Exhibit 4:

OPERATING COSTS

Exhibit 4: Operating Costs

Tab 1 (of 8): Overview of Cost Trends

OVERVIEW

In 2014 Burlington Hydro proposes to recover $18,553,350 of Operations, Maintenance and Administration costs ("OM&A") which represents a $4.2M increase from the 2010 Board approved amount of $14,346,944.

Burlington Hydro performs a wide range of activities in support of providing safe service on an ongoing basis and at an appropriate level of reliability and quality that benefits its customers and stakeholders including:

- System operations (e.g. Service restoration, Switching operations, monitoring and balancing the loading of Burlington Hydro's lines and transformers)
- Communicating with customers so as to keep them informed of events and changes to Ontario's electricity sector.
- Inspecting the distribution system (e.g. dissolved gas analysis of transformers, re-verifying meters)
- Verifying and maintaining the distribution system (e.g., assets, configuration, operating characteristics) with respect to assets deployed throughout the service area
- Complying with Ontario's evolving energy market, changing government policy and evolving regulatory framework
- Operating and maintaining Burlington Hydro's fleet of vehicles
- Appropriately mitigating risks (e.g. insurance)
- Providing safe places for employees to work
- Building and enhancing employee potential through training and talent management planning.
- Providing awareness and education programs (e.g. on public safety)

In its normal course of business Burlington Hydro continues to strive to be as cost efficient as possible, maintaining a safe and reliable distribution system while ensuring both public and employee safety. Burlington Hydro's main cost considerations and drivers are discussed below.

Cost Drivers and Considerations

Substations

Burlington Hydro has 32 Municipal Substations within its distribution system; this is a high number of substations when compared to other similar distribution utilities in Ontario. It is a reflection of the timing of growth within the city and the development of the 4.16kV and 13.8kV systems over many years. Current distribution technology allows the use of the 27.6kV system supplied directly from the Hydro One Transformer Stations, such that there should be no more Municipal Substations required in the future. However, the operation and maintenance of the existing 32 substations remains and will continue to remain a material cost centre since the elimination of substations with a complete voltage conversion to 27.6kV could not be justified as a reasonable business investment for Burlington Hydro. Notwithstanding this assessment, there are some locations in the city where substation operation is a concern and a voltage conversion and substation elimination may have some merit.

Control Room

The operation of a 24/7 Control Room facility has been a feature of Burlington Hydro's system for many years; this is typical of similar sized utilities with complex multi-voltage distribution systems (as described above) and matches the reliability expectations of the community. Staffing of this facility with well-trained Operators carries a substantial cost.

Audits and Inspections

All licensed distributors, in Ontario, have to comply with Ontario Regulation 22/04 Electrical Distribution Safety and compliance with this regulation is subject to annual Audits and Declarations of Compliance. Section 4 of the regulation sets the safety standards and includes the statement:

"All distribution systems and the electrical installations and electrical equipment forming part of such systems shall be designed, constructed, installed, protected, used, maintained, repaired, extended, connected and disconnected so as to reduce the probability of exposure to electrical safety hazards. O. Reg. 22/04, s. 4 (2)."

The regulation is designed to allow distributors to self-regulate, with requirements for annual Audits and annual Declarations of Compliance.

Burlington Hydro has established practices and procedures that comply with Ontario Regulation 22/04 and has had eight satisfactory Audits since 2004. It is also required to submit an annual Declaration of Compliance for certain sections of the regulation; these have all indicated compliance. ESA also undertakes a series of Due Diligence Inspections (DDIs) with all distributors. Burlington Hydro has approximately 2 DDIs per year; there have been no significant items raised from these inspections.

Aging Infrastructure

Burlington Hydro places a high priority on balancing its obligations to accommodate growth while addressing the upkeep and replacement of its aging infrastructure. Asset management leads to increases in operational costs.

Distribution equipment that was placed in-service over 40 years ago, in many cases, has reached its normal useful life. Therefore Burlington Hydro is faced with the ongoing replacement of this aging infrastructure that originated in those early years when growth accelerated. Customer expectations for reliability have increased over time and as new technology is added to the system it can only perform on a solid base of well-maintained distribution infrastructure. Thus, investment in replacement equipment along with its associated operational costs has become a continuous reality for Burlington Hydro as it commits to satisfying the essential community needs.

Obligation to connect and accommodate growth

Burlington Hydro's "obligations to connect" are defined in section 28 of the Electricity Act. These obligations reinforce the importance of good operational planning and capital investments to satisfy new residential and commercial/industrial development. Burlington Hydro has consistently matched the expansion of its distribution system to accommodate this growth. New infrastructure and system capacity require capital investments based on realistic estimates of load growth. The provision for built-in reliability that complies with the Distribution System Code and ideally matches the community expectations is also a high priority within the design considerations. Capital expenditures for load growth are not discretionary and receive a high priority in the budgeting process. However, they are part of the long term planning process and the timing of these expenditures can sometimes be shifted as the rate of growth fluctuates with the economic climate.

It is recognized throughout the company that it is essential to be as effective and efficient as possible in order to simply keep up with the cost pressures placed on the industry. With increases in the price of the electricity commodity, customers are progressively experiencing significant hardship in paying their electricity bills. The utility's emphasis is therefore on seeking to minimize its customers' rates while maintaining at the current level the reliability of supply required by the Distribution System Code. Specific activities include:

- Line managers are constantly challenged by the Burlington Hydro board and senior management to find operational efficiencies and thus reduce OM&A costs, acquire goods and services at a lower cost, progressively reduce station and line maintenance based on condition monitoring reports, find more efficient maintenance processes, etc.

- Sharing best practices with other utilities to identify productivity improvements.

- Working with the other utilities to identify scope-enhancing opportunities, collaborative working arrangements, collective purchasing arrangements, etc.

OVERALL COST TRENDS

As set out in the following table, Burlington Hydro's OM&A spending increased by approximately $4.55M from its 2010 Actual to the 2014 Test Year. This $4.55M OM&A increase includes costs related to OEB required accounting changes ($0.8M). Normalizing the $4.55M increase by removing these accounting related costs results in a 2010 to 2014 OM&A cost increase of $3.7M. This normalized variance represents a 26.8% increase over 4 years, or an average annual increase of only 6.12%.

Table 4-1: OM&A Cost Trend

	Last Rebasing Year (2010 Board-Approved)	**Last Rebasing Year (2010 Actuals)**	**2011 Actuals**	**2012 Actuals**	**2013 Bridge Year**	**2014 Test Year**
Reporting Basis	**CGAAP**	**CGAAP**	**CGAAP**	**CGAAP**	**CGAAP**	**CGAAP**
Operations	$4,464,123	$4,047,491	$4,643,079	$4,387,015	$5,621,434	$6,283,903
Maintenance	$2,864,348	$2,275,554	$2,544,531	$3,149,391	$3,602,291	$3,722,797
SubTotal	**$7,328,471**	**$6,323,045**	**$7,187,610**	**$7,536,406**	**$9,223,725**	**$10,006,700**
%Change (year over year)			13.7%	4.9%	22.4%	8.5%
%Change (Test Year vs Last Rebasing Year - Actual)						58.3%
Billing and Collecting	$2,305,153	$2,396,557	$2,001,083	$3,114,375	$2,221,235	$2,310,532
Community Relations	$41,584	$14,894	$18,589	$16,073	$19,158	$19,500
Administrative and General+LEAP	$4,671,786	$5,266,558	$5,319,521	$5,492,207	$6,008,031	$6,216,618
SubTotal	**$7,018,523**	**$7,678,009**	**$7,339,193**	**$8,622,655**	**$8,248,424**	**$8,546,650**
%Change (year over year)			-4.8%	17.5%	-4.3%	3.6%
%Change (Test Year vs Last Rebasing Year - Actual)						11.3%
Total	**$14,346,994**	**$14,001,054**	**$14,526,803**	**$16,159,061**	**$17,472,149**	**$18,553,350**
%Change (year over year)			3.8%	11.2%	8.1%	6.2%

The overall increase in OM&A spending from 2010 to 2014 is due to several factors. Burlington Hydro has made changes to its accounting policies effective January 1, 2013 that reduced the period expenses eligible for capitalization which results in increased costs. This change in capitalization policy applied to overheads and burdens was mandated by the OEB in its July 17, 2012 letter on Regulatory accounting policy direction regarding changes to depreciation expense and capitalization policies in 2012 and 2013. This change in accounting policy constitutes a material portion of the overall increase in OM&A. Other significant factors include operation and maintenance cost associated with Burlington Hydro's distribution assets and its aging fleet of 32 substations. The costs associated with the maintenance of Burlington Hydro's substations are necessary in order to operate and maintain the distribution system in a safe and reliable manner. The increasing complexity in the regulatory environment, such as the introduction of smart meters, has influenced OM&A spending. Burlington Hydro has various programs in place geared to increasing effectiveness and long term success that include: training and succession planning, process reviews and the implementation of Burlington Hydro's new Information Services Strategy. These programs also contribute to increased OM&A expenses. Burlington Hydro successfully copes with external factors (e.g. damage control due to extreme weather, changes in technology such as the adoption of Wye configurations, the transition to the Smart Grid, changes in government and regulatory policy (e.g. ongoing Code amendments, implementation of the Ontario Clean Energy Benefit) while continuing to provide safe and reliable distribution services. Burlington Hydro established 5 new positions since 2010 that it has successfully recruited for; the associated change in compensation amounts to approximately $1.2M. Like all commercial entities, Burlington Hydro experiences inflationary pressures which caused an increase in its OM&A spending of approximately $1.5M over the 4 year period 2010-2014.

The contributing factors listed above are discussed further in the OM&A programs at Exhibit 4 Tab 3, Schedule 1 and cost drivers Exhibit 4 Tab 1, Schedule 2.

The following OM&A Expense Tables are presented at the next section.

- Appendix 2-JA: Summary of Recoverable OM&A Expenses

- Appendix 2-JB: Recoverable OM&A Cost Driver Table
- Appendix 2-L: Recoverable OM&A Cost per Customer and per FTE
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Year over year variance analysis are presented following the tables or more specifically at Exhibit 4, Tab 2 Schedule 2.

DESCRIPTION OF OM&A ACTIVITIES

Operations and Maintenance

Burlington Hydro's Operations strategy is to provide safe, reliable service at an appropriate level of quality throughout the licenced service area. Burlington Hydro's maintenance strategy is an important part of its overall strategy of minimizing the life cycle costs of assets by minimizing reactive and emergency-type work, through an effective planned maintenance program (including predictive and preventative actions). These strategies are implemented through policies and work practices that promote a good experience for the customer with regard to safety, security of supply, continuity of service, the timely restoration of service and the minimization of undesirable service conditions. Burlington Hydro's customers receive high quality services. Customers see that the system is in a state of good repair, that crews are engaged in inspection, testing, cleaning, and verification activities. Increasingly however, Burlington Hydro's assets and services are less visible – underground conductors encased in conduits; Smart Meters that do not need to be read manually; switches that are operated remotely from Burlington Hydro's Control Room; and, system monitoring (e.g. for voltage sag, line balancing, to ensure backup can be realized) via electronic devices that communicate wirelessly and provide real time analysis that has less of an impact on customers.

Very favorable levels of customer satisfaction were recently reflected in the results of a customer satisfaction survey conducted by Burlington Hydro in the spring of 2013. On demonstrating credibility and trust, Burlington Hydro scored well, with an 86% satisfaction rating – 4 percentage points higher than Ontario and National averages. The company's report card showed impressive results - receiving A's for customer care and service, company image and leadership, corporate stewardship and for operational effectiveness. The highest score – an A+ - was realized for power quality and reliability. This performance snapshot is helping the company identify not only its strengths, but those areas that might require closer scrutiny. With 88% of customers surveyed responding that 'overall the utility provides excellent quality services', Burlington Hydro is moving in a positive direction. The survey provides insight and allows Burlington Hydro a better understanding of customer needs, including the ongoing concerns about increasing electricity prices.

Burlington Hydro's customer responsiveness and system reliability are monitored continually to ensure that its maintenance strategy is effective. This effort is coordinated with Burlington Hydro's capital project work, so that maintenance programs help to identify those areas that require capital investments. Burlington Hydro is then able to adjust its capital spending priorities to address these matters. This process is described in more detail in conjunction with Burlington Hydro's Distribution System Plan, found in Exhibit 2, Tab 5, Schedule 3

Within Burlington Hydro, Operations and Maintenance expenses include all costs relating to the operation and maintenance of the Burlington Hydro electrical system. This includes both direct labor costs and non-capital material spending to support both scheduled and reactive maintenance events. In addition, costs are allocated from support departments to cover the costs of Labour Burden, Engineering, Material and Vehicles. Below is a description of each of the departments involved directly in Operations & Maintenance of the Burlington Hydro system, as well as a description of the indirect costs that are allocated.

- Direct costs:
  - Control Room
  - Meter shop
  - Maintenance (Construction)
  - SubStations Services
- Indirect costs:
  - Engineering
  - Material
  - Vehicles
  - Labour Burden

Control Room:

Burlington Hydro's control room in Burlington is staffed 24 hours a day, 7 days a week and is linked to the distribution system by a data communication network and whose information is processed by a Supervisory Control and Data Acquisition ("SCADA") system. Real-time breaker status, and voltage and current readings from the 5 Hydro One transformer stations that serve Burlington Hydro and from Burlington Hydro 32 substations, are sent to the control room and displayed on the SCADA system. The control room operators continuously monitor the system, rely increasingly on automated devices (many of which can be remotely controlled, including ScadaMates, IntelliRupters, Vista switchgear, IntelliTeam II) to support systems operations, and when necessary, dispatch repair/trouble crews to manage equipment failures. The Control Room also co-ordinates field work to establish and preserve work protection and safe conditions for the crews doing work on the system.

Metering:

This department is responsible for the installation, testing, and commissioning of new metering and for the ongoing operations of existing metering, both simple and complex metering installations. Testing of complex metering installations ensures the accuracy of the installation (e.g. to verify that the appropriate meter multipliers are applied through the billing process). Metering proactively investigates potential diversion and/or theft of power which may give rise to unsafe conditions or risk other customers being inappropriately held financially responsible for costs. This department also provides emergency response to customer trouble call requests, when the Control Room determines that the trouble call is related to one customer only.

The Metering group benefits customers in two ways: first, the ongoing accurate operation of meters provides real time operating data to the SCADA and other systems that supports System Operations, and second, because it ensures that bills are computed correctly and, hence, that customers are fairly charged for the services provided.

Maintenance (Construction)

Burlington Hydro's Construction group is responsible for the field assets that operate at 4kV, 13.8kV or 27.6kV and include approximately 16,600 poles, 1,000 km of 3 phase and single phase overhead lines, 650 km of 3 phase and single phase underground lines and 9,000 transformers and the lines Burlington Hydro owns that egress from HONI's TSs that serve Burlington Hydro where responsibility starts at the 'fenceline' of each of HONI TSs. These Distribution System assets are relied on to provide service to the more than 65,000 customers – or more accurately the nearly 75,000 electricity end users (including apartment and condominium customers fed from a bulk meter) - in the City of Burlington. This is accomplished through predictive and pro-active maintenance programs and equipment repair and, when necessary, the provision of emergency and trouble call response 24 hours/day, 365 days/year. This group is also responsible for constructing expansions of the distribution system to meet customer demand; under Burlington Hydro's accounting policies the work this group performs to expand the system is capitalized and the remaining costs are expensed in the period.

Substation Services:

Substation services activities address the maintenance of all equipment at Burlington Hydro's 32 substations that house 44 substation transformers. As with the maintenance activities, Burlington Hydro's substation maintenance strategy focuses on minimizing, to the extent possible, emergency-type work by improving the effectiveness of Burlington Hydro's planned maintenance program (including predictive and preventative actions) for its substations. This department also provides an underground locate service to anyone requesting verification of underground cable locations. The costs incurred by this group include labor costs and non-capital material spending to support both scheduled and emergency maintenance events.

Engineering

Engineering is responsible for keeping asset related data up to date on a recently purchased electronic Geographic Information System ("GIS") and for the integration of other electronic systems (e.g. the SCADA system) and the associated databases. This data is the basis of numerous applications within Burlington Hydro, including:

- up-to-date mapping in the Control Room that is used for all system switching, load shifting and emergency response activities
- asset management activities
- troubleshooting system problems in the control room
- delivering underground utility locating services for excavating contractors and
- for design and construction activities including new capital projects and customer connections.

The Engineering department produces the annual System Performance Report and the Asset Management Plan, which is used in the development of the annual Capital and Operating budgets. It produces engineering designs and costs estimates for Capital projects and services. Engineering is responsible for Burlington Hydro's compliance with ESA standards and with O.Reg 22/04; these activities include approvals, standard framing design, materials specifications and construction designs, all of which are requires for the construction and energization of projects as per Burlington Hydro's Construction Verification Program. Additional responsibilities include Due Diligence inspections, Annual Audit and Annual Declaration of Compliance. Engineering also delivers drafting services, provides distribution system asset information to many departments within Burlington Hydro, handles service inquiries from customers and developers, produces design standards and guidelines for subdivision and townhouse developments, produces and updates Burlington Hydro's Conditions of Service and completes all required surveys and inspections.

Engineering costs are allocated to operations or maintenance, as is appropriate based on direct labor costs. A standard overhead percentage is set at the beginning of the year and adjusted to actual at year-end.

Materials:

Stores staff is accountable for managing the procurement, control, and movement of materials within Burlington Hydro's service centre in the most efficient manner. This includes monitoring inventory levels, issuing material receipts, material issues, and material returns as required.

A standard overhead percentage is set at the beginning of the year and adjusted to actual at year end. It is calculated based on the annual cost of operating the Stock Room. This percentage is then applied to the cost of the material that is issued from the Stock Room and charged to a project.

Vehicles:

Burlington Hydro operates its 37 vehicle fleet to minimize vehicle down time so that there are no inappropriate delays to dispatching a trouble crew to restore service and to maintain vehicle reliability and safety. An hourly rate per vehicle class is calculated based on the annual cost of operating and maintaining the fleet and includes, among other things, fuel, insurance, licencing and retrofitting costs. This hourly rate is then charged to all projects based on the number of hours the vehicle is used on that project. Vehicle costs are allocated to operations, maintenance, capital and third party billable projects. Costs are adjusted to actual at year-end.

Labour Burden Costs

To capture the labour burden costs, a percentage rate is calculated on the annual cost of the trade employee benefits and the expenses of the trades supervisory department. These costs include items such as employee benefits and payroll taxes such as EI, CPP, EHT, WSIB, and group insurances. Costs are allocated to operations, maintenance, capital and third party billable projects as a total percentage based on direct labour costs charged to each project. An overhead rate is set at the beginning of each year and adjusted to actual at year end.

Billing and Collecting

Burlington Hydro's Billing and Meter Reading department and the Customer Service department are responsible for Billing and Collections activities that include:

- correctly computing and billing customers using approved rates, rate riders, rate adders, loss factors and other regulated rates and charges
- testing and promoting Customer Information System enhancements to support regulatory changes
- processing bill payments in a timely manner to satisfy cash flow requirements, and
- dealing with delinquent accounts appropriately so that all customers pay for the services provided to them.

Billing Department

The Billing group is responsible for all billing activities supporting approximately 65,000 customers in Burlington Hydro's service area. This includes the provision of bi-monthly and monthly billing that results in Burlington issuing over 440,000 invoices annually (including approximately 6,800 final bills for customers moving within or outside of Burlington Hydro's service territory annually). The Billing Department is responsible for managing Electronic Business Transactions ("EBT") and retailer settlement functions for 5,000 retailer accounts; account adjustments; processing of meter changes (e.g. re-verification); and other various account related field service orders, and mailing services. In 2012 Burlington Hydro produced approximately 440,000 bills with a billing error rate of 0.08%.

Burlington Hydro offers customers a number of billing and payment options including an equal payment plan, electronic bill presentment, credit card payment and a preauthorized payment plan. In addition, customers can view their usage and manage their consumption using an online application.

Formerly, Burlington Hydro's Billing department was also responsible for residential and small commercial Meter Reading. With the completed deployment of Smart Meters and the ancillary infrastructure (e.g. AMI), Meter Reading services are now limited to non-interval commercial customers with demand >50kWs.

Customer Service Department

The Customer Service group is responsible for the call centre and collection activities for the approximately 65,000 customers in Burlington Hydro's service area. Burlington Hydro aspires to achieve customer service excellence in its processes and customer programs.

