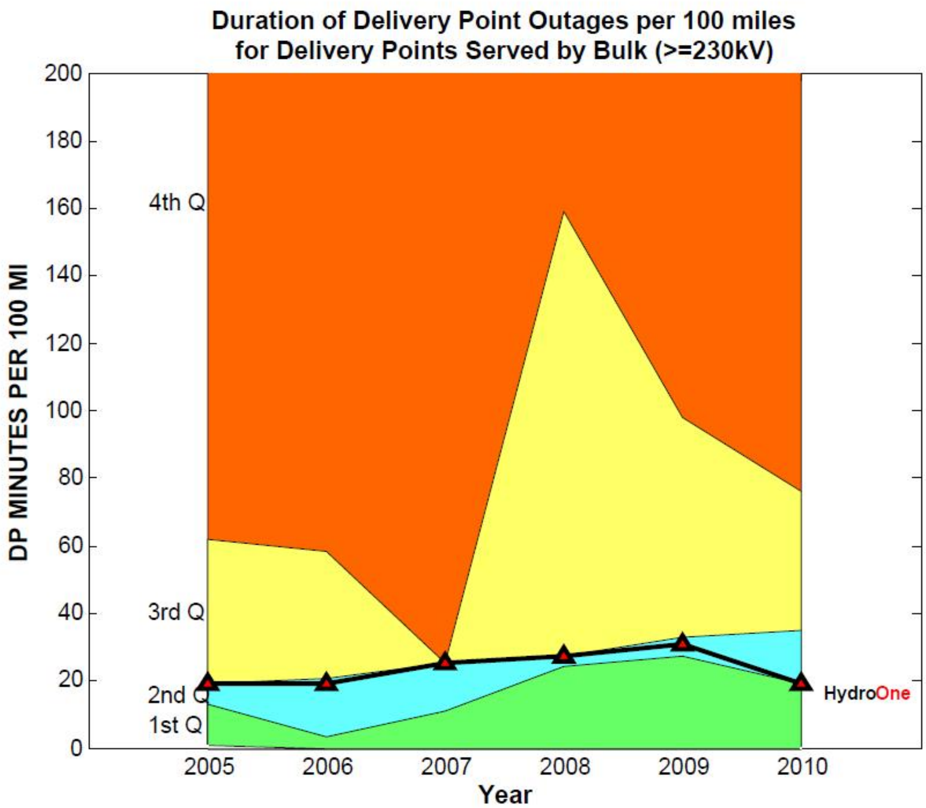


Figure 10
Delivery Point Outage Duration per 100 miles for Delivery Points Served by ≥ 230kV From SGS Transmission Reliability Benchmarking Study Results



Notes
(1) The quartile values are reported as part of the study results.
(2) Measures are system averages for frequency and duration and include non-planned interruptions to transmission delivery points due to circuit outages only.

The results indicate that for 230kV and above systems, Hydro One is generally performing in the second quartile within this study.

5.5 Delivery Point Performance Outliers

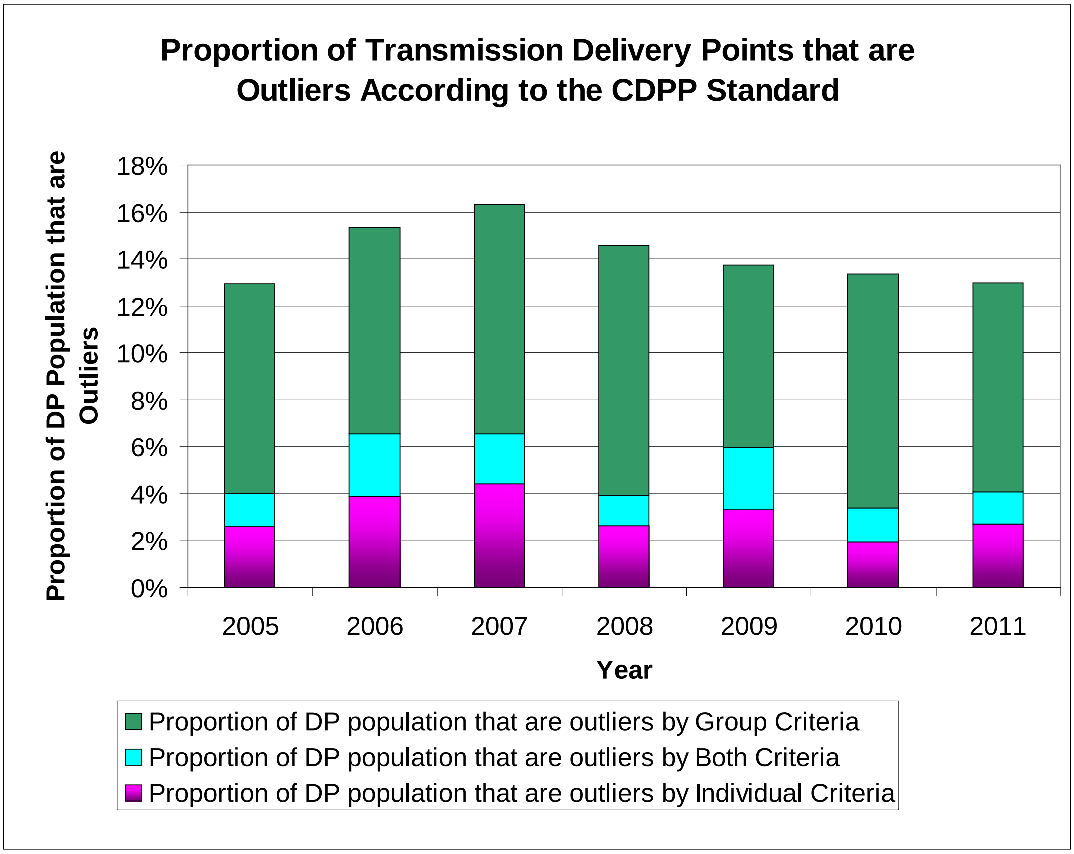
Hydro One tracks reliability performance at its load delivery points according to the standard that Hydro One developed and filed with the OEB.[2] The performance standard is used as a trigger by Hydro One to initiate assessment and follow up with affected customers including to:

- Determine the root cause of unreliability
- Perform technical and financial evaluations
- Decide on remedial action to improve reliability

Figure 11 includes a summary of the transmission load delivery point performance outliers for each of the Group and Individual CDPP Standard criteria since the inception of the standard in 2005. Note that Outliers due to Group and Individual CDPP Standard criteria are not mutually exclusive. The proportion of Hydro One transmission load delivery points that are determined to be performance outliers are determined separately for Group and Individual CDPP Standard criteria, and a composite result is also provided.

[2] Customer Delivery Point Performance (CDPP) Standard, EB-2002-0424

Figure 11
Transmission Load Delivery Point Performance Outliers



The delivery points found to be outliers according to the standard are assessed for incorporation into future investment programs. Hydro One endeavours to keep the number of outliers to 10% or less of the total population of its load delivery points. This will not always be the case as some delivery points are flagged as performance outliers even though they would normally experience better reliability performance than standard. One or two interruptions caused by isolated events may affect the performance result in a particular year. Reliability performance at these delivery points would typically be better than standard again the following year with no incremental investment. Hydro One takes this into consideration in its assessments.

6.0 SHAREHOLDER PERFORMANCE

Delivering shareholder value is a key objective of any business and as such, Hydro One monitors related measures. A key measure in this area is the company's credit rating. Currently the company has a credit rating of "A", which is in line with other large transmission companies in Canada. The goal is to maintain this credit rating in order to ensure ready access to long-term financing at reasonable rates, as Hydro One does not have access to equity markets and must use debt to fund capital requirements and investments. Table 2 below contains Hydro One's credit rating in recent years.

Table 2
Hydro One's Credit Rating (2005-2011)

	2005	2006	2007	2008	2009	2010	2011
S&P Rating	A	A	A	A	A	A	A

Maintaining a good credit rating allows Hydro One to borrow at attractive interest rates, which benefits customers by minimizing the cost of capital.

APPENDIX A

CUSTOMER DELIVERY POINT PERFORMANCE STANDARDS

1.0 INTRODUCTION

The Transmission System Code (TSC) requires transmitters to develop performance standards at the customer delivery point ("CDPP") [1] level, consistent with system wide standards, that:

- reflect typical transmission system configurations that take into account the historical development of the transmission system at the customer delivery point level;
- reflect historical performance at the customer delivery point level;
- establish acceptable bands of performance at the customer delivery point level for the transmission system configurations, geographic area, load, and capacity levels;
- establish triggers that would initiate technical and financial evaluations by the transmitter and its customers regarding performance standards at the customer delivery point level, as well as the circumstances in which any such triggering event will not require the initiation of a technical or economic evaluation;
- establish the steps to be taken based on the results of any evaluation that has been so triggered, as well as the circumstances in which such steps need not be taken;
- establish any circumstances in which the performance standards will not apply.

On May 3, 2002, Hydro One filed proposed Customer Delivery Point Performance Standards to meet the requirements of the TSC with the OEB for review and approval. Subsequently, on September 8, 2004, as a result of stakeholder comments received, Hydro One filed amendments to its original CDPP Standards submission. On July 25, 2005, the OEB issued its Decision and Order (RP-1999-0057/EB-2002-0424) which approved Hydro One's proposed CDPP Standards subject to a number of changes directed by the Board.

[1] A Delivery Point is defined as a point of connection between a transmitter's transmission facilities and a customer's facilities.

The approved CDPP Standards apply to all existing transmission load customers (including customers that have signed a connection cost recovery agreement prior to market opening). For new or expanding customer loads, the delivery point performance requirements will be specified and paid for by the customer based on their connection needs and negotiated as part of the connection cost recovery agreement.

1.0 DELIVERY POINT RELIABILITY STANDARDS

The approved CDPP Standards consist of two components (1) Group CDPP Standards that relate the reliability of supply to the size of load being served at the delivery point; and (2) Individual CDPP Standards that maintain a customer's individual historical delivery point performance. Triggers for each component are used to identify performance "outliers" to initiate technical and financial evaluations to determine the root cause of unreliability and remedial action required to improve reliability. The CDPP Standards and triggers for each component are summarized below.

2.1 Performance Standards Based on Size of Load Being Served: Group CDPP Standards

In this component, the CDPP Standards and the associated triggers are based on the size of load being served. For this purpose, the load is the delivery point's total average station gross load[2] as measured in megawatts. The CDPP Standards vary with the size of the load in groups or bands of 0 to 15 MW, greater than 15 up to 40 MW, greater than 40 up to 80 MW and greater than 80 MW, as shown in Table 1 below.

[2] Total Average Station Gross Load (MW) = (Total Energy Delivered to the Station (MWh) + Total Energy Generated at the Station Site (MWh)) / 8760 hours.

Table 1

Customer Delivery Point Performance Standards Based on Load Size

Performance Measure	Customer Delivery Point Performance Standards (Based on a Delivery Point's Total Average Station Load)							
	0-15 MW		>15 - 40 MW		>40 - 80 MW		>80 MW	
	Standard (Average Performance)	Minimum Standard of Performance	Standard (Average Performance)	Minimum Standard of Performance	Standard (Average Performance)	Minimum Standard of Performance	Standard (Average Performance)	Minimum Standard of Performance
DP Frequency of Interruptions (Outages/yr)	4.1	9.0	1.1	3.5	0.5	1.5	0.3	1.0
DP Interruption Duration (min/yr)	89	360	22	140	11	55	5	25

These CDPP Standards are based on historical 1991-2000 performance, as measured by the frequency and duration of all momentary and sustained interruptions[3] caused by forced outages, excluding outages resulting from extraordinary events that have had "excessive" impact on the transmission system and that, in Hydro One's assessment, strongly skew the historical performance. Included in this category of excluded events are the 1998 ice storm and the 2003 blackout.

2.1.1 Criteria for Minimum Standard Performance to Identify Performance Outliers for Group CDPP Standards

The minimum CDPP standards of performance, for each of the four load groups or bands, are to be used as triggers by Hydro One. The trigger occurs when the three-year rolling average of the delivery point performance falls below the minimum CDPP Standard for the delivery point of the load size group or band (referred to as a performance outlier or

[3] Momentary interruption is any forced interruption to a delivery point lasting less than 1 minute and a sustained interruption is any interruption to a delivery point lasting 1 minute or longer. A delivery point is interrupted whenever its requisite supply is interrupted as a result of a forced outage of one or more Hydro One components causing load loss. Interruptions caused by Hydro One's customers are recorded but not charged against Hydro One's reliability performance for the customer initiating the interruption, but are charged against Hydro One's reliability performance for other interrupted customers.

outlier) or when a delivery point customer indicates that analysis is required. When an outlier is identified, it is considered a candidate for remedial action. In such cases, Hydro One will initiate technical and financial evaluations with affected customers to determine the root cause of the unreliability and any remedial action required to improve the reliability.

2.2 Performance Standards to Maintain Historical Delivery Point Performance: Individual CDPP Standards

In this component, the CDPP Standards are intended to maintain the historical reliability performance levels at each customer delivery point. This is done by identifying customer delivery points with deteriorating trends in reliability performance, irrespective of whether they are satisfactory performers under the Group CDPP Standards (Section 2.1 above). In order to identify customer delivery points with deteriorating trends in reliability performance, a performance baseline trigger for the frequency and duration of forced (momentary and sustained) interruptions is established for each delivery point based on that delivery point's historical 1991-2000 average performance, plus one standard deviation (the "historical baseline"). The historical baselines exclude outages resulting from extraordinary events that have had "excessive" impact on the transmission system and that, in Hydro One's assessment, strongly skew the historical trend of the measure (such as the 1998 ice storm and the 2003 blackout). Also, for delivery points that came into service after 1991, the in-service year is to be the first year of the 10-year period used to determine the performance baseline.

2.2.1 Criteria for Minimum Standard Performance to Identify Performance Outliers for Individual CDPP Standards

Delivery point performance that is worse than the historical baseline (for either frequency or duration) in two consecutive years is considered a performance outlier and a candidate for remedial action. In such cases, Hydro One will initiate technical and financial evaluations with affected customers to determine the root cause of the unreliability and the remedial measures required to restore the historical reliability of the delivery point's performance.

2.3 Remedial Costs to Address Group and Individual Performance Outliers

For Group and Individual Performance outliers, Hydro One will cover the remedial costs of restoring and sustaining the inherent reliability performance of the existing assets to what was designed originally. These costs include appropriate asset sustainment costs, on-going maintenance costs and costs associated with asset refurbishment or replacement. Historically, Hydro One has spent approximately $700 million per year on OM&A and Capital expenditures on the transmission system. About half of these expenditures are related to sustainment work to ensure that transmission assets are in "good" working order and able to perform as intended. These expenditures are made on an ongoing basis consistent with "good utility practices," irrespective of actual delivery point performance or of whether a delivery point is a performance outlier. No customer contribution formula is required for these normal sustainment expenditures.

For Individual Performance outliers, Hydro One will restore the delivery point to the historical level of performance. Hydro One's remedial work will not include capital reliability improvements that significantly enhance the reliability of supply relative to the reliability that was inherent in the original system design or configuration of supply.

For Group Performance outliers, Hydro One's level of incremental investment for improving the performance of an outlier beyond what was designed originally will be limited to the present value of three years' worth of transformation and/or transmission line connection revenue[4] associated with the delivery point. Any funding shortfalls for improving delivery point reliability performance will be made up by affected delivery point customers. In cases where specific transmission facilities are serving two or more

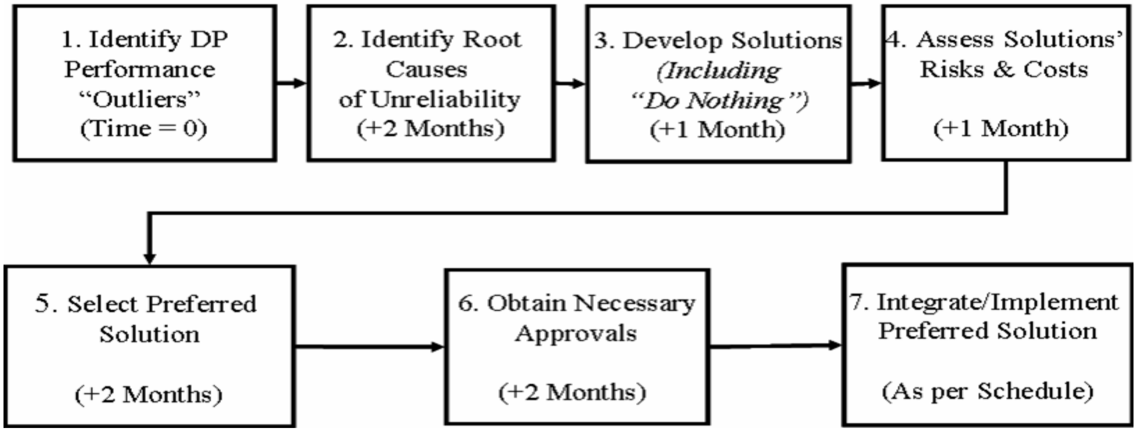
[4] In the special case where a delivery point pays only network tariffs, transmission line connection tariffs are to be used as a proxy in the revenue calculation.

customers in common with outlier performance, Hydro One will approach all affected customers to determine their willingness to contribute jointly to the reliability improvements.

Cost responsibility for these investments is to be consistent with the TSC, specifically: (i) Hydro One will not attribute the costs associated with network investment to any customer and any variance from this approach requires a determination by the Board; (ii) the costs of preparing the final estimate for reliability improvements required to address performance outliers is the only portion of the technical and financial evaluation that is to be included as part of the cost of the remedial work; and (iii) where a customer contribution is required to improve or expand the transmission system to correct outlier performance, the customer will be given contracting privileges consistent with those applicable to contestability for new customer connections. In addition, affected delivery point customers are responsible for all of the costs associated with any new or modified facilities required on lines and stations they own to improve reliability. These financial and cost sharing arrangements are to be detailed in a connection and cost recovery agreement with the affected customers.

2.4 Process Timelines to Address Performance Outliers

The process and associated timelines that will be followed to address performance outliers – both for Group and Individual outliers - and determine the preferred course of action are provided below.



1. Time = 0: Hydro One identifies, annually, delivery point performance "outliers" for both Group and Individual standards. Hydro One will notify customers that are supplied from these performance outlier delivery points and solicit their feedback/issues/concerns on their reliability of supply.

2. Within 2 months: Hydro One will determine the root causes of unreliability associated with each performance outlier identified in (1).

3. Within 1 month: Hydro One will develop solutions to address performance outliers, including, (i) the work to restore and sustain the inherent reliability performance of the existing assets to what was designed originally; and (ii) for Group Performance outliers, the additional capital improvements required to improve the performance of an outlier to within standard and beyond what was designed originally. Hydro One will discuss the proposed solutions with affected customers.

4. Within 1 month: Hydro One will determine the costs and assess the risks of the solutions, including any customer capital contributions required for option (ii) above. Hydro One will present these costs to customers for their review and assessment.

5. Within 2 months: Hydro One and customers select the preferred option and where appropriate customers state their intention on whether to proceed with capital improvements that involve customer contributions identified in option (ii) above.

6. Within 2 months: Hydro One and customers obtain the necessary approvals to proceed with the preferred solutions to address performance outliers.

7. Hydro One will integrate the solutions into its work programs and implement them according to a mutually agreed schedule.

When Hydro One completes work to restore delivery point performance to standard, it continues to monitor the delivery point the year after the work is completed. If future performance suggests that the standard has not been met, then Hydro One will review the work that has taken place and will identify corrective action. Hydro One will not as a practice wait another 3 years and start a new technical and financial evaluation. Hydro One reviews and identifies customer delivery point performance annually, regardless of the investment history.

APPENDIX B

DESCRIPTIONS OF THE RELIABILITY MEASURES

Frequency of Delivery Point Interruptions

Frequency of Delivery Point Interruptions is an indicator of customer reliability related to ***interruptions***, that is, outages on the transmission system that interrupt the supply of energy to transmission customers.

This indicator measures the number of interruptions to the supply of power to customer delivery points[1]. It is expressed mathematically as:

$$\textit{Frequency of Delivery Point Interruptions} = \frac{\sum_{i=1}^{N}(M_i + S_i)}{N}$$

Where:

- M_i is the total number of Momentary[2] Interruptions experienced at Delivery Point i over a one year period.
- S_i is the total number of Sustained[3] Interruptions (caused by either forced or planned outages) experienced at Delivery Point i over a one year period.
- N is the total number of Delivery Points at the end of the reporting period

The frequency of power supply interruptions has long been a concern to customers, and indicators that track such events are almost universally used in some form in other regulatory jurisdictions. Transmission providers in Alberta, Australia, the UK, New Zealand and Sweden use an interruption frequency indicator. Additionally, the Canadian

---

[1] Delivery Points are the interface points between Hydro One's transmission system and its load customers. They consist of all (a) Hydro One owned step-down transformer stations' low voltage buses and (b) stations owned by end use transmission customers, including Local Distribution Companies, and other transmitters interfacing at the 115 kV voltage level and above.

[2] Momentary interruptions are defined as interruptions lasting less than one minute.

[3] Sustained interruptions are those lasting one minute or longer.

Electric Association (CEA) tracks the frequency of delivery point interruptions for most Canadian transmission providers.

This indicator includes all forced and planned interruptions, both momentary and sustained. Including forced interruptions in this measure promotes prudent levels of maintenance and capital expenditures when the goal is to maintain historical levels of reliability performance. Including planned interruptions is a driver for minimizing the number of disruptions to customers by co-ordinating all planned work. Momentary interruptions are included because they can have a significant impact on the quality of supply to transmission customers.

<u>Duration of Delivery Point Interruptions</u>

Duration of Delivery Point Interruptions is an indicator of customer reliability related to the duration of interruptions, that is, the time for which supply of energy is interrupted for customers supplied from the transmission system. This indicator measures the duration of interruptions to customer delivery points[4]. It is expressed mathematically as:

$$\textit{Duration of Delivery Point Interruptions} = \frac{\sum_{i=1}^{N}\left(\mathrm{D}_i\right)}{N}$$

[4] Delivery Points are the interface points between Hydro One's transmission system and its load customers. They consist of all (a) Hydro One owned step-down transformer stations' low voltage buses and (b) stations owned by end use transmission customers, including Local Distribution Companies, and other transmitters interfacing at the 115 kV voltage level and above.

Where:

- D_i is the total effective interruption duration[5] of Sustained Interruptions (caused by either forced or planned outages) experienced at Delivery Point i over a one year period.
- N is the total number of Delivery Points at year-end of the reporting period

Like frequency, the duration of power supply interruptions has long been a concern to customers, and indicators that track such events are almost universally used in some form in other regulatory jurisdictions. Transmission providers in Alberta, Australia, the UK, New Zealand and Sweden use an interruption duration indicator. Additionally, the Canadian Electric Association (CEA) tracks the duration of delivery point interruptions for most Canadian transmission providers.

Unsupplied Energy

Unsupplied Energy is an indicator of customer reliability that combines the duration of interruptions to a customer's power supply with the energy not supplied as a result of the interruption. It is expressed mathematically as:

$$\textit{Unsupplied Energy} = \frac{\sum_{i=1}^{N} U_i \; x \; 60 \,\text{min/hr}}{Pk}$$

Where:

- U_i is the total unsupplied energy, expressed in MWh, at Delivery Point i over a one year period.
- Pk is the current year's system peak, expressed in MW.
- N is the total number of Delivery Points at the end of the reporting period.

[5] This is the effective length of the interruption taking into account the partial restoration of load. For example, the interruption of a 100 MW load where 90% of the load is restored in five minutes and the remaining 10% of load is restored 10 minutes later would have an "effective" duration of six minutes (100% of load unavailable x 5 min. + 10% of load unavailable x 10 min.). Another way of expressing effective duration is total unsupplied energy/total MW (100 MW x 5 min. + 10 MW x10 min.)/100 MW = 6 min.).

Unsupplied energy is normalized by the peak demand for energy to account for the changes in the volume of power delivered by the transmission system and allow a better assessment of changes in performance. The unit of measure for unsupplied energy is expressed in "system minutes". This represents the total energy that is not supplied to the customers normalized by the peak demand of the system (that occurred during the measurement period).

The indicator includes both forced and planned sustained interruptions. Including forced events maintains Hydro One's direction to restore the supply of power to customers as quickly as possible following an unscheduled interruption. Planned events are included to minimize the length of planned interruptions and to schedule interruptions at a time that is least impactive to the customer. Momentary events are not included, since they do not contribute appreciably to unsupplied energy, particularly when compared to the impact from sustained events.

Transmission companies in Canada, U.S., and in Europe use indicators of this type to assess network reliability.

<u>Transmission Unavailability</u>

Transmission Unavailability captures the impact of all outages on transmission equipment, not just the outages that interrupt customers. Outages on transmission equipment impact both end use customers and energy suppliers by limiting their ability to use the transmission system to its full extent.

Transmission Equipment Unavailability due to Forced Outages is grouped into (1) line-related circuit outages, and (2) station equipment outages which is consistent to CEA reliability benchmarking programs.

These indicators are expressed mathematically as:

(1)

All Transmission Line – Related Circuit Unavailability $= \left(\frac{\sum_{i=1}^{N_L} F_{Li}}{T_L} \right) \text{x}\,100\%$

Where:

- F_{Li} is the annual forced outage duration in hours for transmission line-related circuit L_i.
- T_L is the inventory (expressed in hours) of all in-service transmission circuits.
- N_L is the total number of in-service transmission circuits

(2)

All Major Transmission Station Equipment Unavailability $= \left(\dfrac{\sum_{i=1}^{Ns} F_{Si}}{\mathrm{Ts}} \right) \text{x}\, 100\%$

Where:

- F_{Si} is the annual forced outage duration in hours for Major Transmission Station Equipment S_i.
- Ts is the inventory (expressed in hours) of all In-service Major Transmission Station Equipment
- N_s is the total number of in-service major transmission station equipment.

The indicator tracks the extent to which the transmission system, including load and generation connection lines and interconnection lines, is not available for use by electricity market participants. This indicator is focused on the aspect of transmission service within Hydro One's control that most contributes to overall system performance – that is, keeping the transmission system available for market participants to use. It also puts the impact of outages in context with the availability of the transmission system as a whole and expresses the impact of outages in a single, easily understood indicator.

Transmission companies in Canada, U.S., and in Europe use indicators of this type to assess network reliability.

APPENDIX C

RELIABILITY MEASURES HISTORICAL PERFORMANCE

The latest 10 years of performance for the four reliability measures is provided in the figures below.

Figure C1
Historical Performance of Frequency of Delivery Point Interruptions

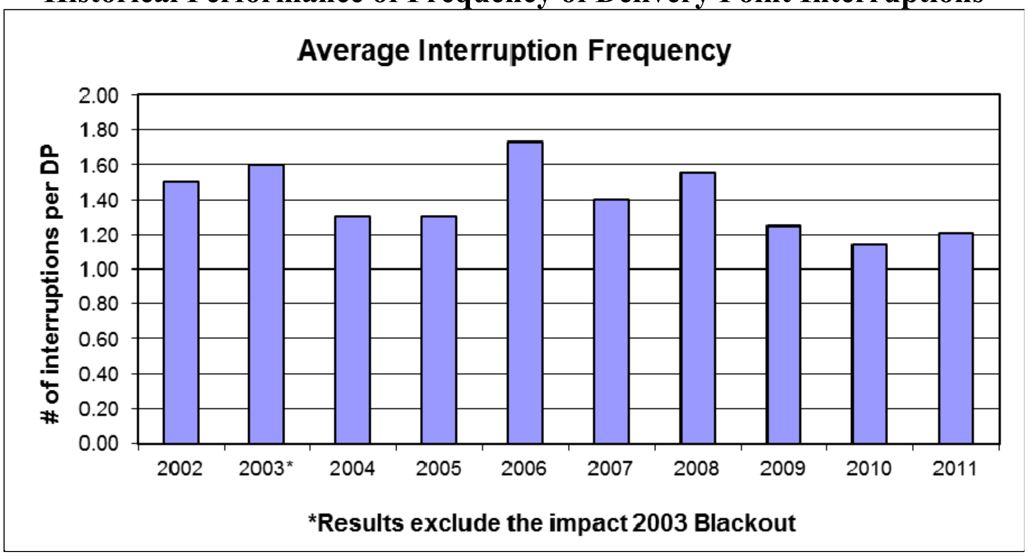


Figure C2
Historical Performance of Duration of Delivery Point Interruptions

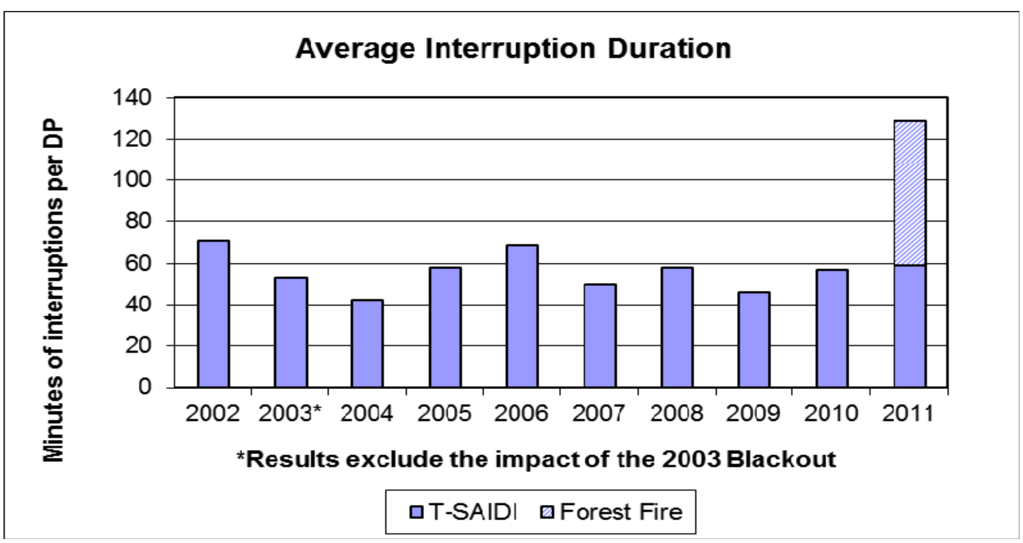


Figure C3
Historical Performance of Unsupplied Energy

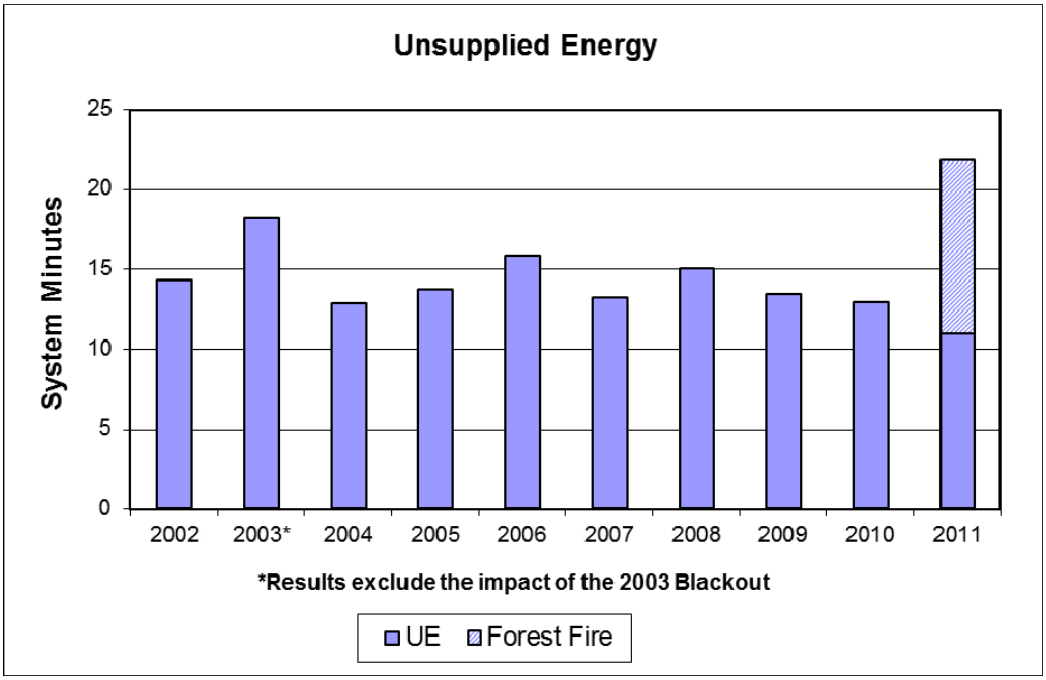


Figure C4
Historical Performance of Transmission Unavailability – Transmission Lines

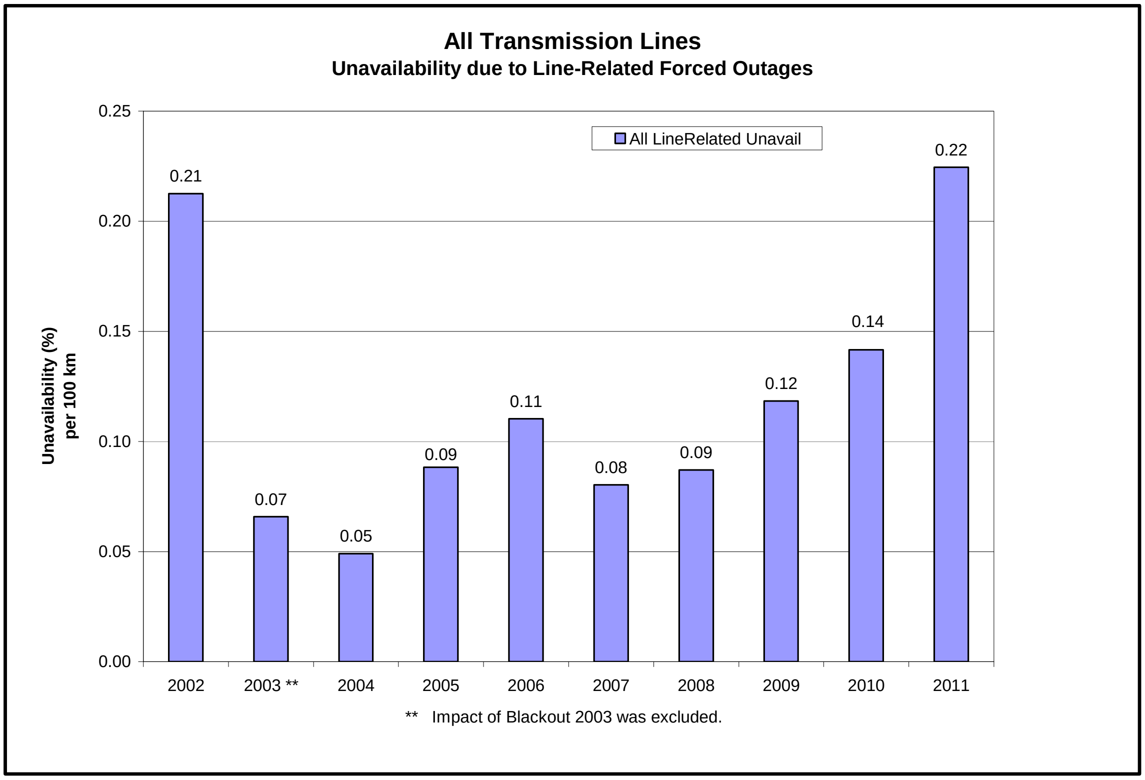
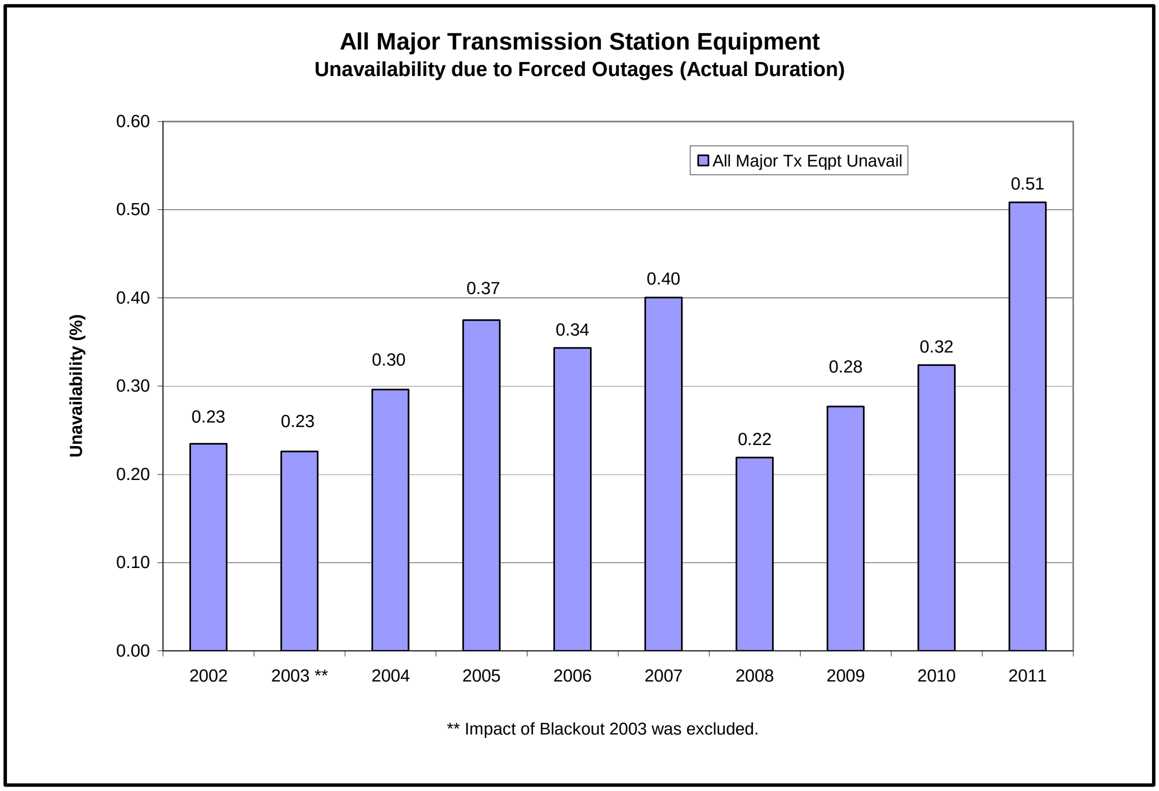


Figure B5

Historical Performance of Transmission Unavailability – Major Transmission Station Equipment



COST EFFICIENCIES/PRODUCTIVITY

1.0 INTRODUCTION

Productivity at Hydro One remains an integral part of the Corporation's strategy and business objectives. This exhibit outlines the historical, present and future productivity initiatives within the Corporation. Section 2 provides a Hydro One corporate overview, Sections 3 and 4 identify current initiatives and how these initiatives offset compensation increases. The last section highlights Hydro One's transmission productivity performance relative to some of its Canadian peers.

2.0 HISTORY OF PRODUCTIVITY

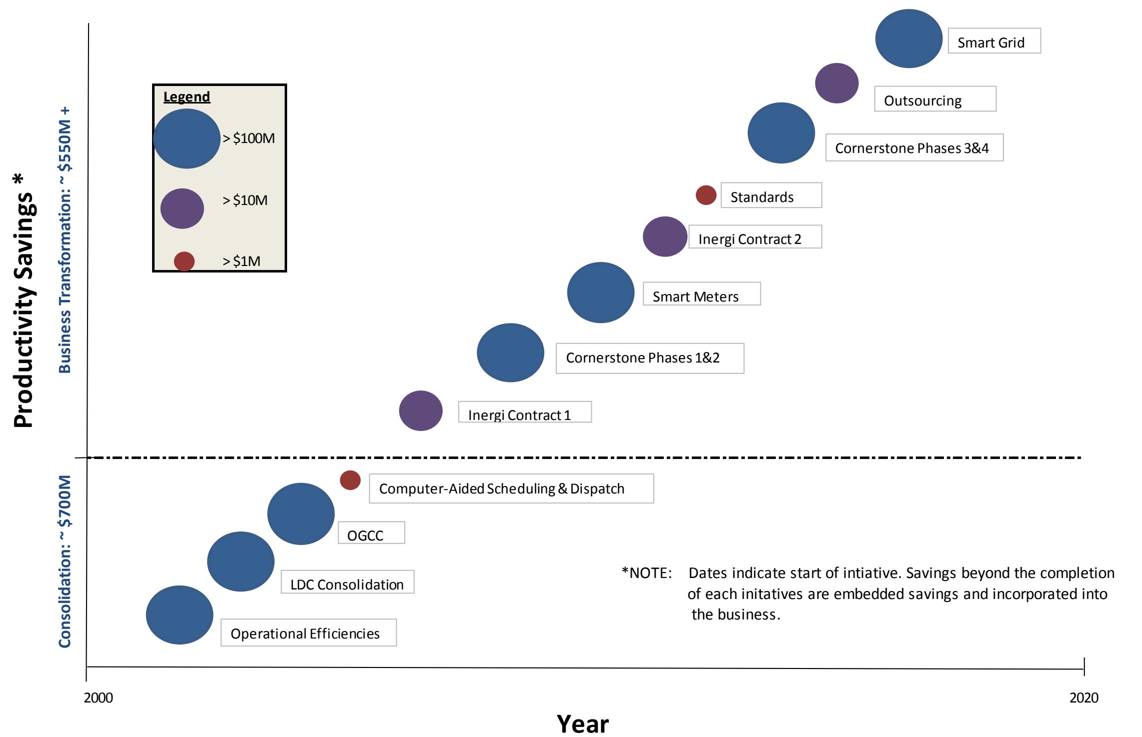
Productivity initiatives typically show results over a number of years and Hydro One Networks, through its history, has realized material cost reductions and avoidances, all of which are of direct benefit to Ontario ratepayers.

These initiatives have put Hydro One in a leadership position amongst utilities, not only in Ontario but across North America and globally.

Figure 1 illustrates the magnitude of the cost savings for select major productivity initiatives. The approximately $1 billion in aggregate savings of these initiatives are incorporated into the operations and embedded in the annual business plans along with the ongoing operational efficiency improvements.

Figure 1

Hydro One: History of Major Productivity Initatives



2.1 Consolidation

2.1.1 <u>Local Distribution Company (LDC) Consolidation (2000 - 2002)</u>

From 2000 t hrough 2002 Hydro One acquired 89 municipal electric utilities. This integration effort resulted in productivity and cost efficiencies in areas such as consolidation of duplicate facilities and rationalized service workforce and administrative functions all of which are now spread over a larger, combined asset base. In addition, this allowed Hydro One Transmission to reduce its wholesale settlement costs. Although the assets that were consolidated were distribution focused, the experienced workforce that was acquired was quickly and efficiently integrated into the larger Hydro One workforce which services both the Transmission and Distribution businesses.

2.1.2 Ontario Grid Control Centre (2000 – 2004)

In 2000, Hydro One began to consolidate the operating control of the distribution and transmission systems ultimately resulting in the opening of the Ontario Grid Control Centre (OGCC) in 2004. The OGCC ultimately replaced 34 fully staffed operating centres throughout the province. The reduced staffing requirements equated to operational savings.