Customer Call Centre

The Customer Call Centre is responsible for handling day to day customer inquiries in regards to their accounts and fielding numerous other questions as they relate to Government and Regulatory policy, conservation and demand management, pricing and consumption inquiries. In addition to this function, the Customer Contact Centre is also responsible for processing of payments dropped off at our office, customer move ins and outs, activations of our Equal Payment program, and numerous other administrative tasks. The Customer Call Centre fields over 68,000 calls and responds to over 8,500 written communications per year (based on our 2012 year end data).

As the number of electricity end users in our service area increases and changes occur within Ontario's electricity market, Burlington Hydro's call and correspondence volumes will continue to increase.

Collections

Collection activity is not exclusive to overdue accounts, it also includes the adoption and continued application of a prudent Credit Policy which is compliant with the OEB's Distribution System Code.

Burlington Hydro utilizes an extensive early collections process to minimize the number of accounts that near the disconnection stage. Active accounts are collected on through phone calls, notices, and hand delivered letters. Overdue final accounts are assigned to a Collection Agency 60 days after the due date. In the recent past Burlington Hydro has benefited from a reduction in its bad debt expense that is attributed to overall economic improvement and increased early delinquency collections.

Community Relations

LDCs are the electricity industry's customer interface with Ontario's power users. For Burlington Hydro this means a commitment to provide relevant and timely consumer information to it's over 65,000 customers, including proactive communications as it relates to the local distribution system and related electricity issues that impact ratepayers. Burlington Hydro maintains a visible presence in the community it serves by educating and keeping its customers informed about electrical safety (at home and in the workplace); energy conservation and demand management as it relates to ongoing public education (at events, in schools, via customer newsletters, marketing and advertising) and delivering a complement of residential and business CDM programs; contributions to the community, including its charitable activities; consumer-based issues such as escalating electricity prices or Time-of-Use rates; projects and local initiatives (i.e. Community Energy Plan); and, any relevant programs, issues and/or projects that impact customers.

Within Burlington Hydro, the costs included in the Community Relations cost category are related to the functions of the Burlington Hydro community safety programs, conservation initiatives that are not funded by the OPA, and activities related to corporate and customer communications.
Descriptions of these various activities are cited below. Burlington Hydro does not have any sales related expenditures.

Education – Electricity Safety

Burlington Hydro supports electrical safety awareness in the community through a number of initiatives including:

- Elementary school safety: Burlington Hydro staff visit local schools to provide age appropriate sessions on Electricity Safety and Conservation to students in grades one through eight. Burlington Hydro targets reaching each school on a three year cycle.

- Secondary school safety: Burlington Hydro staff participates in two programs, “Passport to Safety” and “Our Youth at Work”, that are aimed at reaching new and young workers to assist these groups in workplace health and safety. Burlington Hydro also participates in “Take Your Child to Work” day, during which the sons and daughters of Burlington Hydro staff enrolled in Grade 9 are invited to Burlington Hydro to learn about the work performed by an LDC, including workplace and electrical safety.
- Contractor Safety: Burlington Hydro has initiated a Powerlines Safety Seminar to interested local businesses, with special effort to attract managers or owners/operators of non-electrical businesses whose workers are at greatest risk of inadvertent contact with power lines.
- General Safety: Burlington Hydro continues to work with neighbouring utilities to deliver electrical safety messages throughout the area. Burlington Hydro also supports Crime Stoppers of Halton by educating customers with respect to grow house operations.

Energy Conservation

Building a conservation culture continues to be an important objective for Burlington Hydro. Burlington Hydro is very active in the community promoting conservation initiatives, attending a number of community events each year and distributing information on energy conservation. Burlington Hydro continues to participate with the OPA in administering programs directed at energy conservation such as The Fridge and Freezer Pickup, peaksaverPLUS, Retrofit and Small Business Lighting. The costs of these programs that are planned to be completed as of December 31, 2014 are funded through the OPA. Through these programs and activities, Burlington Hydro supports the Green Energy and Green Economy Act initiatives.

Corporate and Customer Communications

Corporate and Customer Communications is responsible for strategically leading the development, enhancement, alignment and co-ordination of the Corporation's Communications plans and programs, including the development and implementation of customer communications.

As LDC roles and responsibilities have expanded and evolved over recent years, so too has the growing need for effective customer communications. Comprehensive communications is fundamental to establishing sound customer relations, trust and the value that Burlington Hydro delivers to the community – all of which strengthen the Burlington Hydro brand and the long-standing relationship of the company with its customers, stakeholders, and shareholders.

The coordination of both internal and external communications strategies is central to supporting the company's strategic plan, as well as key community, safety, customer and employee initiatives. More particularly, external strategies and plans help to support media relations, website development, the development of various collateral materials, newsletters and the integration of social media into the communications platform. All of these activities focus on enhancing public understanding of their local distributor and Ontario's power system, as well as educating consumers on electrical safety, managing their electricity bill, creating a culture of conservation, CDM program delivery, and activities that directly support community initiatives.

Administrative and General Expenses

Burlington Hydro is an incorporated legal entity that through the provision of governance by its Board of Directors and effective leadership by its Executive team adheres to strong utility practice and good business practice. Burlington Hydro strives to meet or exceed the applicable legislative and regulatory requirements. The administrative and general expenses incurred by Burlington Hydro are necessary to provide the organization with an appropriately skilled and experienced workforce and the materials and goods that support the ongoing provision of service.

Within Burlington Hydro, the following functional areas are considered to be part of general administration and, as such, expenses incurred within these functional areas are accounted for as administrative and general expenses:

- Executive
- Human Resources
- Accounting
- Information Technology
- Regulatory Affairs
- Purchasing

The functions of each of these groups are described in more detail below.

Executive

Burlington Hydro's Board of Directors governs the utility and its 4 Executive members are responsible for the leadership of Burlington Hydro. The costs associated with this group include the salaries, benefits, and miscellaneous costs of the President and CEO; Executive Vice-President of Finance/Administration and Chief Financial Officer; Vice-President Corporate Relations and Vice-President Engineering and Operations and Chief Operating Officer; and allocable costs (e.g. IS&T, office space). In addition to these costs, the remuneration paid to Burlington Hydro's Board of Directors and the costs of their liability insurance is also included in the Executive Salaries and Expenses account.

Corporate Relations (including Human Resources, Communications and Health and Safety)

Corporate Relations is responsible for compensation, benefits administration, pension, health and safety, employee wellness, recruitment, labour relations, performance management, internal and external communications and the training and development of all staff. The department is also responsible for Employee Post-Retirement Benefits include annual expenses for post-retirement benefits provided to eligible Burlington Hydro employees in accordance with company policy and as provided in the collective bargaining agreement between Burlington Hydro and its union. The department is comprised of a;

- Vice-President, Corporate Relations;
- Manager of Human Resources, Health, Safety and Environment;
- Human Resources Generalist;
- Human Resources/Safety Coordinator,
- Customer Service Manager
- Communications Manager.

The Human Resources department is responsible for building and enhancing employee potential through talent management and health, safety and wellness programs. These programs will not only benefit employees, they will also support the organization in meeting its strategic goals and objectives and encourage a culture of customer centric excellence.

Accounting

The Accounting department is responsible for the preparation of statutory financial reporting in accordance with GAAP until December 31, 2014 and in IFRS commencing January 1, 2015; all daily accounting functions, including accounts payable, accounts receivable, and general accounting; accounting systems and internal control processes; preparation of consolidated budgets and forecasts; and supporting tax compliance. Expenses include salaries and all related expenses associated with the Controller, Accountant, Payroll Administrator and two Accounting Clerks.

Information Services

The Information Services department is responsible for the development, operation, maintenance and security of the required infrastructure (hardware, software) to support the business, operations, customer and financial systems utilized by the utility and the integration of these systems. Expenses include salaries and all related costs (e.g. training) associated with the Director of Information System, Business Systems Coordinator, two Network Administrators and two Programmer Analysts, licensing costs, leasehold costs, disaster recovery infrastructure, and compliance with market evolution, compliance with consumer protection programs and evolving government and regulatory policy.

Regulatory Affairs

The Regulatory Affairs department is responsible for all aspects of compliance with applicable legislation and codes governing Burlington Hydro for regulatory reporting and for filing applications. Regulatory reporting includes development and preparation of rate filings, performance reporting, and compliance. The department is comprised of:

- Director, Regulatory Compliance and Asset Management
- Manager of Regulatory Affairs
- Regulatory Accountant
- Regulatory Analyst

The Regulatory Affairs department is also responsible for the management and delivery of all conservation program initiatives that are funded by the OPA.

Purchasing

The Purchasing department is responsible for the procurement of materials (stock) and related services for Burlington Hydro of an appropriate quality at market prices. Purchasing materials and/or services may be through tender, RFQ, RFP, cooperative purchasing (e.g. Halton Cooperative Purchasing Group) or through alliance agreements with the coordination of these processes by the Manager of Purchasing and/or the Buyer in the group. The Purchasing department is also responsible for the disposal of certain materials and for the Stores Department whose duties include inventory control and warehousing functions. The Purchasing department staff consists of the Manager, Stores/Purchasing, 2 Stores clerks and the Purchasing Clerk. A portion of the costs associated with these activities and these groups is allocated to the Operations group through the Stores Overhead charge.

Exhibit 4: Operating Costs

Tab 2 (of 8): Summary and Cost Driver Tables

Attachment 1 (of 3):

Appendix 2-JA: Summary of Recoverable OM&A Expenses

Appendix 2-JC
Summary of Recoverable OM&A Expenses

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Community Relations	$41,584	$14,894	$18,589	$16,073	$19,158	$19,500
Administrative and General+LEAP	$4,671,786	$5,266,558	$5,319,521	$5,492,207	$6,008,031	$6,216,618
SubTotal	**$7,018,523**	**$7,678,009**	**$7,339,193**	**$8,622,655**	**$8,248,424**	**$8,546,650**
%Change (year over year)			-4.4%	17.5%	-4.3%	3.6%
%Change (Test Year vs Last Rebasing Year - Actual)						11.3%
Total	**$14,346,994**	**$14,001,054**	**$14,526,803**	**$16,159,061**	**$17,472,149**	**$18,553,350**
%Change (year over year)			3.8%	11.2%	8.1%	6.2%

32%

	Last Rebasing Year (2010 Board-Approved)	Last Rebasing Year (2010 Actuals)	2011 Actuals	2012 Actuals	2013 Bridge Year	2014 Test Year
Operations	$4,464,123	$4,047,491	$4,643,079	$4,387,015	$5,621,434	$6,283,903
Maintenance	$2,864,348	$2,275,554	$2,544,531	$3,149,391	$3,602,291	$3,722,797
Billing and Collecting	$2,305,153	$2,396,557	$2,001,083	$3,114,375	$2,221,235	$2,310,532
Community Relations	$41,584	$14,894	$18,589	$16,073	$19,158	$19,500

Administrative and General	$4,671,786	$5,266,558	$5,319,521	$5,492,207	$6,008,031	$6,216,618
Total	**$14,346,994**	**$14,001,054**	**$14,526,803**	**$16,159,061**	**$17,472,149**	**$18,553,350**
%Change (year over year)			3.8%	11.2%	8.1%	6.2%

	Last Rebasing Year (2010 Board-Approved)	Last Rebasing Year (2010 Actuals)	Variance 2014 BA – 2014 Actuals	2011 Actuals	Variance 2011 Actuals vs. 2014 Actuals	2012 Actuals	Variance 2012 Actuals vs. 2011 Actuals	2013 Bridge Year	Variance 2013 Bridge vs. 2012 Actuals	2014 Test Year	#N/A
Operations	$4,464,123	$4,047,491	$416,632	$4,643,079	$595,588	$4,387,015	-$256,064	$5,621,434	$1,234,419	$6,283,903	$662,469
Maintenance	$2,864,348	$2,275,554	$588,794	$2,544,531	$268,977	$3,149,391	$604,860	$3,602,291	$452,900	$3,722,797	$120,506
Billing and Collecting	$2,305,153	$2,396,557	-$91,404	$2,001,083	-$395,474	$3,114,375	$1,113,292	$2,221,235	-$893,140	$2,310,532	$89,297
Community Relations	$41,584	$14,894	$26,690	$18,589	$3,695	$16,073	-$2,516	$19,158	$3,085	$19,500	$342
Administrative and General	$4,671,786	$5,266,558	-$594,772	$5,319,521	$52,963	$5,492,207	$172,686	$6,008,031	$515,824	$6,216,618	$208,587
Total OM&A Expenses	$14,346,994	$14,001,054	$345,940	$14,526,803	$525,749	$16,159,061	$1,632,258	$17,472,149	$1,313,088	$18,553,350	$1,081,201
Adjustments for Total non-recoverable items (from Appendices 2-JA and 2-JB)											
Total Recoverable OM&A Expenses	$14,346,994	$14,001,054	$345,940	$14,526,803	$525,749	$16,159,061	$1,632,258	$17,472,149	$1,313,088	$18,553,350	$1,081,201
Variance from previous year				$525,749		$1,632,258		$1,313,088		$1,081,201	
Percent change (year over year)				4%		11%		8%		6%	
Percent Change: Test year vs. Most Current Actual						14.82%					
Simple average of % variance for all years						32.51%					7%
Compound Annual Growth Rate for all years											2046.1%
Compound Growth Rate (2012 Actuals vs. 2014 Actuals)						15.41%					

Attachment 2 (of 3):

Appendix 2-JB: Recoverable OM&A Cost Driver Table

Appendix 2-JD

Recoverable OM&A Cost Driver Table

OM&A	Last Rebasing Year (2010 Actuals)	2011 Actuals	2012 Actuals	2013 Bridge Year	2014 Test Year
Reporting Basis	CGAAP	CGAAP	CGAAP	CGAAP	CGAAP
Opening Balance		$14,032,278.00	$14,526,803.00	$16,159,061.00	$17,472,149.84
5010-Load Dispatching	$1,126,483	$122,660		$220,118	$262,648
5012-Station Buildings and Fixtures Expense	$129,706	$56,123			
5016-Distribution Station Equipment - Operation Labour	$480,523	$106,112		$177,649	$211,799
5017-Distribution Station Equipment - Operation Supplies and Expenses	$351,565	$58,855		$150,558	$67,958
5020-Overhead Distribution Lines and Feeders - Operation Labour	$344,420	$67,743		$50,863	
5025-Overhead Distribution Lines & Feeders - Operation Supplies and Expenses	$251,257	$59,302		$247,657	
5035-Overhead Distribution Transformers- Operation	$39,515			$149,229	
5040-Underground Distribution Lines and Feeders - Operation Labour	$66,684				
5045-Underground Distribution Lines & Feeders - Operation Supplies & Expenses	$641,219			$88,836	
5055-Underground Distribution Transformers - Operation	$69,302	$61,244			
5120-Maintenance of Poles, Towers and Fixtures	$91,409		$123,480		
5125-Maintenance of Overhead Conductors and Devices	$621,416	$78,064	$132,732	$238,820	
5130-Maintenance of Overhead Services	$275,647			$74,964	
5135-Overhead Distribution Lines and Feeders - Right of Way	$523,668			$125,492	
5150-Maintenance of Underground Conductors and Devices	$285,182	$61,030	$223,251		
5160-Maintenance of Line Transformers	$132,285	$64,341			
5175-Maintenance of Meters	$78,832		$72,153		
5310-Meter Reading Expense	$335,903		$1,124,428		
5315-Customer Billing	$741,281		$96,072		
5335-Bad Debt Expense	$202,429			$72,395	
5605-Executive Salaries and Expenses	$847,043			$308,390	
5615-General Administrative Salaries and Expenses	$1,321,872	$373,354	$150,227	$132,168	$53,416
5620-Office Supplies and Expenses	$515,774			$132,955	
5640-Injuries and Damages	$69,727	$64,194		$51,847	
5665-Miscellaneous General Expenses	$876,840	$84,682		$88,664	$85,643
Misc less than $50K		$393,183	$387,815	$362,380	$434,750
OTHER OM&A ACCOUNTS	$3,612,296				
All Other Changes		-$1,156,362	-$677,900	-$1,359,896	-$35,014
Closing Balance	$14,032,278	$14,526,803	$16,159,061	$17,472,150	$18,553,350

Attachment 3 (of 3):

Appendix 2-L: Recoverable OM&A Cost per Customer and per FTE

Appendix 2-L
Recoverable OM&A Cost per Customer and per FTE

	Last Rebasing Year - 2009- Board Approved	Last Rebasing Year - 2009- Actual	2011 Actuals	2012 Actuals	2013 Bridge Year	2014 Test Year
Reporting Basis	**CGAAP**	**CGAAP**	**CGAAP**	**CGAAP**	**NewCGAAP**	**NewCGAAP**
Number of Customers	79,977	78,579	79,615	80,312	81,231	82,161
Total Recoverable OM&A from Appendix 2-JB	14,346,994	14,001,054	14,526,803	16,159,061	17,472,149	18,553,350
OM&A cost per customer	179	178	182	201	215	226
Number of FTEs	101	94	91	93	95	100
Customers/FTEs	792	835	876	861	855	822
OM&A Cost per FTE	142,049	148,821	159,776	173,195	183,917	185,534

OM&A VARIANCE ANALYSIS

The year over year changes since 2010 are explained below. Burlington Hydro's materiality criteria was calculated to be $150,000 as per the OEB's methodology.

2010-2011 Variances, Increases above the materiality threshold are described below

Table 4-2: 2010-2011 Variances

OEB	Description	2010 Actual	2011 Actual	Var	%
3500-Distribution Expenses - Operation	5010-Load Dispatching	$1,126,483	$1,249,143	$122,660	10.89%
3500-Distribution Expenses - Operation	5016-Distribution Station Equipment - Operation Labour	$480,523	$586,635	$106,112	22.08%
3800-Administrative and General Expenses	5615-General Administrative Salaries and Expenses	$1,321,872	$1,695,226	$373,354	28.24%

Administrative and General Expenses: 5615-General Administrative Salaries and Expenses

The increase of $373,353, reflects two recruitments during 2011. The first of the two positions was a Regulatory Accountant which was filled in August of 2011. The Regulatory Accountant who reports to the Regulatory Compliance and Asset Management Director, ensures that the accounting activities for regulatory financial reporting are in compliance with all Ontario Energy Board (OEB) policies and guidelines. Given the increase in regulatory filings and requirements, the position was deemed critical in order to maintain compliance with the regulators. The responsibilities of the role include;

- Track and reconcile all OEB accounts, including business rationale for changes in balances, cost side of accounts subject to prudency review (i.e. conservation, smart meters) and the cost side of Ontario Power Authority (OPA) program;

- Initiate a process that requires managers to be responsible for the review of variance accounts and sign-off on transactions within accounts on a monthly basis;
- Tracking of rate riders, balances and status';
- OEB RRR report preparation, support and backup for filing and its submission to OEB
- Assistance in accounting matters for regulatory applications, such as, rate applications, IRM and specific account clearing proceedings
- Monitor the Smart Meter Implementation Program and Smart Meter monthly reporting to the OEB.
- Calculate contributed capital refund amount and its payment to developer per OEB guidelines. Coordinate with legal counsel for all legal paper work. Annual estimation of buy back amount for year-end accruals.
- Maintain Capital budgeting worksheets.
- Read and interpret directives from OEB and their potential impact on reporting requirements.

The second of the recruitment was for a Level III Engineering Services Technician. This position was filled in July of 2011. The Engineering Services Technician is responsible for providing the customer with the necessary information regarding Burlington Hydro policies, procedures, design standards and charges for servicing new and existing industrial, commercial and residential facilities for both overhead pole lines and underground electrical distribution. The key duties of this position are to;

- Design Hydro Plant layout for servicing new and the upgrading of industrial, commercial and residential facilities
- Prepare labour and material estimates for projects and requisition of transformers

- Prepare drawings, sketches, and select pole framing standards to be included in design packages
- Prepare overhead and underground servicing designs, whether new or an upgrade of an existing service
- Answer inquiries by contractors, electricians and service customers regarding service requirements and, if necessary, meet with them on site
- Assist surveyor in the layout of Hydro plant
- Perform guying calculations, voltage drop calculations and pulling tension calculations
- Review and coordinate subdivision and townhouse projects
- Answer inquiries from customers regarding voltage and tree problems and take appropriate action to rectify
- Act as a liaison between customer and construction crews/contractors
- Prepare instruction orders and assemble design packages for construction crews
- Follow up on instruction orders by tracing their whereabouts in the system upon request of supervisor or customer
- Follow up on completed instruction orders
- Upgrade transformers that are subjected to excessive over loads
- Calculate transformer, feeder and fuse loading when called upon by supervisor or as part of project design
- Monitor the transformers in stock to ensure surplus transformers are not requisitioned

- While in the field, always be aware of any facilities that require repair, i.e., rotten poles, defective equipment

Another contributing factor to the increase was the replacement of a Manager, Regulatory Affairs (which filled a short term vacancy in 2010) and the increment in costs to transition a position in Regulatory Affairs from part-time to full-time.