2.1.3 Computer-Aided Scheduling and Dispatch (Initiated in 2006)

Building on the centralized view offered by the consolidation at the OGCC, Computer-Aided Scheduling and Dispatch linked efficient field work planning with automated dispatch to crews.

2.2 Business Transformation

2.2.1 Outsourcing (Initiated in 2002)

Hydro One negotiated a multi-year outsourcing arrangement for back office elements primarily focused on information technology, call service operations, supply management services, finance and accounting, and payroll administration. The contract had an established annual price decline for the baseline services. The contract was subsequently renegotiated in 2009 through to 2015 with improved service levels and a steeper annual price decline for the remaining five years. Hydro One expects to continue to outsource back office elements beyond 2015.

2.2.2 <u>Cornerstone (Initiated in 2007)</u>

The Cornerstone Projects are major business process transformation initiatives that drive significant effectiveness and efficiency gains at Hydro One. Cornerstone has been achieving its benefits and is poised to realize in excess of $400 million in combined savings across the Transmission and Distribution businesses. For further information on Cornerstone value realization, please see Exhibit D1, Tab 4, Schedule 3.

2.3 Utility Transformation (Initiated in 2006)

Hydro One has been involved in a number of industry initiatives that have a large impact on all provincial rate payers. Examples include Hydro One's leadership in the connection of green energy projects, Hydro One's work with Measurement Canada and Industry Canada, as well as equivalent US based agencies to establish industry standards that will ultimately lead to economies across all Utilities. For each of these initiatives, Hydro One has taken a leadership position in the North American industry and helped defray large implementation costs which would have been incurred by Hydro One, other Ontario utilities and ultimately borne by all Ontario ratepayers.

Recent transformation in the electricity utility industry has been centered on Smart Grid. For Hydro One, Smart Grid commenced with the provincial smart meter mandate. Hydro One recognized that implementing smart meters in a primarily rural geography would be challenging due to the then-existing limitations in metering technology and the lack of metering communications options for data traversal. Hydro One undertook to influence the market to develop robust back office metering solutions with standards-based communications to enable the daily aggregation of over a million meters. This culminated in Hydro One leading Canadian utilities in acquiring dedicated spectrum for the use of the electrical sector. This improved telecommunications reach and connectivity for critical electricity operations can further enable the use of mobile technologies to optimize field work execution. It will allow information, systems and tools to be available to the workforce when they need it and will allow them to status and complete work in real-time thus getting information to asset planners and to customers in a more timely and accurate manner. It is expected that these changes will reduce some of the back-office paper processing now in place. Although Smart Grid focuses on innovative changes in the distribution network, the electrical system is an integrated network, so changes to the distribution system also impact the transmission system with a tie through centralized network controls (i.e. the Transmission Network Management System and the Distribution Management System) consolidated at the OGCC.

Hydro One is part of the Standard Drafting Team on t he North American Electric Reliability Corporation's (NERC) revision to the definition of the Bulk Electric System (BES). At the core, the revision was to designate all elements and facilities above 100kV as BES. Adopting this new approach would have resulted in significant additional Capital and O&M costs to facility owners including Hydro One, as BES elements are subject to meet mandatory reliability standards as established by NERC. Hydro One has been able to influence the proposed BES definition application, specifically the exceptions process, which should avoid significant Capital and O&M costs relative to the original proposal. NERC is continually updating or introducing new requirements and reliability standards applicable to BES elements that would have triggered even higher capital investments in the future if they would have applied to the larger BES asset population.

While reliability standards are driven by external forces, physical asset standards are an internal area of focus for Hydro One; as standards that are developed can have an impact on design, procurement and maintenance costs. These standards will be especially critical as the corporate work program is projected to increase over the next number of years.

3.0 UTILITY SECTOR COST PRESSURES

In parallel to implementing these productivity improvements, Hydro One and the utility sector in general face numerous changes that result in increasing costs. These additional upward cost pressures can distort the perceived effectiveness and productivity of an organization. As examples, Hydro One has incurred material cost increases due to the following changes in the sector:

- The ongoing introduction of mandatory reliability standards including new cyber security requirements. An initial $30-$40 million of Capital was needed to bring our facilities in line with the requirements. On an annual basis there are additional OM&A obligations of approximately $5 million to $8 million annually and also a requirement for affected employees to use additional security controls in their day-to-day activities adding steps to their work process.
- Updated and new environmental standards, such as the elimination of PCBs, result in approximately $2 to $3 million per year.
- New ESA regulations and related escalated engineering requirements and standards result in an annual additional cost of $12 million.
- An increase in the amount of unplanned development initiatives related to Green Energy projects. This impedes the most efficient use of the workforce both in terms of new process requirements and the impact of changes on planned work.

These examples and other future industry challenges/opportunities such as implementation of new protection standards (e.g. IEC 61850), will continue to put upward cost pressures on Hydro One.

4.0 SPECIFIC EFFICIENCY INITIATIVES

Cost efficiency is a core element of the Hydro One strategy. The Corporation's strategic objectives include a commitment to achieve productivity and cost-effectiveness improvements. There are a number of initiatives that leverage the back office platforms and will drive cost efficiencies. Table 1 below identifies the total annual savings, while Table 2 below provides the savings on a year over year incremental basis:

Table 1
Total Annual Savings – Transmission

	2009 Actual	2010 Actual	2011 Actual	2012 Bridge	2013 Test	2014 Test
OM&A (non-Cornerstone) Savings ($M)	18.9	21.7	26.1	35.1	38.4	40.5
Capital (non-Cornerstone) Savings ($M)	10.1	14.4	20.7	26.5	29.0	33.8
Cornerstone OM&A Savings ($M)	6.3	13.1	15.7	15.7	17.4	18.4
Cornerstone Capital Savings ($M)	4.5	9.7	12.4	12.4	18.7	24.0
Total Savings ($M)	39.9	58.9	74.9	89.6	103.6	116.7
Total Work Program Spend** ($M)	1336.6	1356.9	1243.9	1404.6	1522.2	1548.2
Savings as % of Total Spend	3.0%	4.3%	6.0%	6.4%	6.8%	7.5%

Table 2 identifies the total year-over-year incremental cost savings achieved from 2009 to 2011 and the 2012 to 2014 forecasts for Hydro One Transmission.

Table 2
Total Year-over-Year Incremental Cost Savings – Transmission

	2009 Actual	2010 Actual	2011 Actual	2012 Bridge	2013 Test	2014 Test
OM&A (non-Cornerstone) Savings ($M)	3.7	2.8	4.4	8.9	3.4	2.1
Capital (non-Cornerstone) Savings ($M)	2.3	4.3	6.3	5.8	2.6	4.7
Cornerstone OM&A Savings ($M)	6.3	6.8	2.6	0.0	1.7	1.0
Cornerstone Capital Savings ($M)	4.5	5.2	2.7	0.0	6.3	5.3
Total Savings ($M)	16.8	19.1	16.0	14.7	14.0	13.1
Total Work Program Spend** ($M)	1336.6	1356.9	1243.9	1404.6	1522.2	1548.2
Savings as % of Total Spend	1.3%	1.4%	1.3%	1.0%	0.9%	0.8%

The cost savings identified as year over year "incremental savings" are defined as savings over and above those already embedded in the costs of individual programs. Accordingly, the first year impact of a new initiative or enhancements to an initiative are identified and the target associated with that initiative is subsequently monitored to establish the actual savings achieved. Under this concept of incremental savings, the savings beyond the first year are embedded in the annual business plans and are therefore not included in the annual incremental savings listed above unless enhancements to those initiatives are made. As a result, the incremental savings estimates substantially understate the savings from those initiatives that have a cost efficiency impact over more than one year.

Aggregate incremental savings achieved in the 2009 to 2011 period are ahead of internal projections. This is primarily due to:

- earlier than anticipated Cornerstone benefits;
- improved adoption and stabilization of the Cornerstone Phase 1 & 2 solution driven by greater than anticipated utilization of the central asset registry;
- improved reporting and analytics;
- improved process execution for work release; and
- managed reduction of staff development and travel expenses.

Table 2 also provides anticipated incremental savings for 2012 to 2014. The major initiatives contributing to the incremental savings are as follows:

- OM&A incremental non-Cornerstone Savings of $8.9 million in 2012, $3.4 million in 2013, and $2.1 million in 2014. The main initiatives contributing to the savings in this area are: Re-negotiated Inergi contract which obtained a decreasing annual cost curve for base services over the remaining life of the contract; reduced IT application and maintenance costs; reduced backhaul leased circuit costs due to the Wide Area

Network (WAN) Consolidation project; indirect and administration cost reductions; and improvements to our operating processes.

- Capital incremental non-Cornerstone Savings of $5.8 million in 2012, $2.6 million in 2013, and $4.7 million in 2014. The main initiatives contributing to the savings in this area are: savings related to work program optimization, rationalizing telecommunications assets in substations, indirect and administration costs reductions, and contracting cost savings.
- Cornerstone incremental OM&A Savings of $1.7 million in 2013 and $1.0 million in 2014. The initiatives contributing to the savings in this area are outlined in Shared Services - Cornerstone Capital, found in Exhibit D1, Tab 4, Schedule 3.
- Cornerstone incremental Capital Savings of $6.3 million in 2013 and $5.3 million in 2014. The main initiatives contributing to the savings in this area are outlined in Shared Services - Cornerstone Capital, found in Exhibit D1, Tab 4, Schedule 3.

As noted above, Hydro One continues to develop and implement a n umber of productivity initiatives. Highlighted below are details of select efficiency improvements:

- Outage Optimization:

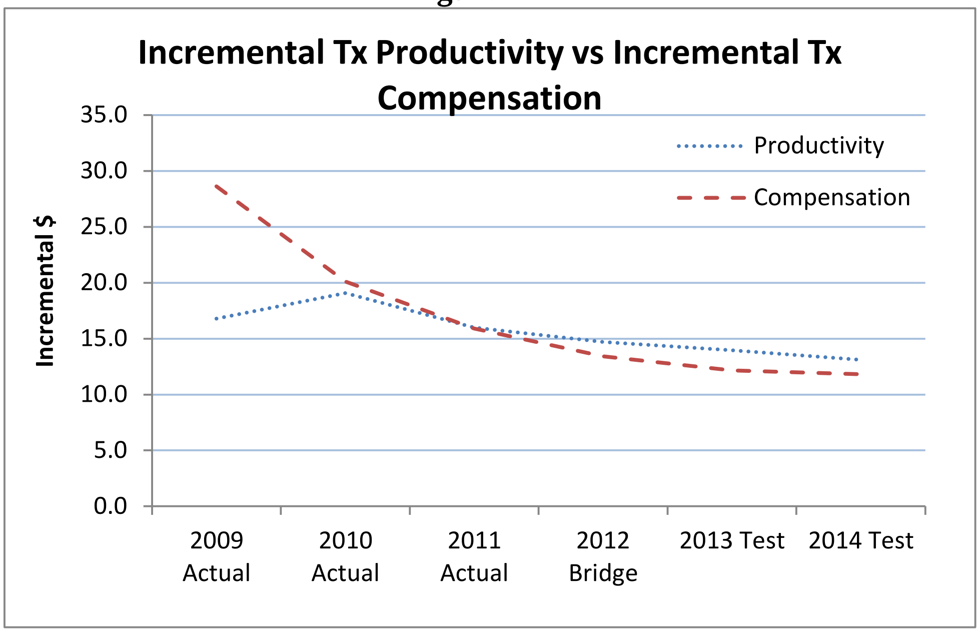
  Outage optimization involves the alignment and adjustment of preventive maintenance frequencies and testing into equipment groupings within Hydro One's work management tool. Asset equipment groupings have been created for all critical transmission elements (e.g. circuits, transformers, buses) with maintenance tasks now aligned into a common year. As an example, all switches on a given transmission circuit are now due in the same year such that Hydro One can minimize the number of outages and increase crew utilization. This type of work optimization decreases the amount of set up costs and number of outages. This reduction in loss of redundancy also has a broader benefit to the manufacturing sector in Ontario with less down time of equipment.

- Telecommunications – Wide-Area Network (WAN):
  The project will expand and upgrade Hydro One's WAN to meet new telecom requirements using technology that provides a much higher bandwidth, better reliability and scalability for future use. It will allow multiple existing networks to be rationalized thus reducing leased circuit annual costs.
- Underground Cable Vault Inspections:
  Cable vault inspections usually involve the need to take the cables out of service and have a crew of four Hydro One employees on site with some of the team physically entering the vault to conduct the inspection. With the utilization of video cameras to remotely inspect, the cables no longer need to be taken out of service, minimizing disruptions to Hydro One customers as well reducing the manpower by 50% and overall cost required to conduct the inspection.

5.0 PRODUCTIVITY AND COMPENSATION

In the Board's EB-2010-0002 Decision with Reasons, the Board noted that it expected Hydro One to highlight productivity gains to match its compensation increases. Figure 2 graphically shows how Hydro One's incremental productivity initiatives outlined in the previous sections met incremental compensation increases in 2011 and continue to outpace incremental compensation increases through the test years. (For compensation figures see Attachment 2 of Exhibit C1, Tab 5, Schedule 2).

Figure 2



As explained in Exhibit C1, Tab 5, Schedule 2, Hydro One has a complex compensation environment, while Management's continued focus on productivity initiatives have been successful in offsetting compensation increases and provide a platform from which further initiatives will evolve.

6.0 INDUSTRY PRODUCTIVITY PERFORMANCE

The initiatives undertaken and detailed in the sections above have underpinned Hydro One's productivity performance. In 2010, t he Canadian Electricity Association – Committee on Performance Excellence (CEA-COPE) conducted a Transmission Study of Canadian Utilities which looked at a number of normalized metrics. In this study, performance is compared across a range of cost, reliability and cost/reliability ratios.

While the individual results are confidential to the CEA, the CEA-COPE releases an average for the seven participants for public use. Table 3 lists the performance indicators along with Hydro One's performance against the utility average. The table shows a wide range of measures and on 17 of 19 measures (90%) Hydro One's performance is better than the study average.

Table 3
Hydro One CEA COPE Ranking (2006-2010)

Performance Indicators	Hydro One vs. Average
Total Cost per Energy Transmitted	Better
Total Cost per System Peak	Better
Total OMA Cost per Circuit KM	Poorer
Total OMA Cost per Energy Transmitted * Circuit KM	Better
Total OMA per Gross Fixed Assets (GFA) (%)	Better
Direct OM Cost per Circuit KM	Poorer
Direct OM per Energy Transmitted * Circuit KM	Better
Direct OM Cost per Gross Fixed Assets (%)	Better
Total OMA + Sustaining Maintenance Capital/ Energy Transmitted GWh * Circuit KM	Better
Total OMA + Sustaining Maintenance Capital per System Peak	Better
Total OMA + Sustaining Maintenance Capital per Gross Fixed Assets (%)	Better
Gross Fixed Assets per Energy Transmitted	Better
Gross Fixed Assets per System Peak	Better
T-SAIDI	Better
T-SAIFI – SUSTAINED OUTAGES	Better
T-SAIDI vs. (OMA + Sustaining Capital) / GFA	
•2010	Better
•2006 -2010	Better
T-SAIFI vs. (OMA + Sustaining Capital) / GFA	
•2010	Better
•2006 – 2010	Better

Hydro One's previous investments in infrastructure, and proactive influencing of participants in the continually evolving utility industry, continues to provide benefits to customers. With respect to future developments, Hydro One is utilizing more and better information to affect initiatives that mitigate the changing external environment and improve overall productivity. Compensation increases reflected in this Application continue to be offset by productivity improvements as illustrated in this exhibit.

PRODUCTIVITY METRICS

1.0 INTRODUCTION

At the conclusion of Hydro One's last transmission rate filing, the OEB directed Hydro One to refresh the 2008 compensation benchmarking study to more appropriately compare compensation costs to those of other regulated transmission and/or distribution utilities in North America. The Board noted that Hydro One must be in a position to provide more robust evidence that compensation increases will be matched with demonstrated productivity gains. For further information on the Compensation Study please refer to Exhibit C1, Tab 5, Schedule 2, Attachment 1. For further information on Hydro One's cost efficiency and productivity initiatives please refer to Exhibit A, Tab 17, Schedule 1. To meet the Board's requirement, Hydro One selected Oliver Wyman to address productivity measurement. Specifically, Oliver Wyman was to study current market standards for measuring productivity and to suggest potential internal metrics for measuring productivity at Hydro One. Please see Attachment 1 to this exhibit for the Oliver Wyman study and Attachment 2 for the OEB Expert Evidence Requirements.

2.0 OLIVER WYMAN PRODUCTIVITY REPORT FINDINGS

For the productivity metrics, Oliver Wyman conducted a broad market survey of U.S. and Canadian utilities. Unlike previous studies, in the current study Oliver Wyman extended the scope of examination to the North American regulators as well. The final report showed most utilities looked at productivity metrics as part of a balanced scorecard to support the understanding of trends of service quality and total cost metrics. None of the participants tracked productivity across all business functions, relying instead on a sampling of different sections of work. Furthermore, no regulatory commission was found to routinely request measures of productivity from utilities under their jurisdiction, but instead focused on outcome metrics of overall service quality and total costs.

In addition, the Oliver Wyman report specifically noted the following: "There was a wide disparity in internal performance measurement with each utility defining productivity, service quality and cost metrics differently. The reason for the disparity may have been because each utility was choosing metrics to track the success of different corporate goals."

As noted above, the utility industry does not have common performance measurement definitions. The Ontario Energy Board has advanced the discussion on measuring various aspects of utility performance through its Staff Discussion Paper on *"Defining & Measuring Performance of Electricity Transmitters & Distributors EB-2010-0379"*. Hydro One staff reviewed the Board staff paper and is a participant in the associated working group as well as on a number of industry working groups on this topic. While the industry continues this work, Hydro One understands the significance of productivity measures and has developed its own productivity metrics in the context of a balanced scorecard. This balanced scorecard is used to drive overall productivity while balancing the need for reliability (SAIDI, SAIFI), customer satisfaction, safety and shareholder value.

3.0 ACTIVITY METRICS

While the Oliver Wyman study does acknowledge that comparing across utilities is difficult, the report does suggest a number of potential activity metrics that can be used internally and prioritized these metrics based on the materiality. The notion of materiality is an important one to Hydro One; while the Corporation understands the value of measuring various productivity initiatives that are implemented across the company, this must be balanced with the cost and effort required to justify, define, track, and defend a metric. To this end, Hydro One has analyzed the suggested Oliver Wyman metrics and, based on materiality and business impact, has selected the following three unit measures to illustrate potential activity-based productivity metrics. It should be noted that, while Hydro One has begun work on productivity metrics at the activity level, issues such as collection of data, stability of allocations, materiality of metrics and therefore consistency across the organization remain. It is also worth noting that with metrics of this type, establishing and trending rolling averages are important as they eliminate typical annual variations such as weather conditions, asset needs/risks and geographical terrain variations where work is done.

The three activity metrics are:

- Transmission Lines Wood Structure Replacement;
- Transmission Brush Control; and
- Insulator Replacement Program

Costs are unitized by work accomplished so that a unit cost of productivity is measured.

3.1 Transmission Lines Wood Structure Replacement ($/structure)

Hydro One's transmission network consists of approximately 28,000 circuit kilometres of overhead transmission lines. The maintenance of overhead lines is necessary to meet reliability expectations, compliance and legal requirements, and to minimize safety impacts associated with failure or end of life of various line components.

The Wood Structure Replacement Program makes up the largest portion of the Overhead Lines Component Refurbishment and Replacement Program and has made efficiency improvements from 2009 through 2011 with this trend projected to continue in the bridge and test years, as illustrated in Figure 1.

The dollars spent on wood structure replacement are divided by the number of wood structures replaced. This provides a unitized value that should, if aggregate variables such as the percentage of remote locations and pole configurations are the same from year to year, provide a measure of efficiency.

Figure 1

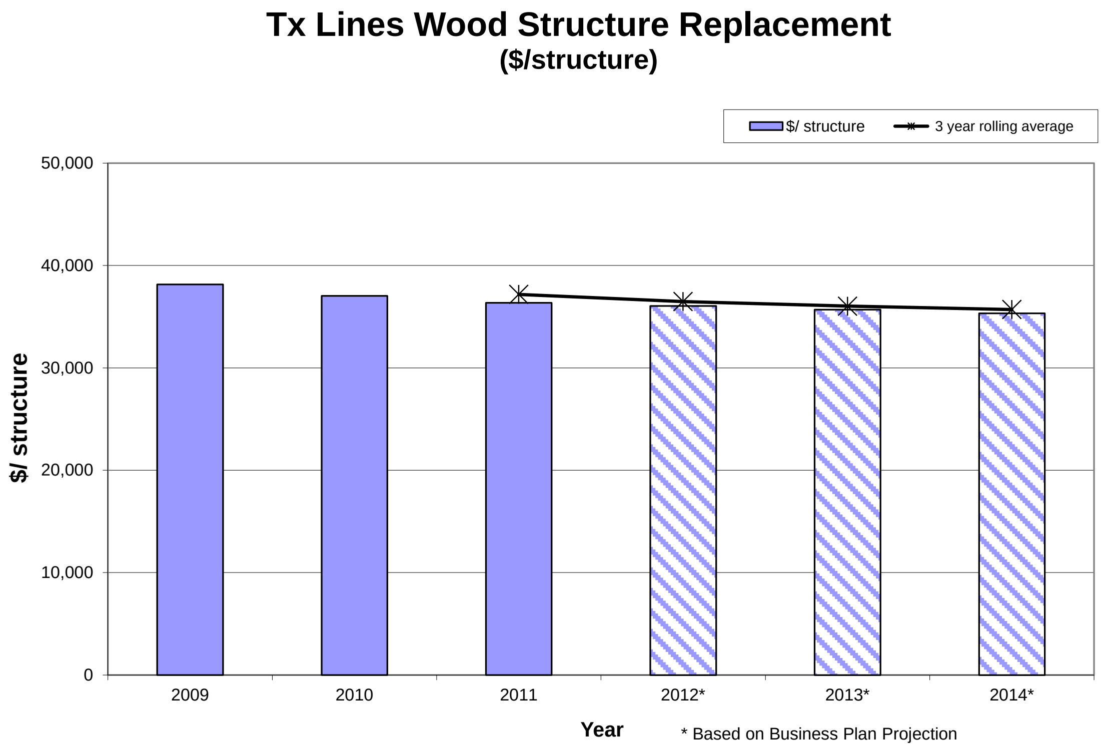


Table 1
Transmission Lines Wood Structure Replacement

	2009 Actual	2010 Actual	2011 Actual	2012 Bridge	2013 Test	2014 Test
Wood Pole Structure Replacement ($/structure)	38,146	37,033	36,353	36,055	35,694	35,338
% Change		-3%	-2%	-1%	-1%	-1%
3 Year Average			37,177	36,480	36,034	35,696

Efficiency gains illustrated above are being realized through expanding the use of existing tools such as the Air Stair and the introduction of Hydro One designed tools such as the Pole Claw. These tools reduce the need for line outages and allow for smaller crews thereby yielding the efficiency gains.

3.2 Transmission Brush Control ($/treated hectare)

Hydro One's transmission network consists of overhead transmission lines that occupy approximately 82,000 hectares of Right of Way (ROW) land. A majority of these ROW support diverse and complex plants that, if left unmanaged, present a risk of growing into energized equipment as well as impeding access to line facilities. The Vegetation Management Program is required to manage natural vegetation and is designed to provide cost effective control of vegetation growth in order to meet reliability expectations, ensure public and employee safety, and minimize environmental, ecological and social impacts.

As shown in Figure 2, the ROW Brush Control program has made efficiency improvements since 2009 and this trend is projected to continue in the future.

Figure 2

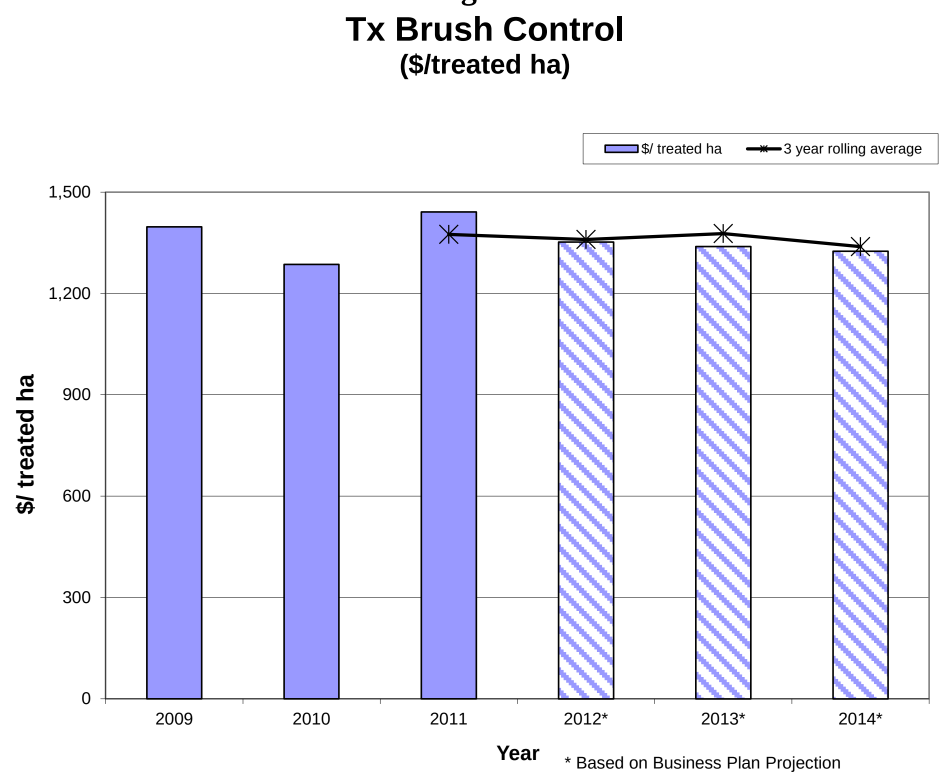


Table 2
Transmission Brush Control

	2009 Actual	2010 Actual	2011 Actual	2012 Bridge	2013 Test	2014 Test
Brush Control ($/ha)	1,397	1,286	1,441	1,352	1,339	1,325
% Change		-8%	12%	-6%	-1%	-1%
3 Year Average			1,375	1,360	1,377	1,339

The dollars spent on brush control are divided by the area that has been cleared. This provides unitized value that provides a measure of efficiency. It should be noted that this metric is influenced by variables such as the total percentage of type of brush cleared, percentage of remote locations in a given year, weather conditions and the availability of crews due to storm activity (increase of mobilization and demobilization costs).

Note that the 2010 cost dip is primarily due to a combination of two factors; ideal field working and access conditions at the time of work execution and lower vegetation densities. For example, ideal weather conditions while working in Algonquin Provincial Park meant more effective use of helicopters to transport staff to the work site. In terms of densities, vegetation requiring removal or control was reported as lower than expected in 2010. In 2011 the work in the program presented densities at more typical levels.

An example of efficiency improvements is the use of side by side all-terrain vehicles (ATVs). Hydro One's vegetation management program involves significant effort to transport staff, equipment and materials down the ROW as they traverse the province, in some cases considerable distances from roads. While single person ATVs have been used in the past, new 'side by side' ATVs are being deployed as an improvement to off road transportation safety. They have the additional carrying capacity of more than one person per unit and increased cargo carrying capacity. Hydro One expects to see efficiency gains in crew transportation in the bridge and test years.

3.3 Insulator Replacement Program ($/insulator)

Insulators are one of the many power system components that support the function of the main components like transformers, circuit breakers and protection & control systems. Their integrity is critical to the safe and reliable operation of the power system. There are over 100,000 insulators located in stations. Replacement programs are designed to cost effectively sustain system reliability, meet compliance requirements, minimize negative safety and environmental impacts, replace failed units and optimize life cycle costs.

The insulator replacement program shows efficiency improvements throughout the 2011 to 2014 period. This is illustrated in Figure 3. Note that 2011 is the first year that the insulator replacement program was specifically tracked so 2010 data is not available.

Figure 3

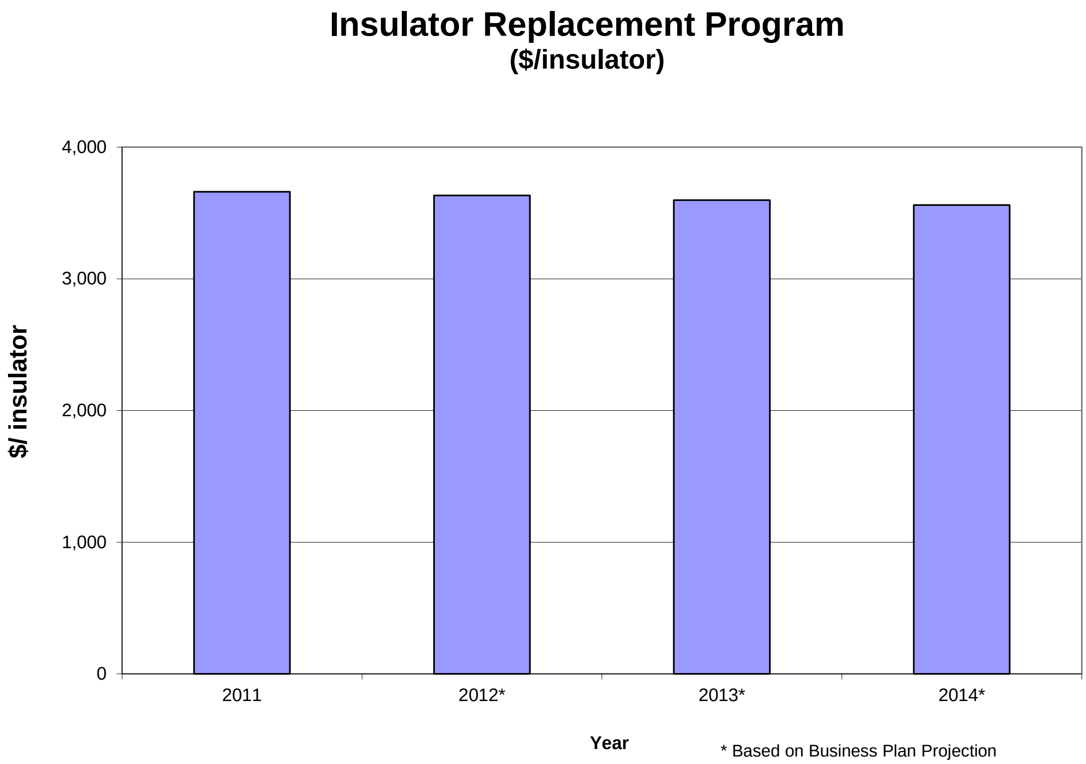


Table 3
Insulator Replacement Program

	2011 Actual	2012 Bridge	2013 Test	2014 Test
Insulator Replacement ($/insulator)	3,661	3,633	3,597	3,561
% Change		-1%	-1%	-1%

Efficiency improvements are largely due to improved outage optimization and work bundling. When other preventive or corrective work requires outages on switches, circuit breakers, transformers and bus work, insulators in that same outage zone are also replaced. This means there is less outage planning time, less mobilize and demobilize time, and less windshield time to specifically deal with insulator replacement.

4.0 CORPORATE TRANSMISSION UNIT COSTS

The Oliver Wyman report showed that there is a disparity in types of productivity measures across the utility sector because most utilities define productivity, service quality and cost metrics differently in order to track success of different corporate goals. While work continues on developing the previously discussed activity-based metrics, Hydro One's Board of Directors continues to use a unit cost indicator of corporate wide productivity in its annual balanced scorecard. This productivity indicator, the Transmission Unit Cost metric, is the corporate level Capital and OM&A expenditures normalized by Gross Fixed Asset. The Hydro One Board annually approves the target for this indicator relative to the work program in the approved Business Plan. The measure for the years 2012-2014 is illustrated in the following table:

Table 4

Measure	Year	Actual	Target
% of Capital and O&MA per Gross Fixed Asset	**2012**	TBD	10.1
	2013	TBD	10.3‡
	2014	TBD	9.9 ‡

‡ Target and Measure for 2013/14 is subject to Hydro One Board approval at the beginning of the respective year.

The Oliver Wyman report highlighted that utilities do not track productivity across all business functions, relying instead on a sampling of different sections of work. Hydro One continues to work internally and to participate in industry working groups to attempt to bring a level of consistency to productivity measure definitions. Hydro One's balanced scorecard metric, Transmission Unit Cost, indicates that the Corporation is achieving its annual productivity goals which are approved by its Board of Directors thereby assuring benefits to ratepayers. It should also be noted that Hydro One's performance is better than the average utility ranking for the similar metric in the CEA-COPE study (Table 3, Exhibit A, Schedule 17, Tab 1).

December 15, 2011

Measuring Productivity at Hydro One

OLIVER WYMAN

Contents

1

Executive Summary

Oliver Wyman was engaged to report current market standards for measuring productivity and suggest potential metrics for measuring productivity at Hydro One.

As part of this effort, Oliver Wyman conducted a broad market survey of US and Canadian utilities and contacted many regulators directly to assess how productivity measures were used. Across Canada and the US, Oliver Wyman contacted 30 utilities and 17 commissions via over 350 documented emails, phone calls and requests for information.

No regulatory commission was found to routinely request measures of productivity from utilities under their jurisdiction. Instead commissions focused on 'outcome' metrics of overall service quality metrics (SQM) and total costs. In many cases, the commissions directed Oliver Wyman to contact utilities directly as the management of productivity was considered the utilities responsibility.

Most utilities did look at productivity metrics internally as part of a balanced scorecard to support the understanding of trends of the service quality and total cost metrics. The productivity metrics found suggest that none of the participants track productivity across all business functions, relying instead on a sampling of different sections of work.

Survey Findings - Metric Collected Per Utility				
Category	**Median**	**Max**	**Min**	**Total**
Cost	6	89	1	213
Productivity	4	59	0	114
Service Quality	25	176	4	478

After analyzing Hydro One's major costs and interviewing many of their staff, 25 metrics have been suggested as candidates to measure productivity, which account for 22% of total O&M and Capex labor related costs. However, as with any measurement, the development of these metrics should be evaluated in the light of the cost to measure them, any potential negative effects they may create (e.g., adverse incentives for employees), and the ability to roll up these up to corporate scorecard measures.

#	Metric	Cost Coverage	% of total costs
1	Cost of brush control per km of line	$98M	4.6%
2	Cost per meter install	$82M	3.9%
3	Cost per pole set	$78M	3.7%
4	Cost per new service installed	$11M - $34M	1.1%
5	Cost per tower constructed	$13M - $26M	0.9%
6	Cost per tower foundation	$13M - $26M	0.9%
7	Cost per km of Tx line cleared (Capital)	$13M - $26M	0.9%
8	Cost per meter read	$22M	1.0%
9	Cost per upgrade	$14M	0.7%
10	Cost per km of transmission line refurbished	$14M	0.6%
11	Cost per insulator replaced	$8M - $13M	0.5%
12	Cost per cable locate	$12M	0.6%
13	Cost per km for line patrol	$6M - $10M	0.4%
14	Cost per breaker	$8M - $10M	0.4%
15	Cost per transformer	$9M	0.4%
16	Cost per RTU	$7M - $9M	0.4%
17	Cost per bill	$1M - $8M	0.2%
18	Cost per km of Tx line cleared (OM&A)	$7M	0.3%
19	Cost per protective device replacement	$2M - $5M	0.2%
20	Cost per Transformer Refurbishment	$4M	0.2%
21	Cost per service cancellation	$4M	0.2%
22	Cost per insulator inspection	$1M - $4M	0.1%
23	Cost per disconnect	$3M	0.2%
24	Cost per reconnect	$3M	0.2%
25	Cost per line inspection	$1M - $3M	0.1%
	Total	~$480M	~22%

2

Background

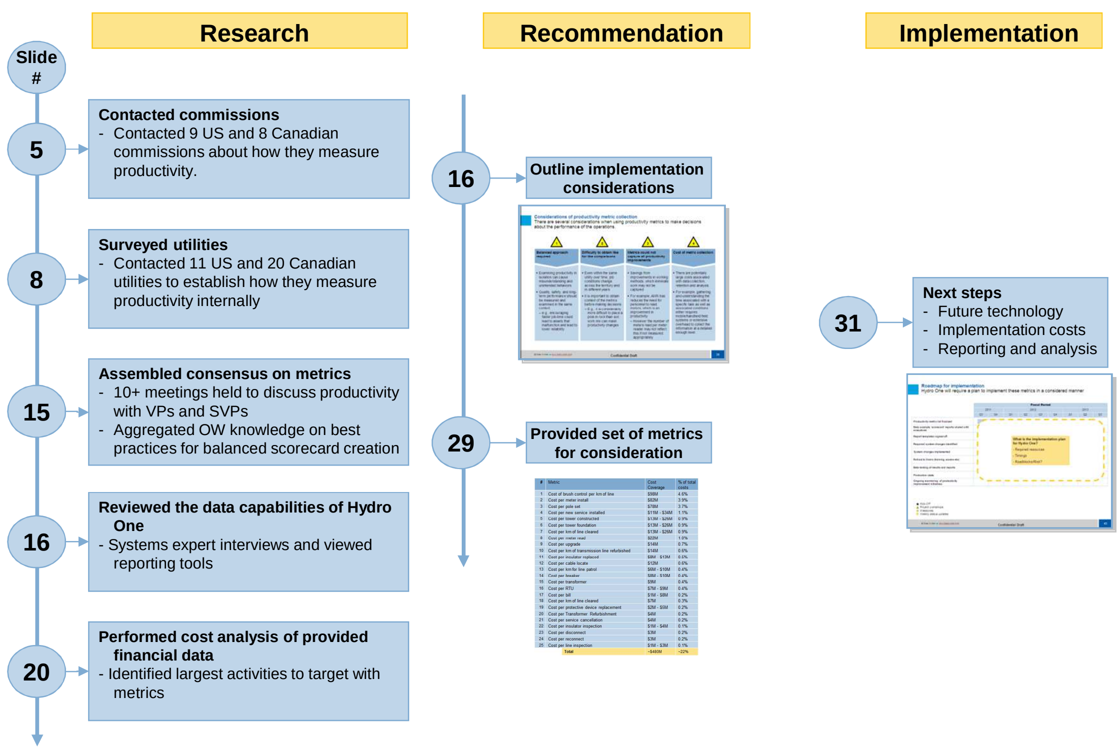
> “In its December 23, 2010 Decision approving Transmission Revenue Requirements for 2011 and 2012, the Ontario Energy Board provided direction and other expectations for further information on compensation and efficiency comparisons.
>
> The Board directed “Hydro One to revisit its compensation cost benchmarking study [the Mercer study] in an effort to more appropriately compare compensation costs to those of other regulated transmission and/or distribution utilities in North America.”
>
> Toward that end, the Board directed "Hydro One to consult with stakeholders about how the Mercer study should be updated and expanded to produce such analyses”.
>
> The Board went on to describe its expectation that Hydro One “be in a position to provide more robust evidence on initiatives to achieve a level of cost per employee closer to market value at its next transmission rate case. The Board will expect compensation increase to be matched with demonstrated productivity gains”.
>
> **Extract from Hydro One RFP # SCO-1000152789, March 2nd 2011**

To satisfy all aspects of the Ontario Energy Boards requests, Oliver Wyman was engaged alongside Mercer. Mercer was responsible for updating the compensation benchmarking study with 2011 data and separately reported changes in relative compensation levels. Oliver Wyman was to provide perspectives on industry best practices for productivity measurement.

3

Report Roadmap

The figure below represents the shape of the report, consisting of three sections; research, recommendations and implementation. The research section contains the findings from utilities and commission research and an analysis of Hydro One's cost. Using the findings from research, a list of the challenges of metric collection was created to coincide with the recommended set of metrics. To implement the data collection and reporting process steps were recommended to ensure that the recommended metrics would provide useful and accurate information.



4

Findings from Regulatory Commissions

17 Regulators across the US and Canada were requested to provide which methodologies they had for measuring performance. Nine commissions were in the US and eight commissions were in Canada.

United States commissions

Canadian commissions

In addition to direct contact via a combination of calls, e-mails and requests for information, a review was performed of publicly filed documents such as rate cases, studies and other regulatory dockets.

The findings were fairly consistent across the different regulators. 15 regulators collected 134 different service quality metrics between them during regular filing processes. 12 of the commissions had annual filing requirements for service quality; these were Alberta, Ontario, Quebec, Massachusetts, New York, Pennsylvania, Michigan, Ohio, Illinois, Connecticut, New Jersey and California.

Service quality metrics were the most standardized of metrics across the regulators. Reliability metrics such as system average interruption frequency index (SAIFI), customer average interruption duration index (CAIDI), and system average interruption duration index (SAIDI) are being collected by the majority of regulators on a regular basis. Customer call center metrics such as % of calls abandoned, and % of calls answered in under 30 seconds were also collected by many regulators.

It was standard practice to collect cost metrics with seven commissions collecting 67 cost metrics. All regulators require financial information to be filed during a rate case, generally as part of the utilities cost of service which include various financial statements.

No commission was found to regularly collect any productivity metrics. Both the Manitoba Public Utilities Board (MPUB) and Nova Scotia Utilities and Review Board (NSUARB) had collected productivity metrics, but not on a regular basis. The MPUB collected "average time per call" and the NSUARB commissioned an ad hoc study containing "calls handled per agent per day."

The summary results from each commission are found in the tables in the appendix. For a detailed review of each commission's metric collection practices please see the appendix.

Rank	Metric Type	Common Metrics	# Found
1	SQM	System Average Interruption Frequency Index	14
2	SQM	Customer Average Interruption Duration Index	13
3	SQM	System Average Interruption Duration Index	11
4	SQM	% of Calls Abandoned	7
5	SQM	% of Calls answered in under 30 seconds	5
6	SQM	Average speed of answer	5
7	SQM	% of In-service appointments met	5
8	SQM	Momentary Average Interruption Frequency Index	3

Further studies identified

There were several other studies identified in the course of research that have related topics and provide additional summary information about the state of metric collection.

CAMPUT

The Canadian Association of Members of Public Utility Tribunals (CAMPUT) commissioned a study in 2009 to review the use of benchmarking as a regulatory tool for public utilities in Canada.

The study reviewed current practices of regulators to determine the information which regulators currently collect from utilities, finding that only service quality and cost data was being collected. The extent to which service quality and cost were being collected varied across each commission.

The study looked at the perspectives on benchmarking from the sides of both the regulators and the utilities. It was determined that utilities focused on performance assessment, target setting, performance improvement and reliability support. Whereas regulators would like to use benchmarking for ratemaking, compliance, audit monitoring and reducing information risk.

Various factors inhibiting the use of benchmarking were found, including the difference in demographics and geography in which utilities operate. The methods of data collection between utilities could pose problem unless strict definitions and processes are created for each metric under consideration. CAMPUT suggested using normalizers, a comparable peer panel and good metric choice in order to mitigate each of these hazards.

The list of metrics which CAMPUT recommended for benchmarking were: call center performance, billing accuracy, customer complaints, system average interruption frequency index, system average interruption duration index, customer average interruption duration index, asset replacement rates for distribution, transmission and substation assets, customer care, bad debt, O&M costs, corporate services costs, safety indices, line losses indices, and conservation indices

CAMPUT suggested starting with stakeholder discussions to determine the metric definition and data collection processes. The next step was identified to start a pilot project to test the feasibility of benchmarking these metrics. The pilot project would start in jurisdictions where the data is already being collected. The pilot project would test the current processes, identifying solutions to the problems as they become apparent.

Hydro One is currently participating in the first pilot of this initiative and is providing mostly reliability (CAIDI, SAIFI, etc.) and some call center information (ASA, Service Level)

Ad hoc studies

Multiple studies were found which were commissioned by regulators during a rate case. These studies either reviewed or benchmarked different aspects of the utility.

The Nova Scotia Utilities and Review Board (NSUARB) commissioned Accenture Inc. to perform a review of Nova Scotia Power’s (NSPI) corporate services due to its recent restructuring. Accenture Inc. benchmarked the corporate services function across a similar peer panel and found that NSPI was an “average to good” performer.

The NSUARB commissioned an operational review of NSPI, which was done by Kaiser Associates. As part of Kaiser Associate’s review, a benchmarking study was administered on operating, maintenance and general expenses (OM&G). The study showed that NSPI operates at a lower normalized OM&G cost than its competitors. The Kaiser study benchmarked one productivity metric; calls handled per agent per day.

5

Findings from Utility Survey

Oliver Wyman conducted a survey to determine how different utilities measure their performance internally through cost, service quality and productivity metrics to establish best practices in the industry.

Respondents

13 utilities across North America were included in the survey panel; the utilities included those in transmission, distribution and generation.

The survey consisted of two parts: the first part was to collect the performance metrics (cost, productivity and service quality), the second part was to determine the automation level of the data collection, the percentage of total cost covered by the performance metrics and what function was responsible for the data collection. For the purposes of this report and the survey, productivity was considered to be an activity-level metric such as "cost per pole" while service quality and cost were higher level metrics.

There was a wide disparity in internal performance measurement with each utility defining productivity, service quality and cost metrics differently. The reason for the disparity may have been because each utility was choosing metrics to track the success of different corporate goals.

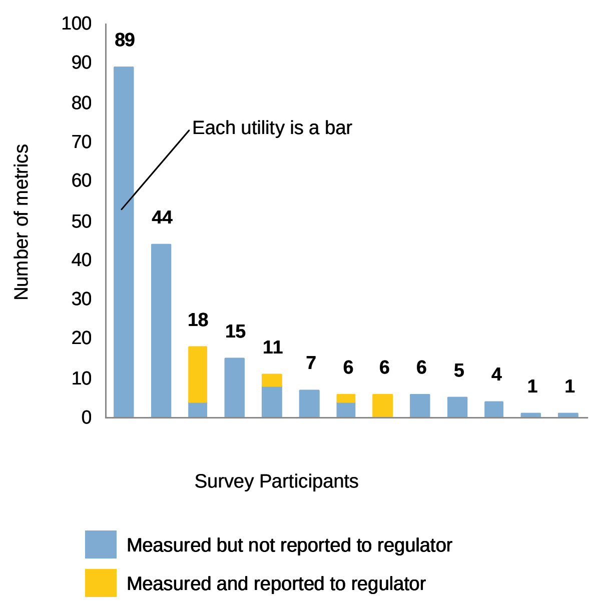
Survey Findings - Metric Collected Per Utility				
Category	**Median**	**Max**	**Min**	**Total**
Cost	6	89	1	213
Productivity	4	59	0	114
Service Quality	25	176	4	478

Cost

The cost metrics collected by utilities detail overall spend in business categories, with metrics such as "distribution spend per customer."

Of all the cost metrics reported internally, 12% are reported to regulators, and 22% are part of a benchmarking effort but not necessarily reported to regulators.

Cost metrics collected in survey



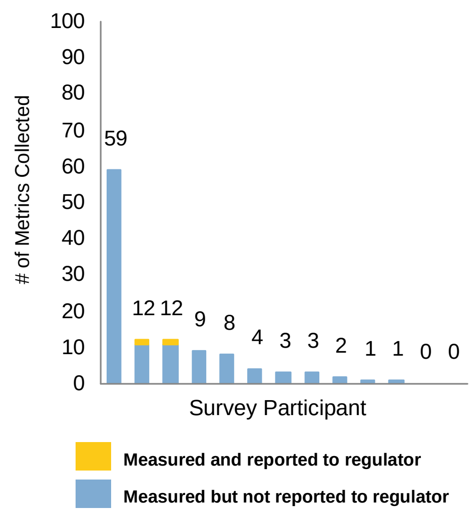
Productivity

12 of 13 utilities collected at least one productivity metric. Productivity is measured at an activity-level; with a median of six metrics per utility, it is likely that most utilities are not measuring productivity across a large portion of their activities and total costs.

The productivity metrics collected are generally not benchmarked, and none are regularly reported as to regulators.

Four strategies were identified for measuring productivity: cost per unit (e.g. cost per pole), units per FTE (e.g. bills processed per FTE), reducing nonproductive time (e.g. average travel time), and time taken per activity (e.g. average time per call).

Productivity metrics collected in survey

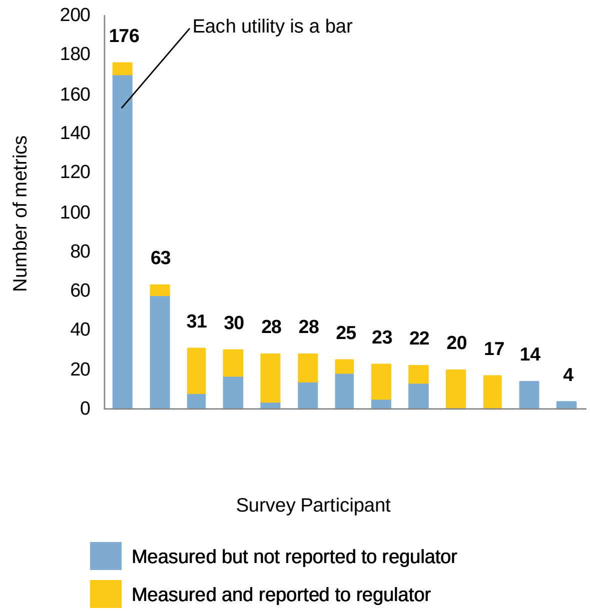


Service Quality

The utilities surveyed place a strong emphasis on measuring service quality as these are often the primary concern of regulators, shown by the number of metrics that were reported to regulators.

The metrics collected can be grouped into five categories: system reliability (e.g. system average interruption duration index), safety, customer call center performance (e.g. % of calls answered within 30s), customer facing operations (e.g. % meters read), customer satisfaction.

Service quality metrics collected in survey



System reliability metrics were standard across utilities with a majority of the utilities collecting; system average interruption duration index (SAIDI), system average interruption frequency index (SAIFI), customer average interruption duration index (CAIDI).

Common Metrics

It was difficult find metrics that were universal across utilities as each utility measured differently. The metrics below are those that were tracked by at least 2 utilities in the survey.

Cost

- Net income
- Net income from operations
- Operations Maintenance & Administration (OM&A) costs per customer

Productivity

- Turnover
- Cost per call
- Meter reads per FTE
- Lost time accident rate
- First call resolution rate
- Average time per call

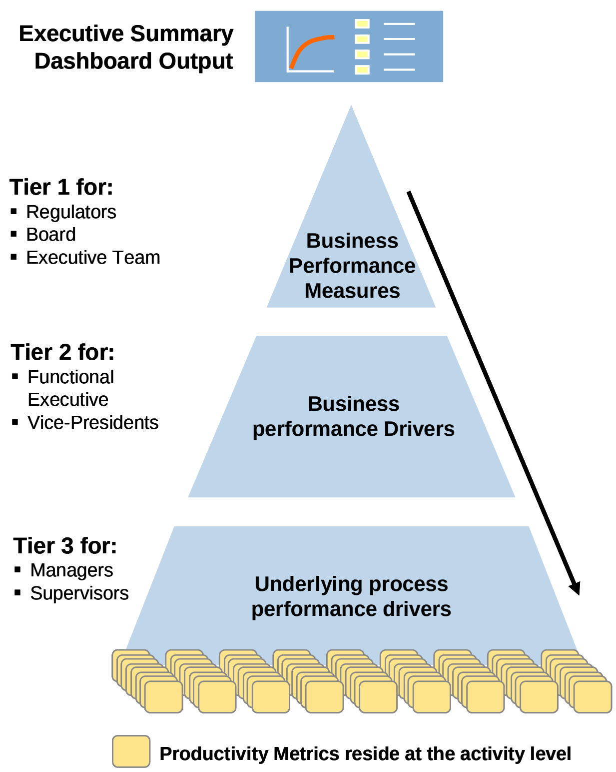
Service Quality

- System avg. interruption frequency index (SAIFI)
- Customer avg. interruption disruption index (CAIDI)
- % of Calls answered in 30s or less
- System avg. interruption duration index (SAIDI)
- % of Calls abandoned
- % of Meters read
- % In-service appointments met
- Customers experiencing multiple interruptions (CEMI)
- Bill accuracy rate
- Average speed of answer
- Occupational Safety and Health Administration Incidence Rate
- Momentary avg. interruption frequency index (MAIFI)
- Emergency response time
- SAIFI – Distribution Only
- # of Off-cycle meter reads/month
- SAIDI – Distribution Only
- Occupational Safety and Health Administration Severity Rate
- # of Post-final adjustment mechanism processed per month
- New service installation factor
- # of Sites billed/month
- # of Sites not billed/month
- Regulatory commission cases per 1000 customers
- Damages per 1000 elect. Locate requests
- Customer satisfaction – overall
- Customer experience long interruption duration (CELID)
- CAIDI – Distribution Only
- CAIDI – Storm
- Average number of energizations per month
- Average number of de-energizations/month
- Average System Availability Index (ASAI)
- % of Meters not read within 6 months
- % of Completed off-cycle meter reads >5 days
- % of Calls answered in under 20 seconds
- Vehicle accident frequency rate

6

Perspectives on Productivity Measurement

Performance measures should "cascade" in various tiers, with productivity metrics normally measuring activity-level performance in the bottom tier. There are three main tiers when measuring performance; business performance measures, business performance drivers, and underlying process performance drivers.



Business performance measures are used for strategic decision making and to align an organization to the company's strategy and vision (e.g. reliability, customer satisfaction, and overall cost to serve). These measures are often reviewed by regulators, the board of directors and the executive team, typically as part of a balanced scorecard.

Business performance drivers are measures that directly impact business performance measures. These metrics can be used to identify opportunities for different business units or operational groups as well for ongoing management education (e.g. customer service cost per customer, inventory turns, or # of outages longer than 4 hours). Business performance drivers are utilized by functional executives and vice-presidents.

Underlying process performance drivers are measures that impact business performance drivers. These drivers enable the identification of specific process improvements and provide ongoing employee education (e.g. cost per call, cost per meter read, or cost per locate). The diversity of work in a utility at this tier would require thousands of metrics to capture productivity covering the entire workforce; therefore it is important to select a representative portfolio of metrics which account for the diversity of work.

Most utilities select the portfolio of metrics using criteria that best fits their business needs. A metric may need to be used in conjunction with other metrics to meet the criteria stated below.

	Metric Criteria	Description	Details for Hydro One
1	**Targets principal labor cost areas**	Build an understanding of labor costs and target the biggest activities first. Choose enough metrics to measure a large proportion of total costs	Major activity costs should be assessed by productivity metrics. Hydro One has several repetitive large costing activities such as locates, pole replacement, tree trimming, etc.
2	**Covers a wide cross section of work**	Choose metrics which measure the major functions of the business.	Categorizing costs into T&D and O&M v Capex allows selection of a stratified sample of the major cost areas. This ensures a balanced wide range of productivity metrics from different areas of the business.
3	**Based on Data Capabilities**	Only use metrics from data that have high confidence levels.	For example do not measure pole replacement costs by location ground type, if ground type is not consistently recorded at Hydro One.
4	**Allows consistent measurement over time**	Metrics should be precisely defined, so year on year comparisons are meaningful	With the introduction of SAP and increases in the resolution of base data, it is important that changes in metric calculations are understood.
5	**Appropriate measurement costs**	Metrics should balance usefulness and costs to measure.	At Hydro One, in order to perform the exact tracking of various field resources, mobile handheld tracking systems, would have to be implemented which are very expensive as it is a new set of hardware, new tracking system and field process restructuring and training
6	**Applicable over long time frame**	Corporate metrics should not be specific to a particular project, but rather valid for multiple years	Project specific metrics are not suitable for long term productivity tracking. This should not prevent larger projects (e.g. Bruce to Milton) to have additional tracking and metrics or be tracked via Earned Value methodologies.
7	**Focus on key areas of customer interest**	Metrics should primarily focus on areas of high concern and/or are important to its customers.	Hydro One has many customer facing activities, which have a large effect on their customer satisfaction. For example average days to complete a locate or percentage of calls answered within 30 seconds

Considerations of productivity metric collection

There are several considerations when using metrics to make decisions about the performance of operations which are; using a balanced approach, the difficulty of obtaining like for like comparison, metrics not capturing all productivity improvements and the cost of metric collection. These considerations detail the various risks associated with data collection, measurement, and use.

Using a balanced approach

A balanced approach to metric reporting considers all factors of safety, quality and long-term concerns when choosing which metrics to include. A balanced approach is required because efforts to increase productivity could lead to a reduction in safety or quality standards as people try to game the system. This is especially a danger if promotions or bonuses are related to metric performance.

Example: A supervisor knows that their bonus will be determined by the metric ‘Cost per km of line cleared’. To increase their bonus, they schedule cheaper vegetation clearance jobs with sparse vegetation that were not critical for another year and push back some difficult line clearance with more impact. The metric improves in the short term, but costs rise later in the year when the uncut vegetation causes an outage in the more critical area.

This problem can be mitigated by building a clear division of labor between work planners and executioners, and not providing an incentive for the planners to affect the metric in either direction. It is necessary to be careful when setting up management and compensation structures to avoid any conflict of interest. In-depth safety training will educate workers about the risks of forgoing service quality and safety standards to expedite the completion of a job. Tracking safety standards within the portfolio of metrics will ensure that the level of safety and service quality does not erode as efforts to increase productivity continue. Measuring a balanced set of metrics prevents undue focus on any one metric.

Like for like comparison

Not all work units are of similar difficulty level, so productivity improvements could be hidden by changes in average job difficulty. Even seemingly homogenous work activities will have their own unique challenges. Each job has its own required travel time, soil type, ease of access, conditions etc. which change the overall cost of the job, these changes have the capacity to dilute increases in productivity.

Example: One year the percentage of pole replacement jobs done in rock increases from 15% to 20%. Since replacing a pole in rock rather than soil is much harder to perform, the cost per pole replacement increases. This effect masks any productivity gains.

Activities should be defined so the differences inherent in each job are not significant. In the pole example replacing a pole in rock, versus earth, could be tracked as two separate activities. This could be done through additional data collection or by defining the metric by zones. Otherwise it is possible to use comparisons across longer time frames to allow for averages to become a better indicator of true performance. This also eliminates any seasonal effects.

Breaking apart activities into similar groups in this manner allows for better like for like comparisons. However, sometimes obtaining the base data to accomplish this is prohibitively expensive, therefore, longer comparison periods should be used instead to normalize the effects of the differences.

Capturing all productivity increases

System productivity enhancements might not be captured by direct consideration of metrics. Initiatives to improve productivity often eliminate manual work streams, in favor of cheaper automated systems. These process changes can cause ‘per work unit’ metrics to deteriorate, while still being an overall productivity improvement. When considering how successful Hydro One has been at increasing productivity all of these savings should be included.

Example: Increased automated monitoring of system availability gives responders the ability to respond faster to outages. However, automated monitoring routinely detects smaller outages, negatively affecting system reliability metrics such as SAIFI.

Savings from new technology programs should be tracked through dedicated programs. It is necessary to compare the total system setup and maintenance costs with the realized savings in order to track how the system influenced productivity. During the transition period to automated meter reading, the cost of meter reads can be divided by the total number of automated reads plus number of manual reads. Similarly for the SAIFI example, during a transition period the metric can be calculated via the old and new methods. When a new baseline for the automated monitoring system is established, the older calculation method can be stopped.

Cost of metric collection

Measuring any metric requires an investment in all of the following areas: setup, data collection, data storage, and reporting and analysis. The benefits of the increased knowledge and understanding from reporting and analysis must outweigh the costs of measurement.

Example 1: Mobile time trackers can be given to all field engineers, recording exact locations and the type of work being performed at any given time. They are expensive to roll out, but allow for much more detailed time studies.

Example 2: Pole replacement costs increase by 30% in a reporting period. After two days of investigation it is found that this is because zone 6 incorrectly reported the number of poles replaced. Two days of overhead costs incurred for no gain in understanding.

In example 1, a detailed cost benefit analysis would be required - a large upfront cost would provide an ongoing wealth of interesting information. In example 2, there is a more straightforward answer; the system should be redesigned to highlight missing input data to prevent losing two days for a simple tear down analysis. Normally reports are setup once and can then be run on an automated schedule, with little to no manual effort. The total costs of measurement and reporting should be understood upfront and compared to benefits in order to decide on its implementation.

Overview of productivity metrics at utilities

Many utilities do measure productivity metrics, as they consider the benefits of understanding their business outweigh the costs and challenges of measurements. The considerations of productivity measurement show that measuring genuine productivity changes is a difficult and sometimes inexact science. There is no automated or fool proof mechanism for capturing all the contextual knowledge required to understand trends and changes in a metric over time. Similarly there is no ‘silver bullet’ metric that does not have any challenges or limitations.

Despite these caveats, productivity metrics are an integral part of the management of a utility. Tracking productivity assists utilities in understanding and explaining the drivers behind changing costs, for use internally and in explanation to regulators. Productivity metrics can assist in targeting corporate initiatives at poorly performing areas and to assess the success of corporate initiatives and of managers.

Most utilities use a balanced set of metrics to obtain the clearest picture of performance. The set of metrics ensure no significant costs of the business are untracked and that productivity is not degrading safety or service quality. Utilities have analysis teams which place results into the context of business cycles and external influences (e.g. weather). The trends in headline metrics are explained by the underlying supporting metrics which is illustrated in the cascade of performance metrics.

Utilities leverage advanced IT systems such as mobile tracking devices to produce detailed productivity metrics without creating large indirect costs. Field workers activities are tracked at a granular level, allowing for a clearer view on productivity without requiring labor intensive and inaccurate detailed timesheets. Activity-level information can be captured on the job site, which helps to further segment activities for like to like comparisons. Utilities that do not have a mobile data collection system to capture every minute of a crew’s day, relying on manual entry of time at the end of a day may sometimes result in incorrect data input or inadequate time breakdown which can generate misleading metrics.

7

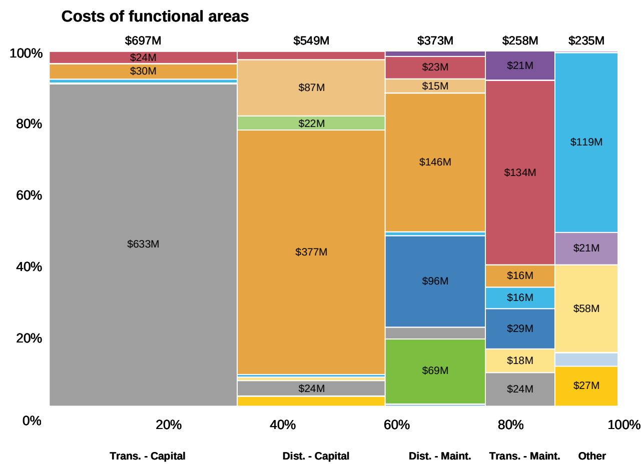
Targeted Cost Analysis

Overview of methodology

Oliver Wyman evaluated Hydro One's project-level data in a four step analysis to better understand how a suite of productivity metrics could be developed.

Step 1: Build overall cost map by functional areas

Projects were grouped into functional areas to ensure that metrics capture major sections of the business.

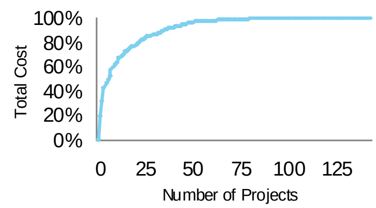


Step 2: Filter cost groups

The four major functional areas were targeted; transmission capital, transmission OM&A, distribution capital, and distribution OM&A. The 'Other' category was not targeted because it includes projects which do not relate to labor productivity. Some of the projects include real estate maintenance as well as IT projects such as SAP. Targeting the major areas allows for a sufficient proportion of the total cost to be tracked. In each of the four functional areas the irrelevant and uncontrollable costs were removed. These are costs that would fluctuate and obscure the productivity gains that are being tracked. In this initial analysis, material costs were removed, which are mainly driven by base commodity prices. Further filters could also target contracts and interest, as these costs do not directly correlate to labor productivity. Interest expense is based on market rates and does not change based on productivity. A productivity metric which includes the cost of contracts might look better if a contract is negotiated with a lower price, or it may be more expensive if internal skilled labor is more efficient. While ‘cost productivity’ may change, these scenarios may not necessarily represent a ‘workforce productivity’ change.

Step 3: Concentration of cost in major projects

It is necessary to understand how dispersed or concentrated projects are within each functional area in order to effectively track performance. Multiple large projects were selected in order to get a large proportion of the costs associated with each functional area. Within these projects understanding which activities meet the metric criteria and represent the largest proportion of cost is mandatory as these are the activities which will be tracked with metrics.



Step 4: Identify suitable metrics for activities

Using the criteria for metric selection, specific metrics within each project and their cost coverage were identified. Some projects were not covered by metrics because the activities which represent the project are not objectively measurable; they either have a short time frame or non-repetitive activities. Short term projects do not allow for long term comparison of the metrics covering these activities, without the comparison tracking the metric becomes a nonproductive effort. Projects may be composed of non-repetitive activities; these activities cannot be measured using productivity metrics as there would be no comparisons available, and tracking it would provide no relevant information.

During the stakeholder session held on October 19, 2011, a point was raised that even if activities are not consistent from activity to activity, a larger group of them should have the same profile if examined over a long period of time. The example discussed was ‘Trouble Response’. While it was agreed that no Trouble Event could be compared to the next because they are very different in nature, over a long period of time a metric looking at the large group of them should be possible. With respect to Trouble Events, it was discussed that even over an annual cycle, the ‘portfolio’ of events would vary because weather patterns change from year to year affecting the frequency and character of trouble events. So, a longer period of time (e.g., 3 years) would have to be examined.

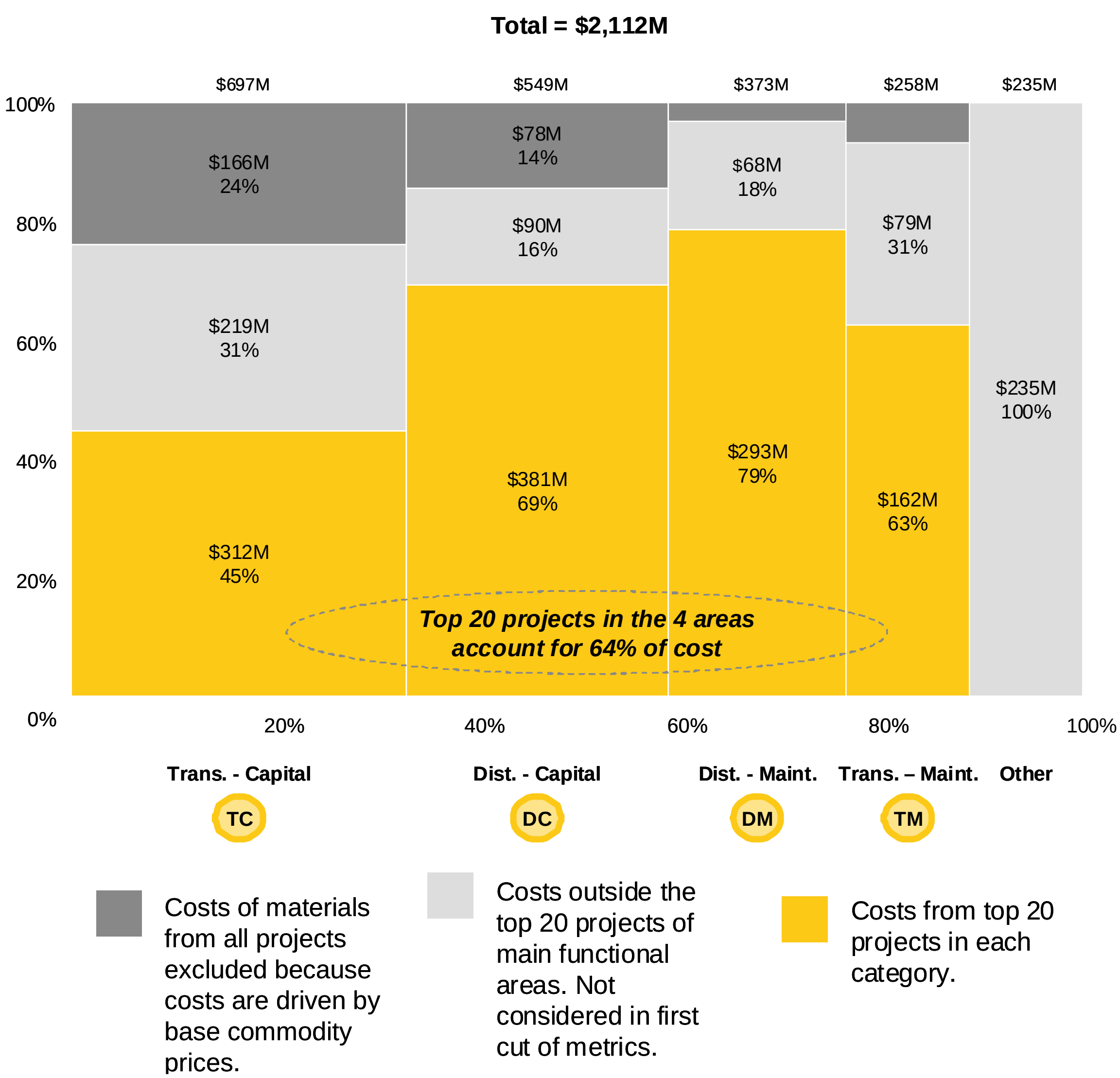
In this report we identify those activities that have potential to be measured over a long period of time. However, we believe that the long duration over which they must be examined prevents them from being used as a management tool to drive improvements in productivity. Management cannot use them on a regular basis to identify and drive improvements. Therefore, while we identify them in their respective sections, we do not recommend pursuing them at this time to drive productivity improvements.

Principal cost driver analysis

Productivity metrics should span all business areas in order to best represent the productivity for Hydro One as a whole. Understanding the cost drivers for each of the main projects in the functional areas will allow for tracking productivity across a large proportion of total cost.

Cost map of the 80 projects in focus from the four functional areas

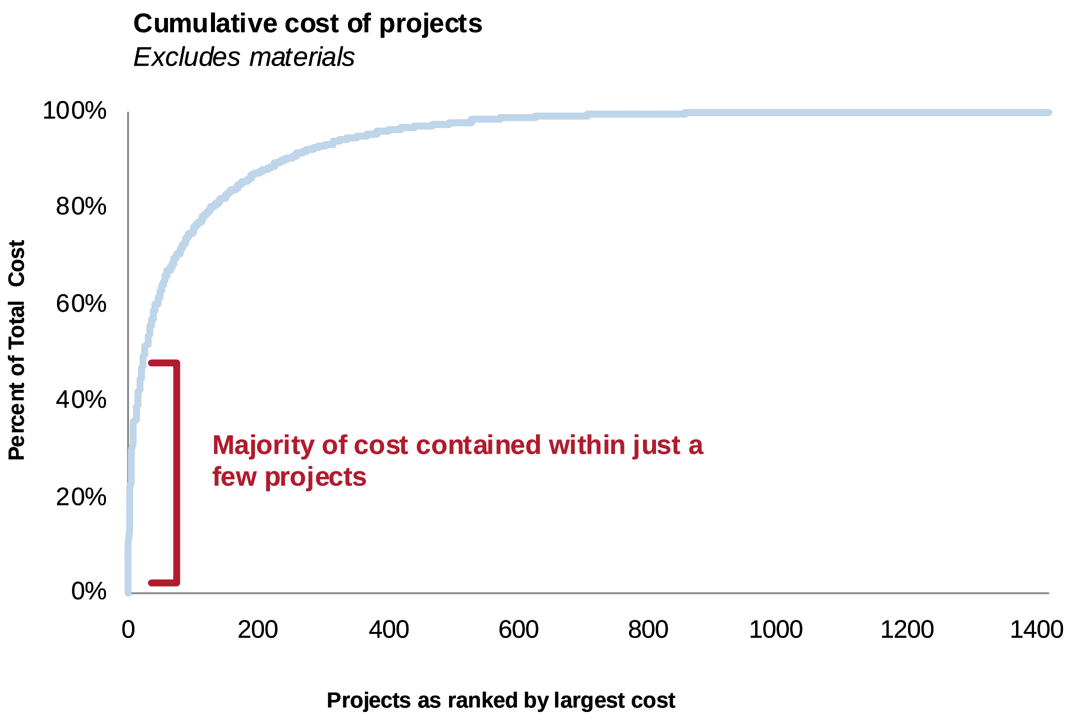
To arrive at a list of activities (projects) that may be measured for productivity, the largest activities (measured by cost) were examined. Material costs are excluded from the analysis as they do not represent workforce productivity and can fluctuate with many uncontrollable factors. Targeting the major cost areas (projects) allows for a large proportion of total cost to be covered, by a smaller number of metrics the top 80 projects (20 from each major cost area, T OM&A, T Capital, D OM&A, D Capital) cover 64% of the total cost.



Note: All costs are approximate and have been annualized from May 2011.

Trends in project costs

Another representation of the concentration of costs is to examine what each incremental activity (project grouping) adds to the total cost of the total. Each major cost area reveals that a large proportion of total cost is covered in a small number of projects. A few metrics targeting these projects cover a large percentage of cost and work. The cumulative cost of activities shows that 80% of costs are from the 126 largest projects, 75% from 96 projects, 50% from 29 projects, and 24% from 6 projects.



**Note: Costs are approximate values and have been annualized from May 2011. Costs do not include projects with negative or zero costs.*

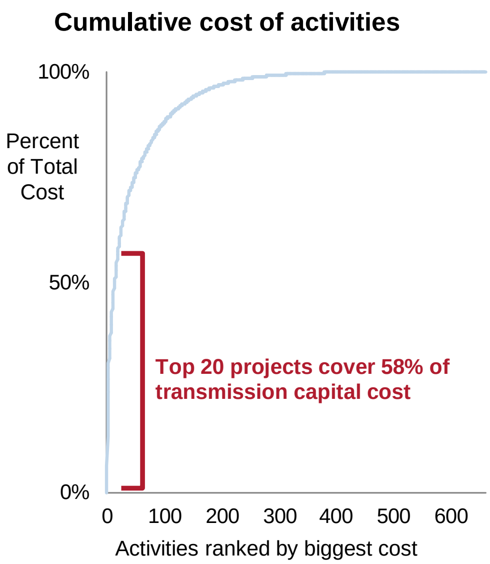
For each major cost area on the following pages we outline the concentration of costs into the largest activities (projects) and illustrate what metrics could be used to measure each.

As stated in the methodology section metrics are identified that have the most promise for measuring productivity based on the criteria outlined. In addition we identify additional metrics that could be compared over longer time frames (e.g., annual or greater), however we do not recommend pursuing these for purposes of improving productivity because they do not provide the regular view into performance required for managers to make useful changes.

Transmission capital project metrics

The top 20 largest Transmission Capital projects were examined to determine which could have associated productivity measures that would fit the criteria outlined above for appropriate productivity metrics. The top 20 projects account for 58% of the total relevant transmission capital spend. However, because these projects are generally one-time in nature and do not endure over time, only nine of the twenty largest transmission capital projects have suitable metrics.

The illustration of the concentration of these costs and the productivity metrics associated with them are illustrated below. Where no metrics are appropriate for a given project (activity) the reason is noted. These are primarily due to the inconsistency of the cost over time. For example the "Burlington Switchyard Reconstruction" has many activities that are likely unique because of the project nature of the work.



#	Activity	Metric	Activity Cost	% Cumulative cost*
1	**Bruce to Milton double circuit line**	▪ Cost per km of line cleared ▪ Cost per foundation ▪ Cost per tower constructed (*metrics do not cover all costs)	$129M	24%
2	**PC&T systems**	▪ Inconsistent over time	$17M	27%
3	**Wood pole replacement program**	▪ Cost per pole	$14M	29%
4	**Burlington switchyard reconstruction**	▪ Project based	$13M	32%
5	**WATR**	▪ Inconsistent over time	$11M	34%
6	**Kirkland Lake Reconnect Idle Line**	▪ Project based	$11M	36%
7	**Wood pole replacement program**	▪ Cost per pole	$11M	38%
8	**Mitigate reliability problems of Shunt capacity**	▪ Inconsistent over time	$11M	40%
9	**Build New Duart TS**	▪ Project based	$10M	42%
10	**SF6 Breaker Replacement Program**	▪ Cost per breaker	$10M	44%
11	**Detweiler: Add 230 kV, 350 MVAr SVC**	▪ Project based	$9.1M	45%
12	**Replace 2010 Richview Transformers**	▪ Cost per transformer	$9.0M	47%
13	**RTU Replacement Program**	▪ Cost per RTU	$8.7M	49%
14	**Nanticoke: 500 kV, 350 MVAr SVC**	▪ Project based	$8.0M	50%
15	**Kirkland Lake TS - Install SVC**	▪ Project based	$7.4M	51%
16	**Protection Replacement Program**	▪ Cost per protective device replacement	$7.3M	53%
17	**BSPS Mods for Bruce for 2009**	▪ Project based	$7.1M	54%
18	**Line Refurbishment Program ('10-'12)**	▪ Cost per km of transmission line refurbished	$6.9M	55%
19	**Line Refurbishment Program ('09-'10)**	▪ Cost per km of transmission line refurbished	$6.8M	57%
20	**Demand Capital - Equipment Failure**	▪ Inconsistent over time	$5.3M	58%
		Totals	**$312M**	**58%**

Legend

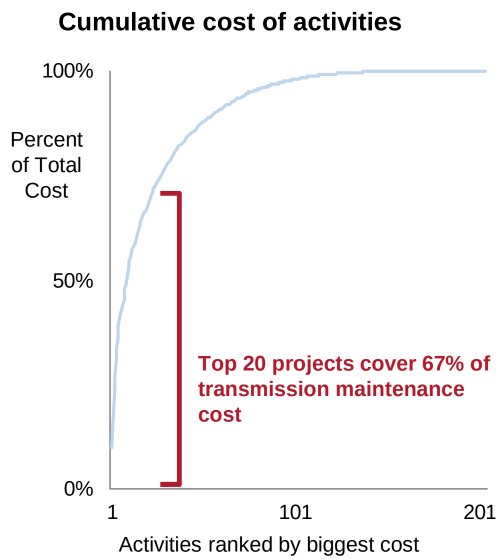
Relevant Metric	Potential metric examined over long time periods	Not measurable

Note: Costs are approximate values, annualized from May 2011. Costs exclude materials and zero value or negative cost projects.
**Metrics listed do not necessarily cover all costs in the category*

Transmission OM&A project metrics

The top 20 largest Transmission OM&A projects were examined to determine which could have associated productivity measures that would fit the criteria outlined above for appropriate productivity metrics. The top 20 projects account for 67% of the total relevant transmission OM&A spend. However, because these activities (projects) do not contain discrete work activities that are consistent over time, only 8 of the areas have suitable metrics. For example, "Corrective Maintenance" contains many activities that are not consistently repeated and therefore, cannot be measured as easily.

The illustration of the concentration of these costs and the productivity metrics associated with them are illustrated below. Where no metrics are appropriate for a given project (activity) the reason is noted. These are primarily due to the inconsistency of the cost over time.



#	Activity	Metric	Activity Cost	% Cumulative cost*
1	Preventive Maintenance - Planned (PMO)	▪Cost per km for line patrol ▪Cost per insulator inspection	$24M	10%
2	Transmission Site Maintenance	▪Inconsistent over time	$18M	17%
3	Tx Lines - RoW Brush Control	▪Cost of brush control per km of line	$16M	24%
4	Corrective Maintenance - Demand	▪Inconsistent over time	$16M	31%
5	Corrective Maintenance - Planned	▪Inconsistent over time	$13M	36%
6	Operating Facilities Support & Mtce - OGCC IT	▪Inconsistent over time	$12M	41%
7	Tx Lines - RoW Line Clearing	▪Cost per km of line cleared	$7.2M	44%
8	P&C NOEA / PQ / Spares / Database / Info. Mgnt	▪Inadequate time frame	$6.3M	47%
9	PSTS Leased Circuits	▪Inadequate time frame	$5.9M	49%
10	2011 Tx ECS Stds Development	▪Inadequate time frame	$5.3M	51%
11	Field Switching - Stations	▪Inconsistent over time	$5.2M	53%
12	P&C Preventative Maintenance / Inspections	▪Cost per inspection	$4.8M	55%
13	Overhead Tx Lines - Preventative Maint. - PL	▪Inconsistent over time	$4.7M	57%
14	P&C EMERG Corrective Maint. and Trouble Call	▪Cost per call out	$3.9M	59%
15	Environmental Mgt- Demand Corrective Mtc	▪Inconsistent over time	$3.7M	60%
16	Transformer Midlife Refurbishment Program	▪Cost per Transformer Refurbishment	$3.7M	62%
17	Overhead Tx Lines - Condition Assessment - PL	▪Cost per km for line patrol	$3.2M	63%
18	Overhead Tx Lines - Demand Work - PL	▪Cost per KM of line	$3.1M	65%
19	Transformer Oil Leak Reduction Program	▪Inconsistent over time	$3.1M	66%
20	2011 Cyber Sustainment	▪Inconsistent over time	$2.8M	67%
		Totals	$162M	67%

Legend

Relevant Metric	Potential metric examined over long periods	Not measurable

Note: Costs are approximate values, annualized from May 2011. Costs exclude materials and zero value or negative cost projects.
**Metrics listed do not necessarily cover all costs in the category*

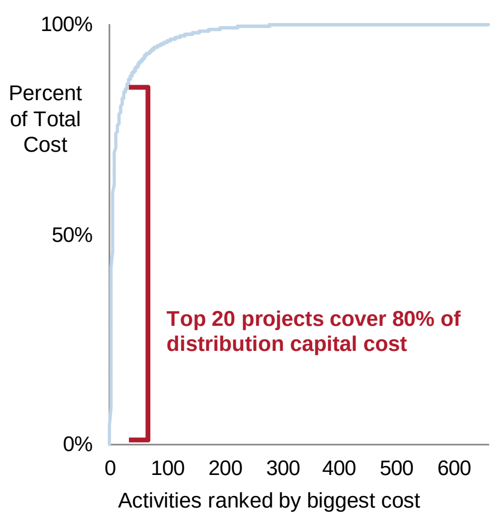
Distribution capital project metrics

The top 20 largest Distribution Capital projects were examined to determine which could have associated productivity measures that would fit the criteria outlined above for appropriate productivity metrics. The top 20 projects account for 80% of the total relevant Distribution capital spend. Only 5 of the areas have suitable metrics, however because many of the activities are not repeated consistently over time. For example, "Storm Damage" contains many activities that are not consistently repeated and therefore, cannot be measured as easily.

The illustration of the concentration of these costs and the productivity metrics associated with them are illustrated below. Where no metrics are appropriate for a given project (activity) the reason is noted. These are primarily due to the inconsistency of the cost over time.

.

Cumulative cost of activities



#	Activity	Metric	Activity Cost	% Cumulative cost*
1	Smart Metering - Capital	▪Cost per meter install	$82M	17%
2	End of Life Replacement of Wood Poles	▪Cost per pole	$53M	28%
3	Residential, Subdivision, Expansion	▪Cost per new service	$45M	38%
4	Dx Capital Storm Damage	▪Inconsistent over time	$38M	46%
5	Joint Use and Relocations (Yearly)	▪Cost per relocation	$37M	54%
6	ADS Project - Phase 1 - Dx Capital	▪Project based	$21M	58%
7	Dx Capital Trouble Call Poles & Equipment	▪Inconsistent over time, materials	$17M	62%
8	Cornerstone Phase 4 - CIS - Capital	▪Project based	$17M	65%
9	Customer Upgrade	▪Cost per upgrade	$14M	68%
10	Other, EI, Data Collection	▪Inconsistent over time	$11M	71%
11	2010 Connection of Micro-Generation Facilities Und	▪Cost per connection	$9.3M	73%
12	Upgrade - Other	▪Inconsistent over time	$4.8M	74%
13	Dx Capital Trouble Call Damage Claims	▪Inconsistent over time	$4.5M	75%
14	2009 Joint Use and Relocations	▪Inconsistent over time	$4.4M	76%
15	Large Project	▪Project based	$4.3M	77%
16	2011+ Distribution System Modifications	▪Project based	$4.2M	77%
17	Dx Capital Post Trouble Call & Power Quality	▪Inconsistent over time	$3.7M	78%
18	Service Cancellations	▪Cost per service cancellation	$3.6M	79%
19	Facilities Improvements DX (segment alignment)	▪Inconsistent over time	$3.5M	80%
20	Dx Capital Trouble Sub and UG Cable	▪Cost per event	$3.4M	80%
		Totals	$381M	80%

Legend

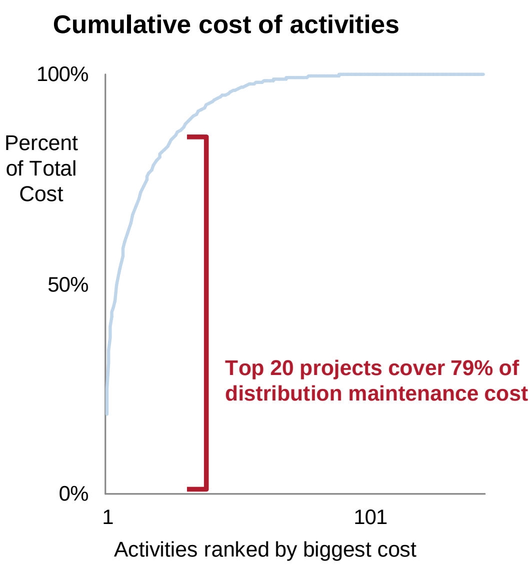
Relevant Metric	Potential metric examined over long periods	Not measurable

Note: Costs are approximate values, annualized from May 2011. Costs exclude materials and zero value or negative cost projects
**Metrics listed do not necessarily cover all costs in the category*

Distribution OM&A project metrics

The top 20 largest Distribution OM&A projects were examined to determine which could have associated productivity measures that would fit the criteria outlined above for appropriate productivity metrics. The top 20 projects account for 79% of the total relevant Distribution OM&A spend. 8 of the areas have suitable metrics because many of the activities are not repeated consistently over time. For example, “Trouble calls” contains many activities that are not consistently repeated and therefore, cannot be measured as easily.