2011-2012 Variances, Increases above the materiality threshold are described below

Table 4-3: 2011-2012 Variances

OEB	Description	2011 Actual	2012 Actual	Var	%
3550-Distribution Expenses - Maintenance	5120-Maintenance of Poles, Towers and Fixtures	$117,114	$240,594	$123,480	105.44%
3550-Distribution Expenses - Maintenance	5125-Maintenance of Overhead Conductors and Devices	$699,480	$832,212	$132,732	18.98%
3550-Distribution Expenses - Maintenance	5150-Maintenance of Underground Conductors and Devices	$346,212	$569,463	$223,251	64.48%
3650-Billing and Collecting	5310-Meter Reading Expense	$209,516	$1,333,944	$1,124,428	536.68%
3800-Administrative and General Expenses	5615-General Administrative Salaries and Expenses	$1,695,226	$1,845,453	$150,227	8.86%

Administrative and General Expenses: 5615-General Administrative Salaries and Expenses

Increase of $150,227

This increase was due to recruitment of a Manager of Corporate Communications. Reporting to the Vice President of Corporate Relations, the Manager of Corporate Communications is responsible for strategically leading the development, enhancement, alignment and co-ordination of the Corporation’s Communications plans. This position is also responsible for planning, developing and implementing customer communications in support of marketing activities which may be required in support of the Community Energy Plan. This position is in part subsidized by affiliates such as GridSmartCity. The key duties involve:

- Provide strategic internal/external communications and marketing expertise.
- Identify key communications issues;
- Develop annual comprehensive internal and external corporate communications plan/budget, in support of the corporation’s strategic plan and of key community, safety, customer and employee initiatives;

- Design communication packages and feedback loops as required that may involve Customers, Board of Directors, Shareholder, Province, key governmental and other agencies (Ontario Energy Board, Ontario Power Authority, Electricity Distributors Association, etc.), Investment community, Media, employees, etc.;
- Develop, recommend, implement and coordinate internal timely communications activities using the full range of communications tactics such as intranet, newsletter, and social media;
- Develop, recommend, implement and coordinate external communications strategies and plans which encompass;
- media relations, press releases, and serving as company spokesperson, as per company policy;
- serving as webmaster for the company website, responsible for content;
- production of print/electronic materials including researching, writing and producing the annual corporate report;,
- Maintain and enhance Community Relations and Customer Care through communications and events.

As LDC roles and responsibilities have expanded and evolved over recent years, so too has the growing need for effective customer communications. Comprehensive communications is fundamental to establishing sound customer relations, trust and the value that Burlington Hydro delivers to the community – all of which strengthen the Burlington Hydro brand and the long-standing relationship of the company with its customers, stakeholders, and shareholders.

The coordination of both internal and external communications strategies is central to supporting the company's strategic plan, as well as key community, safety, customer and employee initiatives. More particularly, external strategies and plans help to support media relations, website development, the development of various collateral materials, newsletters and the integration of social media into the communications platform. All of these activities focus on enhancing public understanding of their local distributor and Ontario's power system, as well as educating consumers on electrical safety, managing their electricity bill, creating a culture of conservation, CDM program delivery, and activities that directly support community initiatives, such as the City of Burlington's Community Energy Plan.

Distribution Expenses – Maintenance: 5150-Maintenance of Underground Conductors and Devices

Increase of $223,251

Burlington Hydro owns and maintains 32 substations. The substations undergo a complete maintenance once every three years.

Year to year maintenance varies as the repairs and maintenance performed is based on the specific assessment and recommendations. Costs can vary depending on the nature of the work involved and the number of substations maintained.

Billing and Collecting – 5310-Meter Reading Expense

Increase of $1,124,428

The $1,124.4k increase related to changes in Smart Meter costs - specifically, the implementation of the OEB's Decision and Order, EB-2012-0081. Of the $1.12M, $913K accounts for one-time Smart Meter related OM&A costs while $345K accounts for AMI and $19.5K accounts for telecommunications costs.

2012-2013 Variances, Increases above the materiality threshold are described below

Table 4-4: 2012-2013 Variances

OEB	Description	2012 Actual	2013 Bridge Year	Var	%
3500-Distribution Expenses - Operation	5010-Load Dispatching	$1,250,534	$1,470,652	$220,118	17.60%
3500-Distribution Expenses - Operation	5016-Distribution Station Equipment - Operation Labour	$501,322	$678,971	$177,649	35.44%
3500-Distribution Expenses - Operation	5017-Distribution Station Equipment - Operation Supplies and Expenses	$378,504	$529,062	$150,558	39.78%
3500-Distribution Expenses - Operation	5025-Overhead Distribution Lines & Feeders - Operation Supplies and Expenses	$290,388	$538,045	$247,657	85.28%
3550-Distribution Expenses - Maintenance	5125-Maintenance of Overhead Conductors and Devices	$832,212	$1,071,032	$238,820	28.70%
3800-Administrative and General Expenses	5605-Executive Salaries and Expenses	$936,134	$1,244,524	$308,390	32.94%

Burlington Hydro notes that its accounting for OM&A spending is impacted by the change in accounting policy to comply with the OEB's mandated changes to capitalization policy; this results in a $836k increase.

Distribution Expenses: Operations, 5010-Load Dispatching

Increase of $ $220,118

This increase is attributable to the hiring of an Electrical Operator Supervisor whose role is to be accountable for the 24 hour, 365 days a year operation of the Control Room. Responsible for the organization, scheduling, and supervision of Electrical Operator(s) and Control Room and is involved in system planning and recovery from emergency conditions. The primary responsibilities of the Electrical Operator Supervisor are to;

- Supervise, co-ordinate and schedule the activities of Electrical Operator(s) to ensure that the Control Room functions safely and smoothly, minimize interruption of power.
- Assigns work per shift, long-term work and shift coverage to ensure the smooth flow of routine work and that all shifts are covered.

- Requisition labour, materials and equipment as required, prepares and acts on Electrical Operator succession plan for smooth transitions into future.
- Supervise outage procedures and orderly restorations
- Ensure satisfactory union relations through a fair administration of the Collective Agreement
- Counsels employees on acceptable workplace behaviors and performance-related problems.
- Organizes non-work-related information programs for staff with Human Resources.
- Trains and ensures the training of the staff on job duties, safety procedures, company policies, and ensures the staff are code compliance and up-to-date as per provincial regulations.
- Identify, investigate, correct and document potential environmental and safety hazards
- Audit safety procedures and conduct and complete safety field visit reports for staff
- Plan and present information for safety meetings and report safety meeting attendance
- Investigate incidents and accidents, and write reports
- Lead by example, while actively participating at safety meetings, job sites, training etc.
- Assist in preparing and controlling department budget.
- Complete and file all petty cash, expense sheets, invoices and allowance.
- Report and calculate monthly variance report
- Monitors daily operations and system conditions to make sure that the system is running safely and properly
- Maintains Scada system database and worldview Mapping system to keep the Scada control system operating and to gather data pertaining to system operations
- Respond to requests for information to supply administration with details on outages or events for insurance claims or customer complaints.

Distribution Expenses: Operation, 5016-Distribution Station Equipment, Operation Labour

Increase of $177,649

This increase is mainly due to the newly added overhead burdens which were formally capitalized.

Distribution Expenses – Operations: 5017-Distribution Station Equipment - Operation Supplies and Expenses

Increase of $150,558

Similar to the previous year, the substations undergo a complete maintenance once every three years.

These costs, above, are shown grouped together, as they are representative of work performed to manage the substations and associated property.

Year to year maintenance varies as the repairs and maintenance performed is based on the assessment and recommendations. Costs can vary depending on the nature of the work involved and the number of substations maintained.

Distribution Expenses – Operations: 5025-Overhead Distribution Lines & Feeders - Operation Supplies and Expenses

Increase of $247,657

These costs are representative of work performed to manage the overhead distribution system. Events such as weather related failures or equipment failures are allocated to this account. Since these are unplanned events, the costs vary from year-to-year. The increase also reflects that Burlington Hydro performed an unusually high level of Feeder construction and Pole Replacement capital work in 2012 that resulted in higher amounts of 2012 costs being capitalized. The completion of this work in 2012 resulted in Burlington Hydro performing a lower level of capital work in 2013.

Distribution Expenses – Maintenance: 5125-Maintenance of Overhead Conductors and Devices

Increase of $238,820

These costs represent work performed to manage the overhead distribution system. Events such as weather related failures or equipment failures are allocated to this account. Since these are unplanned events, the costs vary from year-to-year. Pole replacement is also a contributor to the increase in costs over the previous year. Information on pole replacement can be found in the Distribution System Plan.

Administrative and General Expenses – 5605-Executive Salaries and Expenses

Increase of $308,390

This major portion of this variance is due to the reclassification of $230K from the 5610-Management Salaries and Expenses to the 5605-Executive Salaries and Expenses.

Table 4-5: Reclassification

Before reclassification

5605-Executive Salaries and Expenses	$452,743	$487,494	$34,751	7.68%
5610-Management Salaries and Expenses	$1,124,137	$1,235,692	$111,555	9.92%

After reclassification

5605-Executive Salaries and Expenses	$936,134	$1,244,524	$308,390	32.94%
5610-Management Salaries and Expenses	$376,543	$258,143	$(118,400)	-31.44%

The GIS Supervisor reports to the Manager of Engineering and is responsible for functionality of the GIS and ensuring the connectivity is correct in order to retrieve accurate asset counts and that asset attributes are entered accurately by Operators. A liaison between Engineering and Information Services for all software and hardware needs while remaining focused on GIS. The position's key duties are to;

- Ensure that connectivity is correct in order to retrieve accurate asset counts and asset age.
- Implementing and maintain functionality of applications associated with GIS such as Daffron, Control Room pinning maps application, outage management, mobile asset inspection system.
- Setting protocols for saving information in Engineering on server in I.S. department to avoid loss of information in the event of a system crash.
- Coordinate with Operations department to prepare annual maintenance and inspection programs by providing maps and setting up the MAIS application.
- Create asset management strategy prioritizing assets that pose the highest risk to the company.
- Set up the mobile automated field force application in Operations to tie in applications for instruction orders, work orders, time sheets, trouble reports and system priority orders.
- Set up of the material assembly units required to implement the Daffron CPR unit feature.
- Oversee third party pole attachment permits and field audits to track permit and billing information within the GIS and prepare annual billing queries to facilitate yearly invoicing.
- Assist with third party transfer list in the Operations department by leveraging GIS information and tracking time lapse waiting for completing transfers.
- Primary support for engineering systems and the Control Room pinning map application.
- Provision of asset data for use by the Regulatory department.

$42k of the variance is attributable to the use of a contractor to support Control Room operations.

2013-2014 Variances, Increases above the materiality threshold are described below

Table 4-6: 2013-2014 Variances

OEB	Description	2013 Bridge Year	2014 Test Year	Var	%
3500-Distribution Expenses - Operation	5010-Load Dispatching	$1,470,652	$1,733,300	$262,648	17.86%
3500-Distribution Expenses - Operation	5016-Distribution Station Equipment - Operation Labour	$678,971	$890,770	$211,799	31.19%

Distribution Expenses: Operations, 5010-Load Dispatching

Increase of $262,648

Approximately $103.7k of the increase is due to the reclassification of costs related to the GIS system and the GIS Supervisor. $42k of the variance is attributable to the use of a contractor in support of continued Control Room operations.

Distribution Expenses: Operations, 5016-Distribution Station Equipment Operation Labour

Increase of $211,799

BHI visually inspects all 32 distribution stations, records the temperature of the transformer's oil, monitors transformer loading and documents these findings in monthly reports. Good utility practice guides Burlington Hydro's scheduling of dissolved gas analysis testing; for example, the frequency of testing is greater for those transformers with higher levels of dissolved gas. System operations data (e.g. faults experienced by a transformer) is also relied on to identify the need for and plan the maintenance activities. This data is considered in combination to assess transformers 'health' and to identify the need for and plan maintenance activities. A material portion of the variance relates to the planned recruitment of a Stations Maintenance Supervisor as of the end of 2013. Costs can vary depending on the nature of the work involved and the number of substations maintained.

ONE-TIME COSTS

With the exception of costs related to the regulatory matters, Burlington Hydro has not included any one-time costs in the 2014 operating budget. The estimated costs for completing this application is being amortized over a period of five years. Further details on this topic can be found at Exhibit 4, Tab 2, Schedule 4.

REGULATORY COSTS

Burlington Hydro proposes to recover $715K of regulatory expenses through rates in 2014. The purpose of this evidence is to document Burlington Hydro's ongoing Regulatory costs, the drivers of these costs and the quantified year over year changes. Burlington Hydro has completed the OEB's Schedule 2-M; it is provided at Exhibit 4 Tab1 Schedule 5 Attachment 1.

Burlington Hydro's Regulatory Costs include:

- Salaries, benefits (Account 5610/5615)
- Staff development costs (e.g. conference fees, subscriptions) (Account 5620)
- Licence renewal fees (Account 5655)
- OEB assessment (Account 5655)
- Section 30 cost awards (Account 5655)
- ESA Audit fees (Account 5655)
- Application costs (Account 5655)

Burlington Hydro employs a Regulatory Accountant, a Regulatory Analyst and a Manager, Regulatory Affairs. Their day to day activities are overseen by the Director, Regulatory Compliance and Asset Management who reports to the CFO, EVP Finance and Administration. These positions are responsible for all aspects of regulatory compliance and reporting. The Regulatory Analyst also performs CDM related duties; the costs of these activities are recovered through the OPA's Program Administration Budget.

Burlington Hydro's proposed 2014 costs include $99,400 for the amortization over 5 years of the costs of the subject application. The derivation of the total cost of the subject application and of the proposed amortization expense is provided at Schedule 2-M; it is provided at Exhibit 4 Tab2 Schedule 5 Attachment 1.

In order to prepare the subject Application to the standard expected by the OEB (e.g. that satisfies the OEB's MFG, Filing Checklist) Burlington Hydro has retained consultants with expertise and experience in:

- Rate making
- Load forecasting
- Asset Condition Assessments
- Distribution System Planning
- Adoption of new accounting policies
- Estimation of PILs expense
- Cost Allocation and Rate Design
- Review of LRAM-VA balances and CDM achievements

Additionally, Burlington Hydro has retained experienced legal counsel and consultants familiar with rate-making policies and issues in Ontario's electricity industry. Like many other LDCs, Burlington Hydro has been diligent in preparing a transparent EDR Application that meets the Board's and interveners' expectations.

Burlington Hydro also projects average incremental costs of $25K in each of the following four IRM filing years, or an aggregate amount of $100K, due to the increased efforts expected under the Board's 3rd Generation IRM e.g. revenue to cost adjustments, deferral/variance account dispositions including additional filing requirements such as those arising from the Distribution System Plan, GEGEA, Smart Metering, RRFE etc.

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Appendix 2-M
Regulatory Cost Schedule

	Regulatory Cost Category	USoA Account	USoA Account Balance	Ongoing or One-time Cost? [2]	Last Rebasing Year (2010 Board Approved)	Most Current Actuals Year 2012	2013 Bridge Year	Annual % Change	2014 Test Year	Annual % Change
	(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H) = [(G)-(F)]/(F)	(I)	(J) = [(I)-(G)]/(G)
1	OEB Annual Assessment	5655		On-Going	$ 212,000	$ 187,761	$ 190,000	1.19%	$ 206,000	8.42%
2	OEB Section 30 Costs (Applicant-originated)				$ 11,250					
3	OEB Section 30 Costs (OEB-initiated)				$ 34,883	$ 13,525	$ 12,505	-7.54%		-100.00%
4	Expert Witness costs for regulatory matters	5655		One-Time					$ 10,000	
5	Legal costs for regulatory matters	5655		One-Time	$ 25,250				$ 24,000	
6	Consultants' costs for regulatory matters	5655		One-Time	$ 21,737	$ 45,003	$ 138,095	206.86%	$ 43,000	-68.86%
7	Operating expenses associated with staff resources allocated to regulatory matters	5615		One-Time	$ 38,400				$ 390,000	
8	Operating expenses associated with other resources allocated to regulatory matters [1]								$ 2,400	
9	Other regulatory agency fees or assessments					$ 800	$ 800	0.00%		-100.00%
10	IRM application and other regulatory applications	5655		One-Time					$ 20,000	
11	Intervenor costs			One-Time	$ 8,750				$ 20,000	
12	Sub-total - Ongoing Costs [3]		$ -		$ -	$ -	$ -		$ 596,000	
13	Sub-total - One-time Costs [4]		$ -		$ -	$ -	$ -		$ 119,400	
14	Total		$ -		$ -	$ -	$ -		$ 715,400	

Please fill out the following table for all <u>one-time</u> costs related to this cost of service application to be amortized over the test year plus the IRM period.

		Historical Year(s)	2013 Bridge Year	2014 Test Year
4	Expert Witness costs			50000
5	Legal costs			120000
6	Consultants' costs	45003	138000	215000
7	Incremental operating expenses associated with staff resources allocated to this application.			0
8	Incremental operating expenses associated with other resources allocated to this application. [1]			112000
11	Intervenor costs			100000

Attachment 1 (of 1):

Appendix 2-M Regulatory Cost Schedule

CHANGES IN OM&A DUE TO NEW CAPITALIZATION POLICY

Burlington Hydro has quantified a 700K increase in OM&A which reflects the combined effect of the change in accounting policy that was implemented effective January 1, 2013 as well as changes in the level of capital spending.

Burlington Hydro has provided detailed information on the change in capitalized overhead; please see Burlington Hydro's completed OEB Appendix 2-DB provided at Attachment 1 of this Schedule

Attachment 1 (of 1):

Appendix 2-DB: Overhead Expense (CGAAP or ASPE)

File Number:	EB-2013-0115
Exhibit:	2
Tab:	5
Schedule:	8
Page:	1
Date:	01-Oct-13

Appendix 2-DB
Overhead Expense

The following table should be completed based on the information requested below. An explanation should be provided for any blank entries. The entries should include overhead costs that are currently capitalized on self-constructed assets under revised CGAAP or ASPE (with the changes in capitalization and depreciation expense policies).