The illustration of the concentration of these costs and the productivity metrics associated with them are illustrated below. Where no metrics are appropriate for a given project (activity) the reason is noted. These are primarily due to the inconsistency of the cost over time.



#	Activity	Metric	Activity Cost	% Cumulative cost*
1	Dx RofW Vegetation Management - Line Clearing	▪Cost of brush control per km of line	$70M	19%
2	Dx O&M Trouble Call	▪Cost per trouble event	$46M	31%
3	CSO Sustainment	▪Outsourced	$40M	42%
4	OH Defect Correction & Insulator Replacement	▪Cost per insulator replaced	$14M	46%
5	Smart Metering - OM&A	▪Cost per meter read	$14M	50%
6	Dx Overtime and Forestry Storm Costs	▪Cost per storm (OT and forestry)	$14M	53%
7	Dx RofW Vegetation Management - Brush Control	▪Cost of brush control per km of line	$12M	57%
8	Dx Cable Locates	▪Cost per cable locate	$12M	60%
9	Dx Vegetation Management - Job Plan & Notify	▪Inconsistent over time	$8.3M	62%
10	CSO Service Support - 3rd Party - MR & Billing	▪Cost per bill	$8.0M	**64%**
11	Meter Reading - Prov. Lines	▪Cost per meter read	$7.8M	67%
12	CSO Regulatory Compliance - MR & Billing	▪Inconsistent over time	$7.4M	69%
13	Dx Disconnects / Reconnects	▪Cost per disconnect ▪Cost per reconnect	$6.5M	70%
14	CSO Service Enhancements - MR & Billing	▪Inconsistent over time	$5.8M	72%
15	Small External Demand (Yearly)	▪Inadequate frame	$5.6M	73%
16	OPA Programs	▪Inconsistent over time	$5.5M	75%
17	DS Stations O&M	▪Inconsistent over time	$5.2M	76%
18	PCB and Other Waste Management	▪Inconsistent over time	$3.9M	77%
19	Field Special Investigations	▪Cost per field investigation	$3.7M	78%
20	CSO Regulatory Compliance - Collections	▪Inconsistent over time	$3.5M	79%
		Totals	**$293M**	**79%**

Legend

Relevant Metric	Potential metric examined over long periods	Not measurable

Note: Costs are approximate values, annualized from May 2011. Costs exclude materials and zero value or negative cost projects
**Metrics listed do not necessarily cover all costs in the category*

Summary of recommended metrics

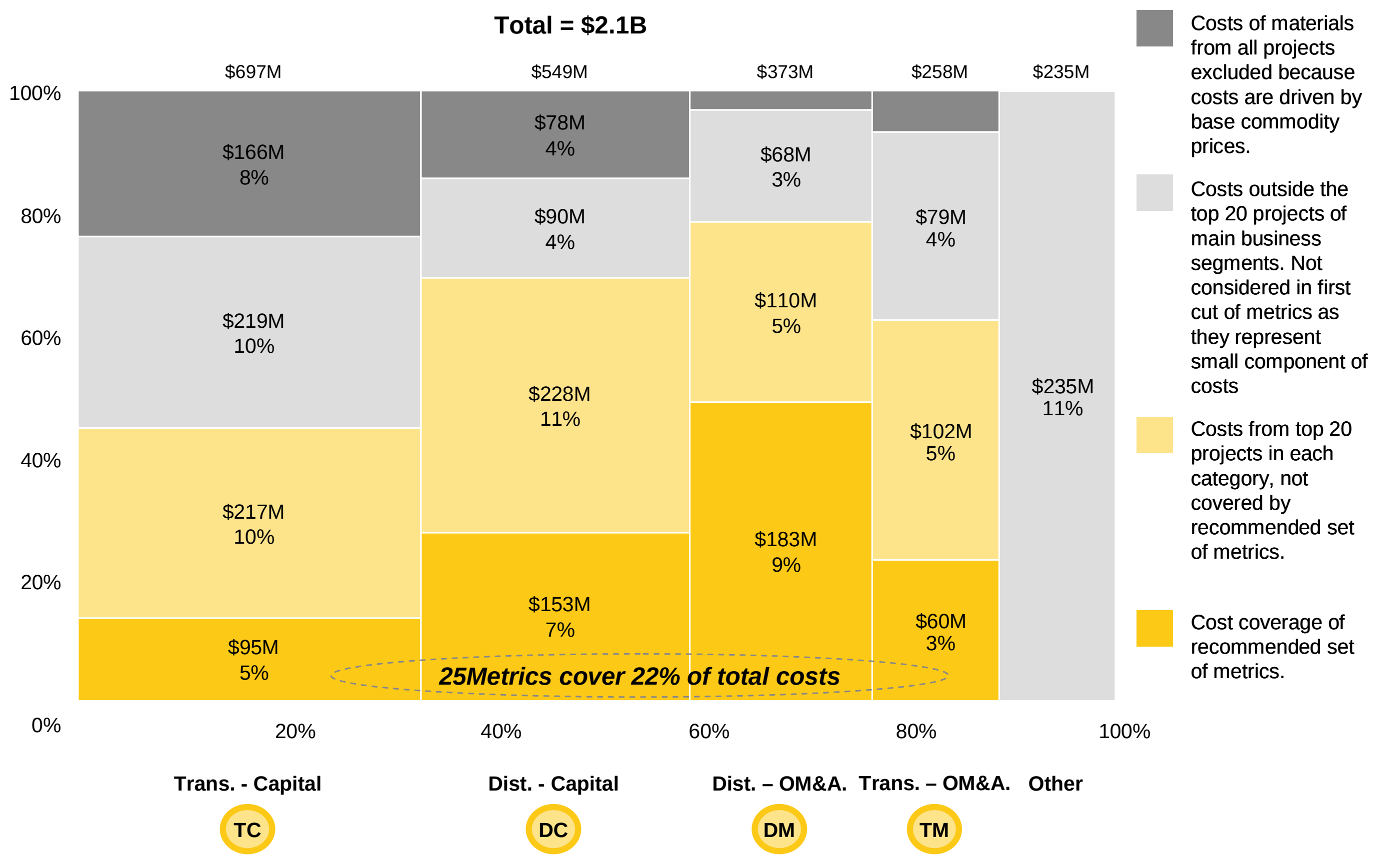
Aggregating the metric choices from the four main functional areas represents a good coverage of total cost; twenty five selected metrics account for approximately twenty two percent of total cost. Some metrics cover multiple activities across different functional areas (e.g. cost per pole). Further subdivision of these metrics may be required to allow better comparisons (e.g. cost per pole could be sub divided into cost per pole per ground type). Estimations of cost coverage were based on project titles, further validation with the business would be required to confirm the assumptions made. A large number of projects could not be understood from titles well enough to suggest metrics.

#	Metric	Cost Coverage	% of total costs
1	Cost of brush control per km of line	$98M	4.6%
2	Cost per meter install	$82M	3.9%
3	Cost per pole set	$78M	3.7%
4	Cost per new service installed	$11M - $34M	1.1%
5	Cost per tower constructed	$13M - $26M	0.9%
6	Cost per tower foundation	$13M - $26M	0.9%
7	Cost per km of Tx line cleared (Capital)	$13M - $26M	0.9%
8	Cost per meter read	$22M	1.0%
9	Cost per upgrade	$14M	0.7%
10	Cost per km of transmission line refurbished	$14M	0.6%
11	Cost per insulator replaced	$8M - $13M	0.5%
12	Cost per cable locate	$12M	0.6%
13	Cost per km for line patrol	$6M - $10M	0.4%
14	Cost per breaker	$8M - $10M	0.4%
15	Cost per transformer	$9M	0.4%
16	Cost per RTU	$7M - $9M	0.4%
17	Cost per bill	$1M - $8M	0.2%
18	Cost per km of Tx line cleared (OM&A)	$7M	0.3%
19	Cost per protective device replacement	$2M - $5M	0.2%
20	Cost per Transformer Refurbishment	$4M	0.2%
21	Cost per service cancellation	$4M	0.2%
22	Cost per insulator inspection	$1M - $4M	0.1%
23	Cost per disconnect	$3M	0.2%
24	Cost per reconnect	$3M	0.2%
25	Cost per line inspection	$1M - $3M	0.1%
	Total	~$480M	~22%

Note: Costs are approximate values, annualized from May 2011. Costs exclude materials and zero value or negative cost projects.

Cost coverage of selected metrics

The aggregated metrics are shown in the overall cost map below. Distribution OM&A has the largest coverage due to having more repetitive activities, suitable for metric collection. Transmission capital has mostly “one-off” project work and a higher percentage of unique, non-repetitive projects.



Note: Costs are approximate values, annualized from May 2011. Costs exclude materials and zero value or negative cost projects.

8

Next Steps

Roadmap for implementation

Hydro One will require a plan to implement and of these recommended metrics, and their associated costs, within a timeline. The plan will need to consider what resources will be required for implementation as well as what risks they foresee during implementation.

	Fiscal Period								
	Q3	Q4	Q1	Q2	Q3	Q4	Q1	Q2	Q3
Productivity metric list finalized									
Beta example 'scorecard' reports shared with executives									
Report templates signed off									
Required system changes identified									
System changes implemented									
Rollout to Users (training, access etc)									
Beta testing of results and reports									
Production state									
Ongoing monitoring of productivity improvement initiatives									

What is the implementation plan for Hydro One?

- Required resources
- Timings
- Roadblocks/Risk?

Potential challenges for utilities in measuring productivity

Initial data collection efforts and interviews highlighted a number of areas of potential challenges for utilities in reporting productivity metrics. These challenges include: data validation, activity segmentation, partial completions, granularity, mobile data collection, indirect costs and their ability to roll up to corporate scorecard measures.

Data validation

In order to ensure useful productivity measurement, the data must be inputted into an enterprise system accurately and consistently. The total number of unit activities needs to be correct to get a valid "cost per unit" measurement. The users of the enterprise system will need to be trained to ensure that the data collected is reliable. Monitoring and auditing compliance should be added to the management review process to ensure the data in the system can be used with a high degree of confidence.

Activity segmentation

Certain activities have widely disparate costs depending on location, ground type, weather etc. and require further segmentation to provide useful measurement (e.g. type of ground for pole replacements). It will be necessary to determine how to segment these activities to ensure that like for like comparisons can be made.

Partial completions

The system should capture 'partial completions' for larger activities or activities with multiple steps. Collecting these partial completions will ensure that a metric does not look poor until the activity is fully completed but rather show a steady result through the duration of the activity.

Granularity

The system data warehouse should capture costs at a granular level. Otherwise there are concerns regarding whether the granular buckets are being used appropriately and if the data is accurate at that level. Effective measurement at an activity level requires high confidence in the data at the most granular levels. The highest level of data confidence is generally achieved through utilities using mobile/handheld equipment.

Mobile data collection

Mobile data collection allows for full tracking of field workers activities and the time taken to complete those activities. The completeness of data that arises from the use of mobile tracking devices allows for highly accurate analysis and better activity segmentation. Using timesheets to track activity level data, which are filled out at the end of the day by the field workers is a labour intensive process. This manual data collection can lead to misleading results as the field worker may be required to estimate the time he spent on each activity throughout the day.

Indirect costs

Are indirect costs traced carefully using an activity based costing model or similar? It is necessary to ensure that certain activities are weighted with appropriate indirect costs. A regular review of how the indirect costs are weighted among each activity will ensure that it is accurate each year.

Generally, each of these challenges can be addressed; they just require additional expense and/or additional time. It is necessary and appropriate for utilities to make deliberate decisions about how to spend their time and money to generate the productivity metrics that add value to the organization. There are costs of implementation to consider, as well as the costs of ongoing maintenance of any system/process put in place to generate the appropriate measurements.

Performance management design criteria

Performance management needs to focus on the following four key building blocks; measures, measurement, goals/targets and action plans and the iterative process.

Measures

The measurement process should not be an overwhelming task; a select portfolio of metrics meeting the criteria and measuring a large portion of business activities and costs should be used. The measures should include the three tiers of performance measurement to allow for strong analysis for those utilizing the metrics at each level. A mix of leading vs. lagging measures will allow for accurate forecasting as well as strong cause and effect analysis.

Measurement

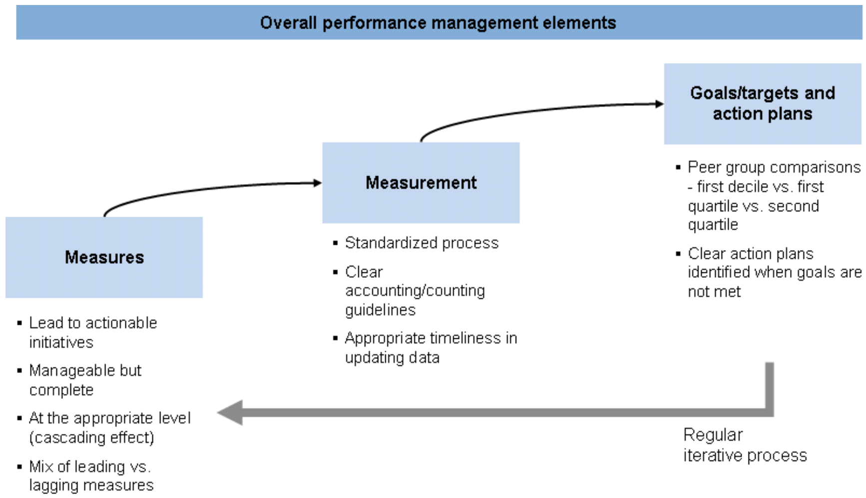
To reduce the burden of measurement, a standardized process would decrease the time and costs necessary to report on the data collected. The process should include clear accounting principles to be strictly followed to ensure data validity at all levels. Regular reporting timelines should be included as part of the process so the data is updated when it needs to be used.

Goals/Targets and action plans

Metrics can be used to track the success of meeting a target, as well as be used to create new targets. These metrics can be used to benchmark against peers and determine areas of opportunity.

Regular iterative process

Each iterative process will re-examine the usefulness of each metric being measured. Some metrics will be removed while others will be added to fit the needs of the current corporate strategy and goals.



Addressing the main drivers of productivity

There are three main drivers of productivity; reducing unproductive time, increasing efficiency of productive time and reducing unnecessary activities.

These levers should be addressed for direct as well as indirect labor (support and admin). When creating the metrics using a 'fully burdened' cost will help to ensure that improvements in the indirect portion of an activity are seen in the metric over time.

Reducing unproductive time

Targeting unnecessary meetings and trainings which are not beneficial will free the time in which the meeting or training participants are not being productive. Training times can be reduced by consolidating training sessions. Unproductive standard meetings can be removed.

Improving scheduling to reduce dead times. These dead times include the time in between jobs and the time at the end-of-day. Improving vacation scheduling to incentivize taking vacations during non-peak work times will create a larger available workforce during peak times.

Building better work planning tools to reduce travel times. These tools could reduce travel time by scheduling more jobs in similar areas together, dispatching the workforce from home instead of coming to yard and having real time traffic information to reduce time spent on the road.

Negotiating for lower minimum bill times will reduce the time that labor is unproductive but still being paid for the job.

Increasing efficiency of productive time

Improving the tools and processes in use during productive time will create an overall increase in productivity. Using more prefabricated construction offsite will allow for faster construction on site when expensive labor needs to be utilized. Technology can be used in planning to allow for more efficient job scheduling. Increasing the use of standardized components would require less training, cheaper procurement and inventory management. Another way of using tools to increase efficiency would be to preload asset location and details onto GPS systems in fleet.

Optimizing working team skill blend reduces the labor cost necessary to complete an activity. Team skill blend can be altered by using mixing more experienced hires with more junior team members (e.g. the apprentice model). Using hiring hall where possible will optimize skill blend because hiring hall is cheaper to use than experienced, often expensive full time staff.

Implement peak shaving through using contractors where applicable to reduce total staff on books required to cover peak work loads.

Align compensation and performance to ensure good audited data and encourage ‘bottom up’ initiatives.

Reducing unnecessary activities

These activities can be reduced by eliminating unnecessary work processes most importantly for indirect costs. Another strategy is to build a strategic contacting strategy by performing activity level benchmarking to determine where activities are under performing a similar panel.

Report Appendix:

- Findings from regulatory bodies
- Additional analysis of costs

Summary of results from Canadian commissions

Comm-issions	Key Findings	Metrics filed regularly		
		Produc-tivity*	Cost**	SQM
British Columbia Utilities Commission	▪ The revenue requirement applications include reliability metrics (SAIDI, SAIFI, CAIDI), factor productivity (# Customers/Network Length), and cost (T+D Capex/T+D line km) ▪ BC Hydro benchmarks reliability through the CEA ▪ Fortis submits an annual review including SQM metrics and general cost of service information	✗	13	29
Alberta Utilities Commission	▪ The general tariff applications include reliability metrics (SAIDI, SAIFI, AIIFR), and cost metrics (O+M spend/gross plant assets) ▪ Rule 002 and Rule 003 detail the service quality filing requirements for annual report	✗	3	24
Saskatchewan Rate Review Panel	▪ SaskPower rate case did not contain metrics ▪ A RFI stated performance metrics would be measured internally by SaskPower but were not collected by SRRP.	✗	✓	✗
Manitoba Public Utilities Board	▪ The *Public Utilities Board Act* has no minimum filing requirements. ▪ The PUB requested independent benchmarking for MH, study is delayed until late 2011 ▪ Manitoba Hydro files an *Electric Board Annual Report* with safety and cost metrics	✗	2	7
Ontario Energy Board	▪ The rate cases contain system reliability metrics, and veg. mgmt. benchmarking study ▪ The *OEB Year Book* and *Electricity Reporting and Record Keeping Requirements* contain service quality metrics and cost metrics filed annually	✗	6	17
Quebec Energy Board	▪ The rate cases contain cost (cost per customer) and service quality metrics (SAIDI, telephone answer rate, telephone abandon rate) ▪ The annual filing requirements include cost, and service quality metrics (safety, reliability)	✗	38	20
Nova Scotia Utilities and Review Board	▪ The rate cases contain cost metrics (OM&G/Customer) and reliability metrics (SAIFI*SAIDI) ▪ A NSPI Rate case contained an operational review called the Kaiser study containing some metrics relating to cost, SQ and productivity (calls handled per agent per day) ▪ An ad hoc independent operational review contained one productivity metric: Calls handled per agent per day	✗	4	6
New Brusnwick Energy and Utilities Board	▪ The rate applications (DISCO, NBSO, NBP) do not contain performance metrics, but do include financial information ▪ The *Electricity Act* does not mandate metrics to be filed	✗	✓	✗

* An x in the productivity column states that there are no regularly filed productivity metrics.
** A checkmark in the cost column represents a commission which collects some financial information but not cost metrics.

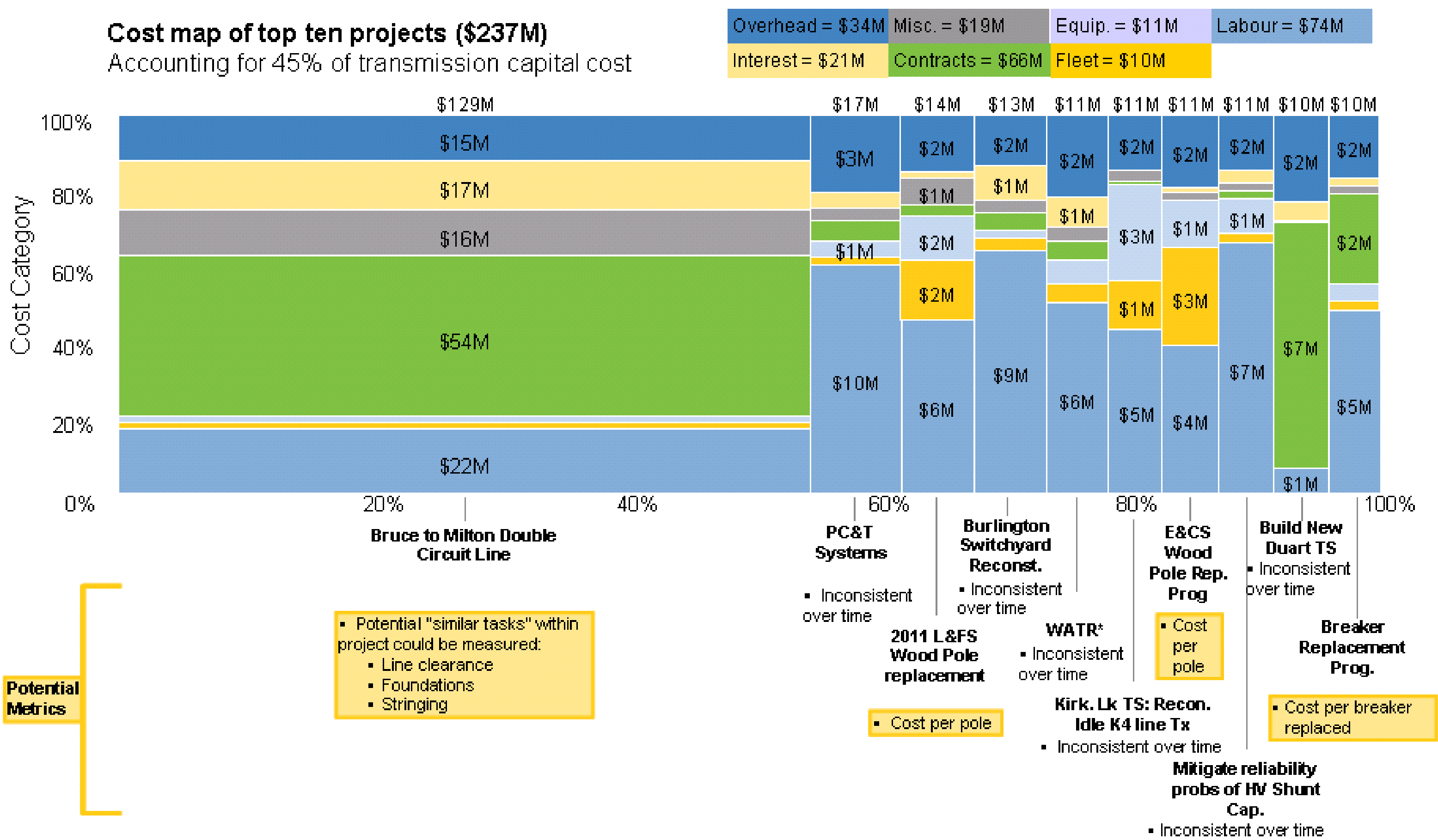
Summary of results from US commissions

Comm-issions	Key Findings	Metrics		
		Produc-tivity*	Cost**	SQM
Massachusetts Department of Public Utilities	▪ *Order 04-116* states annual minimum reporting requirements (CKAIDI, CKAIFI, SAIDI, SAIFI, % Billing Adjustments, and Customer Services guarantees) ▪ Electric and gas utilities in MA are required to file annual service quality reports	✗	✓	19
New York Public Services Commission	▪ The rate cases contain reliability metrics ▪ *NYCRR S. 61* details minimum financial filing requirements for rate cases ▪ Customer service and reliability reports are filed annually with the PSC	✗	✓	13
Pennsylvania Public Utilities Commission	▪ The Pennsylvania Public Utility Code required annual filing of reliability standards ▪ Electric service reliability and quality of service reports are filed each year	✗	✓	16
Michigan Public Services Commission	▪ System performance and power quality reports are filed annually containing service quality metrics (reliability, customer service, % meter reads etc) ▪ The rate cases does not contain performance metrics	✗	✓	13
Public Utilities Commission of Ohio	▪ The minimum filing requirements did not state performance metrics had to be filed ▪ Annual reliability reports are filed annually (SAIDI, SAIFI, CAIDI)	✗	✓	7
Illinois Commerce Commission	▪ No productivity or cost metrics required to be filed ▪ The *Public Utilities Act* and *Electric Supplier Act* detailed filing requirements (SAIFI, CAIFI, CAIDI, customer service survey)	✗	1	8
Connecticut Public Utilities Regulatory Authority	▪ The rate cases contained orders containing call center metrics ▪ Reliability information is required to be filed annually as per the *Connecticut Code*	✗	✓	9
California Public Utilities Commission	▪ The *New Jersey Administration Code* states filing requirements for reliability ▪ The rate cases have customer service metrics	✗	✓	9

* An x in the productivity column states that there are no regularly filed productivity metrics.
** A checkmark in the cost column represents a commission which collects some financial information but not cost metrics.

Transmission capital: Cost map of top ten projects

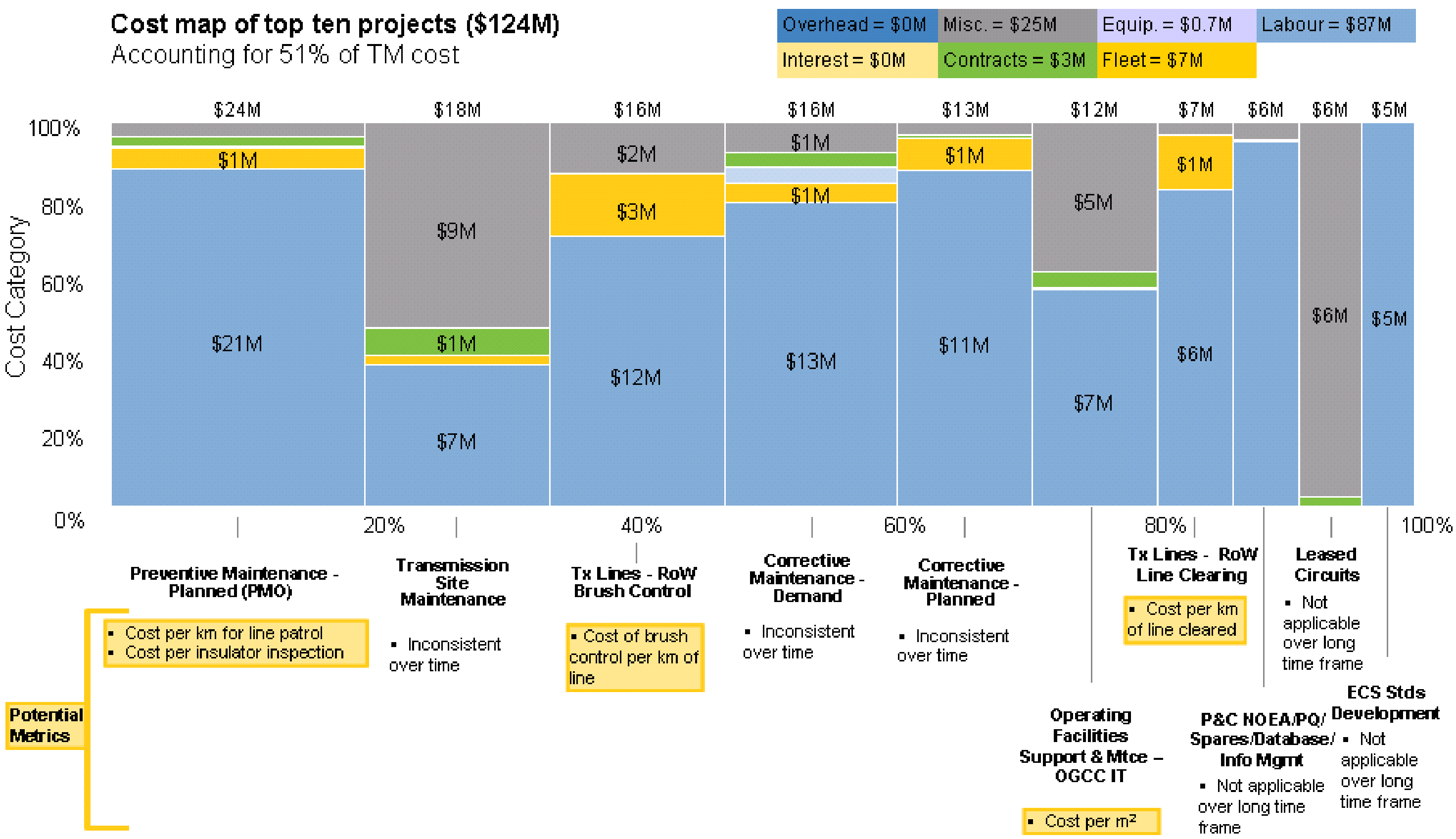
As an illustration of the major components of costs, cost maps were created for each major cost area. The maps of the top 10 largest projects are shown below to illustrate the concentration of costs. Costs are concentrated in a few very large projects. Though these major projects cannot be measured with a single metric, several activities within the project could be potentially measured.



Note: Costs are approximate values, annualized from May 2011. This chart excludes material costs. Total transmission capital cost includes negative and zero cost projects.

Transmission OM&A: Cost map of top ten projects

As an illustration of the major components of costs, cost maps were created for each major cost area. The maps of the top 10 largest projects are shown below to illustrate the concentration of costs. Transmission OM&A is more evenly distributed across the biggest projects than transmission capital, but each project still contains a diverse set of activities.

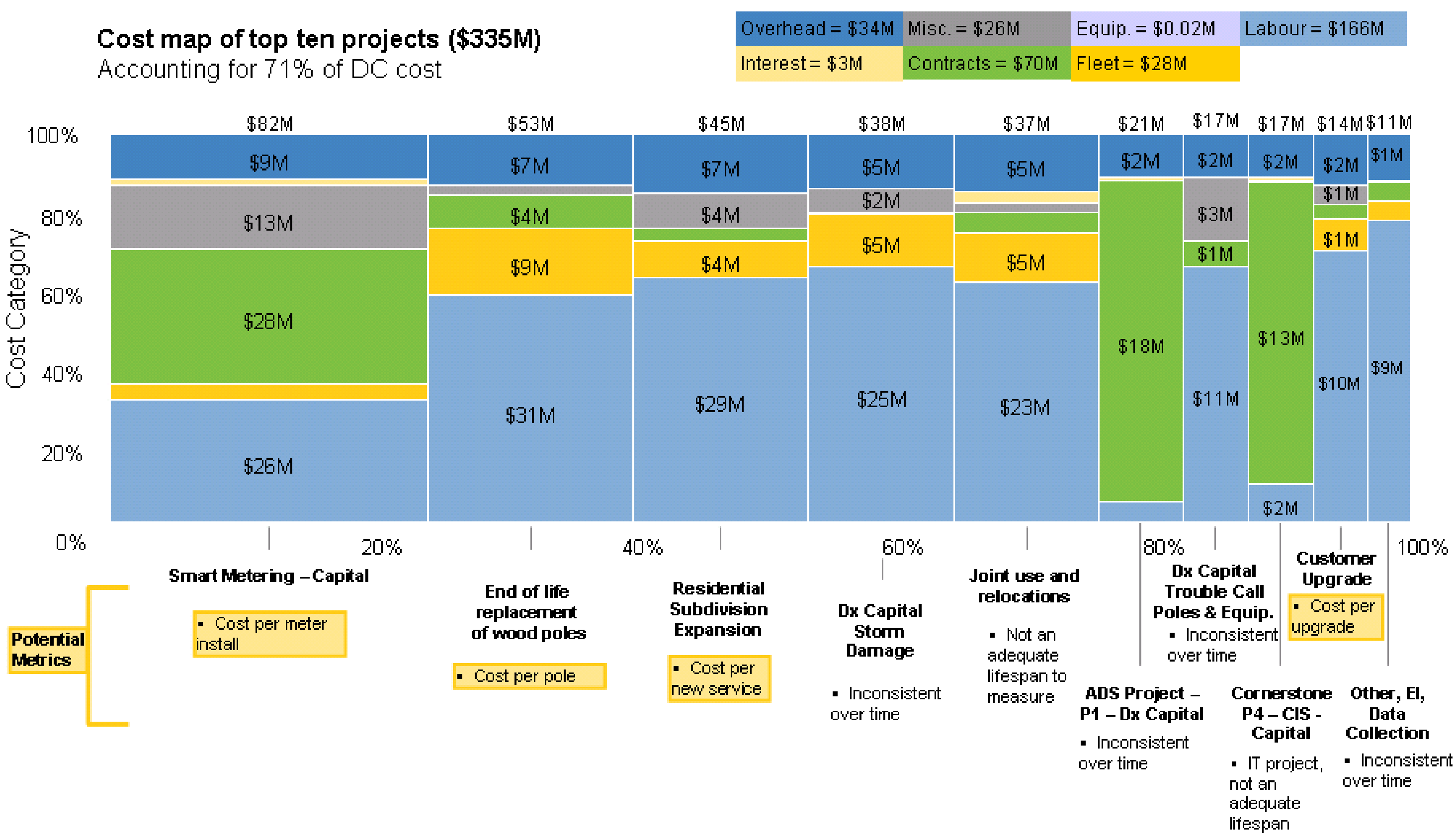


Note: Costs are approximate values, annualized from May 2011. Costs exclude materials and zero value or negative cost projects. Total transmission maintenance cost includes negative and zero cost projects.

Distribution capital: Cost map of top ten projects

As an illustration of the major components of costs, cost maps were created for each major cost area. The maps of the top 10 largest projects are shown below to illustrate the concentration of costs. For Distribution Capital costs, many are large project related and therefore not measureable over time making them less suitable for tracking.

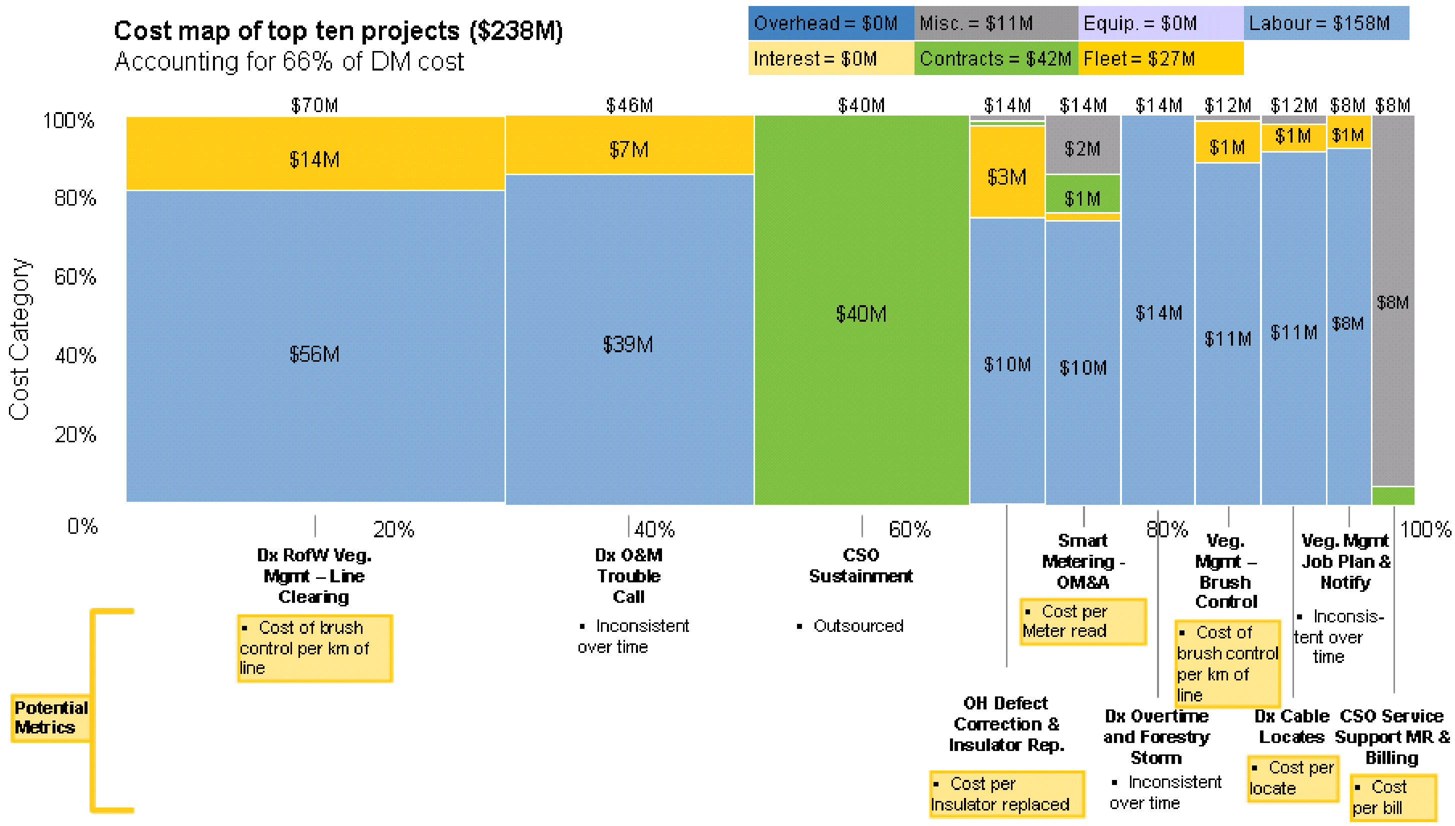
.



Note: Costs are approximate values, annualized from May 2011. Costs exclude materials and zero value or negative cost projects. Total distribution capital cost includes negative and zero cost projects.

Distribution OM&A: Cost map of top 10 projects

As an illustration of the major components of costs, cost maps were created for each major cost area. The maps of the top 10 largest projects are shown below to illustrate the concentration of costs. Distribution OM&A has the largest amount of repeatable activities suitable for metrics.



OLIVER WYMAN

Oliver Wyman, Inc.
200 Clarendon Street, 12th Floor
Boston, MA 02116-5026
1 617 424 3200

OEB Expert Evidence Requirements

The OEB revised their Rules of Practice and Procedure on January 9, 2012 to include a new Rule 13A for 'Expert Evidence'. The revised Practice and Procedure requires that a party that engages an expert shall ensure that the expert is made aware of and has agreed to accept the responsibilities imposed by the new Rule 13A. As the sponsor of a special study being prepared by an external expert on behalf of Hydro One, you have the accountability to ensure that these OEB requirements regarding expert evidence are met.

The following is a check list to ensure that the Expert is aware of and has agreed to Rule 13A; this is a direct excerpt from 13A.03 and 13A.06 of the Rule.

Expert Evidence Check List		Yes or No
Does the expert's evidence include:		
(a)	the experts name, business name and address, and general area of expertise;	Y
(b)	the experts qualifications, including the expert's relevant educational and professional experience in respect of each issue in the proceeding to which the expert's evidence relates;	Y
(c)	the instructions provided to the expert in relation to the proceeding and, where applicable, to each issue in the proceeding to which the expert's evidence relates;	Y
(d)	the specific information upon which the expert's evidence is based, including a description of any factual assumptions made and research conducted, and a list of the documents relied on by the expert in preparing the evidence; and	Y
(e)	in the case of evidence that is provided in response to another expert's evidence, a summary of the points of agreement and disagreement with the other expert's evidence.	NA
Has the expert been made aware of and agreed to accept the responsibilities that are or may be imposed on the expert as set out in Rule 13A.		Y

It is suggested that the report submitted by the expert should include a summary of the above information, signed off and dated by the expert, in the front end of the special study report. Otherwise, a separate summary document containing this information should be signed and dated by the expert and provided to Hydro One. This separate summary document will be submitted with the special study report in the pre-filed evidence.

A template for the separate stand alone summary document is provided as Attachment 1. The complete Rule 13A for 'Expert Evidence' from the OEB's Rules of Practice and Procedure, dated January 9, 2012, is provided as Attachment 2. Both must be provided by you to your external expert.

ATTACHMENT 1

Template for External Expert Rule 13A Sign Off Document

Note that the consultant may choose to provide a reference to where in the study report the relevant information is provided rather than repeat it in its entirety in the sign off document.

Title of Report:

Consultant:
Mark Hirschey
Partner
Oliver Wyman
200 Clarendon Street
Boston, MA 02142
Management consulting to power and utility companies
Extensive experience on metric development, benchmarking, cost analysis and performance improvement for energy utilities

Qualifications:
Education: Bachelor of Arts Dartmouth College 1993,
Bachelor of Engineering, Dartmouth College 1994
MBA, Harvard Business School 2000

Mr. Hirschey has consulted to energy utilities since joining Oliver Wyman in 1994. His clients include the largest utilities across North America and he has extensive experience in developing and reviewing performance of these utilities across most functions of the utility. He has conducted many performance benchmarking of utilities in the areas of cost, efficiency, quality, safety, reliability, and customer satisfaction.

Instructions Provided:

The primary sources of instruction were the RFP, (RFP # SCO-1000152789, March 2nd 2011) that Hydro One issued for this project and various conversations with Hydro One in verifying scope and progress.

The following are excerpts from the RFP:

"In its December 23, 2010 Decision approving Transmission Revenue Requirements for 2011 and 2012, the Ontario Energy Board provided direction and other expectations for further information on compensation and efficiency comparisons.

The Board directed "Hydro One to revisit its compensation cost benchmarking study [the Mercer study] in an effort to more appropriately compare compensation costs to those of other regulated transmission and/or distribution utilities in North America."

Toward that end, the Board directed "Hydro One to consult with stakeholders about how the Mercer study should be updated and expanded to produce such analyses”.

The Board went on to describe its expectation that Hydro One “be in a position to provide more robust evidence on initiatives to achieve a level of cost per employee closer to market value at its next transmission rate case. The Board will expect compensation increase to be matched with demonstrated productivity gains”.

Additional conversations with Hydro One provided direction on how cost analyses could be performed and potential measures of productivity.

Basis of Evidence:

1) Documents obtained from regulators and companies relating to the reporting of metrics to utility commissions
2) Conversations with regulators on the metrics they require
3) Responses from a survey sent to utilities on the metrics used
4) Analysis of cost data to determine relevant potential metrics for Hydro One

A complete list of documents and sources is provided the report.

Context of Evidence:
NA

Confirmation:
The expert has been made aware of and agrees to accept the responsibilities that are or may be imposed on the expert as set out in Rule 13A.

Signature: Mark Hirschey

Name of Expert: Mark Hirschey

Date: 4/2/2012

ATTACHMENT 2
OEB Rule 13A for 'Expert Evidence'

The following is an excerpt in its entirety of Rule 13A from the Ontario Energy Board "Rules of Practice and Procedure" (Revised January 9, 2012), pages 13 &14. A direct link to the entire document is provided here:
OEB Rules of Practice and Procedure

13A. Expert Evidence

13A.01 A party may engage, and two or more parties may jointly engage, one or more experts to give evidence in a proceeding on issues that are relevant to the expert's area of expertise.

13A.02 An expert shall assist the Board impartially by giving evidence that is fair and objective.

13A.03 An expert's evidence shall, at a minimum, include the following:
- (a) the expert's name, business name and address, and general area of expertise;
- (b) the expert's qualifications, including the expert's relevant educational and professional experience in respect of each issue in the proceeding to which the expert's evidence relates;
- (c) the instructions provided to the expert in relation to the proceeding and, where applicable, to each issue in the proceeding to which the expert's evidence relates;
- (d) the specific information upon which the expert's evidence is based, including a description of any factual assumptions made and research conducted, and a list of the documents relied on by the expert in preparing the evidence; and
- (e) in the case of evidence that is provided in response to another expert's evidence, a summary of the points of agreement and disagreement with the other expert's evidence.

13A.04 In a proceeding where two or more parties have engaged experts, the Board may require two or more of the experts to:
- (a) in advance of the hearing, confer with each other for the purposes of, among others, narrowing issues, identifying the points on which their views differ and are in agreement, and preparing a joint written statement to be admissible as evidence at the hearing; and
- (b) at the hearing, appear together as a concurrent expert panel for the purposes of, among others, answering questions from the Board and others as permitted by the Board, and providing comments on the views of another expert on the same panel.

13A.05 The activities referred to in **Rule 13A.04** shall be conducted in accordance with such directions as may be given by the Board, including as to:

(a) scope and timing;
(b) the involvement of any expert engaged by the Board;
(c) the costs associated with the conduct of the activities;
(d) the attendance or non-attendance of counsel for the parties, or of other persons, in respect of the activities referred to in paragraph (a) of **Rule 13A.04**; and
(e) any issues in relation to confidentiality.

13A.06 A party that engages an expert shall ensure that the expert is made aware of, and has agreed to accept, the responsibilities that are or may be imposed on the expert as set out in this **Rule 13A**.

STAKEHOLDER CONSULTATION

1.0 OVERVIEW

This Exhibit reports on the stakeholder consultation process in support of the 2013/2014 Transmission Rate Application and provides a summary of the discussions held during four interactive sessions. Hydro One Transmission's experience has been that early involvement with stakeholders is critical to developing a submission that reflects the broad interests and concerns of the Ontario Energy Board ("OEB") and Hydro One Transmission's constituencies.

Hydro One Transmission sought stakeholder input in the key area of Ontario Energy Board directed studies—Measuring CDM impact and accuracy of assumptions, analysis of density and cost allocation relationship, and update to previous Mercer Compensation benchmarking study.

To assist in developing, implementing and facilitating this process, Hydro One Networks retained several expert consultants. The stakeholder consultation sessions were held throughout 2011.

The overall goal was to improve the quality and comprehensiveness of the pre-filed evidence and to minimize the issues to be addressed at the OEB hearing. The consultation program consisted of presentations of information to stakeholders followed by discussion sessions on the issues raised. The presented information and notes of meeting were also made available through Hydro One Networks' website for those stakeholders that could not attend the sessions. In addition, Hydro One staff were available for informal dialogue with stakeholders throughout the process.

Input received during the consultation sessions was documented and considered in finalizing the application. Examples of this input include: (i) after initial discussions with stakeholders it was decided that an internal CDM study should be undertaken rather than hiring an external consultant to conduct the study, (ii) in addition to comparing Hydro One P50 to Market P50, a comparison was also made of Hydro One median to Market average (mean) by Mercer. This addition was made in response to a stakeholder request made during the compensation benchmarking consultation.

Overall, Hydro One believes the stakeholder consultation process was effective in achieving many of its objectives as listed in Section 2.2.

2.0 CONSULTATION PRINCIPLES, DESIGN AND PROCESS

The following principles and objectives guided the consultation design and implementation.

2.1 Principles

- Hydro One is entering into the stakeholder consultation process in good faith with a view to facilitating and streamlining future OEB proceedings related to the application;
- Hydro One will receive and consider all submissions made by stakeholders, but will retain control over the process of developing its application;
- All consultations are carried out on a without-prejudice basis;
- An independent facilitator will document and report the discussions and any agreements reached with all or some stakeholders; and,
- Agreements reached will be submitted to the OEB as part of its evidence.

The goal for the stakeholder sessions was to create a forum for stakeholders and Hydro One to discuss issues related to the Hydro One Transmission Rate Application and to identify areas of agreement and concern to shape the pre-filed evidence. To further this mandate, participants were asked to:

- Represent the various views of their customers/constituencies; and,
- Assist Hydro One to understand their goals and issues through participation in a process of open dialogue and submissions.

2.2 Objectives

The objectives for stakeholder consultation included:

- Inform and update key stakeholders about Hydro One's Transmission business, and the approaches and methodology used to determine revenue requirement and rate design;
- Give stakeholders a range of opportunities to provide input and feedback on a ll aspects of the application;
- Ensure stakeholder concerns and views are identified, understood and considered in the preparation of the application;
- Act as a forum for the exchange of information and views;
- Assist Hydro One to anticipate and respond to stakeholder and customer views and preferences; and,
- Clarify and scope as many issues as possible prior to the Hydro One submission to the OEB.

2.3 Participants in the Consultation Process

Stakeholder groups including intervenors from previous Hydro One rate proceedings, OEB staff, LDCs and large distribution customers were invited to participate in the stakeholder sessions via an invitation letter and a follow-up e-mail. Approximately forty groups were invited to participate in the stakeholder sessions in person or via teleconference. Hydro One believes that those invited were representative of the interests of the majority of its stakeholders.

Those who were not able to attend were invited to monitor the process through the company's website and to provide input throughout the process.

Stakeholder participation was guided by a Terms of Reference, and funding was made available to eligible intervenors consistent with the current OEB's Practice Direction on Cost Awards.

See Appendix A for a list of stakeholder attendees at one or more stakeholder consultation sessions.

2.4 Website

As part of the consultation process, Hydro One created a 2013/2014 Transmission Rate Application web page. The intent was to provide interested stakeholders the opportunity to monitor the consultation process and to provide input throughout the consultation.

The 2013-2014 Transmission Rate Application web page http://www.hydroone.com/RegulatoryAffairs/Pages/TxRates.aspx was updated regularly and contained meeting agendas, presentations made available at the stakeholder sessions and the meeting notes. Hydro One Transmission stakeholders were advised by email about the sessions, agendas, and how they could participate or follow the proceedings via the regulatory website if they could not attend.

2.5 Consultation Process Design

Four consultation sessions were held in beginning in February 2011 through October 2011:

- February 10, 2011—CDM and Compensation Cost Benchmarking Study, Hydro One Head Office, Toronto
- March 22, 2011—CDM Study and Density and Cost Allocation Study[1], Hydro One Head Office, Toronto
- May 30, 2011—Compensation Cost Benchmarking Study, Metropolitan Hotel, Toronto
- October 19, 2011— CDM, Density and Cost Allocation[1], Compensation Benchmarking and Productivity Studies, Hydro One Head Office, Toronto

Sessions involved presentations on t he pertinent topic followed by a facilitated discussion, which provided stakeholders an opportunity to ask questions and to comment on the presentations and proposed approach to the studies and content of the Application.

3.0 CONSULTATION ON OEB DIRECTED STUDIES

3.1 CDM Study

In its EB-2010-0002 Decision, the Board directed Hydro One Transmission to provide information to the Board and the intervenors respecting the accuracy of its assumptions regarding CDM effects; and the Board directed Hydro One to work with the OPA in devising a r obust, effective and accurate means of measuring the expected impacts of CDM programs promulgated by the OPA.

---

[1] The Density and Cost Allocation Study relates to Hydro One Distribution

Three consultation sessions were devoted to discussing and obtaining stakeholder input on the CDM issue.

The first session, held February 10, 2011 had 17 stakeholder attendees representing 15 stakeholders and OEB staff. The OPA sent written confirmation that they would not attend the session. The letter is included in the Meeting Notes of this session found in Appendix B.

A presentation was given to provide additional insight as to how Hydro One incorporates CDM impacts in load forecasting. The themes apparent throughout the discussion related to defining the categories of measures for CDM, the known data limitations and the associated influences. Much agreement was reached.

The second session, held March 22, 2011 had 17 stakeholder attendees representing 16 stakeholders and OEB staff. The OPA was in attendance at this meeting. Key messages from the previous session were reviewed and the action plan, based on the key messages, was presented to stakeholders for input. A discussion followed the presentation. In general, all Stakeholders were happy with the approach and timeline proposed by Hydro One.

The Meeting Notes of this session are found in Appendix C.

The third and final meeting regarding the CDM study was held October 19, 2011. Eighteen attendees representing 17 stakeholders and OEB staff attended the session. Stan But of Hydro One presented the results of the CDM study. The findings included a literature review of North American utilities with CDM experience. A load forecast survey was also undertaken. The literature review and survey provided a well-defined and comprehensive list of CDM categories. The survey also identified three commonly used models to incorporate CDM impacts in load forecasting. Hydro One reviewed the advantages and challenges associated with each method and on the basis of the review results concluded that the method which adds historical CDM impacts to the actual load and forecasts forward is the one Hydro One should adopt. Further details of the results of the study and how Hydro One intends to incorporate the findings into their forecasting method can be found in the Meeting Notes of this session in Appendix D.

3.2 Compensation Cost Benchmark Study

In its EB-2010-0002 Decision, the Board directed Hydro One to revisit its compensation cost benchmarking study in an effort to more appropriately compare compensation costs to those of other regulated transmission and/or distribution utilities in North America. The Board also directed Hydro One to consult with stakeholders about how the Mercer study should be updated and expanded to produce such analyses.

Three consultation sessions were devoted to discussing and obtaining stakeholder input on the Compensation Cost Benchmark Study.

The first session, held February 10, 2011 had 17 stakeholder attendees representing 15 stakeholders and OEB staff. Hydro One presented a contextual background to the current situation and provided a “straw dog” for the RFP in order to facilitate the discussion. The input revolved around how to effectively update and improve the 2008 Mercer Study. Stakeholders reached general consensus on how to move forward with the study and the group recommended seeking the successful bidder’s counsel on what productivity metric(s) could be used for internal comparisons using readily available internal data.

Meeting Notes for this session can be found in Appendix B.

The second session, held May 30, 2011 had 11 stakeholder attendees representing 11 stakeholders and OEB staff. The intent of this meeting was to introduce Mercer as the successful consultant and for Mercer to communicate its planned approach to stakeholders in order to gather insights and information prior to finalizing the survey. Detailed discussion focused on the most significant and relevant factors affecting compensation.

The Meeting Notes of this session are found in Appendix E.

The third and final meeting regarding the Compensation Cost Benchmark study was held October 19, 2011. Eighteen attendees representing 17 stakeholders and OEB staff attended the session. Iain Morris of Mercer reviewed the preliminary findings of the study.

The Meeting Notes of this session are found in Appendix D.

4.0 STAKEHOLDER CONSULTATION SUMMARY

Hydro One initiated the stakeholder consultation process to meet the objectives described in Section 2.2. Based on the discussions that took place, the consultation process met these objectives. Hydro One believes that the enhanced understanding by stakeholders of Hydro One operations and business practices resulting from the dialogue at these sessions should reduce the effort required by Hydro One to explain its rate application during the OEB proceeding. Hydro One also obtained a good understanding of stakeholder issues and concerns through the consultation process.

In conclusion, stakeholder input helped Hydro One to refine and shape the elements of its Transmission rate application and helped to ensure that customer and stakeholder concerns were understood and addressed.

5.0 LIST OF APPENDICES

A. Stakeholder Attendees at one or more Stakeholder Consultation Sessions
B. Meeting Notes: Stakeholder Discussion Sessions – February 10, 2011
C. Meeting Notes: Stakeholder Discussion Session – March 22, 2011
D. Meeting Notes: Stakeholder Discussion Session – October 19, 2011
E. Meeting Notes: Stakeholder Discussion Session – May 30, 2011

Name	Association	Meeting Dates Participated			
	Facilitators / Consultants				
Carew, Steven	London Economics	March 22, 2011			
Grunfeld, Ben	London Economics	March 22, 2011	October 19, 2011		
Morris, Iain	Mercer	May 30, 2011	October 19, 2011		
Robins, Kristi	Mercer	May 30, 2011			
Thompson, Michael	Mercer	May 30, 2011			
Hirschey, Mark	Oliver Wyman	October 19, 2011			
Betts, Bob	Optimus SBR	February 10, 2011	May 30, 2011	October 19, 2011	
Klein, Keith	Optimus SBR	February 10, 2011			
Murray, Paige	Optimus SBR	February 10, 2011			
Smit, Miles	Optimus SBR	February 10, 2011	May 30, 2011		
Boychuk, Angela	Optimus SBR	May 30, 2011			
Ford, Gary	PowerNex	March 22, 2011			
Poray, Andy	PowerNex	March 22, 2011			
Vainberg, Mark	PowerNex	March 22, 2011			
	Stakeholders				
Grice, Shelley	Association of Major Power Consumers of Ontario (AMPCO)	February 10, 2011	March 22, 2011	May 30, 2011	October 19, 2011
Zajdeman, Marcie	Brookfield Asset Management	February 10, 2011	March 22, 2011	May 30, 2011	
Fraser, Marion	Canadian Energy Efficiency Alliance (CEEA)	February 10, 2011	March 22, 2011	May 30, 2011	
Thompson, Peter	Canadian Manufactures and Exporters (CME)	March 22, 2011			
Girvan, Julie	Consumers Council of Canada (CCC)	February 10, 2011	May 30, 2011	October 19, 2011	
Pasumaty, Dev	Electricity Distributors Association	March 22, 2011			
MacIntosh, David	Energy Probe	February 10, 2011	March 22, 2011	May 30, 2011	October 19, 2011
Silk, Dana	EnviroCentre	February 10, 2011	March 22, 2011		
McGee, John	Federation of Ontario Cottagers' Associations (FOCA)	March 22, 2011	October 19, 2011 (Call)		
Fecteau, Duane	Great Lakes Power Transmission (GLP)	February 10, 2011			
Poch, David	Green Energy Coalition (GEC)	October 19, 2011 (Call)			
Butany-DeSouza, Indy	Horizon Utilities	March 22, 2011			
Simon, Judy	Low Income Energy Network (LIEN)	February 10, 2011			
Reyes, Martin	Mercer	October 19, 2011			
Robins, Kristi	Mercer	October 19, 2011			
Mather, Neil	Ontario Energy Board (OEB)	March 22, 2011	October 19, 2011		
Thiessen, Harold	Ontario Energy Board (OEB)	February 10, 2011	May 30, 2011	October 19, 2011	
Cowan, Ted	Ontario Federation of Agriculture	March 22, 2011	October 19, 2011		
Bond, Reagan	Ontario Power Authority (OPA)	March 22, 2011			
Towstego, Greg	Ontario Power Generation (OPG)	February 10, 2011			
Hodgson, Jan	Ontario Power Generation (OPG)	May 30, 2011			
Babin, Emerissa	Ontario Power Generation (OPG)	October 19, 2011			
Kidane, Bayu	Power Workers' Union (PWU)	March 22, 2011	May 30, 2011	October 19, 2011	
Vainberg, Mark	PowerNex	October 19, 2011			
Yampolsky, Elena	Powerstream Inc.	February 10, 2011	March 22, 2011		
Byck Johnston, Michelle	The Society of Energy Professionals	February 10, 2011	October 19, 2011		
White, Frank	The Society of Energy Professionals	February 10, 2011	May 30, 2011		
Belmore, Mike	The Society of Energy Professionals	May 30, 2011			
Dubeski, Phil	Toronto Hydro Electric System (THESL)	October 19, 2011			
McMahon, Patrick	Union Gas	October 19, 2011 (Call)			
Zebrowski, Steve	Veridian Connections Inc.	February 10, 2011	March 22, 2011	October 19, 2011 (Call)	
McLorg, Laurie	Veridian Connections Inc.	March 22, 2011			
Harper, Bill	Vulnerable Energy Consumers Coalition (VECC)	February 10, 2011	March 22, 2011	May 30, 2011	October 19, 2011
Higgin, Roger	Vulnerable Energy Consumers Coalition (VECC)	February 10, 2011			

CDM and Compensation Cost Benchmarking Study

Stakeholder Consultation

Notes of Meeting

Thursday, February 10th, 2011

1:30 – 5:30 p.m.

Special Events Room, Ground Floor

483 Bay Street, North Tower, Toronto

OPTIMUS | SBR

TABLE OF CONTENTS

The presentation materials used in this session and background materials can be found at this link: http://www.hydroone.com/RegulatoryAffairs/Pages/TxRates.aspx

1.0 Participant References

STAKEHOLDERS

Bill Harper—Vulnerable Energy Consumers Coalition
Duane Fecteau—Great Lakes Power Transmission
David MacIntosh—Energy Probe
Dana Silk—Enviro Centre
Elena Yampolsky—PowerStream Inc.
Frank White—The Society of Energy Professionals
Harold Thiessen—Ontario Energy Board
Julie Girvan—Consumers Council of Canada
Judy Simon—Low Income Energy Network
Michelle Byck Johnston—The Society of Energy Professionals
Marion Fraser—Canadian Energy Efficiency Alliance
Marcie Zajdeman—Brookfield Asset Management
Roger Higgin—Vulnerable Energy Consumers Coalition
Richard Stephenson—Power Workers' Union
Shelly Grice—Association of Major Power Consumers in Ontario
Steve Zebrowski – Veridian Connections Inc.
Greg Towstego – Ontario Power Generation

Hydro One

Allan Cowan—Hydro One
Alexandra Stadnyk—Hydro One
Bill Christie—Hydro One
Bohdan Dumka—Hydro One
Enza Cancilla—Hydro One
Ian Innis—Hydro One
Ian Malpass—Hydro One
Jim Malenfant—Hydro One
Keith McDonnell—Hydro One
Stan But—Hydro One
Susan Frank—Hydro One
Vicki Power—Hydro One

OPTIMUS | SBR

Bob Betts—OPTIMUS | SBR
Miles Smit—OPTIMUS | SBR
Paige Murray—OPTIMUS | SBR
Steve Klein—OPTIMUS | SBR

START 1:30pm

2.0 Welcome by Allan Cowan

Allan Cowan welcomed the attendees and advised the purpose of the session was to get input from stakeholders in accordance with the Ontario Energy Board (OEB) direction to Hydro One Network Inc. (Hydro One) in its recent Transmission business cost of service application [EB-2010-0002] Decision.

In accordance with this directive, stakeholder input was being sought in advance of two studies:

1) Conservation Demand Management (CDM) and the impact of CDM on the load forecast used in the establishment of transmission rates;

2) An update of the Mercer compensation cost benchmarking study completed in 2008.

Hydro One was also directed to undertake a review of its methodology for determining CDM impacts in its Distribution load forecast. It is Hydro One's intention to engage one firm through an RFP process to conduct this review for both distribution and transmission aspects to be ready for its next rate application.

Allan indicated that Hydro One cost of service application filings are on the following timeline:

- 2012/2013 Distribution application for rates is targeted for the 4th quarter of 2011;
- 2013/2014 transmission rate application is targeted for the late 1st quarter or early 2nd quarter of 2012.

3.0 Bob Betts' Introductory Remarks

1:35pm

Bob indicated the session was being recorded to ensure the notes being captured by OPTIMUS | SBR are correct and complete. These recordings will be destroyed once the notes are approved.

Stakeholders would be representing themselves and their clients when they speak. Accordingly, stakeholders were asked to first state their name when asking a question or making a comment to ensure appropriate attribution.

Ontario Power Authority Participation

1) Ian Malpass provided information to the stakeholder pertaining to the OPA participation. Part of the direction from the OEB for the Transmission CDM load forecasting study was for Hydro One to work with the Ontario Power Authority (OPA). Hydro One had received written confirmation that the OPA has chosen not to participate in this stakeholdering session.

The OPA letter set out its rationale for not participating; with OPA's permission copies were provided to the stakeholders. A copy of the letter can be found in Appendix B & on the Regulatory Affairs website at:

http://www.hydroone.com/RegulatoryAffairs/Documents/EB-2010-0002/Feb%209%202011%20-%20OPA%20Letter.pdf

Bob reviewed house keeping matters - room and facilities logistics, along with fire, safety and evacuation procedures and meeting etiquette outlined. After a brief review of the Agenda, the participants were asked to introduce themselves and identify the party they represented. The first presenter, Stan But, was introduced.

See list of attendees (Section 1.0).

4.0 CDM Impacts Presentation, Stan But, Manager—Economics and Load Forecasting, Hydro One

1:55pm

Stan referenced the earlier interpretation of the CDM impacts and outlined his objectives:

- Provide additional insight as to how Hydro One incorporates CDM impacts in load forecasting
- Seek stakeholder views/opinions as input to the upcoming RFP in this area.

In its findings in EB-2010-0002, the Board accepted the Hydro One CDM impacts estimate used in the load forecast but directed Hydro One to:

"...work with the OPA to build a robust, effective and accurate means of measuring the expected impacts of CDM programs" for future applications. The Board was concerned there does not appear to be a broadly accepted methodology in place to identify reasonably anticipated effects of any CDM program on the throughput of the respective distribution or transmission systems".

More clarity was needed for Hydro One and any other local distribution company (LDC) in establishing credible load forecasts.

In both Hydro One's Transmission and Distribution cases, Hydro One had included the CDM impact in its load forecast; a chart was presented for illustration (CDM Impacts Presentation, Slide 4). For historical effects of CDM, Hydro One uses the actual activity and adds back CDM estimated impacts obtained from the OPA. Statistical models are then used to get future years forecast with a reduction for the expected CDM impact applied.

Bill Harper asked several questions about this methodology focussing on the CDM impact estimates that get added back into the model. Bill identified that the accuracy of the forecast is dependent on the OPA estimates of the CDM impacts and whether they used the same five categories as Hydro One show in their next slide.

Using the next slide, Stan stated that the provincially-mandated energy conservation targets for LDCs for the 2011-2014 period specify persistent peak demand of 1330 megawatts and cumulative 6000 gigawatt hours of reduced electricity consumption embracing the following two CDM categories:

1) OPA-contracted programs (in the past Hydro One used OPA-initiated or –funded programs);

2) OEB-approved programs by LDC and funding drawing on the global adjustment.

Hydro One additionally considers three (3) other CDM impacts in their load forecasts:

3) Codes and standards (e.g. EnergyStar, etc.), lighting and efficiency;

4) Government initiatives—Federal and Provincial incentives to use better equipment, such as tax rebates on efficient appliances and consumer efficiencies, other incentive programs from municipalities such as energy audits, etc;

5) Customer-driven conservation actions beyond LDC control, e.g. turning off lights and air conditioning when away from home, using cold water for laundry, etc. Smart meter time-of-use rate impacts are also included; these are not captured by any specific program, but collectively have implications on total load forecasts.

1 and 2 can be grouped as “LDC CDM target programs” or “program specific”, and 3, 4 and 5 can be grouped as “Other CDM programs to be incorporated in the load forecast) or “non-program specific”.

Hydro One, in its rate case load forecasting, used “total” CDM as a reduction which included everything that impacts CDM—both program and non-program specific. While measuring and tracking non-program specific impacts is very challenging, Hydro One has done a lot of additional analysis to improve data accuracy over the last 2 years including econometric analysis, end-use analysis, customer billing analysis, and customer surveys.

This concluded the formal CDM presentation.

5.0 Editorial–CDM Discussion Summary

Following Hydro One’s formal presentation, the floor was opened to a free-flowing question and answer format. The main themes throughout these Stakeholder discussions related to defining the categories of measures for CDM, the known data limitations and the associated influences such as Natural Conservation, Time-of-Use and the Integrated Power System Plan. Underlying all this was the group’s focus on the directives in the Ontario Energy Board’s 2011-2012 Transmission Decision. Through open and generally constructive interactions, much agreement was reached as summarized in the following section.

6.0 CDM—Key Points of Agreement

1) The categories of CDM programs for consideration in any study should, where possible:

    a) Include:

        i) OPA contracted programs

        ii) Board-approved LDC programs

        iii) Codes and standards

        iv) Federal, provincial and other initiatives

        v) Customer conservation actions, including Time of Use (TOU) prices

        vi) Other OPA contracted programs – OPA programs delivered by others

        vii) Natural Conservation

    b) Identify what categories are in use in other jurisdictions

    c) Be chosen so they are easily tracked and provide reasonable historic data

    d) Be considered in light of four categories in the original Integrated Power System Plan (IPSP): energy efficiency, demand response, customer own actions and customer generation, to understand how they were defined and used in the load forecast.

2) Determining CDM impacts in Distribution should involve a breakdown by customer class, because it is important to identify which distribution customer class is providing the savings in order to properly forecast the effect of the savings.

3) A 3rd party review study on CDM impacts for Transmission is not required. The best approach recommended is for Hydro One to work closely with the OPA.

4) Hydro One will meet with interested stakeholders to clarify how Hydro One uses the OPA's megawatts peak reduction to create monthly charge determinants for use in the forecasting methodology.

5) Hydro One will work with the OPA to better define and measure the CDM impacts for use in its load forecast and rate applications submitted to the OEB.

6) Hydro One will be guided by the findings of this consultative to prepare more detailed evidence on CDM impacts for the Transmission and Distribution rate applications. This focus should be on what Hydro One, in working with the OPA, can reasonably do in getting better definition and information from the OPA for its rate applications.

7.0 Compensation Cost Benchmarking Study Presentation, Keith McDonnell, Manager—HR Operations, Hydro One

3:45pm

Keith McDonnell provided a brief contextual background to the current situation, noting two relevant Board decisions in the last few years:

1) The 2007/2008 Transmission case, wherein the Board directed Hydro One to conduct a compensation benchmarking study of Hydro One's compensation against North American Transmission and Distribution utilities. This resulted in "the Mercer Study", initially filed in 2008 in Hydro One's 2009/2010 Transmission rate application, and a referenced resource in subsequent applications.

2) The December, 2010 OEB Decision in the 2011/2012 Transmission application directing Hydro One to revisit the compensation study and consult with stakeholders about how the Mercer Study could be updated and improved.

Hydro One would need outside expertise from a consultant not yet chosen to help guide this update, and provide expertise and methodology. The survey should be kept simple because the peer groups needed as participants will be less inclined to take part if it is difficult to track, gather and report data.

The study should be an independent, testable and repeatable market-based assessment of the reasonableness of Hydro One's compensation.

The confidentiality of the responses is very important. In the past, participants were reluctant to participate without assurance their data would remain confidential.

In the Mercer Study, 13 companies participated, 11 of which were in transmission, distribution and/or generation, and two regulated, non-electrical utilities—Bell and Enbridge. Twenty-one (21) classifications were benchmarked, representing about 47% of the total employee population. The Mercer Study focused on three areas—base salary, total cash, and pension and benefits.

The Mercer Study reported Hydro One results relative to the median. On a weighted average basis, Hydro One compensation was 17% above the market median.

To facilitate the stakeholder discussion, Hydro One put together a possible RFP or "Straw Dog", which could be revised using the input of the group. One of the directives from the OEB was to improve the Mercer Study; a trend comparison using the 2008 study results would be one way to this end. In terms of the peer group, Hydro One has suggested the updated study should be based on the groups from the Mercer Study and expanded as deemed appropriate by the consultant perhaps including more LDCs.

The peer selection criteria might mirror those used in the Mercer Study—participants between 33% and 300% of Hydro One's annual revenue or total assets. However, other participants could be considered if doing so would add validity to the study. In terms of jobs benchmarked, job classifications with a large number of incumbents are key. Ideally, an even comparison is desired, therefore when selecting internal Hydro One jobs, the consultant will need to consider the ease of finding like jobs from the external population.

As to productivity, in its December 2010 Transmission Decision the Board indicated that if there are increases in compensation then Hydro One should be able to map to demonstrated productivity gains. The consultant might be able to report on productivity benchmarks used within peer groups and give advice and guidance as to how those metrics could apply to the Hydro One data to be used. It is also a plus if the consultant brings a knowledge of any applicable academic research pertaining to best practices or metrics to the table.

8.0 Editorial–Compensation Cost Benchmarking Study Discussion Summary

Two issue streams quickly evolved:

- How to effectively update and improve the 2008 Mercer Compensation Cost Benchmarking Study to assist both Hydro One and the Ontario Energy Board in better understanding this significant controllable expense item;
- Meaningful exploration of related factors such as operating and regulatory environments, recruitment and resource influences, internal productivity trends and other compensation related measures.

While a wide range of views and opinions were aired, discussions were consistently productive and in keeping with the Board’s 2011-2012 Transmission Directive. As a result, Stakeholders reached general consensus on how to move forward with an independent compensation cost study. Additionally, the group recommended Hydro One seek the consultant’s counsel on what productivity metric or metrics could be used for internal comparisons using readily available internal data.

9.0 Compensation Cost and Productivity—Key Points of Agreement

1) An update to the Mercer Compensation Cost Benchmarking Study should, where possible:

   a) Indentify its principle objective as being to revisit the compensation cost benchmarking study in an effort to appropriately compare compensation costs to those of regulated Transmission and Distribution utilities in North America.

   b) Be kept simple to entice the maximum number of survey participants

   c) Be an independent, testable and repeatable market-based assessment

   d) Provide participants with the assurance that their information could not be attributable to them

e) Be based on the groups surveyed in the Mercer study and expanded as deemed appropriate by the consultant

f) As much as possible mirror the scoping included in the Mercer study for peer selection, job classes, etc, but changed as recommended by the consultant to improve the results

g) Enable reasonable comparison to the last Mercer study and provide trending analysis for Hydro One's next application, with an eye to establishing a possible path of improvement

h) Consider whether it is more appropriate to compare using the median, or the mean, or both.

i) Consider adjusting compensation levels to reflect the different regional costs of living amongst the study participants

j) Acknowledge that to ensure any respondent-specific information would not be withheld from the report, all parties have agreed that they would not request that data be attributed to individual respondents during a review of the study.

k) Request data supporting an interest in the issue of pension as a percentage of total benefits, and benefits as a percentage of compensation,

l) Rely on the expertise of the selected consultant to recommend appropriate changes in methodology and assumptions.

2) The study to measure productivity should:

a) Acknowledge that to ensure any respondent-specific information would not be withheld from the report, all parties have agreed that they would not request that data be attributed to individual respondents during a review of the study.

b) Request that the consultant recommend a productivity metric or metrics that can be used for internal comparisons using readily available internal data

10.0 Close

5:10pm

10.1 Allan Cowan thanked everyone for their participation and valuable input.

To conclude, Allan summarized Hydro One's assessment of the meeting results as follows:

For the compensation study, the RFP should be drafted and available by the end of February.

Once a successful proponent is selected, the stakeholders would be reconvened to meet with the consultant on the project, with a further meeting in the fall to present the findings.

A CDM study is in abeyance for the moment, but more robust evidence for the 2012/2013 Distribution application will be sought and likewise for the 2013/2014 Transmission application in terms of the charge determinants.

Hydro One expects to advise the OEB of a suggested plan to continue to work with the OPA as they move forward with IPSP 2 and use that to improve the next submission for Distribution and select key pieces for incorporation into the next Transmission submission.

At an upcoming stakeholder session proposed productivity measures will be examined.

5:25pm ADJOURN

APPENDICES

A. **Meeting Agenda**

B. **OPA Letter**

C. **CDM Discussion Notes**

D. **Compensation Cost & Productivity Discussion Notes**

A. Meeting Agenda

Stakeholder Consultation

Rate Applications

Compensation and CDM Studies in Support of Hydro One Rate Applications

AGENDA

February 10, 2011
Hydro One Networks
Special Event Room, Ground Floor
483 Bay Street, North Tower
1:15 p.m. – 5:30 p.m.

1:15 pm	**Registration and Refreshments**	
1:30 pm	Welcome	Allan Cowan, Director, Major Applications, Hydro One Networks
1:40 pm	Introductions and Review Agenda	Facilitator
1:45 pm	Review of CDM Forecasting and OEB Directive	Stan But, Manager, Economics and Load Forecasting, Hydro One Networks
2:00 pm.	Facilitated Discussion about CDM RFP	Facilitator
3:15 pm	**Break**	
3:30 pm	Overview of OEB Directive & Considerations for Compensation Benchmarking Study	Keith McDonnell, Manager, Human Resources Operations, Hydro One Networks
3:45 pm	Facilitated Discussion about Compensation Benchmarking	Facilitator
5:15 pm	Next Steps	Facilitator/Allan Cowan
5:25 pm	Closing Remarks	Allan Cowan
5:30 p.m.	**Adjourn**	

B. OPA Letter

ONTARIO POWER AUTHORITY

120 Adelaide Street West
Suite 1600
Toronto, Ontario M5H 1T1

T 416-967-7474
F 416-967-1947
www.powerauthority.on.ca

February 9, 2011

Susan Frank
Vice President and Chief Regulatory Officer
Hydro One
8th Floor, South Tower
483 Bay Street
Toronto, Ontario M5G 2P5

Dear Ms. Frank,

RE: Hydro One Compensation Benchmarking and Load Forecasting Studies - Stakeholder Session

The Ontario Power Authority (OPA) is writing to thank you for Hydro One's invitation to attend a facilitated stakeholder session on Thursday, February 10th to seek input on two studies that Hydro One is proposing to undertake. The OPA understands that these studies are intended to respond to the Ontario Energy Board's (the Board's) December 23, 2010 Decision relating to Hydro One Networks Inc.'s application for *2011 and 2012 Transmission Revenue Requirement and Rates* (Proceeding EB-2010-0002).

In particular, the OPA is writing with respect to the proposed load forecasting study. The OPA recognizes the Board's direction to Hydro One to work with the OPA to devise a means of measuring the expected impacts of conservation and demand management (CDM) programs promulgated by the OPA. The OPA appreciates the importance of continued collaboration with Hydro One with respect to this matter, and is committed to on-going dialogue with stakeholders in keeping with our guiding principle of transparency.

The OPA is of the view that further discussions are required between the OPA and Hydro One to ensure that both organizations have a complete appreciation of the information that is already available to assist in responding to the Board's direction and the options for responding. Ensuring that a proper inventory of existing information and methodological approaches exists is advisable in order to support stakeholder activities related to this matter. The OPA is concerned that initiating broader discussions prior to such an inventory and a full understanding of the options being in place is premature and could potentially lead to confusion and inefficiency. As a result, the OPA does not anticipate participating in this stakeholder session.

The OPA looks forward to continuing to work with both Hydro One and stakeholders with respect to the Board's direction on CDM forecasting over the coming months.

Sincerely,

Michael Lyle
General Counsel and Vice President
Legal, Aboriginal and Regulatory Affairs

C. CDM Discussion Notes

The vast majority of the CDM discussion focused upon the directive in the Board's 2011/2012 Transmission Decision.

2:15 pm

1. Julie Girvan sought clarity on what Stan But meant by "program- plus non-program-specific". Stan advised the first two categories are program-specific while the other three categories are non program-specific. Hydro One captured both program- and non-program specific CDM reduction impacts in their load forecasts. Julie Girvan asked whether the OPA used non-program specific categories. Stan stated past government targets and forecasts for CDM basically reflected a total impact in terms of both program and non-program components.

2. Elena Yampolsky asked whether natural conservation is a non-program category. Stan clarified natural conservation is part of the load forecasting exercise but was not counted in this CDM forecast.

3. Bill Harper raised historical CDM savings and asked if these were applied to the 5 categories (both program plus non-program) and then included in the historical observed provincial load for the analysis.

   Stan stated that 2004 was the reference year when there were no CDM activities in place with the exception of natural conservation. For later years, such as 2010, presuming a CDM reduction was achieved, this would have been added back.

   Bill —As this CDM reduction would be achieved through factors in varying amounts for all 5 categories, how did Hydro One avoid comparing apples and oranges as it looked both forward and back in its forecasting?

   Stan indicated that from a load forecast modeling point of view, Hydro One added back the CDM result. For modeling using OPA information, Hydro One also added back the CDM component to get an activity base level without CDM impacts and then forecasted forward. Looking ahead, this will be dependent on solid EM&V (Evaluation, Measurement and Verification) results.

   Susan Frank clarified that Hydro One could not rely entirely upon the OPA's simple assessment that the targets were actually achieved. Hydro One needed to understand how they were met to reasonably provide the background and the rationale for the definition/target number in its rate case; it had to undertake its own analysis looking beyond the OPA-contracted programs. In Hydro One's view these programs alone did not amount to savings the OPA claimed Hydro One achieved; using the 5 categories provided a more complete picture and collectively amounted to the savings estimate.

4. Judy Simon found the additional clarification helpful and asked whether Hydro One included non LDC-contracted OPA programs. Stan advised OPA-contracted programs only pertains to the LDC CDM target. For example, the CDM target does not cover First Nations.

5. Marion Fraser inquired how Hydro One will account for the transmission side of the industrial load forecast targets. Stan believed that industrial customers directly connected to transmission are outside

the LDC CDM targets further highlighting the inadequacy of only capturing the LDC CDM targets in load forecasting.

Marion stated these targets have not been set and results are not known or as yet not published. Stan presumed the OPA would release more details in the IPSP proceeding.

Susan asked whether Hydro One needed another box for OPA-delivered programs. Marion concurred. And it was agreed that another category would be added.

6. Roger Higgin, looking beyond the transmission level province-wide, asked whether Hydro One needed to have distribution system data by customer class. Stan agreed stating 'the more information, the better the forecasting'—but the concept would need to be the same for all 5 categories in looking at the CDM impact on all sectors.

   Roger Higgin raised other modeling techniques such as normalized average-use modeling.

   Stan advised Hydro One has done past analysis on a defined set of customers for data consistency and found consumption was reduced over several years. This has been documented in the attachment and published on the website.

7. Shelly Grice inquired why the OPA does not provide details as to how targets are being met. Stan could not answer that saying that Hydro One has the same published information as everyone else, but he acknowledged that the OPA, Hydro One and the Independent Electricity System Operator (IESO) meet regularly to discuss load forecasting which provides increased understanding of what is being planned and the various assumptions involved.

8. Marion Fraser asked if Hydro One has access to the EM&V reports that the OPA has done on their own programs, and if so are they the same as the reports published on the website or more detailed. Stan stated he personally is not on the CDM group working with these reports, but expected they are the same as those published on the website.

9. Dana Silk referenced an OPA document entitled 'Net Load Analysis of Conservation and Demand Management' dated September 2009, page 47 of 49, Appendix K, and wanted clarification on "achieved its projected savings by 73%" (net load analysis). Did this mean that the OPA was projecting to achieve only 73% of the target?

   There was further discussion about that reference and the numbers on the chart, but the question was left unresolved.

10. Bob reiterated the need to focus on the Board's direction to formulate the terms of reference for a request for proposal (RFP). He read from the Board's findings in EB-2010-0002: *"It is important that the terms of reference for the development of this methodology should to the extent possible, be devised with input from and consultation with a sufficiently broad range of stakeholders so as to ensure that the resulting product has credibility within the sector".* Everyone was requested to focus on establishing the

rules and parameters for the study which had to be completed within a timeline so that the results would inform Hydro One's next rate application.

11. Julie Girvan was concerned about the lack of OPA involvement and the absence of its associated knowledge and information would impede the exercise. Bob acknowledged this would leave a gap and asked Susan Frank how Hydro One reacted to OPA's decision. Was Hydro One still comfortable going forward when the Board clearly stated the cooperation with the OPA was important?

Susan said Hydro One had numerous conversations with the OPA and also recently with the OEB. She emphasized it would be preferable to have the OPA here but their letter explained why they weren't in attendance. Susan was confident that the OPA would work with Hydro One on the study, for the programs that either they deliver or that they get the LDC's to deliver, but anything beyond the stated OPA mandate remained uncertain.

12. Bill stated Hydro One, like other LDCs, relies on the OPA's IPSP forecast for the province to establish its share of CDM. The OPA forecasts the conservation target impact on peak, which is one hour a year, and in total gigawatt hours for the year. But for transmission rates and the charge determinant, Hydro One and other transmitters had to come up with the maximum billing demands for 12 months of the year. How did Hydro One (or the others) realistically get from one number to 12 numbers? He stated as an example if the entire summer peak was being saved by demand response programs, then you may only impact one month of the year and have no impact on the others. He felt that while peak demand was important for transmission system planning and design, the real issue in transmission rates was how Hydro One came up with the monthly billing determinants from the information they receive from the OPA.

Susan Frank acknowledged that Bill added an element that previously was not appreciated as part of the scope of work—the notion of getting to monthly charge determinants.

Bill Harper further stated that for the load forecast for transmission, it is ideal to get to the charge determinants within a global forecast. The peak demand in the province is immaterial from a billing perspective, it is important from a transmission perspective and whether expansion is required.

Susan again acknowledged something useful was being added to the scope. Susan also wanted to know in defining peak whether considering the OPA/government numbers from history and for the future, which would be an apples-to-apples scenario, would be OK.

Bill Harper stated he could not endorse this from a program perspective; the need was to understand the charge determinants and which programs make up those numbers. In addition, it is important to identify which distribution customer class is providing the savings in order to properly forecast the effect of the savings.

Stan But clarified they use the monthly energy and peak profile impact given to them by the OPA for Hydro One's transmission rate case. The details now being discussed are beyond the detail available from the OPA, but the total CDM monthly peak and energy reductions are consistent with the OPA.

13. Bob Betts refocused the group in an effort to concentrate on the task at hand. He asked whether the 5 Hydro One-identified CDM categories were the right ones or whether some were more or less appropriate.

Ian Malpass reminded that a category needed to be added for programs not contracted or carried out by the OPA. Judy Simon stated referring to these as OPA-contracted was misleading as OPA-delivered programs are typically contracted out. Judy cited the example of the high performance construction program which until December 2010 was delivered through a contract with Enbridge Gas. Judy suggested the right terminology and distinction could perhaps be LDC-contracted and OPA-delivered or Other OPA-contracted in order to track an LDC's own contribution. Judy concluded that sector-level analysis requires categories for the distribution rates.

For Bill Harper, the key issue pertained to commonly-used categories and maintaining consistency in reporting across the system.

Roger Higgin pointed out the OPA letter, in its last paragraph, highlighted:

- Proper inventory of existing information;
- Methodological approaches.

Roger recognized that was an important starting point for this research. He wondered whether other jurisdictions categorized CDM into these categories and what the implications were for modeling and other purposes, as opposed to inventing new categories. He proposed leveraging some of the work the OPA did for the IPSP on categories and end use modeling.

Bob suggested the consultant's scope could include the review of categories used in other North America jurisdictions. Roger endorsed this.

Elena stated interest in the programs delivered by the utilities that can be tracked, as opposed to the OPA programs delivered by others that cannot be tracked. Roger clarified he was referencing the last three categories as the other 2 are standard.

Susan Frank asked the group to narrow the scope to ensure the study would be focused and maximum value achieved. Roger suggested to start with the IPSP which used the University of British Columbia modeling exercise as it included natural conservation and well-defined codes and standards. Marion Fraser pointed out California is another jurisdiction where codes and standards are a major factor for the California Energy Commission, and in New York State, conservation is run by a centralized group.

Susan suggested the study should look at the IPSP plus the two jurisdictions mentioned for any insight. This encountered some stakeholder pushback as the results may not be aligned to the information Ontario has collected and tracked to date. This led to discussions around current methodology and Hydro One practices in calculating the load forecast.