	(A)	(B)	(C)	(D)	(E)	(F)	(G)
Nature of the Overhead Costs	**Dollar Impact on PP&E Historic Year**	**Dollar Impact on PP&E Bridge Year**	**Dollar Impact on PP&E Test Year**	**Dollar Impact - PP&E Variance Test versus Bridge**	**Dollar Impact - PP&E Variance Test versus Historic**	**Directly Attributable? (Y/N)**	**Reasons why the overhead costs are allowed to be capitalized under CGAAP or ASPE (with the changes in policies) given limitations on capitalized overhead**
Stores				$ -	$ -		
Benefits	68,192.20			$ -	-$ 68,192	N	
Labour	221,396.31			$ -	-$ 221,396	N	
Others	2,204.75			$ -	-$ 2,205	N	
Scrap	2,359.75			$ -	-$ 2,360	N	
Building Expenses	47,426.77			$ -	-$ 47,427	N	
				$ -	$ -		
Payroll Burdens				$ -	$ -		
Health Benefits	94,457.61	106,559.64	102,581.56	-$ 3,978	$ 8,124	Y	Directly attributable
Govt. Deductions	148,536.31	175,500.24	155,729.59	-$ 19,771	$ 7,193	Y	Directly attributable
Other	3,985.38	3,791.01	3,394.98	-$ 396	-$ 590	Y	Directly attributable
Safety and training	24,403.09	0.00	0.00	$ -	-$ 24,403	N	
Vacation and Stats Holidays	118,679.18	133,144.11	109,810.87	-$ 23,333	-$ 8,868	Y	Directly attributable
Foreman Health Benefits	52,943.54	44,151.00	53,168.00	$ 9,017	$ 224	Y	Directly attributable
Foremen Office Supplies	7,053.65	0.00	0.00	$ -	-$ 7,054	N	
Foremen Labour	190,264.54	76,320.00	99,268.00	$ 22,948	-$ 90,997	Y	Directly attributable
Foremen Vehicle Cost	8,877.85	0.00	0.00	$ -	-$ 8,878	N	
Foremen Other	824.37	0.00	0.00	$ -	-$ 824	N	
				$ -	$ -		
Engineering				$ -	$ -		
Benefits	136,969.70	179,174.00	89,371.00	-$ 89,803	-$ 47,599	Y	Directly attributable
Consultants	85,584.03	0.00	0.00	$ -	-$ 85,584	N	
Vehicle Cost	3,396.26	0.00	0.00	$ -	-$ 3,396	N	
Labour	508,644.92	326,126.00	176,728.00	-$ 149,398	-$ 331,917	Y	Directly attributable
Membership	15,588.87	0.00	0.00	$ -	-$ 15,589	N	
Office Supplies	56,079.49	0.00	0.00	$ -	-$ 56,079	N	
Other	13,723.53	0.00	0.00	$ -	-$ 13,724	N	
Pole Testing	12,333.85	0.00	0.00	$ -	-$ 12,334	N	
Software Amortization	92,284.99	0.00	0.00	$ -	-$ 92,285	N	
				$ -	$ -		
Fleet				$ -	$ -		
Benefits	1,259.08	5,377.73	8,484.69	$ 3,107	$ 7,226	Y	Directly attributable
Depreciation	111,441.64	37,769.39	42,563.92	$ 4,795	-$ 68,878	Y	Directly attributable
Labour	1,320.41	5,972.45	8,597.07	$ 2,625	$ 7,277	Y	Directly attributable
Leases	0.00	11,352.29	70,125.12	$ 58,773	$ 70,125	Y	Directly attributable
Service Centre Expenses	44,477.85	0.00	0.00	$ -	-$ 44,478	N	
Trucks	139,437.06	159,973.62	173,879.97	$ 13,906	$ 34,443	Y	Directly attributable
Total	$ 2,214,147	$ 1,265,211	$ 1,093,703	-$ 171,509	-$ 1,120,444		

The following table should be completed based on the information requested below. An explanation should be provided for any blank entries. The entries should include overhead costs that were capitalized on self-constructed assets under CGAAP but are no longer capitalized under revised CG

	(A)	(B)	(C)	(D)	(E)	(F)	(G)
Nature of the Overhead Costs	**Dollar Impact on OM&A Historic Year**	**Dollar Impact on OM&A Bridge Year**	**Dollar Impact on OM&A Test Year**	**Dollar Impact - OM&A Variance Test versus Bridge**	**Dollar Impact - OM&A Variance Test versus Historic**	**Directly Attributable? (Y/N)**	**Reasons why the overhead costs are allowed to be capitalized under CGAAP or ASPE (with the changes in policies) given limitations on capitalized overhead**
Stores				$ -	$ -		
Benefits	9,980.71	71,000.87	70,239.22	-$ 762	$ 60,259		
Labour	32,403.90	231,086.41	229,392.55	-$ 1,694	$ 196,989		
Others	322.69	3,622.80	3,584.91	-$ 38	$ 3,262		
Scrap	345.38	15,106.95	14,798.17	-$ 309	$ 14,453		
Building Expenses	6,941.45	50,739.95	49,188.30	-$ 1,552	$ 42,247		
				$ -	$ -		
Payroll Burdens				$ -	$ -		
Health Benefits	216,747.36	268,033.98	301,342.55	$ 33,309	$ 84,595		
Govt. Deductions	340,839.18	441,508.58	457,377.57	$ 15,869	$ 116,538		
Other	9,145.06	9,535.69	9,973.05	$ 437	$ 828		
Safety and training	55,996.59	75,078.83	90,774.31	$ 15,695	$ 34,778		
Vacation and Stats Holidays	272,327.44	334,903.01	322,579.28	-$ 12,324	$ 50,252		
Foreman Health Benefits	121,487.02	157,600.20	171,106.25	$ 13,506	$ 49,619		
Foremen Office Supplies	16,185.68	19,003.36	19,828.77	$ 825	$ 3,643		
Foremen Labour	436,590.96	476,552.06	555,792.21	$ 79,240	$ 119,201		
Foremen Vehicle Cost	20,371.57	38,110.65	39,696.65	$ 1,586	$ 19,325		
Foremen Other	1,891.66	4,119.04	4,302.10	$ 183	$ 2,410		
				$ -	$ -		
Engineering				$ -	$ -		
Benefits	11,704.11	135,750.33	236,272.75	$ 100,522	$ 224,569		
Consultants	7,313.19	135,676.33	137,963.31	$ 2,287	$ 130,650		
Vehicle Cost	290.21	4,146.99	4,230.81	$ 84	$ 3,941		
Labour	43,463.88	697,360.05	960,755.68	$ 263,396	$ 917,292		
Membership	1,332.07	29,091.23	29,567.04	$ 476	$ 28,235		
Office Supplies	4,792.01	106,682.47	114,426.39	$ 7,744	$ 109,634		
Other	1,172.68	30,245.07	30,782.79	$ 538	$ 29,610		
Pole Testing	1,053.93	29,211.00	29,712.93	$ 502	$ 28,659		
Software Amortization	7,885.78	178,243.57	175,116.63	-$ 3,127	$ 167,231		
				$ -	$ -		
Fleet				$ -	$ -		
Benefits	1,629.29	4,382.50	5,824.07	$ 1,442	$ 4,195		
Depreciation	144,208.82	30,779.58	29,216.78	-$ 1,563	-$ 114,992		
Labour	1,708.66	4,867.16	5,901.21	$ 1,034	$ 4,193		
Leases	0.00	9,251.37	48,135.36	$ 38,884	$ 48,135		
Service Centre Expenses	57,555.67	103,619.73	103,755.05	$ 135	$ 46,199		
Trucks	180,435.72	130,368.02	119,354.85	-$ 11,013	-$ 61,081		
Total	$ 2,006,123	$ 3,825,678	$ 4,370,992	$ 545,314	$ 2,364,869		

LOW-INCOME ENERGY ASSISTANCE PROGRAM (LEAP)

Burlington Hydro has included $40,000 of expense for the Low Income Assistance Program (LEAP) under Deductions Donation Expense (USoA #6205). This amount is based on the Board’s determination that the greater of 0.12% of a distributor’s Board-approved distribution revenue requirement.

Together with Halton Region Burlington Hydro supports LEAP by providing year-round emergency financial assistance program designed to help low-income customers who have difficulty making electricity bill payments.

LEAP is modeled after the “Winter Warmth” program, previously offered by Burlington Hydro. Burlington Hydro chose to partner with Halton Region S&CS to connect individuals and families in crisis to the Region’s full range of assistance programs.

Burlington Hydro reports on funds provided by the distributor to social agencies for: LEAP emergency financial assistance and funds received by the distributor’s social agency partner(s) from non-distributor sources (i.e., donations) that were earmarked for and used to top up, the LEAP emergency financial assistance funds. This information is presented at the next page.

Table 4-7:2012 2.1.16 RRR filing

LEAP funds received from:

Distributor	Non distributor sources*	Unused funds from previous year(s)
33,118.66		

Total funds received
33,118.66

*Funds received by the distributor from a third party or from the distributor's shareholder(s) (i.e., not funded from distribution revenues) as a donation and then provided by the distributor to its social agency partner(s).

Note: Funds received under the terms of the settlement of the class action proceeding regarding late payment penalties should not be included in any of the above.

LEAP funds disbursed for:

Agency administration and program delivery	Grants to distributor customers	Grants to unit sub-metered customers**	Total grants disbursed	Total funds disbursed
0.00	19,180.37		19,180.37	19,180.37

Total unused funds
13,938.29

Funds depleted

* Month in which LEAP funds were depleted
December

Number of LEAP applicants who were:

Distributor customers	Unit sub-metered customers**	Total
36		36

Number of applicants assisted who were:

Distributor customers	Unit sub-metered customers**	Total assisted
36		36

Number of applicants denied who were:

Distributor customers	Unit sub-metered customers**	Total denied
		0

Average grant per accepted applicant for:

Distributor customer	Unit Sub metered average**	Overall average
532.79		532.79

**Applicants that were customers of licensed unit sub-metering providers operating in the distributor's service area, including the distributor if licensed as such.

Table 4-8 2013 2.1.6 RRR filing

LEAP funds received from:

Distributor	Non distributor sources*	Unused funds from previous year(s)
33,118.66	0.00	

Total funds received
33,118.66

*Funds received by the distributor from a third party or from the distributor's shareholder(s) (i.e., not funded from distribution revenues) as a donation and then provided by the distributor to its social agency partner(s).

Note: Funds received under the terms of the settlement of the class action proceeding regarding late payment penalties should not be included in any of the above.

LEAP funds disbursed for:

Agency administration and program delivery	Grants to distributor customers	Grants to unit sub-metered customers**	Total grants disbursed	Total funds disbursed
0.00	7,439.52	0.00	7,439.52	7,439.52

Total unused funds

Funds depleted

* Month in which LEAP funds were depleted
No funds depleted

Number of LEAP applicants who were:

Distributor customers	Unit sub-metered customers**	Total
16	0	16

Number of applicants assisted who were:

Distributor customers	Unit sub-metered customers**	Total assisted
16	0	16

Number of applicants denied who were:

Distributor customers	Unit sub-metered customers**	Total denied
		0

Average grant per accepted applicant for:

Distributor customer	Unit Sub metered average**	Overall average

**Applicants that were customers of licensed unit sub-metering providers operating in the distributor's service area, including the distributor if licensed as such.

CHARGES RELATED TO THE GREEN ENERGY AND GREEN ECONOMY ACT

Burlington Hydro has included $40,000 of expense for the Low Income Assistance Program (LEAP) under Deductions Donation Expense (USoA #6205). This amount is based on the Board's determination that the greater of 0.12% of a distributor's Board-approved distribution revenue requirement.

Together with Halton Region Burlington Hydro supports LEAP by providing year-round emergency financial assistance program designed to help low-income customers who have difficulty making electricity bill payments.

LEAP is modeled after the "Winter Warmth" program, previously offered by Burlington Hydro. Burlington Hydro chose to partner with Halton Region S&CS to connect individuals and families in crisis to the Region's full range of assistance programs.

Burlington Hydro reports on funds provided by the distributor to social agencies for: LEAP emergency financial assistance and funds received by the distributor's social agency partner(s) from non-distributor sources (i.e., donations) that were earmarked for and used to top up, the LEAP emergency financial assistance funds. This information is presented at the next page.

Table 4-7: RRR 2.1.16 2013

LEAP funds received from:

Distributor	Non distributor sources*	Unused funds from previous year(s)
33,118.66		

Total funds received: 33,118.66

*Funds received by the distributor from a third party or from the distributor's shareholder(s) (i.e., not funded from distribution revenues) as a donation and then provided by the distributor to its social agency partner(s).

Note: Funds received under the terms of the settlement of the class action proceeding regarding late payment penalties should not be included in any of the above.

LEAP funds disbursed for:

Agency administration and program delivery	Grants to distributor customers	Grants to unit sub-metered customers**	Total grants disbursed	Total funds disbursed
0.00	19,180.37		19,180.37	19,180.37

Total unused funds: 13,938.29

Funds depleted

* Month in which LEAP funds were depleted: December

Number of LEAP applicants who were:

Distributor customers	Unit sub-metered customers**	Total
36		36

Number of applicants assisted who were:

Distributor customers	Unit sub-metered customers**	Total assisted
36		36

Number of applicants denied who were:

Distributor customers	Unit sub-metered customers**	Total denied
		0

Average grant per accepted applicant for:

Distributor customer	Unit Sub metered average**	Overall average
532.79		532.79

**Applicants that were customers of licensed unit sub-metering providers operating in the distributor's service area, including the distributor if licensed as such.

Table 4-8: RRR 2.1.16 2012

LEAP funds received from:

Distributor	Non distributor sources*	Unused funds from previous year(s)
33,118.66	0.00	

Total funds received: 33,118.66

*Funds received by the distributor from a third party or from the distributor's shareholder(s) (i.e., not funded from distribution revenues) as a donation and then provided by the distributor to its social agency partner(s).

Note: Funds received under the terms of the settlement of the class action proceeding regarding late payment penalties should not be included in any of the above.

LEAP funds disbursed for:

Agency administration and program delivery	Grants to distributor customers	Grants to unit sub-metered customers**	Total grants disbursed	Total funds disbursed
0.00	7,439.52	0.00	7,439.52	7,439.52

Total unused funds:

Funds depleted

* Month in which LEAP funds were depleted: No funds depleted

Number of LEAP applicants who were:

Distributor customers	Unit sub-metered customers**	Total
16	0	16

Number of applicants assisted who were:

Distributor customers	Unit sub-metered customers**	Total assisted
16	0	16

Number of applicants denied who were:

Distributor customers	Unit sub-metered customers**	Total denied
		0

Average grant per accepted applicant for:

Distributor customer	Unit Sub metered average**	Overall average

**Applicants that were customers of licensed unit sub-metering providers operating in the distributor's service area, including the distributor if licensed as such.

CDM COSTS

Distributors have had their licences amended to include the requirement to meet specific Conservation and Demand Management ("CDM") targets by the end of 2014. Burlington Hydro's targets are a net annual peak demand savings of 21.95 MW and a net cumulative energy savings of 82.37 GWh.

Burlington Hydro filed its CDM Strategy with the OEB in accordance with the CDM Code for Electricity Distributors in the fall of 2010. Burlington Hydro began delivering CDM programs in 2011 in order to meet the mandated targets. The emphasis has been on Ontario Power Authority ("OPA") Contracted Province-Wide Programs to residential and general service customers. Burlington Hydro has not sought approval for Board-approved CDM programs.

The OPA provides funding for Burlington Hydro 's CDM programs. Burlington Hydro 's funding portfolio for 2011 to 2014 is approximately $3,847,116. Funding and expenditures for the delivery of OPA Contracted Province-Wide Programs are kept separate and tracked in Non-Distribution Revenue Accounts in accordance with the guidance in Chapter 5, Accounting Treatment of the CDM Code.

In addition, Burlington Hydro has ensured that any function performed within the distribution company for CDM activity has been attributed and tracked in the non-distribution accounts. Therefore, CDM activities are not included in the calculation revenue requirement or revenue offsets.

At this time, Burlington Hydro does not contemplate employing any Board-Approved programs. The intent is to meet demand and energy reduction requirements by delivering OPA-Contracted Province-Wide programs. Burlington Hydro will not be applying for any OM&A costs related to the administration and delivery of CDM programs to be recovered through the revenue requirement.

Burlington Hydro may, in the future, turn to Board-Approved CDM Programs, should the prescribed OPA funding model prove insufficient to deliver OPA-Contracted Province-Wide programs or the net results do not meet intended demand and energy savings.

In compliance with Section 2.3.3 of the Minimum Filing Requirements which states that, distributors filing cost of service rate applications for 2012 and subsequent rate years must file with the Board a GEA Plan as part of such an application, Burlington Hydro's Green Energy Plan and its supporting documents are included in the Distribution System Plan presented at Exhibit 2, Tab 5, Schedule 3.

Burlington Hydro has not forecasted any OM&A costs to address Renewable Generation Connection or Smart Grid development as per the Green Energy Act.

CHARITABLE DONATIONS

In compliance with the filing requirements, which state that “the recovery of charitable donations will not be allowed for the purpose of setting rates, except for contributions to programs that provide assistance to the distributor’s customers in paying their electricity bills and assistance to low income consumers.” Burlington Hydro confirms that no amounts for charitable donations have been included in its proposed distribution expenses for the 2014 test year.

Burlington Hydro confirms that it has reviewed the amounts filed to ensure that all other non-recoverable contributions, including any political contributions if any, were identified, disclosed and removed from the revenue requirement calculation.

The amounts paid in charitable donations from 2010 up to 2012 are presented in the table below.

Table 4-9 - 2010 Charitable Donations excluded from OM&A

G.L. Number	Vendor Name	Description	Amount
70375-01-00	Hydro One	2010 Charity Golf sponsorship	$2,500.00
70375-01-00	MMI Utility Services	Prizes for EDIST 2010	$712.86
70375-01-00	Halton Women's Place	Annual fundraiser dinner	$1,500.00
70375-01-00	YMCA of Ham./Burl.	Strong Kids annual campaign sponsorship	$1,000.00
70375-01-00	Burl.Art Centre	Corporate sponsorship	$200.00
70375-01-00	B.E.D.C.	Mayor's Golf Classic	$4,200.00
70375-01-00	City of Burlington	Take Action Burlington Event sponsorship	$1,666.67
70375-01-00	Engineering Week	Corporate sponsorship	$100.00
70375-01-00	Crosswinds G & C Club	United Way Golf sponsorship	$699.52
70375-01-00	Our Youth, Our Future	Youthfest 2010 sponsorship	$1,800.00
70375-01-00	Ont. Energy Network	2010 OEN charity golf tournament	$1,100.00
70375-01-00	Crosswinds G & C Club	United Way Golf sponsorship	$699.52
70375-01-00	Burl. Chamber of Comm.	Charity Golf sponsorship	$796.00
70375-01-00	YMCA of Ham./Burl.	Strong Kids golf sponsorship	$900.00
70375-01-00	Burl.Art Centre	Mothers Day Tea - Corporate sponsorship	$275.00
70375-01-00	Milton Hydro	Power Saving Series - event sponsorship	$1,000.00
70375-01-00	Ontario Elec. League	O.E.L. Golf sponsorship	$980.00
70375-01-00	Burl. Fire Department	Corporate sponsorship	$600.00
70375-01-00	Burl.Teen Tour Band	Charity Golf sponsorship	$780.00
70375-01-00	R.O.C.K.	Reach Out Centre for Kids charity golf sponsorship	$1,600.00
70375-01-00	Olameter	Charity Golf sponsorship	$400.00
70375-01-00	Crosswinds G & C Club	United Way Golf sponsorship	$228.69
70375-01-00	MMI Utility Services	CUEE 2010 sponsorship	$1,000.00
70375-01-00	Engineering Week	Corporate sponsorship	$550.00
70375-01-00	United Way of Burl/Ham	Campaign 2010 kick-off event	$2,000.00
70375-01-00	Burl.Art Centre	Corporate sponsorship	$80.00
			$27,368.26
70480-01-00	Princess Margret Hospital	Memorial Donation	$100.00
70480-01-00	YMCA of Hamilton	Sponsorship - YMCA Strong Kids	$350.00
70480-01-00	United Way of Burl/Ham	Memorial Donation	$100.00
70480-01-00	Cdn.Breast Cancer Foundation	Company Match - - Run for the Cure	$250.00
70480-01-00	United Way of Burl/Ham	2010 Company Match	$13,056.00
			$13,856.00

Table 4-10 - 2011 Charitable Donations excluded from OM&A

G.L. Number	Vendor Name	Description	Amount
70375-01-00	MMI utility	2011 EDIST Sponsorship	$1,000.00
70375-01-00	Burl.Art Centre Foundation	Art Auction 2011	$150.00
70375-01-00	YMCA of Hamilton/Burlington	2011 YMCA Strong Kids campaign	$1,000.00
70375-01-00	B.E.D.C.	BEDC Signature Event sponsorship	$1,400.00
70375-01-00	Conservation Halton	2011 Conservation Gala	$1,200.00
70375-01-00	The MEARIE Group	Enercom 2011 sponsorship	$1,000.00
70375-01-00	Burl. Community Foundation	2011 BCF Masquerade Ball sponsorship	$2,500.00
70375-01-00	Burl. Chamber of Commerce	Golf Tournament sponsorship	$796.00
70375-01-00	B.E.D.C.	Sponsorship - Mayor's Golf tournament	$4,200.00
70375-01-00	YMCA of Hamilton/Burlington	2011 YMCA Strong Kids Golf Classic	$900.00
70375-01-00	Our Youth, Our Future	Youthfest sponsorship	$1,800.00
70375-01-00	Copetown Woods Golf Club	United Way Golf	$576.00
70375-01-00	Ontario Energy Network	OEN Sunnybrook Charity Golf Tournament	$1,040.00
70375-01-00	Burl. Fire Department	2011 Burlington Fire Department Golf Tournament sponsorship	$600.00
70375-01-00	Rotary Partnership Charity	Rotary Partnership Charity Golf Tournament	$940.00
70375-01-00	Breast Cancer Support Serv.	Corporate sponsorship of 'The Event'	$3,000.00
70375-01-00	Burl.Art Centre Foundation	Soup Bowl 2011 sponsorship	$275.00
70375-01-00	Eng.Week c/o Milton Hydro	Engineering Week 2011 corporate plus sponsorship	$550.00
70375-01-00	Breast Cancer Support Serv.	Event sponsorship	$400.00
70375-01-00	Burl.Performing Arts Centre	Red Carpet Event sponsorship	$798.00
70375-01-00	Burl. Festival of Lights	Burlington Festival of Lights sponsorship	$1,000.00
			$25,125.00
70480-01-00	Halton Women's Place	Donation to annual fundraiser dinner	$300.00
70480-01-00	Canadian Cancer Society	Memorial donation	$100.00
70480-01-00	McNally House Hospice	Memorial donation	$100.00
70480-01-00	Cdn Diabetes Association	Memorial donation	$100.00
70480-01-00	Heart & Stoke Foundation	Memorial donation	$100.00
70480-01-00	Canadian Breast Cancer	Canadian Breast Cancer, Run for the Cure, employee match	$230.00
70480-01-00	St.Patrick's R.C.Church	Memorial donation	$100.00
70480-01-00	Burlington Humane Society	Memorial donation	$100.00
			$1,130.00