14. Bob Betts asked Bill Harper what he would need from this study. Bill replied he would want to see how Hydro One effectively translates OPA's megawatts peak reduction into a forecast—how one CDM reduction number gets turned into monthly reduction targets.

Bob restated that if the methodology defined how Hydro One takes that basic information and converts it into the monthly determinants, then that would be a valuable and important part of the methodology. Bill confirmed this.

Susan Frank then inquired whether Bill Harper would be prepared to meet with Hydro One to better scope this. Allan Cowan wondered whether this was a study issue or whether it was more detailed evidence to support the filing issue. Bill suggested the Board views this more from the perspective of OPA and Hydro One determining how the numbers are derived, as opposed to engaging a 3rd party to study the process.

Susan offered to work with the OPA and stay within their mandate, but wondered whether the Board would be satisfied if they looked at overall OPA-managed programs and how Hydro One gets that into the charge determinants.

Bill hesitated as the demand reductions Hydro One is using include more than OPA programs. Susan acknowledged this is the current reality. Bill clarified the issue is how province-wide forecast savings, for codes and standards for example, translates into a billing reduction that determines the regional 12-month transmission forecast, i.e. the charge determinants used by Hydro One.

Susan acknowledged the concern of taking a total number and turning it into monthly charge determinants needed to be addressed, but Hydro One had not understood this to be a concern before the session. Hydro One believed a 3rd party study would have given the Board comfort, but in light of the discussions now wondered whether an external study was required. It was still unclear whether Hydro One should look past the program-driven tier. The group suggested conservation elements beyond program-driven citing examples from the IPSP, New York, California. She posed the question whether the Board would like Hydro One to consider any other items, for example natural reductions.

15. The discussion then shifted to what the difference was between natural savings and consumers' own actions. The example of an Energy-Star refrigerator being purchased as a replacement for a unit at life's end was considered natural, while buying a better, more efficient unit to replace a reasonably functioning unit was a customer-initiated action. For Stan, natural was defined as anything that was not program-driven.

16. Roger Higgin noted the original IPSP had four categories, such as energy efficiency, demand response, customer own actions and customer generation. The need to understand exactly how these categories were defined, and what the OPA did to run those through to the load forecast would be beneficial. With another forecast underway, the OPA may be expecting to use those categories again. The study would need to be aligned with this.

17. Bob noted the question on the table was whether Hydro One needed to go out and hire a consultant or was it a matter of providing improved information and evidence to the Board. Susan expressed a concern that Hydro One's efforts, despite being done to the best of its abilities, may again be questioned or deemed less than comforting to the Board. Elena concluded it was timely to engage a 3rd party to do what Bill Harper suggested, looking at the methodology and how the peak demand was translated.

Bob enquired if there was an opposing view. Susan sought the Board's perspective on the matter.

18. Harold Thiessen referred to the decision on page 6, which did not say a study had to be done by a consultant. It called for a "robust and accurate means of measuring expected impacts of CDM programs". The decision talked about how the Board had trouble understanding how CDM fit into the load forecast and the quality of the CDM estimate. It therefore concluded that as the OPA is focused on CDM, Hydro One should work with the OPA to set a unified methodology. CDM assumptions either agree with OPA actions or not, but Hydro One might want to try to get the OPA to agree and have clear evidence that demonstrates that all are on the same page.

Harold did not know whether the prior distribution decision called for a 3rd party study. However, this (the transmission) decision further stated that learnings from this study should be shared. This would help address distributor issues as some information could be used in the next distribution rate application to improve rate forecasts for CDM. In addition this knowledge-share with the OPA should be documented. The OPA letter did not say they would not participate, but that they weren't ready to do so at this time.

19. Bob Betts suggested that while parties continue to disagree with CDM impact methodology, the OEB will need to seek resolution. The methodology needs to be acceptable to all parties. He again asked whether the group would be satisfied with this study being done by Hydro One, obviously with the support of the OPA, or whether a 3rd party was required. The group generally agreed that a 3rd party review was not required.

The issue of timing was raised because there was view the study should include the new IPSP as well as general OPA input. To delay the study until the new IPSP, Hydro One would need to seek relief from the Board in terms of the timing; the Board would have to agree that Hydro One would not be required to have this study done for the next rate application.

This again generated considerable discussion, recognizing the need to assure the Board that the OPA and Hydro One, in the context of the new IPSP, would be working together on what the deliverables would be which would include the additional information about calculating the charge determinants of transmission.

Harold Thiessen added that, in Hydro One's letter to the Board seeking relief, good evidence and reasoning in what was being done would go a long way. Also with the additional insights gained at this stakeholder session, Hydro One's distribution filing should reflect an appreciable boost in the CDM portion of the load forecast for added clarity. Telling a clear story of what Hydro One wants to do and what it is doing in transition, in conjunction with the OPA, would be taking a meaningful step in the right direction and into the areas questioned in prior cases.

Susan Frank noted this might not involve a 3rd party; Harold acknowledged this for the distribution case. But this might still be a consideration for the subsequent transmission case once Hydro One conducted an intensive effort with the OPA. Harold reiterated the Board's decision doesn't expressly look for an external study.

Bob Betts sought consensus that all would support Hydro One seeking relief from the Board in terms of the distribution application. All agreed but David MacIntosh emphasized that the entire matter could not wait for 2 years before something happened, the distribution case next year should reflect some improved information.

Bob asked Susan whether Hydro One could focus on the transmission application. Susan pointed out the time between the two applications was quite short; a matter of months. The focus should be on what Hydro One, in working with the OPA, can reasonably do in getting better definition and information from the OPA and in enhancing Hydro One's applications to the Board. While Hydro One appreciated the suggestion it didn't need to do an external study for the distribution case, the scope of work required must be determined and the necessary steps taken to improve its Distribution submission and avoid similar disputes at the Board.

As this addressed David MacIntosh's issue, Bob ascertained there now was unanimous agreement that Hydro One could at least make the request of the Board.

The CDM portion of the session concluded.

BREAK 3:30pm–3:45pm

D. Compensation Cost & Productivity Discussion Notes

3:55pm

1. Roger Higgin noted the concern of mixing productivity and compensation studies together. Potentially some consultants might have utility-specific strength in both areas, but they are different disciplines. Common productivity measures and trends could be one piece of work.

   Keith McDonnell added that in Hydro One's experience it has been very difficult to find metrics that are common among the utilities and suggested the issues be included in the RFP and scoring based on the experience of conducting productivity measures and compensation measures.

   For the Mercer Study, Oliver Wyman, a unit of MMC [March & McLennan Companies] as is Mercer, was brought in for the productivity benchmarking portion but could not execute on this as intended, generating some criticism.

   To the question of whether a productivity study per se is required, Harold Thiessen and Allan Cowan cited the EB-2010-0002 Decision direction whereby "The Board will expect compensation increases to be matched against demonstrated productivity gains. Either one will risk not recovering all of its compensation costs if it fails to tie compensation and cost increases to measureable productivity increase"…while "the Board directs Hydro One to revisit its compensation cost benchmarking study in an effort to appropriately compare compensation costs to those of regulated Transmission and Distribution utilities." Susan Frank summarized that the OEB stated that Hydro One must comment on productivity in its next application however the Board did not direct that a specific productivity study was to be done.

2. Allan Cowan observed that in the previous Mercer Study, Oliver Wyman had trouble getting anyone to participate in the productivity study because of the great deal of effort needed to provide the unique input whereas little benefit was seen to be gained for this effort at the end of the day. Oliver Wyman ended up using high level macro measures which the Board rejected outright.

   Bohdan Dumka added that a separate benchmarking study was conducted by First Quartile Consulting, specialists in performance benchmarking utilities in North America. As part of the transmission performance benchmarking study, Hydro One had asked First Quartile for productivity benchmarking. However, First Quartile encountered the same difficulties as Oliver Wyman did and could not gather sufficient data to provide a productivity benchmark study.

   Bob Betts suggested to first focus the discussion on the compensation benchmarking study update and then discuss how Hydro One could move ahead on productivity.

   Bob suggested that the Mercer Study should be updated to enable reasonable comparison to the last study and to provide trending analysis as meaningful as possible for Hydro One's next application, with an eye to establishing a possible path of improvement.

3. Frank White asked if it was not better to have the employee groups broken down into separate trends and to not have an overall weighted average. In compensation, the tendency is to focus on median numbers although potentially the Mercer study data was aimed at taking samples to predict broader populations. This approach leans on mean averages and standard deviations. Therefore, Frank suggested updating the previous Mercer study to extract mean averages, providing both median and mean average comparisons, as these tend to be distributed differently.

   Bob noted that if this is done without using the Mercer Study classification breakdown it would be a major change rather than an update.

   Roger suggested that Hydro One must rely on the expertise of the company that is contracted to do the survey, but proposed that the question of median and mean average renderings should at least be offered as a question in the RFP, so that the cost and feasibility of dual rendering could be gauged.

4. Roger Higgin further asked if there should be some benchmarking among the peer groups to assess cost of living. For instance, comparative numbers from StatCan show that it costs 7% more to live in Toronto than the Canadian average.

   Bob added that one would want to clarify understanding of the interpretation of cost of living as to:

   1) How compensation applies an annual incremental increase that usually relates to cost of living;

   2) How compensation relates to actual cost of living.

   Bohdan noted one of the dilemmas in the Mercer Study was how to come up with the cost of living metric, based on the employee population, in part because many of the entities did not have the time or resources to ascertain and submit the information needed and therefore would decline participation.

5. Susan Frank suggested stakeholders focus on the peer group question as the Board directed a full North American coverage—the sample and what is to be included. At the time of the original Study there were significant differences in economic performance, patterns and statistics. There is greater convergence now but differences remain. Susan invited comments on considering Transmission and Distribution utilities in the US as well as Canada.

   Richard Stephenson argued that using American utilities produces data that requires too much massaging to make it comparable, such as—the drastic changes in compensation by virtue of foreign exchange issues year over year, underlying currency differences, tax differences, health care differences, and different labour laws, including Right-to-Work states. Likewise Richard suggested company profiles varied by US region making the data much more heterogeneous than it is in Canada. Richard further asked if European or Australasian comparators might be better.

   Bob Betts pointed out that the issue for the Mercer Study was getting a large enough research peer group within Canada. Thus, confining the peer group to Canada might be optimal but not feasible, and the Board's direction now was to include the US, thus any deviation would have to be justified. Nonetheless, the RFP could state that while the Board has requested the peer group be pulled from

North America, Hydro One was seeking the expert advice of the consultant on the question of the optimal peer group to be used.

Julie Girvan, Bob and Susan Frank summarized the discussion, to the effect that the consultant will need to decide what is relevant and most workable in terms of methodology and peer group selection, and this could be included in the RFP. The stakeholder consensus was for a broad peer group that includes other North American Transmitters and Distributors, however the consultant would provide their expert advice as to where the peer group should be selected from.

6. Roger Higgin raised the question of the Board's concern about a "ratchet effect" among Ontario utilities and others in the energy industry such that when there is a compensation increase in one LDC, it affects others. Perhaps in part for this reason the Mercer Study opted to use a broader peer group.

7. Bob, Susan and Bohdan clarified for stakeholder acceptance the Ontario players covered by the scope used in the Mercer report included Hydro One and THC, and may now possibly also include PowerStream after the Barrie Hydro merger, but not others such as Ottawa Hydro.

8. Frank White raised the question of product market comparatives versus a possible alternative focus for Hydro One on labour market comparatives, namely the *de facto* labour market for Hydro One, OPG, etc. Frank suggested a possible way around the sample size might be to have the study consider possible benchmarking of, for example a typical lineman per se—not a specialized role—against the national published data that Mercer typically publishes in labour market surveys.

9. Bob Betts suggested that Board members may be looking for a comparison of Hydro One to the peers that the Board regulates. From that perspective, they would be less concerned about the issue of attracting hires. Bob and Richard Stephenson did however accept the RFP could address issues beyond the written concerns of the Board, such as to establish some understanding of the compensation at Hydro One relative to the broader employment market.

10. Susan raised the principle issue of confidentiality of responses. Potential respondents are chiefly concerned that their information remain confidential. Susan added the more basic constraint imposed by benchmarked parties is that their particular information will not be exposed; if this assurance is not provided, the consultant's ability to gather a reasonable sample of data is severely restricted.

    To ensure any respondent-specific information would not be withheld from the report as it might be identifiable or reproducible, there was no contest from the stakeholder group present to stipulating that only anonymous and aggregate data would be disclosed. It was also the group's desire that the Board also would be guided by this principle of utmost confidentiality.

11. Regarding the participants in the Mercer Study, the 13 comparators who agreed to participate fell well short of the Mercer objective. Several of the participants were Transmission and Distribution only, however many of them were vertically integrated utilities or generation utilities. BC Hydro participated as both a Generation and Transmission concern, and the other participants were Bell Canada, Hydro Québec, TransCanada Corp., OPG, BC Hydro and BC Transmission, EPCOR, Enbridge, TransAlta, THC,

Bruce Power, ENMAX, Manitoba Hydro and New Brunswick Power. Consensus was reached that the Mercer Study participants and similar types of utilities should be included in the new study in order to maximize the peer group population.

12. Roger Higgin asked about the granularity of reporting. To the possibility of a rolled-up report, Susan indicated they would take the idea of asking the successful proponent to consider aggregating the data to higher levels for regulatory reporting purposes.

13. Richard Stephenson asked if there might be greater detail in the trend analysis, asking for internal year-over-year changes, rather than just a trend analysis based on a data set for 2008 and one for 2011. Bob therefore noted respondents should be asked for trends during the intervening years.

14. Susan Frank asked about the challenge of comparing like jobs. Keith McDonnell singled out the Power Workers' Union (PWU) classification of regional maintainer, a higher-paid job because the broad multi-skill set is very different from a typical power-line maintainer (PLM). This may invalidate a comparison to another LDC's PLM. It was suggested the apples and oranges debate is complex enough that the Board will have to accept a reasonable argument for differences, with help from the expert consultant.

15. Harold Thiessen asked if expanding the survey to North America would tend to include more large US Transmission companies to enable better matching of job descriptions. Susan's synopsis was that the back and forth with Mercer last time led to an *ad hoc* job matching solution. Bohdan added that this is why some of the non-electricity utilities seeing they had only several of the 30 comparison jobs dropped out of the study, feeling it was not a fit.

16. Bob Betts recalled the consultant ended up dropping a lot of the classifications originally intended for survey because the responses were not forthcoming. Therefore, Mercer ended up presenting the best data they felt they could use.

    Frank White pointed out that Mercer declared 80% match to be a pretty good result. He suggested another approach is to conduct composite benchmarking—enter the level of engineer and the level of finance and take an average of the two numbers to get a kind of weighted value. This could help with job roles that do not fall into one category or the other.

    Mercer does accept composite benchmarking but attempted to match jobs one-for-one. David MacIntosh recalled that Mercer opined that the greater the massaging required to make categories look more similar would have made the results less credible.

17. Bob suggested that every effort be made to retain the Mercer approach.

    The closer the new and old reports aligned in assumptions used, the less needless debate will arise.

18. Keith clarified definitions of base pay as hourly rate, total cash as base pay plus any short term incentive, and total remuneration as total cash plus pension and benefits. Roger noted the Board interest in the issue of pension as a percentage of total benefits, and benefits as a percentage of compensation, which

was not fully broken out in the Mercer Study. The latter change was set as a consideration within the RFP.

19. Bob Betts asked what is feasible at this stage to help settle or make some decisions about productivity. Roger Higgin indicated that perhaps the first item would be to identify 2 or 3 measures acceptable to everyone.

He commented that the productivity results could be of interest to the Board in two ways: first to compare Hydro One's productivity to its peers and second as a metric to identify if and how Hydro One internal productivity is changing.

20. While benchmarking would determine whether a difference in productivity justifies Hydro One's compensation position in the comparator group the key would be to determine if Hydro One is positively addressing productivity improvements over time. Based upon the difficulty that exists in getting a productivity benchmarking analysis that is acceptable to all, perhaps the internal productivity approach is the most meaningful for all interested stakeholders.

21. Susan Frank reminded the group that with the last study, no one liked the broad benchmark comparison for productivity. Benchmarking at high level across the metrics was a near-fiasco. Thus, as suggested it may be better to look at something in the area of internal productivity measurement and find a way to deliver work in a less costly manner?

Roger countered that it depends on what one is trying to do. The Board has had spreadsheets for years that compare the OM&A per customer for all Distribution utilities and if those are available, there may be some value in having this information, but agreed it may not be applicable here.

Susan pointed out that in any given information there are inconsistencies and problems with what is reported as OM&A; while the Mercer Study had said Hydro One fared well on the benchmark items, Hydro One itself decided it did not.

22. Bob added that the Board finding referred to the need to compare compensation to productivity and that this comparison could be more precisely made by comparing internal productivity year-over-year to compensation changes.

Richard Stephenson suggested it may well be appropriate for a fresh start, with 2011 as the year Hydro One starts collecting data though it likely would not have any meaningful trend for the next 5 years.

23. It was discussed that the consultant may establish appropriate productivity metrics that could be used for internal productivity measurement and that there would be merit in beginning to analyze these against comparable internal data to begin to measure changes in those productivity metrics, and wherever possible to back-cast to historic data.

24. Roger added that there are different ways to express productivity, one of the newer ways being to measure capital. The Board's main interest is on labour productivity. Therefore the charge to Hydro One

is clearly to devise a metric and be able to demonstrate labour productivity, by hours per standard task, or some other measure.

Richard Stephenson argued that measuring higher labour hours is not the solution. The role of technology in capital and the changing role of technology are generally overlooked in setting productivity metrics. There might be added pressure on the entity that spends the most to show the highest productivity.

25. Susan Frank asked the group whether they were aware of any productivity measures that other major utilities used which they could bring to the table. Hydro One would hold another stakeholder consultation to bring forward for discussion and consideration potential metrics for measuring productivity, particularly internal productivity.

Hydro One Networks, Inc.

Stakeholder Consultation Meeting Notes

Density Cost Allocation Studies in Support of Hydro One Rate Applications

March 22, 2011
Special Event Room, Ground Floor
483 Bay Street, North Tower
Toronto, Ontario

Prepared by London Economics International LLC and PowerNex Associates, Inc.

Table of Contents

1 Introductions and Review of Agenda

Enza Cancilla (Manager, Public Affairs, HONI) welcomed participants and provided an overview of the day's agenda. She then invited participants to introduce themselves. In attendance were representatives of the Association of Major Power Consumers of Ontario, Canadian Energy Efficiency Alliance, Canadian Manufacturers and Exporters, Electricity Distributors Association, Energy Probe, EnviroCentre, Federation of Ontario Cottagers' Associations, Horizon Utilities, Ontario Energy Board, Ontario Federation of Agriculture, PowerStream, Power Workers Union, Veridian Connections, and the Vulnerable Energy Consumers Coalition. Also present were HONI staff, and the LEI/PNXA presentation and facilitation team.

The full list of participants, together with the agenda, is provided in Attachment 1. Attachment 2 includes a copy of the presentation that was delivered by LEI/PNXA to stakeholders.

Ian Malpass (Director, Regulatory Support, HONI) welcomed participants and gave a quick overview of the status of the project. He encouraged participants to provide their ideas and perspectives on the proposed methodology that would be presented. He asked that participants identify themselves when making comments so this could be included in the notes of meeting. He then introduced Andy Poray (AP) of PNXA who would facilitate the proceedings.

2 Presentations and Discussion

2.1 Slide 2

AP provided an introduction to the presentation that would follow. He requested that questions be asked from the floor throughout the presentation.

These notes of the meeting make reference to the slides that were presented at the meeting and included in the package that was sent to stakeholders prior to the meeting.

AP noted that there were two general objectives for the stakeholder session:

- To reach a general agreement on the proposed methodology; and
- Receive specific feedback from stakeholders

He then introduced Benjamin Grunfeld (BG) of LEI and Mark Vainberg (MV) of PNXA to make the presentation.

2.2 Slide 4

BG reiterated that the objective of the session is to get general agreement from the stakeholders on the proposed methodology and to receive specific input from stakeholders. He reviewed the three objectives of the LEI/PNXA engagement and noted that these follow the OEB's direction to HONI for the density study. He addressed the confusion that sometimes exists related to characterising groups of customers specifically when using the word 'density'. Customer density is one specific characteristic of a group of customers (e.g. population density). This is not to be confused with other characteristics of customers groups. For example, a rural or urban description tends to include multiple characteristics (e.g. distance from major load centre, levels of vegetation, network topology). However, there is typically overlap between the two classification methodologies e.g. low-density customers also tend to be rural customers, which contribute to 'misuse' of the low-density term.

2.3 Slide 5

The existing cost allocation methodology allocates approximately $110 million of costs to R2 and seasonal customers from UR and R1 customers, based on current density weighting factors. If the density weighting factors were removed (i.e. set to one), $110 million would shift back to UR and R1 customers, which would have a material impact on per customer cost in all of the residential sub-classes. The UR and R1 cost per customer would increase by 81% and 23% respectively, while the R2 and Seasonal cost per customer would decrease by 22% and 12% respectively. The impacts are similar for the General Service Customers, if existing density weighting factors are removed. John McGee asked if these costs represented only the distribution portion of costs. BG confirmed this to be correct.

Peter Thompson inquired as to what the basis is for the shift of costs from one group to another. BG and MV explained HONI's current cost allocation methodology and the way in which the density weighting factors are calculated. Density weighting factors are applied to a number of cost categories. HONI first assigns a portion of the total length of each distribution feeder to each of the individual customer sub-classes. Feeder length is allocated to sub-classes either on the basis of i) the number of customers in each sub-class on a feeder relative to the total number of customers on the feeder or ii) the volume of throughput (MWh) delivered to each sub-class on a feeder relative to the total volume delivered on the feeder. The calculation is performed on individual feeders and then aggregated up to the sub-class level. The customer density (customers per km of line) for each rate sub-class is determined as the ratio of the total number of customers in each sub-class to the total assigned feeder length. Likewise, the energy density (delivered kWh per km of line) for each rate sub-class is determined as the ratio of the total consumption for each sub-class to the total assigned feeder length for that class. The density weighting factors are calculated as the inverse of the ratio of the sub-class specific density to the average density across the class. Transformer cost density weighting factors are determined slightly differently. Instead of the density weighting factors being calculated on the basis of an allocation of a length of an individual distribution feeder to a sub-class, the density weighting factors are based on an allocation of the net book value of transformers on a feeder to a sub-class

John McGee asked about the sub-transmission costs and if they are included in the rate classes being considered. BG responded that no, sub-transmission costs are not included and only the eight rate classes illustrated in this slide are impacted by density weights in the cost allocation model.

2.4 Slide 6

BG noted that HONI previously engaged Elenchus Research Associates to assess the impact of density on distribution rates.

In designing rate classes and cost allocation methodologies, one of principle objectives is to consider fairness. BG emphasized that one of the objectives of the study is to consider fairness in a number of dimensions such as:

- equal customers treated equally; and
- unequal customers treated unequally.

What is being proposed by LEI and PNXA is to differentiate customers based on the cost incurred by HONI in providing distribution services to different sub-classes through a comprehensive study providing evidence of a potential cost difference, thus providing justification for different distribution rates for different classes of customers.

The study will consider a number of specific questions and BG noted that this study will examine whether there is evidence of differences in cost to serve low and high density customers.

BG noted that there may not be a difference between the way rural and urban customers use electricity. Dana Silk disagreed noting that there are those who feel that there are differences in consumption of electricity between different customer classes. BG responded that that may be the case for Seasonal customers, but not in general for year-round customers. BG noted that the electricity volumes of rural customers may be less than for year-round customers, but that in terms of fixed costs, the cost to connect is higher for rural customers.

John McGee noted that there are seasonal customers that are adjacent to year-round customers and feels that there may no longer be a justification for having Seasonal classes.

Ted Cowan noted that given the significance of the $110 million cost shift due to density weights, it is important to consider an option of how much a utility would have to pay to low density customers to exit the grid (self-generate). He suggested a capital solution should be considered in dealing with the rate differential and that the Rural and Remote Rate Protection (RRRP) program is outdated and may need to be adjusted. MV noted that such considerations at this time are premature and not within the scope of the study since the cost/density relationship is not yet fully known, which is the focus of the study. Ray Gee (HONI) pointed out that differences in rate classes also provide a signal to future consumers. Ian Malpass noted that this study is not intended to address RRRP and only considers the cost to serve. Ted Cowan reiterated that this study is an opportunity to look at all available options, including the RRRP. AP summarized the focus of the project and noted that rate design is another topic for HONI and the OEB to consider following the results of this study.

Peter Thompson sought clarification on the Slide 6 statement, "after correcting for other exogenous factors". BG clarified that there are other factors that have an impact on cost to serve. For example, costs that may be correlated with density, but are not specifically density related.

BG noted that there may be some qualitative discussion based on the results of the study that may address other concerns not specified in the current scope.

2.5 Slide 8

This slide illustrates the proposed methodology, which relies on two separate but complementary analyses (econometric and engineering). The first entails an econometric analysis that will look at the OM&A and OM&A and capital costs that HONI incurs across its operating areas (approximately 50 in total), in which there is variability in customer density. BG noted that the analysis will look at 'OM&A only' and will also look at 'OM&A and capital'. BG noted that previous econometric studies, in support of utility cost benchmarking, performed on behalf of the Ontario Energy Board have relied only on OM&A costs, as obtaining and normalizing data on capital costs is problematic when looking across utilities. BG also noted that while the quality of the underlying data has been a concern in previous OEB proceedings, the use of econometric techniques has generally been accepted. By using HONI-specific data for each of the operating areas, information is consistent and in greater depth, therefore less contentious regarding its accuracy.

The second part entails an engineering analysis, or a direct cost assignment study. This study will identify sample areas across HONI's distribution network which will vary in terms of customer density. Sample areas will also vary in terms of geography, undergrounding, and other characteristics. The study will then assign operating area level costs to sample areas and assess how costs differ with respect to customer density.

Bill Harper asked what specifically is being achieved in the engineering analysis and the use of smaller sample areas. BG responded that looking at smaller sample areas provides a broader range of densities than the average densities across the operating areas. Bill Harper also noted that distance from service centres could be another consideration in defining of density. He also asked if the density defined in the econometric study is used in the engineering study. MV noted that the engineering study is designed to be blind to the results of the econometric study and to the definitions of density in the econometric study. The engineering study focuses on the cost to serve different groups of customers (in terms of density) and that individual results will allow for independent conclusions. Henry Andre (HONI) noted that part of the feedback received from the 1st density study stakeholder session was that it would be useful to have more than one approach for looking at the density issue.

Bayu Kidane noted that relying on one analysis is not as reliable as two. He asked what happens if the two studies do not support each other? BG remarked that the econometric study can isolate specific impacts of customer density on cost. Engineering analysis, while it can normalize for other factors, is more aptly designed to determine the total cost difference in serving one group versus another (where density is a factor). They may not necessarily come to same conclusions; however they may provide different views or interpretations.

John McGee asked about the use of CAPEX in the studies. BG noted that CAPEX represents a plan on how the rate base will grow in subsequent years. BG also discussed asset intensity and the fact that you cannot simply add OM&A (OPEX) and CAPEX to derive total costs. Laurie McLorg also raised a similar question on this point. MV added that capital expenditure (CAPEX) is used and partially proportioned to deal with annual costs, because approximately 10% of CAPEX is depreciated annually.

Marion Fraser asked which study will isolate CAPEX already incurred. BG clarified that both studies will isolate these costs. Econometric analysis will look at O&M and the substitution effect of CAPEX (CAPEX today will reduce O&M tomorrow). In engineering analysis, there is less of a substitution effect; however asset intensity will be examined for costs already incurred.

2.6 Slide 9

This slide illustrates the major steps that will be followed in the econometric analysis. BG explained the four major steps involved in an econometric analysis.

- Identify a utility cost function that includes inputs, outputs, and operating characteristics;
- Compile a data set that incorporates the necessary input, output, and operating characteristics;
- Solve the model to minimize the error term in the cost function; and
- Interpret the estimated coefficients to reveal the sensitivity of costs to changes in the independent variables.

BG noted that operating areas within HONI's service territory provide a natural break in terms of how costs, customers, and assets are tracked. The goal is to minimize bias in the results by using these natural breaks and delineation points. The advantage in looking at intra-HONI costs versus inter-LDC costs is that no assumptions are needed on cost allocation since there are no differences in capitalization rules. Marion Fraser noted that the flip side is also true in that what is representative of averages does not necessarily reflect the extremes. BG agreed.

Peter Thompson referred to Jay Shepherd's email comment regarding the proposal not to use other Ontario LDCs cost data in the study. BG responded that the granularity in LDC cost data is insufficient for the purposes of the study and that differences in capitalization policies and treatment of shared services make a direct comparison difficult. Ted Cowan noted that for an LDC study the boundary problems are vastly more difficult and have great effects and agreed that the approach of the study will provide a more accurate picture. MV further elaborated on the fact that cross-subsidization within municipalities influences LDC cost data and makes its use problematic. Bill Harper noted that if you were to compare LDCs and HONI, you would not be able to determine if cost differences were due to density or differences in company efficiency. BG noted that the report will document the reasons why the use of cost and customer data from other Ontario LDCs is problematic when considering the impact of density on HONI's cost to serve.

Ted Cowan noted that it may be useful to take a look at data from other LDCs with different densities (if data is available). BG pointed out that the level of detail with HONI data is much greater than with the other LDCs data. For example HONI knows exactly the number of poles in each operating region. Peter Thompson asked if similar data from Slide 23 were available for the Kingston LDC. BG and Ray Gee noted that there will be differences in data and its availability.

Henry Andre suggested that comparing operating areas within HONI to other LDCs is more of benchmarking exercise than a study looking at density as sought by the Board.

2.7 Slide 10

This slide illustrates the major steps that will be taken in the engineering analysis. The steps include:

- Select operating areas and sample areas within them;
- Compile data on operating areas and sample areas ;
- Calculate assignment factors;
- Assign operating area and provincial level costs to sample areas;
- Calculate asset intensity for each sample area; and
- Evaluate the distribution of costs across the sample areas to indicate costs to serve different groups of customers.

There was no discussion on the content of this slide.

2.8 Slide 11

BG invited participants to offer comments or suggestions concerning the two methods being proposed. John McGee noted that operating areas are not set up as utilities. For example, feeders are intertwined. If a transformer station is within an operating area, this would cause problems. MV explained that there is good data granularity and connectivity data. It can be determined which feeders and portions of feeders go through which operating areas and sample areas. There is also connectivity of every feeder with every transformer station. Bill Harper asked if every operating area has its own service centre. BG responded yes, and noted that in some cases there are two service centers per operating area. MV also emphasized the power of GIS and that the physical location of all assets in system can be determined.

Peter Thompson suggested that in the final report, it would be helpful to note other potential methodologies that were considered and why there were rejected (e.g. using LDCs in comparing costs). MV agreed to consider this.

2.9 Slide 13

BG provided an overview of the econometric methodology. BG reiterated that the analysis will look at two separate cost functions (OM&A only and OM&A and capital). BG noted that scale (magnitude) is a major cost driver for HONI. Density is a measure of customer intensity. BG also went through a number of other factors that could be considered. BG noted that while increasing the number of data points (observations) will improve accuracy, as the number of characteristic variables increases, the accuracy of the function decreases. An appropriate balance needs to be established. John McGee suggested dropping the use of aerial customer density (customers per km^2). BG stated that the study will look at both aerial and linear density, while recognizing that the denominator used to determine aerial density will be an issue. MV remarked that it is important not to miss areas where there are physical assets, but there are no customers. Laurie McLorg inquired about data time series (use of multiple years of data). BG indicated that 3-5 years of data would be used and, if available and usable, more years of data will be utilized.

Bill Harper asked if there were any other measures of customer density that could be used (e.g. average distance from service center). BG and MV noted that the engineering analysis will look at these factors.

Bill Harper also noted that vegetation management is on a seven-year cycle and should be taken into account. BG responded that multiple years of vegetation data is available and will be properly accounted for and that it is recognized that vegetation management is a major cost driver.

Marion Fraser asked if distributed generation is being considered. BG indicated that this will not be considered as the window of data available is too small.

Neil Mather noted that cluster size is part of the existing definition and that boundary issues warrant particular attention. Ted Cowan noted that the econometric study will eliminate border issues with regards to clustering. MV agreed and indicated that the sample areas will not take into account cluster sizes, but rather representative densities. Bill Harper suggested using (binary) flags to represent certain break points in cluster size. He also remarked that this study may not determine if current rate class definitions are appropriate and suggested there may be a continuum of cluster sizes and questioned if there are any reasonable break points. On the issue of the appropriateness or otherwise of the current rate differential, BG described that what is intended is to compare current ratio of costs allocated to different customer classes against comparisons of the cost ratios between high-, medium-, and low-density sample areas. Bill Harper noted that the results may be difficult to interpret because any differences may be the result of density differences or may be simply the way density is defined.

Ted Cowan asked about the number of samples being considered. BG indicated that the econometric study will use all 50 operating areas and that the engineering analysis will select a number of sample areas from operating areas. MV remarked that based on some preliminary analysis, to acquire statistically meaningful results would require about 15 samples for each of high-, medium-, and low-density categories.

Ted asked if both planned and unplanned outages are addressed. BG confirmed that will be the case.

Elena Yampolsky asked if the econometric analysis will be able to use different definitions of density. BG responded yes, and that the study will present the best model (highest statistical significance or minimization of error term) but that the final report will document the other potential cost functions.

2.10 Slide 15

BG reviewed briefly this slide which illustrates HONI operating areas within the province. There were no comments on this slide.

2.11 Slide 16

BG reviewed briefly this slide which illustrates the density (both linear and aerial) diversity of operating areas. Ted Cowan asked if the HONI median value was known, but BG indicated that the median was not illustrated in the chart.

2.12 Slide 17

MV discussed the "bottom-up" approach (the use of unit costs and number of units to build up to a total cost) that was considered, but ultimately excluded from the proposed methodology. MV discussed the "top-down" approach which uses cost categories and assigns these costs to customer groups. To choose customer groups, sample areas will be selected which are representative of high-, medium-, and low-density customers, not necessarily customer groups based on the current rate classifications. Selection of sample areas is facilitated with GIS data. Both OM&A costs and CAPEX will be used in the study. Fixed asset related costs are apportioned based on an asset intensity analysis.

Approximately 80% of HONI's costs will be assigned using a specific factor in the engineering analysis. The remaining 20% of costs are assigned based on ratio of the number of customers.

2.13 Slide 18

MV reviewed the definition of the various assignment factors. Several questions were asked on this slide, primarily to clarify the understanding of the various assignment factors. Laurie McLorg asked for additional detail on how the Asset Intensity Ratio (AIR) is calculated, the use of replacement costs, and the variability of installed costs throughout the province. MV clarified that installed costs do vary geographically and that this data is available and will be taken into account. Bill Harper requested further detail on what the AIR assignment factor is applied to. MV responded that it is used to assign certain CAPEX costs tracked at the operating area level to the sample areas (as is the case with the other assignment factors).

Neil Mather asked for additional detail on the characteristics of sample areas. MV provided a general description of the sample areas (e.g. range of 20-30 square kilometres with consistent density in each sample). MV also indicated that in order to achieve a reasonable confidence, 15 samples in each of the high-, medium-, and low-density categories (45 in total) would be required.

Ted Cowan asked if regression analysis would be used for the engineering analysis. MV clarified that regression will only be used in the econometric study. BG added that the econometric analysis does not incorporate cost data at a level lower than the operating area since a number of assumptions would have to be made to derive much of the data points. BG also noted that the engineering study will go into greater detail than the econometric study by looking at the sample areas within the operating areas. Ted Cowan indicated that he would provide written comments on his thoughts regarding statistical analysis.

2.14 Slide 19

MV discussed the next slide which looks at cost groupings at the provincial and operating area level, and the proposed assignment factors to be used in the engineering analysis. Laurie McLorg noted that PDR and CKM factors take into account distance, but not explicitly travel time. MV noted that travel time is a difficult item to deal with. For example, it is not known if each trouble call requires its own trip from the service center. MV also noted that delays occur even on high speed roads and that weather can reduce the speed of travel. In general, MV indicated that these travel time related factors are likely of second order magnitude relative to distance. Ray Gee expanded on the point and BG said that looking at distance traveled led to non-material changes from the use of "as the crow flies" distance.

Ted Cowan used an analogy of a horse and jockey to explain his thoughts on the importance of management experience at the operating area level and that management experience at the operating areas should be a factor to consider in the econometric analysis. BG indicated that this factor could potentially balance out when looking across all operating areas.

2.15 Slide 20

Elena Yampolsky asked how provincial level costs are apportioned to operating areas. BG noted that these costs are small ($23 million of provincial costs compared to $129 million directly assigned at the operating area level) and will be assigned to operating areas based on customer numbers, area, line km or "expanded" assignment factors. The costs are then allocated to the sample areas based on specific assignment factors.

Ted Cowan asked if line losses should be considered and density weighted. Henry Andre noted that delivery costs and rates are not impacted by losses and as such they are not density weighted. Losses apply to the commodity portion of the bill.

2.16 Slide 21

MV discussed the HONI databases described in this slide. There were no comments on this slide.

2.17 Slide 22

MV discussed the necessary characteristics of selected sample areas. There were no comments on this slide.

2.18 Slide 23

MV and BG elaborated on the abilities of the GIS. There were no comments on this slide.

2.19 Slide 24

MV summarized the two approaches (econometric and engineering) of the engagement. Qualitatively, costs incurred by high-, medium-, and low-density customers will be compared with tariffs based on the current rate classification.

3 Closing Remarks

AP remarked that there was good discussion regarding the study methodology and thanked participants for being engaged and that several good suggestions were heard. He asked all stakeholders if there were any further suggestions and whether the consultants could conclude that stakeholders were comfortable with the proposed methodology. Generally, there were no further comments, except for the following:

Bill Harper confirmed that the methodology is appropriate, but the team needs to be careful in defining the sample areas and work to get the analysis right in order to answer the following questions related to the last two questions on slide 4, namely:

- Whether the existing density-based rate classes and density weighting factor appropriately reflect costs incurred
- The appropriateness and feasibility of establishing alternate customer class definitions or delineation points

Ted Cowan reiterated his view that line losses should be density-weighted. AP remarked that the study needs to deliver on the scope defined by HONI which is based on satisfying the Board direction.

Susan Frank thanked participants for attending the session by taking time from their busy schedule and recognizing the importance of the subject matter discussed today. She commented on the wide ranging discussion but reminded participants that in as much as the comments received are valuable and appreciated, it is not possible to include them all as the scope of the study is limited and that the budget for the study has been set. She indicated that the consultants will weigh the input provided in today's discussion and what can be incorporated within the scope of their engagement.

Stakeholder Consultation

Rate Applications

CDM and Density Cost Allocation Studies in Support of Hydro One Rate Applications

AGENDA
March 22, 2011
Hydro One Networks
Special Event Room, Ground Floor
483 Bay Street, North Tower
8:30 a.m. – 12:30 p.m.

8:15 am Registration and Refreshments		
8:30 am	Introductions and Review Agenda	Enza Cancilla, Manager, Public Affairs, Hydro One Networks
8:35 am	Welcome	Ian Malpass, Director, Regulatory Support, Hydro One Networks
8:40 am	Update on CDM Forecasting and OEB Directive	Stan But, Manager, Economics and Load Forecasting, Hydro One Networks
9:45 am	**BREAK**	
10:00 am	Overview and Update of Density Cost Allocation Study	Andy Poray, Facilitator, PowerNex, Ben Grunfeld, Presenter, London Economics
11:00 am	**BREAK**	
11:05 am	Overview and Update of Density Cost Allocation Study Cont'd	Andy Poray, Facilitator, PowerNex, Ben Grunfeld, Presenter, London Economics and Mark Vainberg, Presenter, PowerNex
12:25 pm	Next Steps and Closing Remarks	Ian Malpass
12:30 pm	**Adjourn**	

Attachment 1 – Participant List

Name	Affiliation
Bond, Reagan	Ontario Power Authority
Butany-DeSouza, Indy	Horizon Utilities
Cowan, Ted	Ontario Federation of Agriculture
Fraser, Marion	Canadian Energy Efficiency Alliance
Grice, Shelley	Association of Major Power Consumers in Ontario
Harper, Bill	Vulnerable Energy Consumers Coalition
Kidane, Bayu	Power Workers' Union
MacIntosh, David	Energy Probe
Mather, Neil	Ontario Energy Board
McGee John	Federation of Ontario Cottagers
McLorg, Laurie	Veridian Connections Inc.
Pasumaty, Dev	Electricity Distributors Association
Silk, Dana	Enviro Centre
Thompson, Peter	Canadian Manufacturers and Exporters
Yampolsky, Elena	Powerstream Inc.
Zajdeman, Marcie	Brookfield Asset Management
Zebrowski, Steve	Veridian Connections Inc.
HYDRO ONE	
Andre, Henry	Hydro One Networks, Inc.
But, Stanley	Hydro One Networks, Inc.
Cancilla, Enza	Hydro One Networks, Inc.
Frank, Susan	Hydro One Networks, Inc.
Gee, Raymond	Hydro One Networks, Inc.
Innis, Ian	Hydro One Networks, Inc.
Li, Clement	Hydro One Networks, Inc.
Malpass, Ian	Hydro One Networks, Inc.
Stadnyk, Alexandra	Hydro One Networks, Inc.
PRESENTERS	
Carew, Steven	London Economics International
Ford, Gary	PowerNex Associates, Inc.
Grunfeld, Ben	London Economics International
Vainberg, Mark	PowerNex Associates, Inc.
Poray, Andy	PowerNex Associates, Inc.

Attachment 2 – LEI/PNXA Presentation

(this page is intentionally left blank)

CDM Study in Support of Hydro One Rate Applications

Stakeholder Consultation

Tuesday, March 22nd, 2011

8:30 am – 9:30 am

Special Events Room, Ground Floor

483 Bay Street, North Tower, Toronto

TABLE OF CONTENTS

1.0 Participant References

STAKEHOLDERS

Raegan Bond—Ontario Power Authority
Indy Butany-DeSouza—Horizon Utilities
Ted Cowan—Ontario Federation of Agriculture
Marion Fraser—Canadian Energy Efficiency Alliance
Shelly Grice—Association of Major Power Consumers in Ontario
Bill Harper—Vulnerable Energy Consumers Coalition
Bayu Kidane—Power Workers' Union
David MacIntosh—Energy Probe
Neil Mather—Ontario Energy Board
John McGee—Federation of Ontario Cottagers
Laurie McLorg—Veridian Connections Inc.
Dev Pasumaty—Electricity Distributors Association
Dana Silk—Enviro Centre
Peter Thompson—Canadian Manufacturers and Exporters
Elena Yampolsky—PowerStream Inc.
Marcie Zajdeman—Brookfield Asset Management
Steve Zebrowski—Veridian Connections Inc.

Hydro One

Henry Andre—Hydro One
Stan But—Hydro One
Enza Cancilla—Hydro One
Susan Frank—Hydro One
Raymond Gee—Hydro One
Ian Innis—Hydro One
Clement Li—Hydro One
Ian Malpass—Hydro One
Alexandra Stadnyk—Hydro One

2.0 Welcome by Hydro One

Ian Malpass welcomed the attendees and advised the purpose of the session was to provide stakeholders with an update on Conservation Demand Management (CDM) and the impact of CDM on the load forecast used in the establishment of transmission and distribution rates.

Ian Malpass asked participants to ask questions and make comments throughout the presentation. He also asked participants to identify themselves when asking questions and indicated that minutes will identify the individual asking questions or making comments.

Ian Malpass and Enza Cancilla reviewed house keeping matters - room and facilities logistics, along with fire, safety and evacuation procedures and meeting etiquette outlined. After a brief review of the Agenda, the participants were asked to introduce themselves and identify the party they represented. The first presenter, Stan But, was introduced.

3.0 CDM Forecasting Initiative Presentation, Stan But, Manager—Economics and Load Forecasting, Hydro One

See attached PowerPoint presentation in appendix A

Stan But reviewed key messages from February 10, 2011 stakeholder session:

- As recommended by stakeholders, a 3rd party study on CDM impacts is not required
- Hydro One will review what CDM categories other utilities in North America are using in their load forecasting process
- Hydro One will work with the OPA to better define and forecast CDM impacts
- Intervenors are interested in more details of CDM impacts on charge determinants in Hydro One's Transmission rate application and CDM impacts on customer rate classes in Hydro One's Distribution rate application

Stan But discussed action plans based on the above key messages:

1. Determine the appropriate CDM categories for use in load forecasting by Hydro One
    - Hydro One will review the CDM categories used by other utilities (based on publicly available regulatory filings)
    - This review will include California, New York, British Columbia and more. Hydro One is part of the Edison Electric Institute ("EEI") and North American Electric Reliability Corporation ("NERC") Load Forecasting group and will plan to survey EEI and NERC forecasting group members

- Hydro One will work with the OPA to better understand the CDM categories they plan to use in the 2011 IPSP
- Hydro One will undertake a survey on CDM categories, including estimation methodology
- Timelines of these action items were presented

2. Prepare bottom-up CDM forecast using available information consistent with the new OPA IPSP to be filed in 2011

   - Hydro One met with the OPA to discuss OEB requirements and intervenor expectations. Hydro One will continue to meet and work with the OPA in the next 2 months to sort out details
   - Hydro One will review historic CDM achieved to date. CDM impact up to 2010 should be available when Hydro One submits its next Distribution Cost of Service rate submission
   - Hydro One will take into consideration OPA, LDC and other CDM categories (e.g. Codes & Standards, Federal & Provincial CDM initiatives) to develop forecast
   - Hydro One will ensure consistency with the new IPSP to be filed in 2011
   - Hydro One will examine CDM impacts by category and by sector (residential, commercial, industrial)
   - Hydro One will align the CDM forecast with the OPA on monthly energy and peak and hourly profile of CDM impacts
   - Timelines of these action items were presented

3. Prepare evidence of CDM impacts on rate classes in future rate applications

   - Hydro One will provide a breakdown of CDM impacts by category and by sector
   - In Hydro One's next Transmission rate application - it will document how Hydro One uses the above information (first bullet) to estimate the charge determinant forecast. The three transmission charge determinants are: i) Network charge, ii) Transformation connection charge and iii) Line connection charge
   - In Hydro One's next Distribution rate application - it will document how Hydro One uses the above information (first bullet) to estimate customer rate class forecast
   - Timelines of these action items were presented

This concluded the formal CDM presentation.

4.0 CDM Forecasting Initiative Presentation - Discussion

Following Hydro One's formal presentation, the floor was opened to a free-flowing question and answer format.

1. Time of Use Impact on Peak Demand

Question from John McGee: *Given the uncertainty of the Time of Use ("TOU") rates, how does Hydro One plan to forecast the impact of TOU rates on peak demand?*

Comment from Stan But: *The ratio between on-peak and off-peak rate is currently set at about 2. Going forward, Hydro One will use the latest and best available information to perform TOU rate impact analysis.*

Comment from Susan Frank: *Susan agreed there will be uncertainty but Hydro One will use best available information to forecast.*

Question from Dana Silk: How do you forecast TOU impact?

Comment from Stan But: *In the past, Hydro One had undertaken a TOU pilot project and estimated TOU impact. Hydro One plans to make use of this information. In addition, Hydro One also plans to get information from the OPA regarding TOU impact (which will be part of the assumption in the OPA's upcoming Integrated Power System Plan ("IPSP").*

Comment from Raegan Bond: *The OPA is currently in the process of revising its estimate on TOU impact for the next IPSP.*

Comment from Ted Cowan: *TOU rates may have a different impact on low income and high income customers. Additional information (such as income level by postal code) could help Hydro One analyse TOU impact on customers with different income levels.*

Comment from Stan But: *Agreed with Ted Cowan's point but stated that Hydro One does not have any reliable information regarding customer's income level and therefore will not be able to perform analysis.*

Comment from Dana Silk: *Agreed that LDC's do not have this kind of data.*

2. CDM Impact Categories

Comment from Bill Harper: *Bill suggested that Hydro One should add a middle column, "Monthly Impact" to the flow chart on page 12 of the presentation – Proposed data collection framework for Tx. This additional column (Monthly Impact) should be between the column - "By Category" and the column – "By Charge Determinant".*

Comment from Stan But: *Agreed.*

Comment from Ted Cowan: *Ted suggested Hydro One to add two sub-classes to the flow chart on page 11 of the presentation – Proposed data collection framework for Dx. Under the column "By Rate Class", two additional sub-classes should be added - i) Farm customers, ii) Customers with Rural Rate Assistance ("RRA").*

Comment from Stan But: Both farm customers and customers with RRA could be identified in *Hydro One's customer information system and therefore potentially we could address Ted's suggestion.*

3. Board-Approved CDM Programs

Question from Bayu Kidane: *Does an LDC need OEB's approval before deploying and implementing Board-Approved CDM Programs? Bayu expressed his concern given that Hydro One had recently withdrawn their Board-Approved CDM program applications.*

Comment from Susan Frank: *Yes. Hydro One and other LDC's do need OEB's approval for Board-Approved CDM Programs. Hydro One's current plan is to reapply for Board-Approved CDM programs later in the year.*

4. General Comments and Conclusion

Question from Ian Malpass: We would like to hear from stakeholders if they think that what Hydro One is proposing is a good approach.

Comment from Bill Harper: *Agreed that what Hydro One is proposing is a good approach.*

Comment from Marion Fraser: *Also agreed that this is a good approach although there are some uncertainties right now.*

Comment from Dana Silk: *The category "Natural CDM" should be expanded to include additional components, such as i) impact of TOU rates, ii) impact of projected electricity rate by sector and by rate class.*

Comment from Ian Malpass: Hydro One will ensure that CDM categories are well defined.

Comment from Marion Fraser: *Interrogatory questions from Green Energy Coalition ("GEC") and corresponding responses from the OPA in the current OPA 2011 Revenue Requirement Submission to the OEB (EB-2010-0279) may contain useful information and suggested Hydro One to look up. Also, the OPA may have information regarding low Income customers but not sure if they will share that with LDCs due to confidentiality issue.*

Comment from Bill Harper: *Don't think they will share with LDCs..*

Question from Peter Thompson: *When does Hydro One plan to file its next Distribution Cost of Service rate application?*

Comment from Susan Frank: *We are in the process of determining the appropriate timing of filing.*

Comment from Ted Cowan: *Weather normalization usually ranges from 2 to 6% and CDM impact is within this range. We need to be careful that impacts from CDM and weather do not get mixed up or overlap.*

Comment from Stan But: *All Hydro One forecasts are weather normalized. Hydro One does not believe this is an issue since our weather correction methodology is proven.*

Comment from Ted Cowan: *Would Hydro One's weather correction take into account the variation of drying load (demand could be quite high) due to a wet/dry season?*

Comment from Stan But: *Hydro One does not believe this is an issue. Our weather correction methodology will take this into consideration.*

5.0 CDM Forecasting Initiative — Conclusion and Next Steps

1) Stakeholders provided valuable suggestions and comments. Hydro One will take all stakeholder input into consideration.

2) In general all Stakeholders were happy with the approach and timeline proposed by Hydro One.

Appendix A

CDM Forecasting Initiative

Presentation on March 22, 2011

CDM Forecasting Initiative

March 22, 2011

Stan But

Manager, Economics &
Load Forecasting

hydro one

Key messages from February10, 2011 stakeholder session

- As recommended by stakeholders, a 3rd party study on CDM impacts is not required
- Hydro One will review what CDM categories other utilities in North America are using in their load forecasting process
- Hydro One will work with the OPA to better define and forecast CDM impacts
- Intervenors are interested in more details of CDM impacts on charge determinants in our TX rate application and CDM impacts on customer rate classes in our DX rate application

Action plans

1. Determine the appropriate CDM categories for use in load forecasting by Hydro One
2. Prepare detailed bottom-up CDM forecast using available information consistent with the new OPA IPSP to be filed in 2011
3. Prepare detailed evidence of CDM impacts on rate classes in future rate applications

Action Plan #1: Determine CDM categories for use by Hydro One

- Hydro One will review the CDM categories used by other utilities
- This review will include California, New York, British Columbia
- Hydro One will work with the OPA to better understand the CDM categories they plan to use in the 2011 IPSP
- Hydro One will undertake a survey on CDM categories, including estimation methodology

Action Plan #1: Schedule

Task	Milestone
2nd stakeholder session	22-Mar-11
Review rate application evidence on CDM from selected utilities	15-Apr-11
Finalize CDM survey questionnaire	15-Apr-11
Tabulate CDM survey results	6-May-11
Document CDM survey results	31-May-11
Assess alignment with OPA's IPSP	June 2011

Action plan #2: Prepare a bottom-up CDM forecast

- Hydro One met with the OPA to discuss OEB requirements and intervenor expectations
- Hydro One will review historic CDM achieved to date
- Hydro One will take into consideration OPA, LDC and other CDM categories to develop forecast

Action plan #2: Prepare a bottom-up CDM forecast

- Hydro One will ensure consistency with the new IPSP to be filed in 2011
- Hydro One will examine detailed CDM impacts by category and by sector (residential, commercial, industrial)
- Hydro One will align the CDM forecast with the OPA on monthly energy and peak and hourly profile of CDM impacts

Action Plan #2: Schedule

Task	Milestone
Meeting with OPA to discuss OEB requirements and intervenor expectations	**11-Mar-11**
Assess CDM impacts by category	**April - June 2011**
Assess all CDM impacts	**30-Jun-11**

Action plan # 3: Provide detailed evidence of CDM impacts in future rate applications

<u>TX rate application</u>

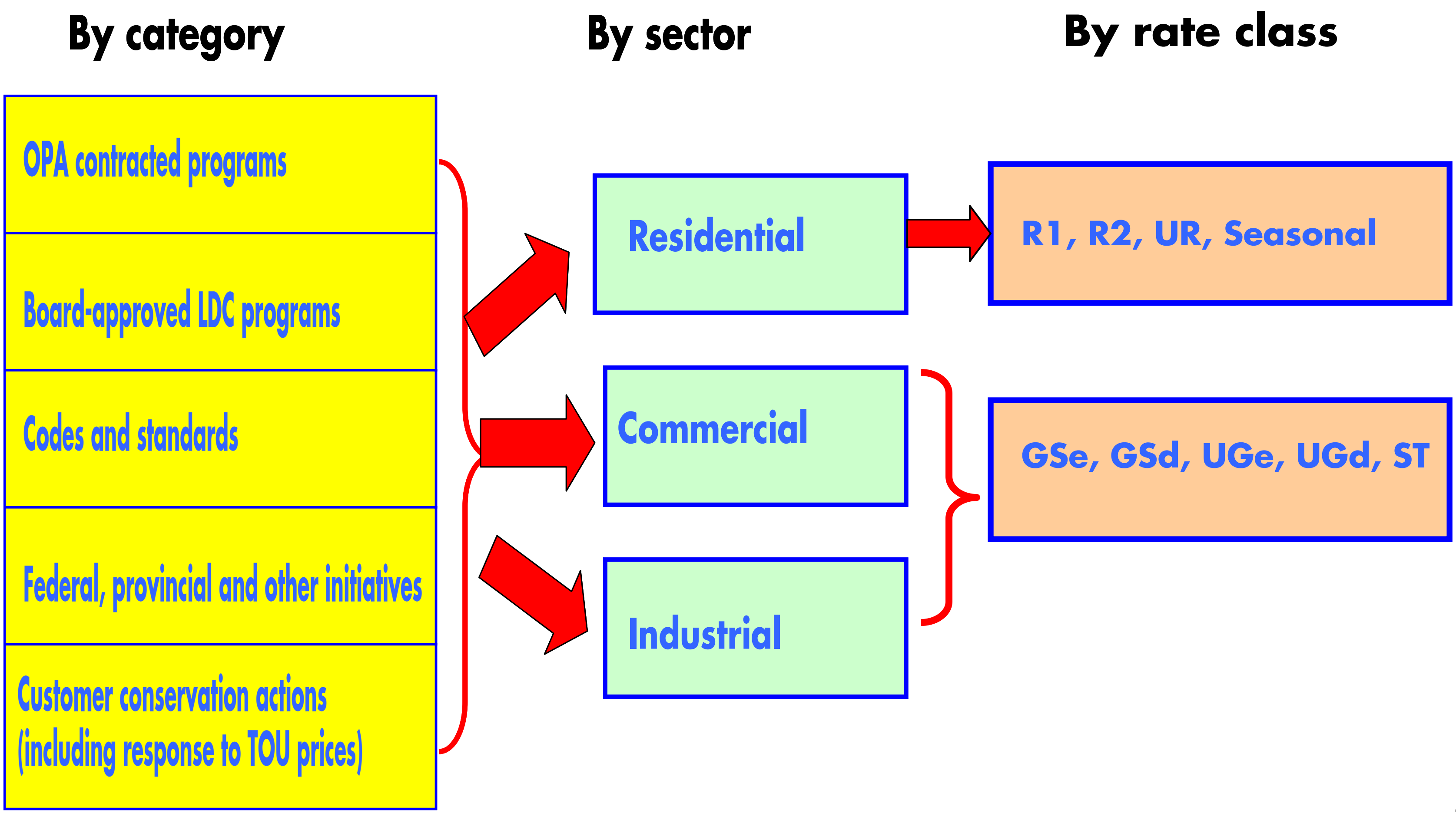
- Hydro One will provide detailed breakdown of CDM impacts by category and by sector
- Hydro One will document how we use the above information to estimate the charge determinant forecast

Action plan # 3: Provide detailed evidence of CDM impacts in future rate applications

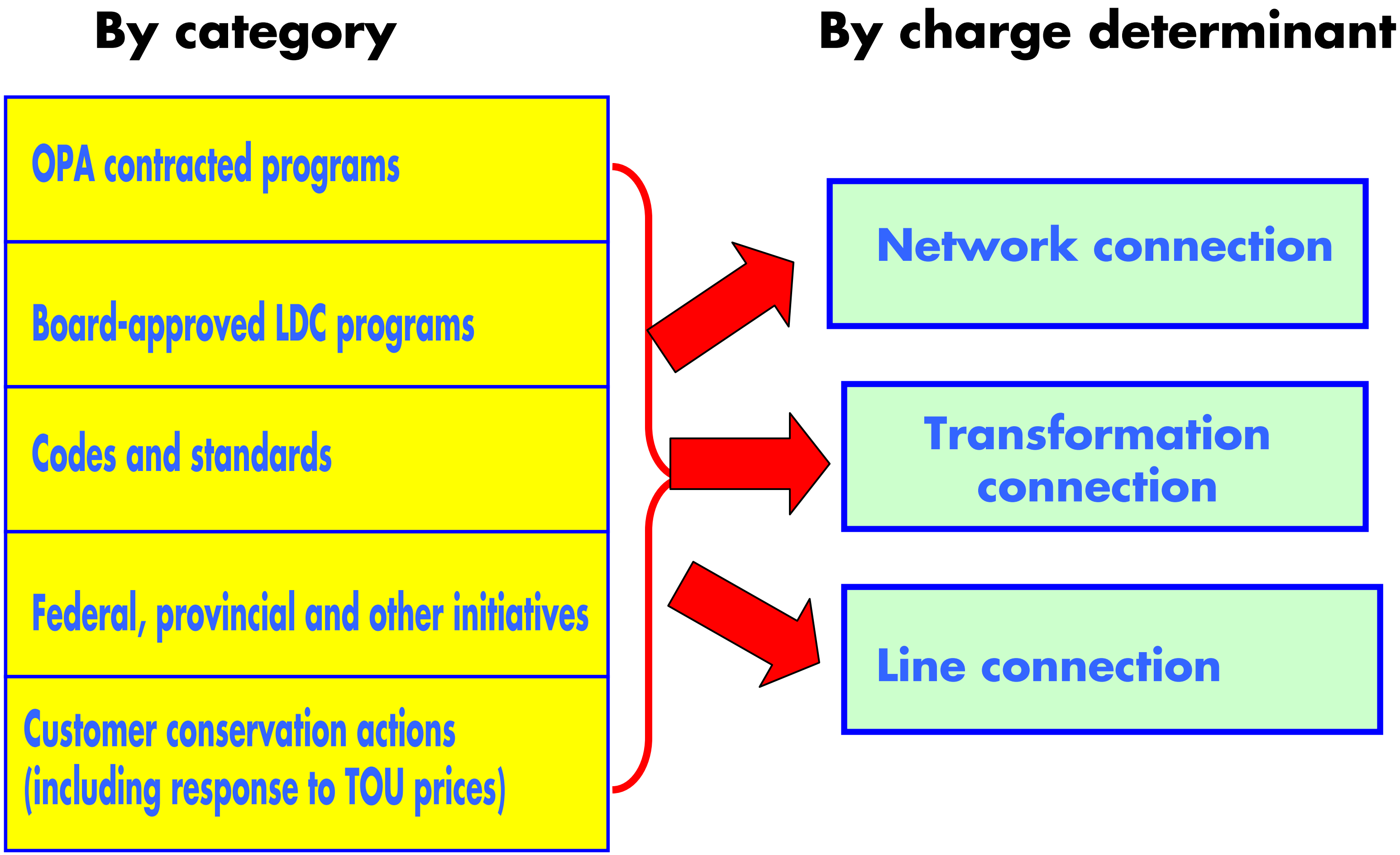
DX rate application

- Hydro One will provide detailed breakdown of CDM impacts by category and by sector
- Hydro One will document how we use the above information to estimate customer rate class forecast

Proposed data collection framework for DX



Proposed data collection framework for TX



Action Plan 3: Schedule

Task	Milestone
Preliminary CDM impacts by customer rate class	**31-Jul-11**
Finalize CDM impacts by customer rate class	**31-Aug-11**

Stakeholder Consultation Notes

CDM, Density Cost Allocation, Compensation Benchmarking and Productivity Studies and Cornerstone Phase 4 CIS Replacement in Support of Hydro One Rate Applications

October 19, 2011
Hydro One Networks
Special Event Room, Ground Floor
483 Bay Street, North Tower
1 p.m. to 5 p.m.

OPTIMUS | SBR
REGULATORY SERVICES

Table of Contents

The presentation materials used in this session and background materials can be found at this link:

http://www.HydroOne.com/RegulatoryAffairs

1. Participants

Stakeholders

- Emerissa Babin – Ontario Power Generation
- Michelle Byck Johnston – Society
- Ted Cowan – Ontario Federation of Agriculture
- Vincent DeRose (Conference Call) – Canadian Manufacturers and Exporters
- Phil Dubeski – Toronto Hydro Electric System
- Julie Girvan – Consumers Council of Canada
- Shelley Grice – Association of Major Power Consumers in Ontario
- Bill Harper – Vulnerable Energy Consumers Coalition
- Bayo Kidane – Power Workers' Union
- David MacIntosh – Energy Probe
- Neil Mather – Ontario Energy Board
- John McGee (Conference Call) – Federation of Ontario Cottagers
- Patrick McMahon (Conference Call) –Union Gas
- David Poch (Conference Call) – Green Energy Coalition
- James Sobota (Conference Call) – Pollution Probe
- Harold Theissen – Ontario Energy Board
- Mark Vainberg – PowerNex
- Steve Zebrowski (Conference Call) – Veridian Connections Inc.

Hydro One

- Carm Altomare – Hydro One
- Henry Andre – Hydro One
- Richard Bertolo – Hydro One
- Allan Cowan – Hydro One
- Susan Frank – Hydro One
- Ellen Holden – Hydro One
- Sabrin Lila – Hydro One
- Ian Malpass – Hydro One
- Keith McDonell – Hydro One
- Tony Miles – Hydro One
- Vicki Power – Hydro One
- Anne-Marie Reilly – Hydro One
- Nikita Sheth – Hydro One

Presenters

- Brad Bowness – Hydro One
- Stan But – Hydro One
- Ben Grunfeld – London Economics
- Mark Hirschey – Oliver Wyman
- Iain Morris – Mercer
  Marvin Reyes – Mercer
- Kristi Robins – Mercer

OPTIMUS | SBR

- Bob Betts – OPTIMUS | SBR
- Tara Murphy – OPTIMUS | SBR
- Miles Smit – OPTIMUS | SBR

2. Welcome by Allan Cowan, Director, Major Applications, Hydro One Networks

START 1:00pm

Allan Cowan welcomed all participants to the Stakeholder Consultation meeting. He outlined the Agenda for the day and listed the topics that would be discussed:

1. Conservation and Demand Management (CDM) Study
2. Density Cost Allocation Study
3. Compensation Benchmarking Study
4. Productivity Measures
5. An update on the CIS Replacement – Phase 4 of the Cornerstone project.

OPTIMUS | SBR will be providing the note-taking and facilitation. Allan introduced Bob Betts as the facilitator and to start the meeting.

3. Opening Remarks by Bob Betts, Facilitator

1:07pm

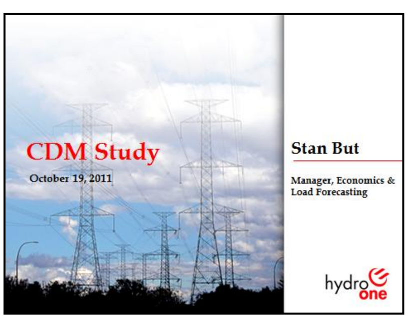
Bob Betts welcomed all participants, and advised that he is facilitating together with OPTIMUS | SBR. Bob introduced the OPTIMUS | SBR team (Tara Murphy and Miles Smit) as note-takers.

Bob began his presentation with several housekeeping items and pointed out the emergency exits. Bob stated that notes will be taken during the meeting and that the meeting and discussions will be recorded. He noted the recordings will be destroyed once the notes are produced. Any comments made will be attributed to the individual and the party they represent. Participants were instructed if they want comments to be off the record to advise beforehand.

Bob asked all attendees to introduce themselves, stating name and company for the record. He reviewed the agenda, asked for phones to be turned off and mentioned that questions are welcome as they arise. The presentations and notes generated will be published on the Hydro One website.

CDM Study, Stan But, Manager, Economics and Load Forecasting, Hydro One Networks

1:15pm



View or download a copy of the CDM Study Presentation

Stan But began his presentation with an explanation of why the CDM study was undertaken. The CDM study was directed by the Ontario Energy Board (OEB), which requested more details about the CDM analysis and particularly credible load forecasts and greater accuracy than has previously been available. The Board accepted Hydro One's CDM estimates used in load forecast, but directed Hydro One to work with the Ontario Power Authority (OPA) to devise a robust, effective and accurate means of measuring expected impacts of CDM programs. Stan reviewed the recommendations made by stakeholders in the February 2011 and March 2011 consultations:

1. Conduct the CDM study in-house;
2. Review the CDM categories and methodologies used to incorporate CDM impacts into load forecasts by utilities in other jurisdictions;
3. Comprehensive CDM categories that are trackable;
4. Work closely with the OPA to better define and measure CDM impacts for use in load forecasting;
5. Present CDM impacts by sector and customer rate class.

Stan But stated that Hydro One had acknowledged and addressed each of these recommendations.

The study had two main objectives. The first was to develop a robust methodology to forecast CDM impacts and the second was to develop a methodology to incorporate the CDM impacts into Hydro One's load forecast.

The study findings included a Literature Review involving British Columbia, New York, California (as per stakeholder recommendation) and other major utilities in North America with CDM experience. Web-search and personal communication were used to gather data. Hydro One did a comparison study of load forecast methodologies commonly used by other utilities that incorporate CDM impacts into their forecasts. Finally Hydro One has been in close communication with OPA staff over the last 6 months to incorporate this information into CDM estimates.

A Load Forecast Survey was sent to approximately 100 organizations in North America, and 41 responses were received. The Literature Review and Survey provided a roster of well-defined and comprehensive CDM categories:

- Programs initiated by the utility;
- Programs initiated by other organizations;
- Building codes and standards;
- Rate structures;
- Increased conservation effect.

The Load Forecast Survey identified three commonly used models to incorporate CDM impacts in load forecasting.

- Method 1 forecasts using the actual load (without CDM adjustments);
- Method 2 forecasts CDM impacts as a variable on the right-hand side of the econometric equation;
- Method 3 adds historical CDM impacts to the actual load and forecasts forward.

Hydro One reviewed the advantages and challenges associated with each method. On the basis of the review results, Hydro One has adopted Method 3.

Susan Frank asked which method the OPA uses. Stan replied that the OPA also uses Method 3.

Ted Cowan asked for clarification on the main differences with respect to weaknesses in Methods 2 and 3. Ted suggested Method 2 regresses data weakly and Method 3 might contain errors in the CDM data. Stan clarified that both Methods 2 and 3 require CDM estimates for the history, so the same CDM data is used in each Method. Method 2 has a potential to create bias in the forecast because of collinearity issues. Method 3 adds the CDM impact to the actual load, which avoids multiplying any such collinearity issues.

Ted agreed that Method 3 addresses the issue of including CDM impact, but posited that they are still embedded in the initial regression estimates you are subtracting from. He asked if it was correct to say that all of the Methods have some weaknesses, but in Method 3 the weakness is confined to the CDM data. Stan clarified that the same CDM data is used in both models, but the data is used differently to achieve unbiased coefficients in Method 3. Ted responded that Method 2 and 3 do not differ substantially with respect to error.

Stan acknowledged that there are pros and cons for each method. Methods 1 and 2 are not invalid or incorrect, but they have characteristics that make them less suitable for Hydro One's specific requirements.

Ted Cowan asked for Stan's intuitive relative assessment of the merits of the three methods. Stan replied that Hydro One has determined that in light of the Board's request for a robust, accurate model, Method 3 is the most appropriate choice.

Ted inquired about the experience Hydro One has using Method 3. Stan replied that Hydro One has effectively been using Method 3 for a number of years and is comfortable with its performance.

Stan proceeded to review the study findings. He identified that the categories in the Hydro One CDM forecast that are aligned with the OPA Policy Instruments referring to Slide 10 of his presentation:

- Programs, further broken down in Hydro One's forecast into Hydro One/OPA programs, and other influences;
- Codes & Standards;
- Rate Structure.

Hydro One uses a number of methods and models to track customer actions. Accordingly, Hydro One has deployed an additional category called the Increased Conservation Effect. This was defined as customer behaviour to conserve energy that is not influenced by Hydro One, OPA, and other non-government programs.

Ted Cowan asked, regarding rate structure, whether separate analysis is conducted for customers that are demand billed versus customers that are volumetrically billed. He suggested there is a larger price effect for those who are demand billed.

Stan replied that for rate structure Hydro One uses CDM impact data from the OPA, and assumes that it covers all customer data. Ted agreed that all customers are considered, but asked whether demand- and volumetrically-billed customers are distinctly identified in the data. He asked specifically about the possible case of a farmer on demand billing, who conserves more than a farmer on volumetric billing.

Stan said that the impact is accounted for in each billing scenario. Ted inquired whether it is possible to tell the two billing methods apart, because there is a difference in savings for each billing type. Stan did not believe that the data from the OPA breaks the information down by rate class. Ted suggested that the savings differences by volumetric versus demand rate classes should be identified in the data.

John McGee asked whether Hydro One had any figures on the demand reduction from the Smart Meter program. Stan replied that for 2013 the Smart Meter (Time of Use) impact for all Hydro One customers was approximately 20 megawatts.

Bill Harper sought clarification on the definition of the term “Increased Conservation Effect” used by Hydro One. He asked whether the Increased Conservation Effect was equivalent to, or aligned with, the OPA’s definition of Natural Conservation. Stan replied that they are not the same effect. Hydro One’s definition of the Increased Conservation Effect is any non-program savings above or beyond Natural Conservation.

Bill observed that electricity rates are increasing by 10% and inflation is up 2%. He wondered whether the Increased Conservation Effect could be a response to customer awareness of higher bills. Stan replied that the Increased Conservation Effect does not capture increases due to inflation. Inflation and increases in price are captured in Natural Conservation. Historically, electricity prices trend upward, and a conservation response is expected without additional interventions.

Bill used a potential example to highlight his point: a customer who looks at an energy-efficient product (without a program coupon) and wants to be environmentally conscious is counted in the Increased Conservation Effect if he purchases the product. Alternatively, if the customer chooses to buy the product because of his increased electricity bill it is considered Natural Conservation. Bill suggested that the process to determine whether conservation is increased or natural is unclear, given the definition of the Increased Conservation Effect.

Stan But proceeded to describe the steps taken to understand and align with the savings assumptions used in the OPA’s current conservation forecast.

The preliminary CDM impacts for 2011-2013 shown on his Slide 12 include the following categories:

- Impacts of Hydro One and OPA Programs;
- Other Influences;
- Codes and Standards.

Each of these categories is expected to drive increased energy savings over time. Stan did not present data for Rate Structure impacts on energy because the Rate Structure data from the OPA only includes Peak Savings while his Slide focused on energy savings. The fifth category, Increased Conservation Effects was based on data from 2010 actual, forecasting no increase in this category 2011 to 2013.

Stan indicated that the flat-line Increased Conservation Effect forecast was a conservative stop-gap, and Hydro One will need the actual 2011 data to make accurate forecasts beyond 2010.

Bill Harper asked for clarification on the forecasted data. He asked whether the forecast for 2013 was based on impacts from 2013 only or if it was the cumulative impact of programs implemented in 2011, 2012 and 2013. Stan clarified that the forecasted data represents the cumulative impact for that year. Therefore the difference between two years is the incremental change from year to year.

Susan Frank asked for an explanation of how the forecasts for Increased Conservation Effect were calculated. Stan replied that multiple analyses were used to determine the forecasted impact of Increased Conservation Effect. The first was using the hourly load of Hydro One in 2002-2010 to run econometric analysis. The impact of economy and weather were removed and the remaining impact was the total impact attributed to the CDM.

In addition to the econometric analysis, the customer information system was utilized. In this approach the annual energy consumption for over 500,000 residential customers with consistent information was analyzed. The result of this method showed consistent savings with the econometric approach. The final method was using tracking surveys where customers listed their own actions towards conservation and actions driven by programs. This information confirmed that there is an Increased Conservation Impact from the customer.

Julie Girvan questioned the validity of using customer surveys to calculate the increased conservation impact. Stan explained that the large survey (approximately 6000 customers) results were not used in the calculation, but rather to confirm the econometric results.

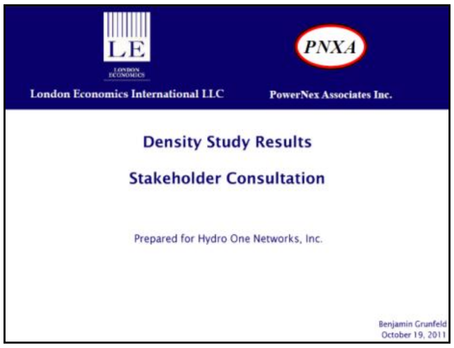
Stan provided a summary of the CDM impact study and indicated that the study was nearing completion, incorporating stakeholders' recommendations and meeting the Board's Directive.

Susan Frank added that the OPA did not evaluate the impact of the Increased Conservation Effect and asked whether other organizations are using this category. Stan replied that the results of a web survey showed that 1 in 5 utilities in the survey use a category that captures Increased Conservation Impact. He mentioned that the state of California is making a major effort to monitor customer behaviour, actions and savings associated with market transformation. This is an emerging issue that is being studied in other organizations.

Julie Girvan asked if the Green Energy Benefit (a 10% discount) would cause customers to reduce conservation efforts. Stan replied that the 10% reduction in the customer's bills is a new feature that was not captured in the analysis. Ben Grunfeld, of London Economics stated that the Green Energy Benefit came out around the same time as HST, which increased customer bills. Therefore from an incremental impact on customer bills the HST likely neutralizes the Green Energy Benefit reduction for the next 3 to 5 years.

4. Density Cost Allocation Study, Ben Grunfeld, London Economics

2:05pm



View or download a copy of the Density Cost Allocation Study Presentation

Ben reviewed the mandate given to London Economics and PNXA to evaluate the relationship between customer density and distribution service costs. He outlined that the study was initiated in response to a request from the OEB. The study also assessed whether the existing density-based rate classes and density weighting factors appropriately reflect this relationship. A third object was to consider the appropriateness and feasibility of establishing alternate customer class definitions. The third objective, while covered in the report would not be discussed to a large degree in this afternoon's presentation.

Referring to his Slide 5, a two phased approach was used to perform the study, with the first phase being the Methodology Development and the second and current phase Methodology Implementation. The methodology consisted of two complementary analyses: Econometric study of the operating areas, and Direct Cost Assignment of smaller sample areas. Both analyses considered operating, maintenance and administrative costs and proxies for capital costs.

Julie Girvan asked for the definition of an operating area. Ben explained that an operating area is a geographic area within the province. Each operating area has service centres used to respond to customer calls, manage maintenance, operating programs and capital programs for that area. Julie asked whether the operating areas are the areas listed on the Hydro One website during an outage. Ben confirmed this is correct.

Ben continued with an outline of the econometric methodology. Using his Slide 6, he explained that the functional form of the econometric model was chosen based on theory and prior experience and pointed out that this is the form used by the OEB. The equation takes into account that an increase in customers from 5 to 500 for a given area equals an increase in cost that is not uniform. Determining the cost function was an iterative process, where a number of different specifications were tested. The five independent variables included in the final model were:

1. Customer Density (stakeholder recommendation);
2. Number of customers;
3. The square of the number of customers
4. Energy density;
5. A time or trend variable.

Ben explained that a representative cross section of sample areas was selected. A total of 11 operating areas were utilized for the direct cost assignment. The study included 62 samples areas, 24 low-density, 22 medium-density and 16 high-density from the 11 operating areas. The sample area selection guidelines included:

- Similar areas, approximately 20 km^2;

- 100 – 200 customers for low density;
- 700 – 1200 customers for medium density; and
- Over 2000 customers for high density.

Ben indicated that the costs were directly assigned to the individual sample areas. These cost groups include:

- Lines and Stations (operations, maintenance and administrative costs);
- Vegetation Management;
- Asset Intensity (representing capital costs in the ground).

Julie asked about other assets not in the ground, specifically the cost of trucks. Ben stated that fixed capital costs are not dealt with in this direct cost assignment study, but maintenance costs for assets such as trucks would be included in maintenance costs for the sample area. Ben stated that the proportion of Hydro One assets reflected by vehicles is small compared to other assets in the ground.

Henry Andre confirmed that the costs associated with trucks and other vehicles are included in maintenance costs. He continued with an example, stating pole replacement costs include the cost of equipment required to replace the pole. Maintenance costs include labour and equipment.

Bill Harper asked if lines and stations administrative and maintenance costs were combined, given that distance is important for lines and not important for stations. Ben Grunfeld replied that they are dealt with separately. He added that station costs were allocated based on the number of distribution stations within an operating area and the way they are used to serve load in the sample areas.

Ben introduced the results portion of his presentation and asked for questions before he continued.

Julie asked if the approach that Ben is undertaking has been used in other jurisdictions. Ben replied that based on the research there are no jurisdictions that have yet used this level of detail to analyze the effects of customer density. He added that he has seen econometric models to predict utility costs that incorporate customer density, as considerations. The OEB cost allocation model uses a number of allocation factors to distribute cost to classes of customers. [This general approach, of allocating costs based on factors, is similar to the one used in the direct cost assignment analysis. However, the direct cost assignment analysis looked at smaller samples of customers that vary with respect to density, as opposed to a complete class - Note this clarification is subsequent to the session.] Ben reiterated that the specific approach of looking at customer density is a unique feature.

Ben continued with the results, stating that the econometric analysis indicates a negative or inverse relationship between cost and customer density. Four distinct models were analyzed, and all showed a negative relationship:

1. OM&A (operations, maintenance and administration) using circuit km.
2. OM&A using sq. km.
3. OM&A and a capital proxy using circuit km.
4. OM&A and a capital proxy using sq. km.

Bill asked for clarification about the final bullet point on Slide 12 suggesting that it should say that according to the fourth model, a fivefold increase in customer density should correlate to a 150 percent decrease in cost per customer. Ben confirmed this is correct.

Julie asked if Ben was referring to cost per customer. Ben replied that it is the measure of total cost. He stated that the number of customers is included in the econometric model so they normalized for scale already. He explained with an example, where if the number of customers stayed the same, but the density increased there would be a decrease in cost.

Ted Cowan sought to clarify Ben's example, asking if, in the hypothetical case of two different 20km^2 areas, one with 200 customers and one with 1000 (i.e., a fivefold difference in density) the one with 200 customers would see a 50% decrease in cost.

Ben replied that the relationship depends on the number of customers being constant. Ben used an example of a 20km^2 area and a 4km^2 area with the same number of customers. In that case, the cost would be different: it would cost 50% more for the less dense area. This is the conclusion from the econometric model, and is also consistent with direct cost assignment approach.

Ben elaborated other results, indicating that the individual sample area results revealed a sharp decline in cost per customer as density increases.

Ted asked whether most of the variation is found in areas under 100 customers per km^2 and whether most of the variation within that range is under 20 customers per km^2. This would mean that most of the variation is in low and very low density. Ben replied that Ted's interpretation was correct.

Bill asked how a density of 100 customers per km^2 would translate into customers per line km. Ben answered that in Hydro One's rate class definition, a cluster of 100 customers and 20 customers per line km. Subsequent to the session Henry Andre confirmed that the definition is based on 15 customers per line km.

Ben stated that the sample mean averages in the study were distinct, and confirmed the negative relationship. He concluded that the two independent analyses confirm that the average cost to serve Hydro One customers increases as the customer density decreases with 99% statistical confidence.

Bill asked if graphs were created for customer per km of line. Ben answered that those graphs were generated and that they could be found in the final report.

Beginning to address the second study objective whether the existing density-based rate classes and density weighting factors appropriately reflect this relationship, Ben discussed customer density as a differentiator on his Slide 15.

He noted four elements of Hydro One's existing rate class structure to consider:

1. Type of rate classes;
2. Number of rate classes;
3. Demarcation points;
4. The cost of allocation factors.

The first significant point he made was that from a rate making perspective, based on “cost causality”, it is reasonable to differentiate between customer classes by customer density.

The results also support having different classes, two general service customer classes makes sense, given a much smaller number of customers. There was no strong evidence to support a change in demarcation points.

Vince DeRose asked whether the report would look at municipal or regional boundaries. Ben answered that the report will look at both and the pros and cons associated with each approach.

Julie Girvan asked how Hydro One currently demarcates the rate classes. Ben answered that an urban rate (UR) class is an area that has 3000 customers total and has a line density of more than 60. The Medium density grouping applies to residential (R1 and R2) and has over 100 customers and a line density of 15, the Low density for residential is the remainder. For general service, there is a distinction between urban and non-urban customers.

Ben explained that the last objective was to consider cost allocation factors, of which there are two elements: non-density factors and the density-weighting factors. The study compared the overall results of the cost allocation model to the direct cost assignment analysis. The concern was with the ratio of per customer assigned costs, not the total magnitude. Ben concluded that the existing allocation may not capture the actual differences between the mean costs of serving year-round residential customers in areas with varying customer densities.

Slide 17 of the presentation package showed the comparison between the allocation factors for Hydro One’s current UR, R1 and R2 classes, 1.0, 1.6 and 1.7 respectively and the allocation factors resulting from the study for HD, MD and LD, 1.0, 1.7 and 3.8 respectively. While the relative comparison did reflect a higher cost per customer in a low density area versus a higher density area, it indicated that the higher costs are not being fully allocated.

The study further found that:

- The average customer density of the Seasonal rate class falls between that of the R1 and R2 classes;
- The average customer density of the urban GS classes, UGe and UGd, is similar to that of the UR class; and
- The average customer density of the non-urban GS classes, GSe and GSd, falls between that of the R1 and R2 classes.

Ben reviewed the three study objectives. He concluded that two independent analyses demonstrated that there is a statistically significant negative or inverse relationship between customer density and costs. The study demonstrated that cost to serve customers of different densities is different, supporting the use of density-differentiated rate classes.

Existing allocation and weighting factors may not capture the magnitude of the difference in costs to serve customers of varying density. The report addressed alternative customer class definitions, including structures based on municipal boundaries or regional rates. Ben concluded that a move to such a design is a long-term decision that should be considered in the context of a broader provincial dialogue that looks at rate design across all of the LDCs. Overall, the study's objectives have been accomplished.

Julie asked for a restatement of the conclusion for seasonal classes. Ben replied that the costs currently assigned to seasonal customers is 1.5 times the per customer cost assignment of urban class, this is in line with R1. The average density for seasonal customers is between the R1 and R2 rate classes, this indicates under representation of the costs to serve those customers. A similar conclusion applies for the non-urban general service classes.

Susan Frank pointed out that the results of this extremely comprehensive and expensive study cannot be ignored when it comes to rate design. Susan asked Henry Andre how Hydro One would implement the impact of the study.

Henry replied that the results of the study were very compelling. Some changes to Hydro One's cost allocation and rate design to incorporate the study are warranted, and Hydro One expects to respond appropriately.

The extent of the impact on cost allocation and rate design is dependent on how the results are used within the cost allocation model. Hydro One has not explored this in detail, but they did look at the last cost allocation model that was filed with the 2008 Distribution Application. Based on that model and trying to incorporate the findings of the 2011 study, there could be an approximate decrease of 10-15% in UR rates, and a potential approximate increase of 2-3% for the R2 rate classes.

The increase in R2 rates matching the decrease in UR is less because the volume of revenue collected from the R2 class is significantly more. In terms of delivery rates, delivery is approximately 1/3 of the transmission bill, so one could divide the estimated increase/decrease by 3 in terms of overall bill impacts. These are mere approximations because Hydro One has not utilized the new cost allocation model for the upcoming application. The findings are based on the previous cost allocation.