Table 4-11 - 2012 Charitable Donations excluded from OM&A

G.L. Number	Vendor Name	Description	Amount
70325-01-00	United Way - Burlington Hydro's contribution	Burlington Hydro's matching contribution - 2011	$12,778.00
70325-01-00	United Way - Burlington Hydro's contribution	Burlington Hydro's matching contribution - 2012	$14,011.50
			$26,789.50
70375-01-00	United Way		$100.00
70375-01-00	Conservation Halton Fdtn.	2012 Conservation Gala	$1,200.00
70375-01-00	Halton Women's Place	Annual Dinner, Dance & Auction	$300.00
70375-01-00	City of Burlington	Sponsorship - Mayor's Cabaret	$2,500.00
70375-01-00	IBEW	Hole sponsorship for golf tournament	$500.00
70375-01-00	City of Burlington	Sponsorship for Inspire Burlington	$2,500.00
70375-01-00	YMCA of Hamilton/Burlington	2012 YMCA Strong Kids Campaign	$1,000.00
70375-01-00	Burl. Chamber of Commerce	Past Chair's Golf Tournament sponsorship	$796.00
70375-01-00	B.E.D.C.	Sponsorship - Mayor's Golf tournament	$2,100.00
70375-01-00	Youthfest 2012	Our Youth, our Future	$1,800.00
70375-01-00	Rotary Partnership Charity	Rotary Partnership Charity Golf Tournament	$980.00
70375-01-00	Burl. Community Fdtn.	2012 BCF Masquer. Burlington	$2,500.00
70375-01-00	Ontario Energy Network	2012 OEN Golf Tournament	$1,080.00
70375-01-00	Crosswinds Golf & C.Club	Mayor's Golf Tournament	$688.00
70375-01-00	Copetown Woods Golf Club	United Way Golf	$610.00
70375-01-00	Plug 'N Drive Ontario	Charge My Car So Plug	$5,000.00
70375-01-00	Breast Cancer Support Serv.	Events sponsorship	$3,300.00
70375-01-00	Carmen's Banquet & C.C.	Event Sponsorship	$1,500.00
70375-01-00	Burlington Arts Centre	Event Sponsorship	$275.00
			$28,729.00
70385-21-00	Crimestoppers of Halton	2012 Golf Tournament	$1,250.00
70480-01-00	Brain Tumour Fdtn.	Memorial donation	$100.00
70480-01-00	Reformation Lutheran Church	Memorial donation	$100.00
			$200.00

Exhibit 4: Operating Costs

Tab 3 (of 8): Program Delivery Costs with Variance Analysis

PROGRAM OVERVIEW

Burlington Hydro aims to meet or exceed the system maintenance and inspection requirements of the Ontario Energy Board's Distribution System Code (DSC) in order to minimize subsequent repair and/or replacement costs. Section 4.4.1, of the DSC states:

"A distributor shall maintain its distribution system in accordance with good utility practice and performance standards to ensure reliability and quality of electricity service, on both a short-term and long-term basis."

The following routine maintenance programs are consistent with good utility practices and are applied annually within the Burlington Hydro distribution system.

- General Maintenance of Overhead and Underground Distribution Assets
- Safety
- Training
- Vegetation Management
- Transformer Inspection
- Insulator Cleaning/Washing
- Infrared Inspection
- Cubicle Washing
- Pole Testing
- PCB Management
- Fleet
- Locates

Each program is discussed further below.

General Maintenance of Overhead & Underground Distribution Assets:

Maintenance work performed outside of the capital budget accounts is captured through the operating maintenance accounts. This work can be either planned or unplanned, and can involve capital work under the general service capital budgets. Maintenance and operating budgets are prepared based on historical values. The field asset inspection program identifies a number of immediate concerns and concerns requiring immediate analysis. Most of the concerns were slated under planned work and categorized as priority scheduled work or normal scheduled work.

Except for the pole replacements, transformer replacements, and wire replacements; the bulk of the concerns will be charged to maintenance. It is expected that the maintenance budget will be fully utilized with the normal volume of maintenance work.
Landscaping around Burlington Hydro padmounted equipment is an ongoing issue, but Burlington Hydro has not allocated resources to deal with the many non-compliant situations in the field. A single location could involve many labour hours of engineering labour, for example, speaking with the customer to communicate the reason for what may appear to a change in practice. The field asset inspection program provided photos of each location setting the premise for corrective action. A letter and mail insert is provided to the customer to reinforce the safety issues and corrective action required. The ESA and Burlington Hydro's shareholder support the initiative to address existing landscape issues. Burlington has hired a public relations consultant to prepare a mail insert for the purpose of educating customers on potential problems that unauthorized and improper landscaping can cause to the electrical equipment from a reliability and safety perspective. Burlington Hydro continues to place a warning sticker on new transformers from the vendor and by Burlington Hydro on in service transformers.

Safety:
Burlington Hydro's Safety Plan supports an effective 'loss prevention' and risk management approach. A strong operating discipline is required to create a safety culture where all employees take accountability for their own safety and that of their

coworkers, where leadership sets an example that no LTI is acceptable and where progress is tracked, measured and improved upon; fundamentally the Ontario Health & Safety Internal Responsibility System (IRS). When healthy and safe organizations employ this operating discipline, they are able to provide management with leading indicator metrics that track and assess the effectiveness of the organization's efforts.

The Safety Plan supports Burlington Hydro's Occupational Health and Safety Management System ('OHSMS') that builds and incorporates an accountability structure, empowers employee involvement and continually measures its performance with the goal of preventing, minimizing and mitigating current and potential areas of loss for the organization. For example, Burlington Hydro participates in the ZeroQuest® – Paths to Zero formal safety program that is targeted to LDCs. It is a four-level program based on commitment, effort, outcomes and sustainability that requires a rigorous process to achieve certification at a specific level.

Burlington Hydro employs a leading indicator approach that measure proactive efforts that can uncover weaknesses before they develop into full-fledged problems. Leading indicators are effective predictors of safety performance because they focus on the types of issues that are key to successful safety performance including leadership, worker participation, incident investigations and root cause analyses. The success of the leading indicator program depends on the audit program, analysis of risk and hazard reviews, near-miss reporting and analysis, employee safety suggestions, training programs and ongoing and rigourous compliance with engineering and legislated standards and guidelines.

Burlington Hydro's Occupational Health & Safety Management System uses a formal "Plan, Do, Check, and Act" process that ensures all employees understanding their accountability for:

- Identifying, reacting to, and mitigating risk in the workplace
- Acting within compliance and safety work practice codes
- Developing preventable measures and objectives tied to performance
- Monitoring and conducting corrective action, as necessary

Training:

Burlington Hydro maintains a comprehensive training program for all its employees. Please see Talent Management Plan at Exhibit 4, Tab, 4, Schedule 2.

Vegetation Management:

To manage the tree trimming activities in the City of Burlington, Burlington Hydro has divided the city into three areas. Each year a tree trimming tender is issued to approved tree trimming contractors that are known in the industry to be capable to undertake the scope of work. In order to control costs, the tender is a fixed price tender for the designated area.

In conjunction with the contract tree trimming area, the contractor is also requested to submit their time and material costs for selection of a contractor to perform miscellaneous tree trimming. This contract requires tree trimming services for unplanned tree trimming due to storms and tree trimming or removals involving customers, and line clearing for Burlington Hydro capital projects; essentially all work out scope of the defined area tree trimming contract.

Tree trimming is a critical element of the overall maintenance program that brings measurable results to the utility. Burlington Hydro is proactive to minimize the destructive impact caused by trees.

Substations and Buildings

Burlington has a comprehensive substation capital improvement program that includes a select number of the 32 substation (44 transformers) encompassing the station equipment and the associated buildings and properties. Monthly patrols of each substation and a thorough inspection every 3 years is key to determine the substations that require capital improvements such as; breaker re-commissioning; relay upgrades; RTU upgrades; transducer upgrades; SCADA software upgrades; paint and refurbishment of metalclad switchgear or the station transformer; switch gear replacement; conversion to vacuum breakers; replacement of batteries and chargers. Substation re-commissioning is performed on a 5 year cycle as a means to extend the service life of the equipment. A substation transformer replacement program began in 2011, targeting transformers more than 40-years old in combination with their specific dissolved gas analysis data. The substation buildings and the properties also require maintenance of foundations, roof repair, alarm system upgrades, grounding, fence repairs, etc.

Insulator Cleaning/Washing:

Burlington Hydro's annual insulator washing program targets hydro poles carrying 27.6kV feeders, and underground circuits attached to the same 27.6kV pole line. The pole lines along high traffic volume routes are a concern due to salt spray from vehicles and other contaminants. The more susceptible routes, such as along highways, are washed twice in the same year. The qualified contractor performing the washing is also required to complete an inspection sheet for each pole to indicate if there are concerns with the pole or any of the attached hardware. These records are kept as evidence of asset inspection as part of the Distribution System Code requirements.

Infrared Inspection:

Although relatively inexpensive, Burlington Hydro's annual thermography of the overhead lines, transformers and stations is essential in detecting hot spots that will lead to connection or equipment failure. The locations of concerns are catalogued and dealt with based on priority.

Cubicle Washing:

Burlington Hydro is currently on a 10 year cycle to clean approximately 20 of the 168 switching cubicles each year. The CO2 cleaning process allows the equipment to remain energized while cleaning operations proceed, therefore the contract must have qualified staff to perform this type of work. The CO2 cleaning process essentially sends a high pressure blast of CO2 pellets which explode on contact and change their state to gas. This change of state facilitates the cleaning of the energized equipment. The contractor provides evidence of cleaning by way of photographs before and after the cleaning. The contractor also advises Burlington Hydro staff of possible concerns noticed before cleaning proceeds.

Since 2008 Burlington Hydro has incorporated into the distribution system the Vista switchgear unit, a self-contained dead front unit, capable of remote supervisory control complete with electronic protection settings. One of the advantages of the Vista unit is that it is a self-contained unit such that future CO2 cleaning will not be not required.

Pole Testing:

As previously mentioned, the integrity of a portion of all hydro poles are tested annually by a pole testing contractor having expertise in using non-invasive testing methods, and if deemed necessary, invasive pole testing methods i.e. sample boring. The current rate of pole testing will see every pole testing in approximately 15 years. The contractor provides Burlington Hydro with the results as a report stating the pole condition and a relative rating of when the pole should be replaced or the remaining life expectancy of the pole. The performance system report suggests that the replacement of the poles identified to be replaced is to be accelerated to minimize the risk of an incident due to a defective pole known to exist. The backlog of defective poles discovered in previous year’s pole testing program have been replaced.

PCB Management:

The replacement of PCB transformers is legislated by the Federal Government of Canada, for all hydro distribution companies. The replacement schedule mandated by the OEB is as follows:

- All transformers containing PCB levels greater than 500ppm to be replaced by the end of 2009.
- Padmount transformers containing PCB levels from 50ppm up to 500ppm to be replaced by the end of 2014, unless located with 100 metres of a sensitive area, by Federal definition.
- All transformers containing PCB levels from 50ppm up to 500ppm located within 100 metres of sensitive areas, by Federal definition, are required to be replaced by the end of 2009.
- Overhead transformers containing a PCB level greater than 50ppm are required to be replaced no later than the end of 2014.

The vault transformer replacements involve extensive engineering design and labour forces to complete, accompanied by the added cost for temporary generator supply. Meeting the compliance deadlines to replace the PCB transformers has impacted the capital budget and has strained construction crews to complete this work in conjunction with the large volume of capital infrastructure work. Long term benefits to the public and the utility are safe working environment, minimal restoration costs in the event of an oil spill, and reassurance to the public that the equipment located in their backyards are environmentally friendly.

Fleet

Burlington Hydro operates a 37-vehicle fleet. Fleet management and operations are geared to minimizing vehicle down time so that there are no inappropriate delays to dispatching a trouble crew to restore service and to maintain vehicle reliability and safety.

In order to contain costs, Burlington Hydro is exploring whether there are cost benefits associated with leasing fleet vehicles.

Locates

A significant portion of Burlington Hydro's distribution system is buried. Whenever Burlington Hydro's customers are preparing to excavate they contact Ontario One Call to request that a Locate be performed. Ontario One Call relays the customer's request to Burlington Hydro who assigns it to a contractor. The contractor fulfills the request within the mandated 5 business day window; this data is valid for 30 calendar days. The contractor provides the data directly to the requesting customer and copies Burlington Hydro so that the customer can safely commence their planned excavation. This is a reactive activity and in a typical year Burlington Hydro responds to over 10,000 requests.

Burlington Hydro maintains and operates an extensive fleet of vehicles and rolling stock. The fleet is comprised of:

1. Pick-up Trucks (13)
2. Trouble Trucks (1)
3. Single or Double Bucket Truck (6)
4. SUV`s (7)
5. Radial Boom Derrick (RBD) (3)
6. Sprinter Van/ Vans (6)
7. Dump Truck (1)
8. Trailers (7)
9. Backhoe (1)
10. Lift Truck (2)

All of which have an established replacement cycle that can be adjusted depending on the particular condition and duty of the individual vehicle. Replacements are reviewed annually and are accommodated within Burlington Hydro's capital budgeting process.

Burlington Hydro currently has one electric and three hybrid Sport Utility Vehicles (SUVs) as part of its fleet and as vehicles become due for replacement consideration will be given to more of these drive trains. This is part of its strategy to operate a more "green" fleet consistent with the City of Burlington's "Greening the Corporate Fleet Transition Strategy" and its profile as an environmentally responsible company. The City of Burlington's strategy includes a goal to "Transition to a green corporate fleet of vehicles using low emission vehicles, cleaner fuels and right sizing vehicles for the job". The strategy comprises ten sections:

1. Right Sizing Fleet Vehicles
2. Hybrid Technology
3. Alternative, Cleaner Fuels
4. Clean Diesel

5. Electric Plug-in Vehicles
6. After-market Automotive Products
7. Vehicle Maintenance
8. Driver Training
9. Transportation Demand Management
10. Monitoring

Appendix 2-JC which shows historical and forecasted costs by programs is presented at the next page.

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Appendix 2-JC
OM&A Programs Table

Programs	Last Rebasing Year (2010 Board-Approved)	Last Rebasing Year (2010 Actuals)	2011 Actuals	2012 Actuals	2013 Bridge Year	2014 Test Year	Variance (Test Year vs. 2012 Actuals)	Variance (Test Year vs .2010 Acutals)
Reporting Basis	CGAAP	CGAAP	CGAAP	CGAAP	NewCGAAP	NewCGAAP		
Program Name #1								
General Maintenance of Overhead & Underground Distribution Assets:	Not Available	2,001,556	2,175,624	2,652,519	1,751,500	2,145,300	-507,219	143,744
							0	0
							0	0
							0	0
							0	0
Sub-Total	0	2,001,556	2,175,624	2,652,519	1,751,500	2,145,300	-507,219	2,145,300
Program Name #2								
Safety:	Not Available	289,331	407,673	379,000	430,542	444,600	65,600	155,269
							0	0
							0	0
							0	0
							0	0
Sub-Total	0	289,331	407,673	379,000	430,542	444,600	65,600	444,600
Program Name #3								
Training:	Not Available	7,277	6,037	6,419	14,750	15,000	8,581	7,723
							0	0
							0	0
							0	0
							0	0
Sub-Total	0	7,277	6,037	6,419	14,750	15,000	8,581	15,000
Program Name #4								
Vegetation Management:	Not Available	387,610	366,722	385,728	449,513	457,650	71,922	70,040
							0	0
							0	0
							0	0
							0	0
Sub-Total	0	387,610	366,722	385,728	449,513	457,650	71,922	457,650
Program Name #5								
Transformer Inspection	Not Available	101,582	65,255	180,762	121,813	122,000	-58,762	20,418
							0	0
							0	0
							0	0
							0	0
Sub-Total	0	101,582	65,255	180,762	121,813	122,000	-58,762	122,000
Program Name #6								
Insulator Cleaning/Washing	Not Available	36,863	40,476	57,352	59,600	60,650	3,298	23,787
							0	0
							0	0
							0	0
							0	0
Sub-Total	0	36,863	40,476	57,352	59,600	60,650	3,298	60,650
Program Name #7								
Cubicle Washing:	Not Available	18,360	14,960	16,320	29,000	29,500	13,180	11,140
							0	0
							0	0
							0	0
							0	0
Sub-Total	0	18,360	14,960	16,320	29,000	29,500	13,180	29,500
Program Name #8								
Pole Testing	Not Available	9,474	29,561	23,737	30,000	30,550	6,813	21,076
							0	0
							0	0
							0	0
							0	0
Sub-Total	0	9,474	29,561	23,737	30,000	30,550	6,813	30,550
Program Name #9								
PCB Management	Not Available	53,286	13,983	55,627	7,191	139,684	84,057	86,398
							0	0
							0	0
							0	0
							0	0
Sub-Total	0	53,286	13,983	55,627	7,191	139,684	84,057	139,684
Program Name #10								
Fleet	Not Available	726,747	827,694	785,952	741,134	533,300	-252,652	-193,447
							0	0
							0	0
							0	0
							0	0
Sub-Total	0	726,747	827,694	785,952	741,134	533,300	-252,652	533,300
Program Name #11								
Locates	Not Available	778,669	557,829	525,617	550,824	550,508	24,891	-228,161
							0	0
							0	0
							0	0
							0	0
Sub-Total	0	778,669	557,829	525,617	550,824	550,508	24,891	550,508
Miscellaneous							0	0
Total	**0**	**4,410,755**	**4,505,814**	**5,069,033**	**4,185,867**	**4,528,742**	**-540,291**	**4,528,742**

Attachment 1 (of 1):

Appendix 2-JC: OMA Programs Table

Exhibit 4: Operating Costs

Tab 4 (of 8): Employee Compensation - Staffing and Compensation Levels

DESCRIPTION OF COMPENSATION STRATEGY AND BENEFIT PROGRAM

Compensation

Burlington Hydro is committed to making the company increasingly safe, secure and efficient. To succeed in an environment of increased growth in budget constraints, technological advances to the grid, Green Energy Act and regulatory change Burlington Hydro must recruit and retain individuals with the appropriate skill set to remain current and competitive. In order to meet this challenge, Burlington Hydro requires employees who are skilled, creative and committed to accomplishing the company's objectives.

In an industry faced with an aging workforce and the challenges of a competitive labour market, Burlington Hydro is faced with a potential turnover approaching 33 percent of its workforce within the next five to ten years. To manage this level of change in its workforce, Burlington Hydro must position itself to attract, motivate and retain the talent that is critical to maintaining and renewing its distribution system. Therefore, Burlington Hydro's total compensation package and ability to offer a rewarding work experience must enable it to compete successfully for employees with the requisite skill sets. Burlington Hydro's workforce is comprised of unionized and non-unionized employees.

<u>Unionized Employees</u>

IBEW Local 636 is the sole bargaining agent for over 70 percent of Burlington Hydro's employees. Compensation for unionized employees is negotiated through the collective bargaining process. When negotiating wage levels, consideration is given to the skill sets required to work within our distribution system, as well as the competitive wage levels of its geographic market.

Burlington Hydro has two Collective Agreements with IBEW Local 636 representing both Office and Trades workers. Burlington Hydro has negotiated a new 2-year collective agreement with both bargaining units, in place effective April 1, 2012. Wage increases were negotiated at 2.9 percent for each contract year. This is consistent with other negotiated settlements with the LDCs in its geographic area. The previous negotiated wages increases were:

2009 – 3.0%
2010 – 3.0%
2011 – 3.0%

Management and Non Union Employees

Burlington Hydro provides its non-unionized employees (Executive, Managers and Non-union) with a total cash compensation package comprised of two elements: base salary and incentive pay. Burlington Hydro's performance-based philosophy ensures that rewards are appropriately aligned with strategic direction of the company.

Burlington Hydro has a formal and disciplined approach in awarding merit increases to employees (see Exhibit 4 Tab 4 Schedule 1 Attachment 1 for details). Merit pay is intended to provide a system to reward employee's success and achievement through increases to base pay. The Merit budget for 2013 and previous 3 years is as follows:

2010 – 3.0%
2011 – 2.9%
2012 – 2.9%
2013 – 2.9%

A merit increase is the amount of additional compensation added to current base salaries following a review of employee performance. The most Senior Manager reviews the performance of each non-union employee in their department, taking into consideration the remarks and comments from the employee's direct supervisor who conducted the review.

In order to ensure Burlington Hydro is remaining competitive in their compensation package for their non-union staff, a review is conducted at least every three years. The last review was conducted by Hay Group in November 2011.

Incentive Pay

Burlington Hydro has an Incentive Compensation Plan for its non-unionized employees. This plan is intended to be variable and as such, provides for significant variability in incentive payouts to employees from year to year, reflecting differences in corporate and/or individual performance.

The purpose and goal of the plan is to motivate staff to look for continued efficiencies within their respective business units. The Incentive Compensation Plan is reviewed annually to ensure continued alignment with corporate direction. Performance in Burlington Hydro is measured against a balanced scorecard of key performance indicators in each of four categories:

1) Financial
2) Internal Processes
3) Learning and Growth
4) Customer/Stakeholder

The plan is activated by achieving corporate objectives which are established at the beginning of each fiscal year. Once activated, the compensation paid under the plan is determined by two components: Corporate performance measures and individual performance measures where weightings are assigned for each.

Weightings for the corporate and individual performance measures differ by position and may change from year to year. Weightings refer to the percentage of the total direct incentive pay that will be paid based on achievements matched to the goals. Incentive pay is then calculated based on a combination of Burlington Hydro corporate balanced scorecard results and the employee's individual performance balanced scorecard results.

Performance Management Program

Non-Unionized Employees

Performance management is a shared communication process that includes input from the employee and the supervisor. It is the collaborative process that facilitates the link between the employee's job duties and expectations and the organization's mission, vision, values and corporate strategic objectives.

The performance management process assists employees in identifying where there may be opportunities for development and to learn about potential career paths that may be available to them in the organization. This feedback process improves productivity and enhances employee motivation and commitment.

Unionized Employees

All unionized employees participate in a formal performance review annually to discuss their performance with their supervisors.

Goals and objectives are agreed to for the next review period in areas that require improvement to meet job or performance targets.

OMERS Pension Plan

The employees of all LDCs are required to participate in the OMERS retirement plan. Therefore, the pension benefits provided to the employees of Burlington Hydro are consistent with the pension benefits provided to employees of other LDCs.

The plan is a contributory plan with employees contributing 50 percent of the premiums and Burlington Hydro contributing 50 percent.

Employee Benefit Plan

A comprehensive and competitive benefits package exists which includes health and dental insurance, life insurance, vacation and leave policies. The plans are designed to address the health and wellness needs of the employee's.

All benefit plans for each employee group are essentially the same. The unionized benefit plans, negotiated through collective bargaining, play a significant role in driving the plan design for the non-unionized employees, with many plan provisions remaining common across all employee groups.

In addition to a pension benefit from OMERS, employees also receive post-retirement health, dental and life insurance benefits up to the age of 65. Post 65 benefits include only Life insurance in which Burlington pays 100% of the premium.

A document detailing Staff Planning is presented at Exhibit 4 Tab 4 Schedule 2.

Attachment 1 (of 2):

Merit Increase Guidelines

Burlingtonhydro inc.

Compensation

Merit Increase Guidelines

As per our compensation philosophy (see below) in order to attract, retain, motivate, and develop talented individuals Burlington Hydro Inc. will provide a competitive and rewarding compensation plan (please see below compensation philosophy). To avoid falling behind the market it is important that on-going maintenance of the compensation system be done as well. With that in mind, each year any recommended compensation adjustments are based on market data from various HR consultants and industry projections.

MERIT MATRIX

a) Merit Increases Guidelines

Annually, Burlington Hydro develops a merit increase guide matrix (see attached) to administer salaries in the compensation program. This guide follows the general compensation principles:

1. Higher rewards shall be granted for higher levels of performance.
2. Higher increases to salaries that are at the lower end of the pay grades (i.e., between 80% and 100%) shall be granted in order to move salaries to the job rate (i.e., 100%) within a reasonable period of time.
3. The amount of increase for competent performance at midpoint (100%) is set at the market “going” rate for merit pay.

b) Salary Positioning in the Range

The movement of an employee through the salary range is based on the individual’s performance against the requirements of the position.

Although performance should always be the primary criterion to support movement through the range it is common practice for any employee to reach the midpoint of the salary range in no more than 3 to 4 years. Under the assumption that a new employee is hired with a salary between 80% and 85% of the range midpoint, the positioning of the salary for the following years should go as follows:

End of year 1:	**At about 87%-88% of midpoint**
End of year 2:	**At about 92%-93% of midpoint**
End of year 3:	**At about 97%-98% of midpoint**
End of year 4:	**At midpoint**

c) Sample Projected Salary Increase Market Data

ORGANIZATION	PROJECTED 20__ Increase	Comments	ORGANIZATION
Hay Group Survey National Ontario Utilities	2.9% 2.7% 3.1%	500 companies surveyed	Hay Group Survey National Ontario Utilities
Morneau Shepell Canada National	2.6%	250 companies surveyed	Morneau Shepell Canada National
Mercer Compensation Survey National Ontario	3.2% 2.9%	750 companies surveyed	Mercer Compensation Survey National Ontario
AON Hewitt Canadian Salary Increase Survey National Greater Toronto	2.9% 3.0%	542 companies surveyed	AON Hewitt Canadian Salary Increase Survey National Greater Toronto
World At Work National Ontario Hamilton/Toronto	3.1% 3.0% 2.8%/3.0%	417 Companies surveyed	World At Work National Ontario Hamilton/Toronto
Culpepper Average Median	2.97%	1160 Companies surveyed globally	Culpepper Average Median
Towers Watson	2.9%	200 companies	Towers Watson
MEARIE Survey Average LDC's surveyed in Geographic area	2.7% 3.0%	49 Local Distribution Companies surveyed	MEARIE Survey Average LDC's surveyed in Geographic area
Burlington Hydro Union contract increase	2.9%		Burlington Hydro Union contract increase
Ontario CPI	2.0%	2013 projected	Ontario CPI

Based on the above guidelines and market data management would then recommend an appropriate Merit Matrix. Another consideration would be adjustments to salaries of junior staff (as there is no progression schedule to salaries) that are at the minimum area of the salary range and to recognize superior performance.

SAMPLE MERIT MATRIX – Non Union

BASED ON PERFORMANCE LEVEL AND CURRENT POSITION IN SALARY RANGE

When performance as measured against full accountabilities of the position is:	**Up to 84%** Merit Increase	**85 – 94%** **Merit Increase**	**95 – 104%** **Merit Increase**	**105% - 114%** **Merit Increase**	**115% - 120%** **Merit Increase**	**120% - 125%** **Merit Increase**
Greatly exceeds expectations 5% of population	Up to **8.0%**	**Up to 7.0%**	**Up to 5.0%**	**Up to 4.0%**	**Up to 3.0%**	**Up to 2.0%**
Exceeds expectations 15% of population	**Up to 7.0%**	**Up to 6.0%**	**Up to 4.0%**	**Up to 3.0%**	**Up to 2.0%**	**Up to 1.0%**
Meets expectations 65% of population	**Up to 5.0%**	**Up to 4.0%**	**Up to 3.0%**	**Up to 2.0%**	**Up to 1.0%**	**NO INCREASE**
Does not meet expectations 13% of population	**Up to 3.0%**	**Up to 2.0%**	**NO INCREASE**	**NO INCREASE**	**NO INCREASE**	**NO INCREASE**
Significantly below expectations 2% of population	**NO INCREASE**	**NO INCREASE**	**NO INCREASE**	**NO INCREASE**	**NO INCREASE**	**NO INCREASE**

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Appendix 2-K
Employee Costs

	Last Rebasing Year - 2010- Board Approved	Last Rebasing Year - 2010- Actual	2011 Actuals	2012 Actuals	2013 Bridge Year	2014 Test Year
Number of Employees (FTEs including Part-Time)[1]						
Management (including executive)	23	20	20	21	22	23
Non-Management (union and non-union)	78	75	70	71	73	77
Total	101	94	91	92	96	100
Total Salary and Wages including ovetime and incentive pay						
Management (including executive)	$ 2,355,752	$ 2,507,949	$ 2,640,630	$ 2,872,537	$ 3,092,527	$ 3,308,436
Non-Management (union and non-union)	$ 5,406,640	$ 5,533,801	$ 5,717,355	$ 5,910,958	$ 6,234,850	$ 6,755,621
Total	$ 7,762,392	$ 8,041,750	$ 8,357,985	$ 8,783,495	$ 9,327,377	$ 10,064,058
Total Benefits (Current + Accrued)						
Management (including executive)	$ 608,875	$ 591,120	$ 662,296	$ 755,048	$ 888,510	$ 905,624
Non-Management (union and non-union)	$ 1,503,990	$ 1,297,083	$ 1,405,992	$ 1,656,437	$ 1,752,389	$ 1,830,091
Total	$ 2,112,865	$ 1,888,203	$ 2,068,288	$ 2,411,485	$ 2,640,899	$ 2,735,715
Total Compensation (Salary, Wages, & Benefits)						
Management (including executive)	$ 2,964,627	$ 3,099,069	$ 3,302,926	$ 3,627,585	$ 3,981,037	$ 4,214,060
Non-Management (union and non-union)	$ 6,910,630	$ 6,830,884	$ 7,123,347	$ 7,567,395	$ 7,987,239	$ 8,585,712
Total	$ 9,875,257	$ 9,929,953	$ 10,426,273	$ 11,194,980	$ 11,968,277	$ 12,799,772

Attachment 2 (of 2):

Appendix 2-K: Employee Costs

WORKFORCE STRATEGY AND PLANNING

OVERVIEW

Workforce strategy and planning is the foundation upon which other human capital activities such as talent management, performance and evaluation and succession management are built. Burlington Hydro Inc. is facing the same challenges the electricity industry is as a whole, relative to its aging demographics and infrastructure. Matching the resource capability with the work demands in the electrical distribution sector requires both short and longer term planning. Numerous contributing factors are impacting workforce planning, including: a shortage of proficiently skilled labour, and increased work demands, due in part to an aging distribution infrastructure across Ontario. The five main factors driving the necessity to review current and future work demands against Burlington Hydro's labour supply are:

1. Aging demographics and pending eligible retirements
2. Competitive and strained labour market supply
3. Multi-year lead time to bring skilled trades to the level of proficiency/qualified
4. Long-term investment and increased work demands due to an aging distribution plant
5. Unpredictability of the Cost of Service ('COS') Rate Application process

Burlington Hydro's workforce strategy primarily focuses on its trades and technical staff, inclusive of the front-line management required to lead and manage the trades groups. Burlington Hydro's workforce strategy takes a broad view of its trades group, such as those skills that are required to maintain and grow its distribution system: power line technicians, substation electricians, metering technicians and electrical control operators. In addition, it includes it's technical and supervisory staff that also support Burlington Hydro's core distribution business: line supervisors, project/supervisory staff, engineering technicians and P&C Supervisors.

Workforce planning involves identifying, assessing, developing and sustaining employee workforce skills required to successfully accomplish business goals and priorities, while balancing the needs and expectations of employees and the business. Essentially, workforce planning is identifying gaps between the labour demand of an organization and the available workforce supply, leading to strategies used to close those gaps.
Burlington Hydro develops long-term plans to support its investment in its distribution business, for both its capital and maintenance programs. Burlington Hydro's core business is providing; a safe and reliable supply of electricity to its customers, efficient customer service and reasonable continued investment in its aging infrastructure. To achieve these outcomes Burlington Hydro needs the right complement of skilled trades, technical and supervisory staff who are proficient and able to meet the work demands now and into the future.

Workforce planning has become increasingly more important in the past few years for a number of reasons:

- Demographic pressures, particularly related to baby boomer retirements, have made the job of staffing organizations more challenging
- With declining birth rates, increased educational requirements and technical complexity, there is both a labour and talent shortage locally and nationally
- Organizations are increasingly realizing that one of the best ways to create a long-term competitive advantage is through developing and leveraging their human capital assets. Much of which comes about through effective workforce planning
- Due to increased complexity and specialization, greater amounts of time and money are being committed to workforce training and development which in turn requires effective workforce planning
- The achievement of strategic objectives for many organizations can only be accomplished if they have the workforce to carry out their strategic

plans. Hence the need for workforce planning to go hand-in-hand with strategic planning and talent management

Workforce strategy and planning provides a strategic basis for making human capital decisions. It allows Burlington Hydro to anticipate change rather than being surprised by events, such as those stated above. As well, it provides an opportunity to develop strategic approaches for addressing present and anticipated workforce issues.

ELEMENTS OF THE WORKFORCE STRATEGY

Workforce Analytics

Sometimes referred to as "human capital data mining", workforce analytics focuses on gaining greater insight into Burlington Hydro's existing workforce and uses that information to identify the workforce needed today and over the next five to ten years aligned to the distribution work demands over the same timeframe. A key element of Burlington Hydro's analytical approach is "segmentation" whereby it has identified those skills and expertise required to maintain: a safe and reliable supply of electricity to its customers, efficient customer service and reasonable continued investment in its aging infrastructure. To achieve these outcomes Burlington Hydro needs the right complement of skilled trades, technical and supervisory staff who are proficient and able to meet the work demands now and into the future.

Burlington Hydro's Workforce analytics continues to improve and develop as it distinguishes those elements that do or may have an impact on its day-to-day core operations, and achieving its strategic goals, relative to its human capital.

Assumptions

The single most critical element of workforce strategy is the assumptions used in developing the analytics. Wrong or incorrect assumptions could:

- Impact forecasting the right complement of manpower to meet the work demand

- Impact the integrity of the workforce strategy
- Leave the business open to criticism and attack from interveners during a Rate Application
- Leave Burlington Hydro unprepared in a rapidly changing demographic and technological environment
- Put its business strategies and safety performance at risk

The goal of workforce planning is to reduce the risk to Burlington Hydro's strategy execution associated with workforce capacity, capability and flexibility. The foundation for workforce planning is the business strategy; therefore, it needs to be owned by the business units. Business unit owners know their business needs, and understand what work needs to get done and how to do it. They understand their challenges related to productive versus non-productive employee time and the fluidity of their own workforces. Human Resources ('HR') plays a critical role of stewardship in the process. HR supports and challenges the business unit leaders to think about what drives their workforce demands.

Burlington Hydro has consulted and collaborated with senior and mid-level leaders to develop, affirm and determine the elements and assumptions appropriate for its workforce strategy. As can be expected, these assumptions can and likely will evolve year-over-year due to Burlington Hydro's business needs and regulated environment.

Following are the elements and associated assumptions used in Burlington Hydro's Five-Year workforce strategy:

RETIREMENTS

How many employees does Burlington Hydro anticipate will retire during the five-year planning window? To determine such and define a level of reasonableness Burlington Hydro relies on it past historical trends and determines retirement eligibility as the age by which an employee can receive an un-discounted and or full pension from the Ontario Municipal Employees Retirement System ('OMERS') pension fund.

ATTRITION

What has Burlington Hydro's experience been with employees leaving voluntarily or, involuntarily, due to termination? Staff turnover can have a substantive impact on workforce analytics when trying to realistically plan for its workforce needs over the next five to ten years.

Burlington Hydro's historical trend for turnover of its trades/technical FTE's is relatively low. On an annual average only 2.216 or 2.4% of employees left Burlington Hydro over the past five years, either voluntarily or involuntarily. Including retirements, 4.8 or 5.2% on average left Burlington Hydro over the same five year period.

PROMOTIONS/TRANSFERS

Burlington Hydro's workforce strategy anticipates temporary or permanent promotions or transfers within the workforce. Burlington Hydro's talent management program promotes the progression of trained and qualified powerline technicians into line supervisory roles. Such can leave a gap where once a proficient and highly skilled worker is taken out of the workgroup, thereby causing an impact on the ratio of safely allocating the number of Powerline technicians to work with less skilled and non-proficient apprentices.

COLLECTIVE AGREEMENT

Burlington Hydro reviews it Collective Agreement against its ability to perform core distribution work. Questions that are asked are: have there been any changes in the hours of work clause, increased training requirements, etc.?

For this planning cycle, Burlington Hydro affirms there is no substantive element of its recently negotiated collective agreement that would impact its workforce strategy.

PRODUCTIVITY/EFFICIENCIES

Under the rules of the Ontario Energy Board ('OEB'), as part of its Incentive Rate Mechanism ('IRM') process, Burlington Hydro is required to achieve a 'productivity factor', at a percentage that is currently relative to its size. This factor is determined through an OEB mandated calculation that sets the percentage, less an industry specific consumer price indices resulting in the required productivity factor Burlington Hydro must achieve ‘annually’, as part of its operating budget. Simply put, after Burlington Hydro determines the budget and headcount it requires to maintain and operate its distribution system and business, it is required to find additional savings of 1.5% ‘each year’ between its COS rate filings.

In its normal course of business Burlington Hydro continues to strive to be as efficient as possible while maintaining a safe and reliable distribution system, and both public and employee safety. Burlington Hydro introduced in its 2011 business planning, a multi-year project to identify potential cost savings within each cost centre and to ‘right size’ staff complement while maintaining sufficient service levels to its customers. Specific goals of the program are to increase the effectiveness and efficiency within all departments and the overall performance of Burlington Hydro.

As a direct result of this program, which is incorporated into Burlington Hydro’s future workforce analytics, and a concerted effort to re-negotiate a number of key vendor contracts, Burlington Hydro has realized efficiencies ‘equal to’ three Full Time Employees (‘FTEs’) and approximately $200,000 in contract savings. This has not translated into a finite reduction of three FTE’s in its overall employee complement, as further detailed under the section ‘Year-over-Year FTE Changes (2010 -20143)’.

RATIO MIX OF APPRENTICES TO QUALIFIED TRADES

Burlington Hydro has tracked and monitored its employee demographics over the last five years, cognizant of the increased pending potential increase in retirements, specifically of its highly skilled trades and technical positions.

Burlington Hydro budgeted for and hired, three new apprentices in each of the 2008 and 2009 operating years. These hires were needed at that time to provide sufficient time for apprentices to become proficient before, or close to, the year that qualified skills were anticipated to retire. Due to a change in the mix of powerline and electrical control operators over the past few years, Burlington Hydro found itself in the position where it did not require advance hires of apprentices between 2010 and 2011. Burlington Hydro lost some powerline technicians and control operators to other utilities and industry associations, which resulted in an unsafe ratio of qualified versus non-qualified apprentices. For the next three year planning cycle, Burlington Hydro considers it has an appropriate level of proficient versus apprentice workers to maintain a safe work environment for the employees and the public. Therefore, In 2013 Burlington Hydro is planning on introducing advance hires where deemed appropriate. Two control apprentices and one lines apprentice are budgeted for 2013 and one lines apprentice and one stations apprentice in 2014 to plan for journeymen retiring in the next 3 to 5 years.

CONTRACTING VERSUS IN-HOUSE MANPOWER

Burlington Hydro relies on some third party contracting primarily for a small portion of it capital program. This is a usual scenario in a utility environment, where it would not be prudent or fiscally responsible to maintain a level of workforce that 'is on hand to do work as it comes along', but where it complements its own workforce when needed as the workload demands.

Burlington Hydro also relies on contacting of some of its trades and technical work as it relates to the level of competency to do the work. This is explained in more detail under the section Burlington Hydro's Skilled Trades/Technical Workforce Philosophy.

TECHNOLOGICAL CHANGES

Has Burlington Hydro experienced or can it anticipate any technological or environmental changes to its business that will require a different skill set or the way in which certain work is performed, in its trades and technical workforce? What impacts will the evolution of its Energy Plan or a shift to a more comprehensive Smart Grid have on the utility's workforce skills and required training? In consideration of the current state of the business and its regulated operating environment, Burlington Hydro puts forth that there are no technological changes that will impact workforce strategy in this planning cycle. This may change however, as the industry and legislated industry changes evolve year-over-year.

VARIANCE ANALYSIS OF HEADCOUNT AND COMPENSATION

Year-over-Year FTE Changes (2010-2014)

In relation to its FTE headcount, Burlington Hydro determined its best course of action was to redefine its workforce philosophy related to its core business and contracting opportunities. Since 2010, Burlington Hydro has invested time and energy in identifying the high-level skills and knowledge of its workforce, that add the greatest value to its core business – in short, utilizing its skilled and trained workforce to undertake the work they are best qualified and trained to do, and contract out the remaining more menial and less core value added activities.