Julie Girvan asked how the study might help Hydro One rethink the seasonal rate design. Julie stated that she would like Hydro One to be more proactive on the issues involving seasonal rate design. Henry Andre replied that in terms of cost allocation, the study suggests that the cost of serving seasonal customers as a class (made up of low density and higher density area customers), would likely fall between R1 and R2. The current cost allocation model is pinning them at the R1 level (Subsequent to the meeting Hydro One clarified "pinning them at the R1 level" reflects that under the current cost allocation model the total costs per customer allocated to the Seasonal and R1 rate classes are about the same).

Henry stated that he took the point about issues with seasonal rate design. He continued that Hydro One could look at shift between fixed and variable costs, a concern raised by some seasonal customers. The study suggests that the cost to serve seasonal customers is higher because they are made up of medium- and low-density (corrected subsequent to the meeting from high-density) areas.

Bill Harper asked if Hydro One should alter the definition of the class or if they should change the way density is considered in the cost allocation model. Bill noted that the study suggested a change in allocation factors rather than changing the class definitions. Bill asked if Hydro One is considering choosing a different allocation factor other than customer per km to weigh customers by class.

Henry replied that Bill was correct. There is no current plan to change the definition of the rate classes. Hydro One does plan to look at the cost allocation model to consider whether the density weightings need to be changed. He raised the question of whether something else needs to be done at the bottom line to shift costs.

Bill asked if Hydro One was considering a new parameter for the model. Bill noted that changing the bottom line outcome of the model would be a new approach to cost allocation overall.

Henry clarified that his preference would be use the current approach, but the study suggests there is not enough differentiation between the weighting factors. The differentiation between the weighting factors would need to be increased so that more is allocated to the R2 class versus the UR class.

Bill observed that the study analysis assumes relationships between costs and density. He noted that the differences in the end are a function of what allocation factors were used in the analysis and stated that the differences need to be reflected in the Hydro One model. Henry agreed.

Ted Cowan mentioned that the general service class is the life-blood of the economy in rural Ontario. He asked if there would be any changes to their rates based on the results of this study. Henry replied that the ratios for the general service class were not covered in Ben's presentation, but they will be included in the final report. He noted that if the general service class is a blend of R1 and R2 then there might be some adjustments made. Ted asked if this would likely mean a 2% adjustment. Henry replied that he has not made any calculations on the general service class and so could not speculate, but there would be a higher differential based on the results.

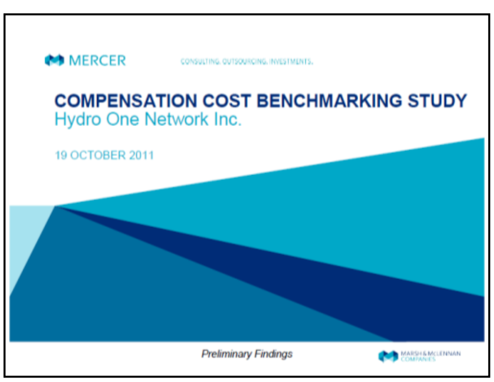
Julie asked when Hydro One was planning to file the Distribution Rate Case. Susan Frank replied that the original filing date was after the November Board Meeting, but the filing would be delayed until the shareholder could review it, including the new Minister.

The filling date will likely be early 2012, after the budget is reviewed by the shareholder.

Vince asked if that meant the Distribution Rate and Transmission Cases would be occurring simultaneously. Susan replied that this is a likely possibility.

5. Compensation Benchmarking Study, Iain Morris, Mercer

3:27pm



View or download a copy of the [Compensation Cost Benchmarking Study Presentation]

Iain Morris began by discussing the input from the May 2011 Stakeholder consultation. He stated that consideration was given to all Stakeholder requests, but not all could be met in professional opinion of the consultant. For example, Mercer did include a comparison to market average compensation.

Iain described how benchmark positions were determined and listed the positions used. He noted two differences between the previous study and this one resulting from insufficient available data to benchmark the Field Service Coordinator and the Tree Trimmer positions. In the case of Tree Trimmers, this position is most likely been contracted out at other utilities, and the Field Service Coordinator responsibilities were generally distributed throughout other job classes.

Mercer's experience also suggests that there needs to be a balance in the number of benchmark positions to use because often survey participants will avoid surveys that involve too many benchmark jobs; the 34 they chose is a reasonable balance. He reviewed the chosen jobs in the three Groups, Non-Represented, Professionals and Power Workers contained on Slide 5 of his presentation. He indicated that these jobs collectively represent approximately 3300 employees, or approximately 49% of Hydro One's workforce. In Mercer's opinion this is a representative sample size.

Iain described the process for determining the peer group. A similar approach to the 2008 study was taken. The process met the key objective of creating a single peer group to assess total compensation costs for the entire set of benchmark jobs. The list of peer groups was provided on Slide 7, and Iain noted that because some organizations such as Bruce Power and Bell Canada opted out of the study in 2011 and while others were added, this would generally be expected to result in an overall lower survey group benchmark in the marketplace than the 2008 study.

Iain gave a description of elements included in Total Compensation which are the same as 2008. It focuses on items that can be monetized including:

- base wages or salaries;
- short-term incentives;
- long-term incentives;
- insured benefits;
- retirement plans.

Definitions and methodology for determining total compensation were discussed and outlined on Slides 9 &10. Slide 10 provided the definitions of average and P50 (the 50th percentile). Mercer took this opportunity to once again state their reasoning for relying on the P50 or the middle point in a distribution of data rather than the average, including its representation of the compensation paid by the employer in the middle of the group and its stability coming from ignoring occasional skewing associated with extremely high and extremely low compensation circumstances of some survey participants. However, as requested by some stakeholders, Mercer has provided comparisons on the market mean in addition to the market median.

Iain reviewed the preliminary results in Slides 11 to 17. He compared the Hydro One median to the Market median changes from 2008 to 2011. Overall, there has been a decrease in Hydro One's total compensation from 2008, but total compensation remains above the Market median on a weighted average basis. Iain noted that wage and salary freezes and turnover costs affect total compensation; and further that many organizations in the study have also been attempting to reduce compensation costs just as Hydro One has. Iain explained that as a result of these efforts to reduce labour costs (in addition to the lower survey group benchmark noted earlier), the market median is effectively lower in 2011 than it would have been in 2008; but despite this lower market median, Hydro One has been more effective in reducing its relative compensation costs and has moved closer to the market median in 2011. He also explained that greater variation between 2008 and 2011 may be driven by low job incumbency and high turnover, where a more junior staff replaces a higher paid senior staff that retired.

Michelle Byck-Johnston asked for a definition of the Engineer F position. Keith McDonnell responded that it is a management-level compensation job (typically a band 7, and may contain some band 6 positions). Iain added that Engineers A to F are generic titles that line up with the Professional Engineers Ontario (PEO) categories.

Shelley Grice asked about the “not applicable sign” beside positions such as Senior Legal Counsel and Area Superintendent. Iain replied that the not applicable sign denotes that insufficient data exists, for example when a statistically significant sample is not available. In the case of Senior Legal Counsel, Area Superintendent, Business Analyst A, Electrical Apprentice and Lines Apprentice, “not applicable” is indicated because these jobs were not included in the 2008 study.

Bill Harper asked for clarification on the weighted averages. He asked if the 2008 weighted average was based on the incumbents in 2008 or those in 2011. Iain replied that the 2008 weighted average was based on incumbents in 2008. Bill asked what the effect of positions that had insufficient data in either year had on the weighted averages. Iain replied that overall the effect was insignificant.

Iain presented the comparison of overall - total compensation averages on Slide 17 as was requested by some stakeholders. He stated that the results did not differ greatly from the overall total compensation median results found on Slide 11. The only strong difference was in the Power Workers category.

Bill asked why the average compensation was not listed for 2008. Iain replied that the average was not calculated in 2008.

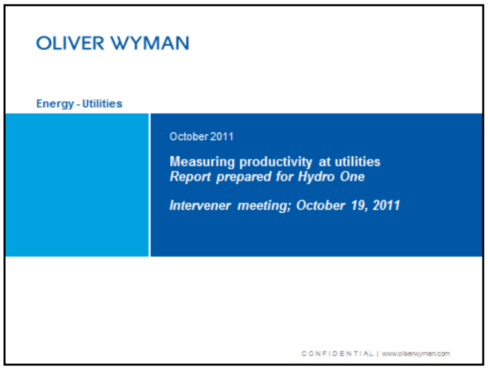
Iain concluded that overall the Hydro One relative position is still above market, but its efforts at controlling compensation costs have been effective and Hydro One has moved closer to market median since the 2008 study.

Ted Cowan asked if there was a comparison for turnover rates. He also asked for information on productivity, asserting that one needs to analyze what is produced to determine value of the compensation package.

Iain replied that he could not comment on turnover as it was not part of the study and was not a metric used in the past. Iain further stated that productivity was also not a factor in the study and mentioned that Mark Hirschey would discuss productivity in his presentation.

Productivity Study, Mark Hirschey, Oliver Wyman

4:05pm



View or download a copy of the Productivity Study Presentation

Mark began by stating that the 2008 Productivity study made reference to compensation and could be consulted to answer at least in part Ted Cowan's question about mapping to compensation.

Mark provided the background to the study, explaining that the Board had requested Hydro One to provide more robust evidence on initiatives to achieve a level of cost per employee closer to market value at its next transmission rate hearing. He noted that the Board will expect any compensation increases to be matched with demonstrated productivity gains.

Mark outlined the approach on his Slide 3, where internal and external research was conducted to build a set of recommendations around how Hydro One could measure productivity. He explained the research, recommendation and implementation processes. The results of the study suggest a number of metrics as candidates to measure productivity.

The primary research used US and Canadian regulators. The majority of regulators examined measured total costs and service quality metrics instead of productivity metrics. In fact, no commission or regulator was found to routinely measure productivity directly.

A survey of utilities' productivity was administered to understand which metrics could be collected internally. The list of survey recipients and respondents was presented on Slide 8. The findings from the productivity survey noted a wide disparity in internal performance measurement. Common metrics for cost, productivity and service quality were collected if measured by at least two utilities. The criteria for choosing a set of metrics was highly dependent on the individual business needs.

Moving to his Slide 15 he focused on the process of selecting appropriate metrics to be used. The first step to determining the area to measure was understanding the breakdown of spend on resources (principally being labour), included in transmission and distribution capital and operations, administrative and maintenance costs. In Slide 16, Mark gave examples including distribution operations, maintenance and administrative project metrics. The eight largest distribution projects had suitable metrics to measure. Most metrics were inconsistent over time and could not be measured.

Ted Cowan stated that he had trouble accepting the inconsistencies attributed to trouble calls over time. He suggested that each trouble call is distinct, but at the end of each year they could be useful as aggregated information and compared from year to year. He used an example of unique ER visits at a hospital, which provide cumulative metrics that can be measured.

Mark granted that Ted's comment was correct, when looking at trouble calls over a multi-annual basis, since weather added a large variability from year to year. Ted noted that there are other examples of projects that can be measured over 5 years. Mark replied that it is difficult to utilize the results on an assessment made every 5 years. Mark acknowledged that further study could possibly establish some consistencies in multi-year trouble call data to allow that to be used in some way as a productivity metric.

Slide 17 listed the twenty-five productivity metrics that have been recommended and which account for approximately 22% of the total project costs. Unfortunately, the last quarter of these metrics reflect no more than 0.2% of Total Costs individually, but they are all associated with discrete units of work that can be measured.

Michelle Byck Johnston noted that there were two metrics titled "Cost per km of line cleared", and asked for clarification regarding their differences. Mark explained that one referred to line clearing in transmission new-build projects and the other in distribution maintenance.

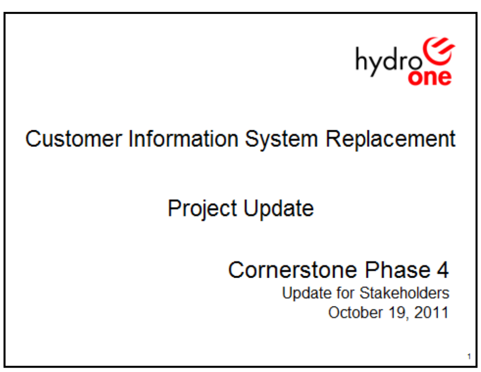
The idea was for Hydro One to choose a set of metrics that could be measured and managed over a shorter time period to begin to effect positive changes. Hydro One will require a detailed plan to develop a set of productivity metrics that are integrated and aligned with the overall corporate scorecard and direction.

Julie Girvan asked if the metrics were strictly field-related, because administration work is contracted out.

Mark replied that the metrics have fully-loaded overhead costs showing savings in overhead over time. Julie asked why there were no service quality indicators or typical customer service measures in the metrics. Mark replied that the customer service measures are associated with a contracted work force; Hydro One's work force aligns with field service measures.

6. Cornerstone Phase 4 CIS Replacement, Brad Bowness, Hydro One

4:37pm



View or download a copy of the Cornerstone Phase 4 CIS Replacement Presentation

Brad Bowness began with a status update, confirming that the CIS project is nearing the end of the Blueprint phase. The project schedule is on track to the baseline plan and the targeted "Go Live" of October 2012. The forecast cost at completion remains at $179.8 million (including contingency, which has not been used thus far). Brad further added that the contingency is "owned" by the Hydro One Board and cannot be used without their prior approval.

The Phase 4 Project involves four phases the first is the Blueprint phase which is nearing completion. One of the key objectives of the Blueprint phases is to validate the benefits and confirm benefits will be realized as part of the program. The requirements also have to be validated. The other three phases are Realization, Final Preparation, and Verification and Stabilization, which commences following Go-Live. The status of these phases and other Milestones such as Implementation Kickoff and Go-Live are progress reported regularly to senior management and the Hydro One Board.

Brad. explained that the process was intended to minimize customer impact, but that they would follow up about specific touch points with the customer.

Ted Cowan asked whether additional customer inputs through the Customer advisory Board would be included in the design phase. Brad responded that the Blueprint phase will be completed on October 31st, 2011 so the next consultation window would likely come after blueprinting. Ted confirmed that the Customer Advisory Board meets next on December 9th, 2011, and expected the matter could be discussed at that time. As a follow up to this item, it was confirmed that the Customer Advisory Board received an update regarding this project on September 29th.

Brad indicated that the Realization phase will commence in November 2011 and it will involve system configuration, building interfaces and data migration programs, change management communication plans and training design, and making sure that business process changes have been documented and are fully understood. Following Realization comes Final Preparation which ensures that business users understand and accept the system changes. It is also the point that data conversion is fully planned and tested. After Go-Live October 9th, 2012, the new system will be stabilized and verified.

Bill Harper asked when the old system will be retired. Brad responded that the Go-Live Milestone is scheduled for October 9th, 2012. He stated that the process generally requires 3-4 days to shut down the old system, migrate the data, set-up the new system and validate functioning appropriately and begin billing customers.

Susan Frank indicated, from a regulatory perspective, that the Go-Live date may not be the date that the assets go “into service”, in the regulatory framework. Hydro One is looking to go to USGAPP, which has criteria as to what is considered an in-service IT system. It is currently believed that some of the testing that occurs in the stabilization and verification phase has to happen before it can be considered “in-service”. This is why the words “in service” do not appear in the presentation. The actual in-service date is probably after October 9th, 2011 and could be as late as February 15th, 2013. These additional steps are for regulatory accounting purposes.

Brad then moved to his Slide 5 and outlined details of the CIS that were requested in the last consultation, including that:

- 15 current systems will be retired;
- 40 existing systems will be integrated with the new CIS;
- 68 Business Processes designs are included in this solution
- ±2700 Business Requirements have been met and will used throughout the project;
- 1500 employees and contract employees will be impacted as part of this implementation.

Hydro One will utilize change management methodology to address staff and customer impacts.

Michelle Byck Johnston asked what the total number of systems will be after retiring the old and integrating the new systems occurs.

Brad responded that across the landscape the application portfolio is broken up into 4 types of applications: core business, productivity tools, specialty software and system tools. Business systems (core, productivity, specialty) currently total approximately 800. Detailed information would be included in the filing. They have decommissioned upwards of 400 items across the 4 types driven by the Cornerstone Program, and are continuing to make progress. In follow up Hydro One confirms that it expects 15 business systems and an additional 10-15 system tools will be decommissioned as a part of CIS and replaced with 3 new business systems (SAP, Itron, Streamserve) and a small number of system tools.

The main functions of the CIS are in:

- Customer Service;
- Service Order and Work Management;
- Metering;
- Billing and Payment;
- Retail and Wholesale Market.

Each function in the CIS has several major IT components supporting it. Over 80 Interfaces will be built and tested within the 40 existing systems that will be integrated with the new CIS.

Brad's final Slide 9 provided a high level summary of the $179.8 million Project Total Cost.

ADJOURN 5:00pm

7. Appendices

A. Summary of Stakeholder Session

The Stakeholder Session was structured to afford stakeholders a concise summary of study results and progress reports on a number of fronts with the potential to inform the next round of Rate Applications, and to allow open, frank discussion of important issues and questions concerning:

1. Conservation and Demand Management (CDM);
2. Density and Cost Allocation;
3. Compensation Benchmarking;
4. Productivity and Metrics;
5. Cornerstone Phase 4—Customer Information System (CIS) Replacement.

Throughout the session, there was wide-ranging, free-flowing two-way discussion with Stakeholders, covering questions, issues of concern, requests for detail or explanation, challenges to various study premises and methods, and explicit requests for further input and consultation. Broadly stated, open questions and options include:

- Clarification of the Method used for load forecasting including CDM, and its suitability for co-ordination with OPA;

- Consumer input on the design phase of CIS replacement, through the Customer Advisory Board (Complete);
- Likely schedule for pending Rate Applications.

External consultants and Hydro One internal specialists explained the rationale, approach and results for each study, and indicated where further details and explanations would be forthcoming in the filing dossiers.

B. Key Actions and Notable Items

1. There was stakeholder interest in having volumetric/energy-billed and demand-billed rate classes separately broken out in CDM impact data, to ascertain whether either shows a greater price effect.

2. Stakeholders indicated a desire to have the impact of the Green Energy Benefit factored into CDM impact forecasting.

3. Stakeholders expressed an interest in a more robust and explicit comparison of the merits of the three prevalent Methods of forecasting CDM, including the resolution of data regression and collinearity issues.

4. Stakeholders asked for a clearer definition and explanation of reductions attributable to Increased Conservation Effect as compared to Natural Conservation, and of the specific value or benefit of including Increased Conservation Effect in load forecasting.

5. Hydro One indicated that it would clarify how Increased Conservation Effect growth will be forecast, once 2011 actual data is available.

6. Hydro One will consider including a review of the Seasonal Rate class cost allocation factors when implementing Density Cost Allocation Study results.

7. The CIS project leads were asked to present an update to the Customer Advisory Board at their December 9, 2011 meeting. Subsequently confirmed as complete on September 29th presentation to CAB

8. The exact number of systems affecting and affected by CIS replacement will be confirmed.

9. Hydro One confirmed that CIS Replacement project is "green" (on-track and on-budget) and has not yet had to use any of the contingency funds included in its total budget. Subsequently confirmed to be 15 business systems and approximately 10-15 system tools to be replaced.

10. Hydro One confirmed that the Distribution Rate application filing will be delayed to a date uncertain, but the new filing date will likely be early 2012.

C. Meeting Agenda

Stakeholder Consultation

CDM, Density Cost Allocation, Compensation Benchmarking and Productivity Studies and Cornerstone Phase 4 CIS Replacement in Support of Hydro One Rate Applications

AGENDA
October 19, 2011
Hydro One Networks
Special Event Room, Ground Floor
483 Bay Street, North Tower
1 p.m. to 5 p.m.

1:00 p.m.	Welcome	Allan Cowan, Director, Major Applications, Hydro One Networks
1:10 p.m.	Introduction	Bob Betts, Facilitator, OPTIMUS|SBR
1:20 p.m.	CDM Study	Stan But, Manager, Economics and Load Forecasting, Hydro One Networks
2:00 p.m.	Density Cost Allocation Study	Ben Grunfeld, London Economics
3:00 p.m.	**BREAK**	
3:15 p.m.	Compensation Benchmarking Study	Iain Morris, Mercer
4:00 p.m.	Productivity Study	Mark Hirschey, Oliver Wyman
4:30 p.m.	Cornerstone Phase 4 CIS Replacement	Brad Bowness, Director – Business Architecture, Hydro One Networks
5:00 p.m.	**Adjourn**	

Compensation Cost Benchmark Study Stakeholder Session

Monday May 30, 2011

9:30 – 12:00 p.m.

Mandarin Ballroom B

Metropolitan Hotel

108 Chestnut Street, Toronto

TABLE OF CONTENTS

The presentation materials used in this session and background materials can be found at this link: **http://www.hydroone.com/RegulatoryAffairs/Pages/TxRates.aspx**

Participant References

STAKEHOLDERS

Mike Belmore—The Society of Energy Professionals
Marion Fraser—Canadian Energy Efficiency Alliance
Julie Girvan—Consumers Council of Canada
Shelly Grice—Association of Major Power Consumers in Ontario
Bill Harper—Vulnerable Energy Consumers Coalition
Jan Hodgson—Ontario Power Generation
Bayu Kidane—Power Workers' Union
David MacIntosh—Energy Probe
Harold Thiessen—Ontario Energy Board staff
Frank White—The Society of Energy Professionals
Marcie Zajdeman—Brookfield Asset Management

Hydro One

Enza Cancilla—Hydro One
Allan Cowan—Hydro One
Bohdan Dumka—Hydro One
Susan Frank—Hydro One
Keith McDonnell—Hydro One
Vicki Power—Hydro One

Mercer

Iain Morris—Mercer
Kristi Robins—Mercer
Mike Thompson—Mercer

OPTIMUS|SBR

Bob Betts—OPTIMUS|SBR
Angela Boychuk—OPTIMUS|SBR
Miles Smit—OPTIMUS|SBR

START 9:35am

1.0 Welcome by Allan Cowan

Allan Cowan welcomed all participants to the second stakeholder consultation on the pending compensation cost benchmarking study. Following the initial (February 10, 2011) meeting, the Request for Proposal (RFP) was issued and Mercer was selected as the consultant. Mercer will use the current session to communicate its planned approach to stakeholders and to gather stakeholder insights and information before finalizing the survey.

Allan then introduced Bob Betts, of OPTIMUS|SBR, the session's facilitator.

2.0 Bob Betts' Presentation

9:40am

Bob Betts welcomed all participants and reviewed items agreed for follow-up from the Feb 10 session.

Bob covered housekeeping items including emergency exits and instructions. Note-taking will be provided by OPTIMUS|SBR. Bob indicated that the meeting would be recorded but that the recording would be disposed of once the notes of the meeting were accepted. He also indicated that the comments of participants would be attributed to them, unless they expressly requested that they be "off-the-record".

Bob then reviewed the agenda for the meeting and advised of some meeting process rules, summarizing the background of this current study and the Board's directives, and reviewed the key points of agreement that resulted from the Feb 10 consultation. He introduced Iain Morris from Mercer to present the planned approach.

3.0 Compensation Cost Benchmark Study preview and Q&A, with Iain Morris, Mercer

10:00am

Iain introduced the Project Team, outlined Mercer and Oliver Wyman's capabilities and expertise. He indicated that while their mandate has been largely fashioned through the RFP, they are here to gather additional detailed input from interested stakeholders in order to finalize their work plan. He went on to say that the Mercer/Oliver Wyman team have developed many best practices and proven approaches to these kind of studies and will explain those to stakeholders if they should conflict with suggestions from the group. Ultimately, they must stand behind the report as it is presented to the Ontario Energy Board and they reserve the right to exercise the judgement in producing the best result possible. He invited all participants to ask questions and challenge concepts as they arise.

Mercer's mandate for this study is to provide:

- A reliable and repeatable study, improving on the initial 2008 study;

- Productivity metrics used by regulated transmission and distribution utilities – omitting specific results and statistics, to encourage participation and protect confidentiality;
- Recommended internal productivity measures;
- Defensible findings and recommendations as required – employing Mercer's proprietary standards and methodologies.

Iain Morris added that the report on metrics recommended for internal performance assessment is intended to allow trending information on a go-forward basis. In the last Mercer study, they found utilities were very reluctant to provide productivity metrics that they could be challenged to justify in their respective jurisdictions. In this case, the intention is to survey participants to establish what would be considered appropriate metrics for productivity measurement. It is hoped through this approach the request will result in greater survey participation.

Bayu Kidane asked how the Board direction that compensation increases should match productivity gains would be met, adding that he understands that this will not be another attempt at a productivity comparison among utilities.

Iain Morris confirmed that this would not be another productivity comparison study among utilities but said that Mercer will establish a set of metrics as a baseline to look at Hydro One productivity performance and align compensation changes with productivity gains on a go-forward basis. Allan Cowan added that the Board emphasized developing internal productivity comparisons. It is difficult to make external comparisons, as organizations are reluctant to share data. As a result, data suitable for like-to-like assessments are not available.

Bayu Kidane also asked if the internal measures will be used for the next application. Allan Cowan indicated the next application will identify metrics from this study and establish a reference anchor, but that it would be unlikely that there would be trending analysis available at that point in time.

In his presentation, Iain reviewed the approach for customized benchmarking surveys:

1. Determine survey sample and jobs to be benchmarked – framing the marketplace, and canvassing the comparators' organizations' total compensation;
2. Design survey – Interest in shared results will determine if they will participate. The challenge is creating a survey that is comprehensive but easy to complete quickly;
3. Identify method of contact;
4. Test survey and modify as needed;
5. Collect data and analyze – clarify data, ensure job matching, answer questions from participants, and resolve discrepancies.

Iain Morris emphasized that it is key to protect confidentiality of participant's information in order to receive participation in the study.

Iain Morris summarized some challenges to benchmarking for total compensation cost in the Canadian market:

- Small sample size within the utility sector. The industry sector offers a much larger sample base, and may include appropriate comparators for Hydro One. The challenge is ensuring comparable jobs, especially for managerial or one-off roles;
- Regional differences in the compensation market can be significant. Cost of living and cost of labour are not always clearly correlated. Mercer will look at regional pay differences. Cost of living is highly variable, but employers are slow to adjust pay to account for cost of living.

Susan Frank asked how regional cost of living differences impact compensation costs. Iain Morris replied that over a long period of time, there is some correlation; however, there are many examples of delinking also, citing the Vancouver market as an example. Furthermore, he noted that many large corporations do not have regional pay structures, which serves to disassociate compensation from regional cost of living. For the survey, the focus is on cost of labour. Mercer seeks a representative sample, balanced by region, with rigorous means for comparison and minimally-adjusted numbers.

Susan Frank also questioned if rural areas have different impact on cost of living and therefore the cost of labour than urban areas. Iain Morris advised that typically many employers don't differentiate wage structures by location. Some differences are evident when looking at small employers in local markets, but generally not the larger corporations.

Mike Belmore asked why Quebec is seen as a unique market. Iain Morris responded that Quebec has more senior / executive level jobs that have pay levels lower than elsewhere particularly in the broader public sector; the reason is assumed to be that employees in Quebec are significantly less mobile than their counterparts in English speaking Canada. The sample in this case is not heavily weighted towards Quebec.

Iain Morris offered a few points on the sampling strategy:

- Cross-border compensation comparisons are treacherous. US-Canadian concerns struggle when trying to set up parallel pay structures due to, e.g., the high cost of benefits in the US and steeper pay lines in the US. Currency is another challenge, as there was a 30% swing in exchange since 2008, making it difficult to prepare a repeatable study;
- The sample selection process requires an understanding of the chosen organizations' underlying compensation philosophies.

Julie Girvan asked how Mercer would fulfill the Board's direction to review the overall North American market.

Iain Morris advised that US organizations will be canvassed for productivity metrics. On pay comparison, currency issues, different labour market and different philosophies are reasons why US information will not provide an effective comparison for Hydro One.

Bill Harper asked if the 2008 study included a significant sampling of US utilities.

Iain Morris confirmed that it did not include US companies.

Mike Belmore asked for a fuller explanation on the last bullet point and why the selection process requires an understanding of the chosen organizations' underlying compensation philosophies.

Iain Morris advised that it means they would focus on information from organizations with similar complexity, types of roles, similar tech content and regulatory environments.

10:35am Morning Break

10:50am

Iain Morris continued.

Mercer's recommended approach is an integrated survey to benchmark costs and identify productivity measures:

- From Canada, compensation benchmarking at comparable organizations and identifying internal productivity measures for tracking over time;
- From US reporting internal productivity metrics and any productivity reporting requirements for electricity utilities.

The 2011 Compensation Cost Benchmark Study will utilize a similar methodology to the 2008 Mercer study. The study needs to be repeatable. While they look for areas of improvement, the core of the study will be the same in order to do comparisons. The data collected will be the same as before and the data collection process will be streamlined. The analytical methodology will remain the same, by using the standard assumption for pension and valuing benefits, while the core participant list and core benchmark jobs will be expanded slightly.

Benchmarked jobs will be reviewed carefully to ensure relevance and population size.

To ensure an appropriate sample selection Mercer will use Canadian companies with total assets between 33% and 300% of Hydro One and reviewed to consider including some additional LDCs, such as PowerStream or Hydro Ottawa. In the previous study only Toronto Hydro was a suitable comparator.

In the previous study, Mercer invited companies from other regulatory environments to participate. A majority declined to participate due to lack of interest or comparable jobs, concerns about confidentiality, etc. Mercer recommends re-using the willing participants from 2008.

Frank White asked for comments on a planned approach constrained to the product market rather than the alternative of looking at a broader labour market.

Iain Morris answered that a consistent market is needed, with a representation of skills and roles similar to Hydro One.

Frank White also asked whether the information from the benchmark jobs could be supplemented with Mercer's 1100-job database covering base pay and total cash.

Iain Morris advised that there would be significant difficulties in comparisons, as total compensation is not covered by the database.

The same Peer Groups from the 2008 study will be invited to participate again for this year's study. They will look for new participants but they need to be aware that dropping or adding participants will affect the sample differently. They need to minimize the amount of change.

Other companies with similar regulatory environments were invited to participate in 2008. Only Bell, Enbridge, TransAlta participated fully, with limited information from TransCanada.

Susan Frank commented that some relevant utilities are excluded, and having more participants would enrich results. She asked what is being done to get other participants, to ensure that the results are as definitive as possible.

Iain Morris answered that the last study had a robust sample with the number of organizations and that the results were credible. However, the study is meant to be repeatable as compensation will change over the years and as such the group should be one that will dependably participate whenever the study is repeated.

Susan Frank continued by asking Mercer if they were saying that even by getting the same group to participate as did in the 2008 study, that study results would be good.

Iain Morris replied by saying that the results from the 2008 study were considered very credible, and that group of participants should be the target group again. Additions will be made judiciously, with a focus on maintaining credibility and ensuring repeatability.

Bayu Kidane asked how the Board direction that the study be updated and expanded will be met.

Iain Morris indicated that a few (likely 2 or 3) organizations could be added, as could a number of benchmarked jobs. The study needs to be similar to enable comparisons but there will be changes and Mercer needs to be thoughtful in the change, ensure robust size and add jobs that may be needed to represent different functions and organizational levels.

Mercer will look at individual jobs, jobs in aggregate, balanced number of jobs (they usually recommend 30 – 40 in a survey like this one, as with the last study) and ensure like-to-like comparisons. Mercer uses a job-matching standard of 80% on skills, responsibility and content.

Susan Frank asked what percent of the employee population is sufficient to get a complete picture.

Iain indicated that the last study represented 47% of the population and the target is 50%+ for this study, predominantly full-time employees.

Julie Girvan asked how the 30–40 job target related to the 50% target.

Iain responded by saying that in the last study 30 jobs represented 47% of the population.

Iain previewed the elements of total compensation that they look at. They will focus on items that can be monetized – base salary, short-term incentives, long-term incentives, insured benefits, retirement and savings plans and pay for time not worked.

Susan Frank asked what the time frame would be for the compensation survey data.

Iain Morris advised that the study will be a snap shot in time with an effective date of April 1, 2011.

Susan also asked how the study will address experienced employees (e.g. a given accountant job with 5 years versus 10 years' experience.)

Iain Morris advised that they will look at actual rates of pay rather than pay design, typically assuming similar experience distributions in a mature work force, with junior and senior roles balanced. The study will focus on comparable jobs, and identify key job content. The sample must be representative of the organization and represent marketplace trends.

Regarding Productivity Metrics in this study, there will be no comparison of Hydro One productivity to the market. The aim is to gather data on which productivity measures are being used by utilities and US regulators and supplement that with Oliver Wyman's expertise on total rewards, etc.

Mercer will work with Hydro One to understand internal metrics currently used or under development in the organization, to further understand unique business, market and territory characteristics, to understand key cost drivers, to share knowledge of practices and to recommend performance metrics to track and improve over time.

Susan Frank asked all of the parties in the room whether they thought that the Board's focus is actually on labour productivity, or does it include other measures of productivity such as capital productivity. After some discussion around the room, the consensus appeared to be that the Board is looking for productivity metrics that relate to compensation cost.

Julie Girvan asked if there are other studies that cover North America overall.

Iain Morris said he was not aware of any.

Iain restated the design principles to be used to ensure a survey and results that are:

1. Objective;
2. Simple;
3. Independent, testable, repeatable;
4. Not attributable to participants;
5. Group surveys – will use the same selection criteria, conduct assessment to expand and increase sample, add more benchmark jobs, increase percentage of population;
6. Compatible in scope to Mercer study of 2008;
7. Comparable for trending analysis.

Iain reviewed each of the Key Points of Agreement from the Feb 10, 2011 Consultative meeting and confirmed that each will be addressed in this study. Specifically with respect to the question of the mean or the median and a question from Frank White, Iain indicated that studies such as these almost universally use the median because it is more representative of the middle of the market and a better comparison for the study. It also tends to be a more stable number and less influenced by extremes within the survey participant group.
Frank White stated for the record that he believes Mercer should look at both median and mean values, since the main effort is in data collection, not analysis.

Mercer seeks to avoid using multiple measures. Mean averages are distorted more by outlier values than are medians; therefore the industry standard for compensation studies is to use median values. Iain Morris expressed his concern on behalf of Mercer that the mean could confuse the comparisons and reduce the credibility of the study.

Mike Belmore commented that if there were two different number sets [i.e. mean and median], the Board and stakeholder groups will be able to debate on the meaning and the Board will make a decision.

Mike Thompson advised that with small survey samples, it is very difficult to preserve confidentiality of data when mean values are disclosed. With very large samples, breaking out means and distributions is more plausible.

Bob Betts restated the agreement of all parties in the February 10, 2011 consultative that the use of means / medians will be left to the discretion of the consultant.

In addition to designing the survey and the targeted sample, action Items sitting with Mercer include:

1. Defining the approach for assessing pension and benefits data;
2. Soliciting productivity metrics used elsewhere;
3. Process for designing recommended productivity metrics.

This concluded Iain's presentation and he asked for further questions.

Julie Girvan expressed her opinion that expanding the survey group would be useful.

Bayu Kidane requested that the study include a list of limitations and deficiencies.

Iain responded by summarizing the approach to the study--to sample organizations and jobs that will be representative and will meaningfully compare Hydro One compensation costs to the relevant market. Standard assumptions are made to estimate pensions and benefits using Mercer's expertise and actuarial norms. The only limitations and deficiencies are those that exist in all surveys and studies of this kind, primarily comparability of survey participants, and the degree and quality of the participation in the survey

Bill Harper raised the distinction between productivity metrics requested by regulators, metrics which are calculated by regulators, and measures derived or applied by the organizations themselves. He commented that it might be useful to ask for each of these in the survey.

4.0 Close

12:00pm

Allan Cowan concluded the meeting, thanked participants, Iain Morris and Bob Betts, and outlined next steps.

Mercer will finalize its survey design, using inputs from the session, with the aim of sending out the survey before summer vacation. Once they have all the results, it will be analyzed and shared with this consultative in the fall, hopefully in the September timeframe.

Hydro One plans to submit a 2-year Distribution application in Nov 2011 and a 2-year Transmission application in April 2012. For the Distribution application, business planning has begun and HONI is looking at potential stakeholder sessions around June 22-29 to report on Accounting issues and the advancement from 2016 of the Customer Information System (CIS) replacement.

ADJOURN 12:05pm

APPENDICES

A. Summary

The topic was approached by way of a brief review of the prior Stakeholder discussion in February 10, 2011 and a thorough introduction by Mercer consultants to their intended approach.

An open Q and A was held throughout the proceedings, allowing Stakeholders to query Mercer about the methods, samples and benchmarked jobs to be used.

Detailed conversation focused on the most significant and relevant factors affecting compensation. The possibility of determining national, regional, local and sector-specific compensation cost drivers was reviewed at length. Further, concepts such as cost of living and cost of compensation were clarified and distinguished.

Mercer outlined, and fielded questions regarding the two key tracks to be pursued:

1) assessing comparator compensation costs, and;

2) identifying productivity measures used at comparable entities.

Mercer further led a discussion of the separate respondent pools and methodologies needed for each track of the study.

Clearly-stated opinions were candidly offered from a variety of perspectives. A broad, inclusive focus led to productive discussion about the meaning of the Board's direction and the optimal capture and use of market trends to help guide Hydro One's compensation practices in coming years.

B. Key Points of Agreement

1) The revised Compensation Cost Benchmarking Study will, as much as possible:

   a) Assess regulated Transmission and Distribution utilities' compensation cost benchmarks appropriately across Canada, and productivity measures across North America;

   b) Be short and simple to entice the maximum number of survey participants;

   c) Conform to best industry standards for independence, testability and repeatable market-based assessment;

   d) Assure participants categorically by the study's design, methodology and process that respondent information cannot be attributed or inferred;

   e) Mirror the scoping included in the 2008 study for peer selection, job classes, etc, and expanded selectively to increase the % of employees benchmarked and otherwise enhanced, as recommended by the consultant;

f) Enable reasonable comparison to the 2008 study and provide trending analysis for Hydro One's next application, with an eye to illuminating possible paths to improved productivity;

g) Use the most appropriate and practicable metrics and averages;

h) Rely on the expertise of the selected consultant to recommend appropriate changes in methodology and assumptions.

2) To balance the repeatability and durability of results obtained, the consultant will selectively attempt to enhance the scope of the 2008 study by targeting additional benchmarked jobs and, potentially, additional comparators.

3) The consultant must determine the proper standards and measures for its report, but will consider the merits of approaches (including mean and median measures, as well as jurisdictions, regions, sectors and specific comparator organizations and jobs for inclusion) suggested by various stakeholders.

C. Meeting Agenda

Stakeholder Consultation

Compensation Cost Benchmarking Study in Support of
Hydro One Rate Applications

AGENDA
May 30, 2011
Metropolitan Hotel
108 Chestnut Street, Toronto
Mandarin Ballroom B, Lower Level
9:00 a.m. – 12:00 p.m.

9:30 a.m.	Welcome	Allan Cowan, Director, Major Applications, Hydro One Networks
9:40 a.m.	• Introductions • Background on Compensation Cost Benchmarking Study • Key Points of Agreement from February 10th Stakeholder Session	Bob Betts, Facilitator, OPTIMUS|SBR
10:00 a.m.	Approach to Compensation Cost Benchmarking Study & Facilitated Discussion	Ian Morris, Mercer and Bob Betts
10:45 a.m.	**BREAK**	
11:00 a.m.	Approach to Compensation Cost Benchmarking Study & Facilitated Discussion (Continued)	Ian Morris, Mercer and Bob Betts
11:45 a.m.	Next Steps and Closing Remarks	Bob Betts/Allan Cowan
12:00 p.m.	**Adjourn**	

SUMMARY OF BOARD DIRECTIVES AND UNDERTAKINGS FROM PREVIOUS PROCEEDINGS

This exhibit identifies the Board directives to Hydro One Transmission from the previous transmission proceeding. The table also indicates the Exhibit number in this Application in which Hydro One's evidence responds to the Board directives.

Board Directives from Proceeding EB-2010-0002
(2011/2012 Transmission Rates)

Item #	Issue	Summary of Directive	Reference Exhibit
(i)	CDM Measurement Study	Hydro One directed to work with the OPA in devising a robust effective and accurate means of measuring the expected impacts of CDM programs promulgated by the OPA. *(Decision page 6/7)*	Exhibit A-15-2
(ii)	Smart Grid	Hydro One is required to file a detailed report in its next transmission rates application describing the OM&A activities for Smart Grid undertaken along with an analysis of the results achieved and a description of how they relate to the transmission system. *(Decision page 14)*	Exhibit C1-3-3
(ii)	Compensation Benchmarking Study	Hydro One directed to revisit its compensation cost benchmarking study in an effort to more appropriately compare compensation costs to those of other regulated transmission and/or distribution utilities in North America. *(Decision page 20)*	Exhibit C1-5-2
(iii)	Rights Payments	Establish a variance account to track the difference between the amount provided for in the revenue requirement and the actual payments. *(Decision page 21)*	Exhibit F1-1-1
(iv)	Bruce to Milton Variance Account	Hydro One directed to establish a variance account to track the change in 2012 revenue requirement if the project is not closed to rate base as currently projected. *(Decision page 28)*	Exhibits D1-3-3, D2-2-3 Will not be required In service date – Q2 2012

Item #	Issue	Summary of Directive	Reference Exhibit
(v)	Transmission Other Revenues Variance Accounts	The other revenue variance accounts shall remain in place until Hydro One can demonstrate improved accuracy in the forecasting of these amounts (Secondary Land Use, Station Maintenance, Engineering and Construction) *(Decision page 52)*	Exhibit F1-1-1
(vi)	Forecast of Export Revenues	Variance account to be maintained to address forecast uncertainty of these revenues. *(Decision page 54)*	Exhibit F1-1-1
(vii)	Export Transmission Service (ETS) Tariff	The Board concludes therefore that the most pressing requirement is that a genuinely comprehensive study be undertaken to identify a range of proposed rates and the pros and cons associated with each proposed rate in time for the next transmission rate application. In the Board's vies, the most appropriate party to undertake the study is the IESO. *(Decision page 75)*	Exhibit H1-5-1 Expected completion date for the IESO study is May 2012

Board Directives from Proceeding EB-2011-0268
(2012 Transmission Rates - USGAAP)

Item #	Issue	Summary of Directive	Reference Exhibit
(i)	Review of Capitalization Practices	The Board considers it appropriate to require Hydro One to conduct a critical review of its current and proposed capitalization practices. This review shall not be a benchmarking study per se, but should include information with respect to what other U.S. transmitters typically capitalize and the capitalization methodologies used by other transmitters with a view to comparing these to Hydro One's capitalization policies. This review should be available in time for the company's next rate application. *(Decision page 13)*	Exhibit C1-7-2

PROCEDURAL ORDERS – CORRESPONDENCE - NOTICES

To be filed behind this tab as and when Procedural Orders, Correspondence and Notices are filed.

LIST OF WITNESSES

To be filed behind this tab when witness selection has been completed.

CURRICULUM VITAE

To be filed behind this tab when witness selection has been completed.