In doing so Burlington Hydro has balanced its contracting out with the need to supplement its workforce, thereby maintaining a lower level of reliance on third party contractors, and utilizing its decreasing workforce to its best advantage for the customer and community.

The table below provides the year-over-year change in FTE headcount from 2010 to 2014, a portion of which are actual and projected FTEs.

Table 4-12: Staffing levels 2009 to 2014

Year		Open	Jan	Feb	Mar	Apr	May	June	July	Aug	Sept	Oct	Nov	Dec	End		Avg
2009	Total	92	92	92	92	94	95	94	95	94	93	91	91	92	92		92.92
	Exec	6	6	6	6	6	6	5	5	5	5	5	5	5	5		5.42
	Mgmt	13	13	14	14	14	15	15	15	15	15	15	15	15	15		14.58
	Union	68	68	67	67	69	69	69	70	69	69	67	67	68	68		68.25
	Non Union	5	5	5	5	5	5	5	5	5	4	4	4	4	4		4.67
2010	Total	92	93	92	92	94	93	94	96	96	96	95	95	93	93		94.08
	Exec	5	5	5	5	5	5	5	5	5	5	5	5	5	5		5.00
	Mgmt	15	15	14	14	15	15	15	15	15	15	14	14	14	14		14.58
	Union	68	69	69	69	69	68	69	70	70	70	70	70	69	69		69.33
	Non Union	4	4	4	4	5	5	5	6	6	6	6	6	5	5		5.17
2011	Total	93	93	92	92	91	90	90	90	90	90	90	91	90	90		90.75
	Exec	5	5	5	5	5	5	5	5	5	5	5	5	5	5		5.00
	Mgmt	14	15	15	15	15	15	15	16	16	16	15	16	15	15		15.33
	Union	69	68	67	67	66	65	65	64	64	64	65	64	64	64		65.25
	Non Union	5	5	5	5	5	5	5	5	5	5	5	6	6	6		5.17
2012	Total	90	91	92	92	93	93	93	93	92	92	92	92	92	92		92.25
	Exec	5	5	5	5	5	5	5	5	5	5	5	5	5	5		5.00
	Mgmt	15	15	16	16	16	16	16	16	16	16	16	16	16	16		15.92
	Union	64	65	65	65	66	66	66	66	65	65	65	65	65	65		65.33
	Non Union	6	6	6	6	6	6	6	6	6	6	6	6	6	6		6.00
2013	Total	92	94	94	94	94	94	94	94	94	95	98	98	98	98		95.08
	Exec	5	5	5	5	5	5	5	5	5	5	5	5	5	5		5.00
	Mgmt	16	17	17	17	17	17	17	17	17	17	18	18	18	18		17.25
	Union	65	66	66	66	66	66	66	66	66	67	69	69	69	69		66.83
	Non Union	6	6	6	6	6	6	6	6	6	6	6	6	6	6		6.00
2014	Total	98	100	100	100	100	100	100	100	100	100	100	100	100	100		100.00
	Exec	5	5	5	5	5	5	5	5	5	5	5	5	5	5		5.00
	Mgmt	18	18	18	18	18	18	18	18	18	18	18	18	18	18		18.00
	Union	69	71	71	71	71	71	71	71	71	71	71	71	71	71		71.00
	Non Union	6	6	6	6	6	6	6	6	6	6	6	6	6	6		6.00

HeadCount

Establishing headcount and wages is part of Burlington Hydro's business planning process. As such there is a thorough review and approval process. The starting assumption is that current staffing levels are sufficient and any increases need to be justified.

Planning starts by each business unit reviewing existing headcounts and ensuring that the utility has the proper headcount in place ensures critical success factors and supports objectives which are described in Exhibit 2 as well as Exhibit 4.

Each business unit then identifies the headcount required with consideration of the requirements for delivering the team's commitment to Burlington Hydro's strategy. Staff are required to perform important functions to meet Burlington Hydro's strategic objectives and provide value added services to Burlington Hydro's customers.

Burlington Hydro continues to experience increases in customer growth, while continuing to operate in an environment of increasing regulatory, technical and other requirements, often imposed by third parties all of which have caused Burlington Hydro's workload to increase with a corresponding increase in the number of staff that is required to carry out that work.

Senior management are required to justify the need for all new staff positions to the Executive Management Team ("EMT"). The EMT recommends the changes to the Audit and Finance Committee of the Board of Directors, and to the Board of Directors, as a whole, as part of the overall budget.

As provided in the table above, Burlington Hydro has attempted to maintain its trades/technical complement of FTE's since its 2010 COS Rate Filing. That said, Burlington Hydro was forced to reduce its overall FTE complement by 3 in 2011. The decrease was a calculated decision by Burlington Hydro to address the negative impact of its 2010 COS decision. The impact continued until 2014, whereby its trades/technical staff complement is increased by 5 additional headcount.

Burlington Hydro would have experienced even greater reductions in its trades/technical staff, if it had not implemented its three business directives relative to supplementing its decreasing workforce as a result of its 2010 COS Rate Filing decision. These initiatives are:

- A temporary reduction in Burlington Hydro's FTE's in 2011 required to provide an 'optimum' level of workforce within each trades/technical area
- Realizing on productivity and efficiency efforts (section Productivity/Efficiencies)
- A redirection of the trades/technical work philosophy to utilize its skilled and trained workforce to undertake the work they are best qualified and trained to do, and contract out the remaining more menial and less core value added activities.

Three management positions have been added since 2010. The 2012 budget led to the approval of a new Communications Manager while 2013 led to the approval of 2 new positions namely a GIS supervisor and trade supervisor which is being filled in the fall of 2013. Both the GIS postion and Trades position are described as part of the 2012-2013 variances analysis at [Reference]

The 2013 and 2014 budget process also led to the approval of 2 new trades positions in order to mitigate upcoming skills shortages of Burlington Hydro's aging workforce.

Attachment 1 (of 1):

Talent Management Plan

Burlington Hydro's Integrated Talent Management Strategy

Table of Contents

Integrated Talent Management Strategy

Introduction

In today's competitive labour market, organizations are paying very close attention to how they manage their human capital. The loss of experience that is preparing to retire and walk out the door, the overall shortage of talented leaders, the need to engage and retain high-potential employees at every level of the organization, and an environment which demands that businesses continually do more with less, all combine to make Talent Management an organizational priority.

Talent Management has grown significantly in recent years as more and more organizations have recognized the value of aligning workforce and human capital planning with business strategy. A systematic approach to the alignment of human capital with the business needs can ensure the future viability of an organization. No matter how impressive a business plan is, if an organization does not have the workforce to support it, it is unlikely to achieve its business objectives.

Building and enhancing employee potential will not only benefit employees, it will also support the organization in meeting its strategic goals and objectives and encourage a culture of customer centric excellence.

An integrated approach to Talent Management recognizes the interweaving of human resource strategies and practices with the organizations strategic goals and business results. Burlington Hydro Inc. ('BHI') continues to develop its human capital practices to prepare the organization to respond to current and future workforce challenges.

Industry & BHI Demographics

Canada's electricity sector faces the prospect of a prolonged period of increasing competition for professional and skilled workers, prompted by an aging labour force and a diminishing supply of suitably trained and educated young workers. In the past, the electricity sector has generally benefited from its ability to attract young talent.

Additionally, once employed in the sector, workers tended to remain in the sector throughout their careers. Today these conditions are changing. Competition for staff from within the utility industry is coming from small but growing independent power producers, as well as organizations outside the electricity industry. As a result of these changes, talented younger workers have considerably more career choices.

Retirements will continue to be a significant issue for human resource planners in the electricity industry in the future. Based on employer estimates, 32.9% of the current electricity workforce is expected to retire between 2011 and 2016, a higher annual rate of retirement than that estimated in the 2008 Electricity Sector Council study. An aging workforce, a growing economy, coupled with aging infrastructure and the need to build new facilities, threatens the reliable generation, transmission and distribution of electricity to Canadians across the country.

Increasingly the short supply of trained graduates into the electricity sector will be a challenge.

Currently, qualitative evidence suggests that the electricity sector is not very popular as a career choice among high school and post-secondary graduates.

Generally speaking, universities are reporting an increase in enrolment in programs that are closely related to the electricity sector, specifically engineering and apprenticeships. The expansion of college and university programs, are adding to the pool of potential distribution workers at these levels over the next five years.[1]

BHI recognizes that the effects of its aging workforce could pose significant challenges to meeting its work demands, realizing on business strategies and maintaining a high level of public and employee safety. In 2013, the average age of BHI's workforce was 47.4 years, with its trades/technical staff at 45.1 years and its management team at 49.4 years. Although BHI's average age of its management team is comparative with the industry sector, its trades/technical average age is lower than the sector age of 47.2%. This provides BHI an advantage in staging the progression of its workforce planning strategies.

At an organizational level, BHI can expect 30, or 30% of its employees to retire over the next five years, with the vast majority (17) eligible to retire in 2014 and 2015. The table below provides a five-year (2014-2018) projection of eligible retirements broken down by employee category.

	# Staff	Average Age	# Retirements					%
BHI Team	**2013**	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**	**Next 5 Years**
Management	28	49.44	2	3	3	0	0	28.6%
Office Staff	26	49.32	1	2	2	3	1	34.6%
Trades/Technical	45	45.07	5	4	0	3	1	28.9%
Total FTE Staff	99	47.44	8	9	5	6	2	30.3%

Concurrently as employees who are eligible to retire leave BHI, it is faced with recruiting the "Millennium Generation". The current generation of employees coming out of the education system value personal time for social pursuits more than they value money. This generation values flexibility, paid time off and cross-training opportunities more than the promise of a pension after thirty years of service.

Benefits of a Talent Management Strategy

Organizations that effectively manage their talent provide benefits to the employee and to the customers whom the organization serves.

The outcomes associated with integrated talent management are:

- ✓ Supports effective Workforce Planning
- ✓ Assists organizational development of talent
- ✓ Richer career development and mapping

[1] Electricity Sector Council – 2011 Labour Market Report

- ✓ Supports business continuity
- ✓ Focuses on customer service excellence
- ✓ Supports employee engagement efforts
- ✓ Aligns employees with organizational goals

Talent Management Success Factors

There are numerous critical success factors in developing and implementing an Integrated Talent Management Plan. BHI has a good understanding of its demographics over the next ten years, continues to update its workforce planning, and aligns succession planning to its performance management system. Moreover it recognizes that the quality of the work place is integral to the attraction and retention of top talent. In addition to these factors, the following organizational elements must be present for the program to remain effective:

- ✓ Active participation by the senior leadership team
- ✓ Alignment to BHIs current and future business strategies
- ✓ Identification of the key gaps between the talent in place and the talent required to drive business success
- ✓ Employee input, engagement, and participation
- ✓ Connection of individual and team goals to corporate goals, and providing clear expectations and feedback to manage performance
- ✓ Continuous evaluation, monitoring, and improvement efforts
- ✓ Monitoring and evolving within the regulated environment

BHI's Approach

Talent Management Philosophy

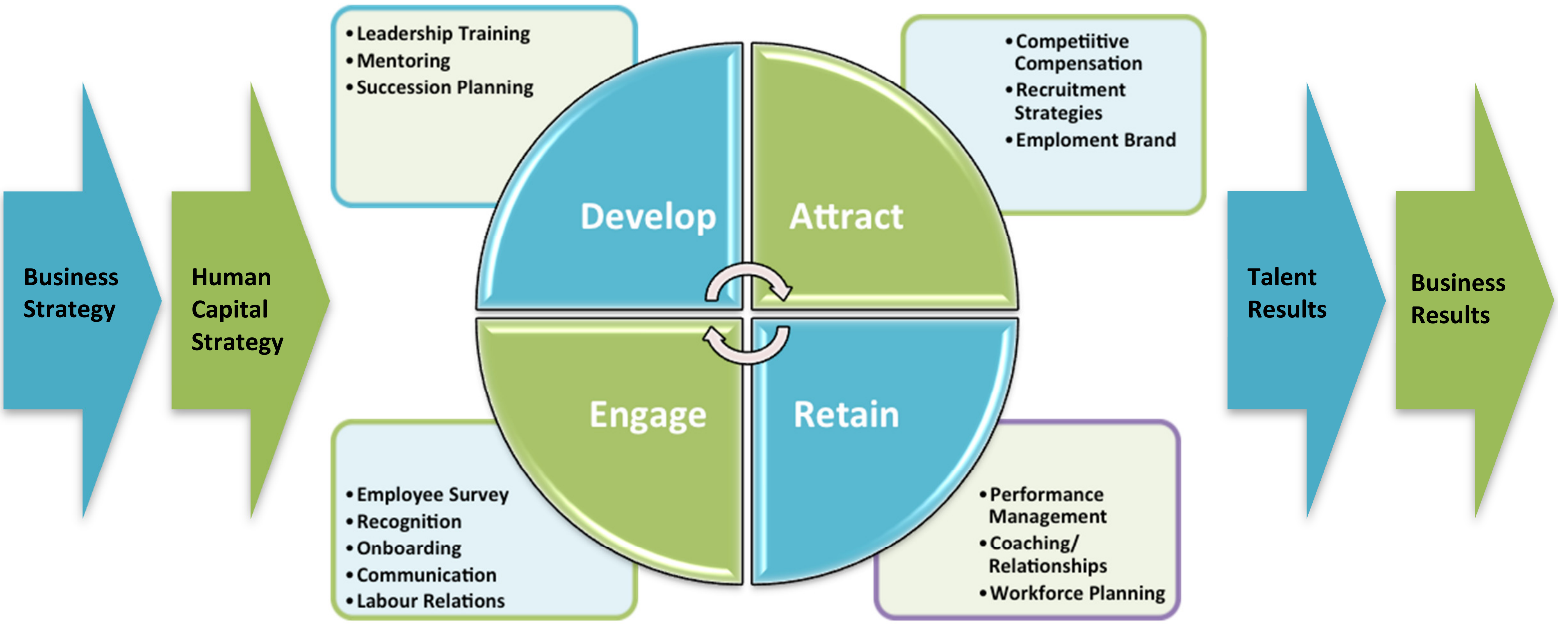
In consideration of the challenging and restrictive regulatory environment in which BHI operates, the Talent Management plan supports a conservative and fluid philosophy. *BHI strives to be an employer of choice and a great place to work, aligning its outputs to improving the customer experience while working within the constraints of the Ontario Energy Board's ('OEB') Cost of Service ('COS') Rate Application process.*

As reflected in BHI's COS Application decision in 2010, it has been operating within a constricted and unsustainable budget, primarily as a result of the mandated implementation of International Financial Reporting System ('IFRS') changes in accounting practices and the OEB's non-acceptance of BHI's projected load forecast.

Both have had an impact on BHI's workforce planning since 2010, and continue to impact its labour and Talent Management strategies now and over the next 3 years. More explanation and detail is provided in the appended Workforce Planning document.

BHI's Talent Management Model

The model below is a graphical depiction of BHI's Talent Management program and elements.



BHI's approach to integrated Talent Management aligns the elements of the employee 'life cycle' with its business priorities. The key components of BHI's programs are centred on the employee: Attracting (recruitment), Retaining, Employee Engagement and Development.

Responding to BHI's Demographics

As provided in the section, Industry & BHI Demographics, the organization is facing a substantive potential exodus of both trades and management staff over the next five to ten years. BHI puts forth that a robust and progressive Talent Management strategy assists in mitigating its risk associated with attracting and retaining top talent.

Of the eight management employees eligible to retire over the next five years, two are in accounting, two operations, one metering, one in engineering, one in HR/health & safety and one senior level position which is in regulatory. BHI has a solid Succession Planning process to support and manage the two senior level positions, and to some extent the manager level positions. Overall the risk to BHI is minimal considering the job types that will be affected and its ability to hire, with the exception of the regulatory positions. Regulatory expertise in the LDC environment is scarce and those with experience are sought after on a regular basis. To mitigate BHI's risk, it hired a new position in 2010 (Regulatory Accountant) that is being developed and trained as a potential successor.

Over the next five years, twelve trades/technical staff are eligible to retire, comprising almost 13% of the workforce. BHI has a robust Workforce Planning process that takes into consideration those employees eligible and likely to retire, the pending skills shortage and matches it with the demands associated with maintaining a safe and reliable distribution system. BHI's Workforce Plan for 2014 has been appended to this document to provide more detail of the program.

Alignment to BHI's Business Plan

The best talent management programs always start with strategy. Knowing where the business is headed – and how it's organized – is the only way to understand the future demands on employees and leaders. This should inform your talent management strategy.[2]

BHI continually reviews its business and operational goals against; its workforce needs, its financial strength and the impact on its customers. BHI recognizes the importance and value of maintaining a highly skilled and engaged workforce, where all employees are customer focused and proud to work for the company.

In 2013, BHI developed an Integrated Community Energy Plan (ICE). The multi-year ICE Plan positions BHI to be seen as an organization that is an integral part of the community and an essential contributor to its growth and success. BHI's three-year Talent Management Plan has been developed with input from business team leaders, it builds on existing programs and focuses efforts on attracting, retaining, developing and engaging employees. Without the right people, in the right jobs at the right time, BHI will be challenged to meet its business objectives, complete its infrastructure renewal programs and remain an employer of choice for its community.

Environmental Scan

Environmental scanning is the acquisition and use of information about events, trends, and relationships in an organization's internal and external environment, the knowledge of which assists management in planning the organization's future course. Organizations scan the environment in order to understand internal issues and external barriers or forces of change so that they may develop effective responses, which secure or improve their position in the future. To the extent that an organization's ability to adapt to its environmental pressures depends on knowing and interpreting the issues and changes that are taking place, environmental scanning constitutes a primary mode of organizational learning.

Its use in the Talent Management process provides BHI a critical look at its ability to be an employer of choice, a great place to work and a customer centric organization. BHI engaged the assistance of a number of its business leaders to identify critical challenges, opportunities and barriers to recruiting, retaining and advancing its talent pool. The following table provides the outputs of the environmental scan, identifies areas where BHI's programs are meeting the organizations needs and opportunities of focus over the next three years.

[2] Hay Group 2011 'Take Aim' Publication

BHI Environmental Scan 2013-2015			
Plan Elements	**Internal**	**Meeting Needs**	**Opportunity**
Attracting	• **Competitive Compensation**	• ✔	
	• **Behavioural Based Interviews**	• ✔	
	• **Personality Profile Testing**	• ✔	
	• **Employment Branding**		• ✔
	• **Use of External Recruiters**	• ✔	
	External		
Attracting	• **Competition for trades/talent LDC's & Industry Associations**	• ✔	
	• **Concerns of M&A's, Regulatory Impacts**		• ✔
	Internal		
Retaining	• **Effective Performance Management System**	• ✔	
	• **Supportive Coaching/Relationship Building**		• ✔
	• **Workforce Planning**	• ✔	
	• **Special Project Assignments – Build Talent**	• ✔	
	External		
Retaining	• **LDC & Industry Association Poaching**		• ✔
	• **Concerns of M&A's, Regulatory Impacts**	• ✔	
	Internal		
Engaging	• **Consistent Employee Survey**		• ✔
	• **Labour Relations Partnership Philosophy**	• ✔	
	• **Employee Onboarding**		• ✔
	• **Effective Communication**	• ✔	
	Internal		
Development	• **Leadership Training**	• ✔	
	• **Mentoring for Success**	• ✔	
	• **Succession Planning**	• ✔	
	External		
Development	• **Budgetary Constraints**	• ✔	

BHI's Three-Year Talent Management Plan

Taking into consideration BHI's 2014 Business Plan and future outlook, the results of the environmental scan and building on current programs, BHI shall add focus to its Talent Management efforts over the next three years in the following areas:

Attracting Employees

1. Developing a BHI Employment Brand

Building on the successful launch of BHI's new brand in 2012, it shall undertake the development of a comprehensive Employment Brand Program. Utilizing the characteristics established with the new brand such as confidence, trust, inspiration and community – BHI shall build these into its recruitment strategies, advertising and publications to identify BHI as an employer of choice.

Attracting talent to come to BHI, to be part of its engaged employee community and live in its vibrant city – supports the business strategies and provides some risk mitigation associated with its demographic challenges over the next five to ten years. Further, effective efforts in building a solid

Employment Brand, will assist in mitigating concerns relative to potential Merger &Acquisition ('M&A) activity when attracting employees to join the company.

A supporting element to this goal is the expansion of BHI's Customer Centric Training, to employees outside of the customer service department. The training is provided by a third-party expert and aligns with BHI's goal to train all employees who have contact with the customer. Expanding the training will add value to enhance the customer experience, heighten BHI's reputation in the community and better identify BHI as an employer of choice.

Retaining Employees

1. Coaching and Relationship Building

While people often join companies with high expectations, it is often their managers and supervisors that they leave, and not the company. The leadership skills of managers are the greatest source of employee fulfillment at work, according to 2011 research from Wilson Learning Worldwide.

As part of the environmental scan, it was identified that the organization would benefit from a more defined and collaborative approach to employee coaching, and building the employee/manager relationship.

BHI has been committed to developing strong leadership teams and skills. As such it has partnered with Centric Dynamix Inc. to provide in-house training to enhance leadership skills individually and as a leadership team. The program is targeted to Managers, Supervisors, and non-union positions with 'indirect' influence and/or potential successor candidates. Two thirds of this group has undergone both phases of the training. The remaining are scheduled to complete the training in 2013 and 2014.

To build upon the program, BHI shall review and enhance the training criteria to ensure sufficient focus is placed on the importance of the employee/manager relationship. It shall also review, research and determine a coaching model appropriate to its business that provides both internal and external support to managers, relative to their positions and the needs of the organization.

Engaging Employees

1. Third-party Employee Engagement Survey

To be an employee of choice and build a great place to work, BHI continues its focus on enhancing the employee experience while meeting the needs of the customer. *High levels of employee engagement in an organization are linked to superior business performance, including increased employee retention & profitability, customer excellence and safety performance*.[3]

BHI has undertaken informal employee surveys over the past many years. These surveys have provided some insight into the current state of the workforce, relative to its engagement and concerns. Survey results can prove to be challenging to interpret and difficult to identify tangible

[3] Mercer & Associates 2012 Publication "Getting it Right"

areas that BHI should focus efforts towards improving employee engagement. Furthermore, the surveys have not had a direct or meaningful relationship to BHI's business strategies and goals. BHI will continue to survey its employees and shall engage the assistance of a third-party who specializes in the application and interpretation of employee engagement surveys. The survey should be able to be sufficiently customized to meet the specific needs of BHI and its employee base. The results of the survey will provide BHI with reasonable action plans over a three-year period, in between repeating the same survey to gauge success and continued and new areas of focus.

2. Strategic Employee Onboarding

Onboarding — the process, which includes interviewing, hiring, orienting and successfully incorporating new employees in your company's culture so they become productive faster — has become a hot topic for many companies, thanks largely to the recent talent crisis. Prospective employees form opinions of their employers early in the recruiting process. They are most likely to leave a company within the first 18 months of their tenure and 90 percent of new hires decide in their first six months on the job whether or not they're going to stay with the company.[4]

BHI recognizes the strategic advantages of successfully onboarding employees; bringing them into the organization, making sure they know what is expected of them, making sure they know how they are going to add value, and making sure they understand how they fit into its culture and business.

BHI shall develop and execute on a long-term strategic employee onboarding program that links with the organization's business objectives and its performance management system; that exemplifies its employment brand and company mission; and, is aligned to its leadership training programs for management staff.

Critical Supporting Strategies and Plans

Within BHI's Talent Management program there are three critical areas of focus that play a significant role in the long-term sustainability of the organization. They are considered part of everyday business, assist in long-term planning and support an engaged workforce.

Effective Labour Relations

BHI has maintained a collaborative approach in its labour relations both with employees and its union executive. Recent negotiations concluded in the second quarter of 2012, resulting in an average compensation adjustment of 2.9% over two years. BHI had provided in its 2012 business plan and budget a goal of 2.9%, which was achieved for both its inside and outside workers, without the use of third-party intervention at the negotiating table.

BHI anticipates labour peace and a continued overall improvement in employee engagement over the next year. The relationship will be further enhanced as a result of the three-year Talent Management strategies relative to:

[4] 2010 Research by Cornerstone on Demand, HR Consultants

- ✓ The Employee Engagement survey to be conducted 2nd quarter of 2013, will provide clear, tangible and actionable outcomes to focus on for all employees, with the intent of building a great place to work and improving the employee experience
- ✓ Improving the management teams coaching skills, and focusing on enhancing the employee/manager relationship will have a direct positive impact on labour relations
- ✓ The efforts associated with the Employment Brand program will bolster employee confidence, trust and pride in the organization they work for

In 2014 BHI will begin focusing on the upcoming negotiations (expires March 31 2014), anticipating some challenges relative to the continued regulatory burden placed on Local Distribution Companies (LDCs) and the still to be determined outcome of its 2013 COS Rate Application.

Strategic Workforce Planning

Strategic Workforce Planning involves identifying, assessing, developing and sustaining employee workforce skills required to successfully accomplish business goals and priorities, while balancing the needs and expectations of employees and the business. Essentially, strategic workforce planning is identifying gaps between the labour *demand* of an organization and the available workforce *supply*, leading to strategies used to close those *gaps*.

BHI develops long-term plans to support investment in its distribution business, for both its capital and maintenance programs. BHI's core business is providing; a safe and reliable supply of electricity to customers, efficient customer service and reasonable continued investment in its aging infrastructure. To achieve these outcomes BHI needs the right complement of skilled trades, technical and supervisory staff who are proficient and able to meet the work demands now and into the future.

BHI continues to update and improve upon its Workforce Planning analysis. Appended to this document is a comprehensive review and report that analyzes BHI's current workforce against its requirements over the next three to five years. The analysis takes into consideration assumptions relative to retirements, attrition, time to reach proficiency for trades, advance hiring, productivity/efficiency improvements, technological change and future skills requirements.

Succession Planning

Since 2008 BHI has undertaken Succession Planning at the senior leadership level of the organization. BHI updates its plan annually and reports out confidentially to its Board of Directors. According to a 2011 poll by Korn Felt Inc., BHI is progressive in its implementation and adherence to its plan. Out of 1,300 companies surveyed, 98% indicated the importance of doing succession planning, while only 35% admitted they had undertaken a program. Of that 35%, only 49% responded they had not updated their plan in the last four years.

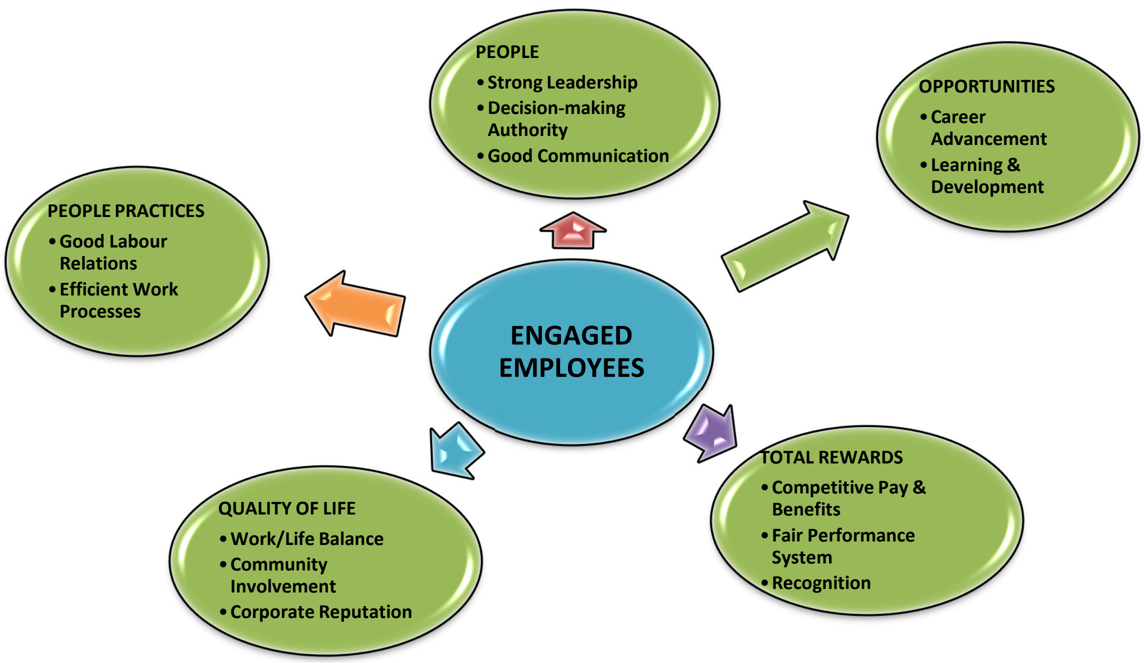
BHI worked with a third-party consultant to develop an evaluation tool based on its leadership competencies and performance evaluation scale. The tool is designed to numerically evaluate and rank succession candidates based on both quantitative and qualitative inputs.

The Plan is updated annually, with assumptions re-verified, changed and/or modified relative to each of the four Leadership positions: CEO, CFO, COO, and VP Corporate Relations. Potential candidates are engaged by their leader to discuss the opportunities and feed into their individualized development plans. A plethora of development is encouraged inclusive of formal education, structured development interactions, experiential learning and external training courses.

Employee Engagement Drivers

The final element of an effective Talent Management process is to continually assess it against its alignment to what motivates and drives employee engagement: those drivers that attract employees, retain them and keep them engaged.

BHI's model below provides an overview of the current drivers that it considers relevant to being a great place to work, while supporting a customer centric focus. These drivers are reviewed every few years against the changing environment and new generation of talent entering the workforce.



Conclusion

Talent Management when done well provides a strategic advantage to the organization over its competitors, it places the right amount of importance on its human capital and it aligns to and supports organizational objectives and business plans.

BHI recognizes the challenging and restrictive regulatory environment it is required to operate within, and the impact its 2010 COS Rate Application decision has had on its workforce planning and talent management efforts. BHI is confident in it talent management approach as provided in its Plan. If able to undertake and achieve the stated goals, over the next five years, BHI will progress substantively along the path to being an employer of choice, a great place to work for its employees and a customer centric organization that understands and knows how to respond to evolving customer expectations.

Exhibit 4: Operating Costs

Tab 5 (of 8): Corporate Cost Allocations

SHARED SERVICES & CORPORATE COST ALLOCATIONS

The purpose of this evidence is to document these arrangements, provide an overview of the Shared Services that Burlington Hydro purchases from and provides to its affiliates and to address the Board's Direction from its March 1, 2010 Decision and Order (EB-2009-0259).

Burlington Hydro provides services to Burlington Hydro Electric Inc. ("BHEI") and provides services to and receives services from Burlington Electricity Services Inc. ("BESI"). Burlington Hydro is owned by BHEI who also owns BESI; this ownership structure is documented at Exhibit 1 Tab 5 Schedule 7. Burlington Hydro is an affiliate of BESI and of BHEI and its business dealings with these entities is governed by the Board's Affiliate Relationship Code (the "ARC"). Burlington Hydro provides services related to the provision of Conservation and Demand Management activities, which is a non-distribution activity performed in fulfillment of a condition of its Distribution Licence.

The Services Agreement between BHEI and BESI took effect in September 2012 and is provided at Exhibit 4 Tab 5 Schedule 5. Burlington Hydro is also an LDC member of GridSmartCity, a co-operative that is operated and administered by BESI and has executed a GridSmartCity LDC Membership Agreement with BESI.

Pursuant to the Services Agreement, Burlington Hydro provides Shared Support Services and Shared Corporate Services to BHEI and BESI upon request and provides additional services from time to time, provided it has the capacity to do so and without detriment to its own business or operations. During the 2014 Test Year and for the duration of the IRM period Burlington Hydro expects to provide Shared Support Services to BESI in the form of Water and Wastewater billing services for Region of Halton Water and Wastewater customers situated in Burlington Hydro's licenced service territory. These services include: meter reading, bill preparation and presentment, payment processing, collections, bad debt management, customer care. Burlington Hydro also expects to provide Shared Corporate Services to BESI and to BHEI in the form of Administrative services, chiefly accounting services. Burlington Hydro provides these services at the level of quality that it achieves for Burlington Hydro's customers.

The Services Agreement specifies the transfer pricing for these services; the transfer pricing methodology adheres to the ARC's transfer pricing rules. Further details are provided at Exhibit 4 Tab 5 Schedule 2.

Burlington Hydro appropriately protects its confidential information by requiring, as a condition of the Services Agreement, that no party to the Services Agreement request disclosure of confidential information and through data protection protocols. Each party to the Services Agreement is responsible for the risks specific to their operations. Burlington Hydro is solely responsible for obtaining and carrying Workplace Safety and Insurance Board coverage for its employees engaged in the provision of Shared Services; the cost of this coverage is appropriately included in the allocated costs. The term of the Services Agreement is 5 years.

Burlington Hydro complies with the DSC's rules for payment processing (e.g. the rules governing the application of partial payment amounts). Any amounts incurred for Bad Debt are billed to the Region who remits payment in full.

Burlington Hydro has used USoA accounts 4375 and 4380 to record the costs transferred to affiliates.

OEB Appendix 2-N Shared Services/Corporate Cost Allocation is presented at Exhibit 4 Tab 5 Schedule 1, Attachment 1.

The last page of the Appendix shows a year over year variance of Shared Services. Corporate Cost Allocation has remained constant since 2010.

Attachment 1 (of 1):

OEB Appendix 2-N Shared Services/Corporate Cost Allocation

Appendix 2-N
Shared Services and Corporate Cost Allocation

Year: 2010

-

Shared Services

Name of Company		Service Offered	Pricing Methodology	Price for the Service	Cost for the Service
From	To			$	$
Burlington Electricity Services Inc.	Burlington Hydro Inc.	Billing Service	Rate per Bill	386375	350774
Burlington Electricity Services Inc.	Burlington Hydro Inc.	Accounting	LumpSum	2000	2000
Burlington Hydro Inc.	Burlington Electricity Services Inc.	Sponsorship	LumpSum	50000	50000
Burlington Hydro Inc.	Burlington Hydro Electric Inc.	Directors' Fee	LumpSum	110882	110882

Corporate Cost Allocation

Name of Company		Service Offered	Pricing Methodology	% of Corporate Costs Allocated	Amount Allocated
From	To			%	$
Burlington Hydro Electric Inc.	Burlington Hydro Inc.	Accounting	LumpSum	2000	2000

Year: 2011

-

Shared Services

Name of Company		Service Offered	Pricing Methodology	Price for the Service	Cost for the Service
From	To			$	$
Burlington Electricity Services Inc.	Burlington Hydro Inc.	Billing Service	Rate per Bill	352747	323621
Burlington Electricity Services Inc.	Burlington Hydro Inc.	Accounting	LumpSum	2000	2000
Burlington Hydro Inc.	Burlington Electricity Services Inc.	Sponsorship	LumpSum	50000	50000
Burlington Hydro Inc.	Burlington Hydro Electric Inc.	Directors' Fee	LumpSum	94455	94455

Corporate Cost Allocation

Name of Company		Service Offered	Pricing Methodology	% of Corporate Costs Allocated	Amount Allocated
From	To			%	$
Burlington Hydro Electric Inc.	Burlington Hydro Inc.	Accounting	LumpSum	2000	2000

Year: 2012

-

Shared Services

Name of Company		Service Offered	Pricing Methodology	Price for the Service	Cost for the Service
From	To			$	$
Burlington Electricity Services Inc.	Burlington Hydro Inc.	Billing Service	Rate per Bill	345013	316526
Burlington Electricity Services Inc.	Burlington Hydro Inc.	Accounting	LumpSum	2000	2000
Burlington Hydro Inc.	Burlington Electricity Services Inc.	Sponsorship	LumpSum	41452	41452
Burlington Hydro Inc.	Burlington Hydro Electric Inc.	Directors' Fee	LumpSum	99582	99582
Burlington Electricity Services Inc.	Burlington Hydro Inc.	Misc Services	LumpSum	61610	61610

Corporate Cost Allocation

Name of Company		Service Offered	Pricing Methodology	% of Corporate Costs Allocated	Amount Allocated
From	To			%	$
Burlington Hydro Electric Inc.	*Burlington Hydro Inc.*	Accounting	LumpSum	2000	2000

Year: 2013

-

Shared Services

Name of Company		**Service Offered**	**Pricing Methodology**	**Price for the Service**	**Cost for the Service**
From	**To**			**$**	**$**
Burlington Electricity Services Inc.	Burlington Hydro Inc.	Billing Service	Rate per Bill	349000	320183
Burlington Electricity Services Inc.	Burlington Hydro Inc.	Accounting	LumpSum	2000	2000
Burlington Hydro Inc.	Burlington Electricity Services Inc.	Sponsorship	LumpSum	10000	10000
Burlington Hydro Inc.	Burlington Hydro Electric Inc.	Directors' Fee	LumpSum	79750	79750
Burlington Electricity Services Inc.	Burlington Hydro Inc.	Misc Services	LumpSum	66460	66460

Corporate Cost Allocation

Name of Company		**Service Offered**	**Pricing Methodology**	**% of Corporate Costs Allocated**	**Amount Allocated**
From	**To**			**%**	**$**
Burlington Hydro Electric Inc.	Burlington Hydro Inc.	Accounting	LumpSum	2000	2000

Year: 2014

-

Shared Services

Name of Company		**Service Offered**	**Pricing Methodology**	**Price for the Service**	**Cost for the Service**
From	**To**			**$**	**$**
Burlington Electricity Services Inc.	Burlington Hydro Inc.	Billing Service	Rate per Bill	365829	335623
Burlington Electricity Services Inc.	Burlington Hydro Inc.	Accounting	LumpSum	2000	2000
Burlington Hydro Inc.	Burlington Electricity Services Inc.	Sponsorship	LumpSum	10000	10000
Burlington Hydro Inc.	Burlington Hydro Electric Inc.	Directors' Fee	LumpSum	85000	85000
Burlington Electricity Services Inc.	Burlington Hydro Inc.	Misc Services	LumpSum	66460	66460

Corporate Cost Allocation

Name of Company		**Service Offered**	**Pricing Methodology**	**% of Corporate Costs Allocated**	**Amount Allocated**
From	**To**			**%**	**$**
Burlington Hydro Electric Inc.	Burlington Hydro Inc.	Accounting	LumpSum	2000	2000

ALLOCATION METHODOLOGY FOR SHARED SERVICES

Burlington Hydro allocates the following costs in order to provide Water and Wastewater Billing Services:

- Burlington Hydro staff positions, being
  - 1 Billing Clerk
  - 1 Customer Service Clerk
  - 1 Programmer

    (The fully burdened costs include: Canada Pension Plan, Employment Insurance, Ontario Municipal Employees Retirement System, Extended Health Benefits, Employers Health Tax, Workers Safety Insurance Board)

The costing methodology includes an Administration fee. This fee is a percentage of the budgeted Administration costs for the year divided by the budgeted Revenue for the year. The rate is adjusted at the end of the year for a true-up of actual costs and revenues.

Burlington Hydro charges BESI a monthly fee for the provision of Water and Wastewater Billing Services. The monthly fee is based on:

- Estimated number of bills;
- Estimated cost per bill to perform:
- Billing services;
- Collection services;
- Programming services;
- Administrative charges;
- Estimated profit margin consistent with Burlington Hydro's OEB approved weighted cost of capital.

Burlington Hydro invoices BESI monthly. Labour costs are invoiced based on fully burdened costs of the three positions relied on to provide Water and Wastewater Billing services. The Overhead costs associated with these positions (e.g. office space, telecommunication, IT hardware) are recovered through the combination of the Administrative charge and the Profit charge. The methodology used to quantify the Administrative and Profit charges are described elsewhere.

Pursuant to the Services Agreement, Burlington Hydro invoices BESI at an agreed upon annual cost based on estimated usage which is then "trued up" at the end of each year by computing the actual costs incurred and adjusting the total payments made during the year, either by charging an additional payment or by providing a refund.

Burlington Hydro allocates $66k to GridSmartCity and to BESI, being an allocation of the costs of its Executive and Senior Management team members. This allocation assigns costs responsibility for the time and effort expended by the Executive team, Communications staff, Regulatory staff and Accounting staff to provide services related to BESI's GridSmartCity and other activities.

GridSmartCity charges each LDC member an annual membership fee of $10,000 (plus applicable taxes). Pursuant to the LDC Membership Agreement Burlington Hydro will remit this amount to GridSmartCity in 2014 and in return will enjoy the use of the GridSmartCity marks, participate in the GridSmartCity forums and conferences and will be among the first in the province to learn of its innovations and successes.

Burlington Hydro also incurs other Accounting costs in support of BESI and BHEI. These costs are recovered through an annual $2k charge to each affiliate. Upon true up at year-end any under-recovery is quantified and the appropriate affiliate remits the amount to Burlington Hydro

Burlington Hydro assigns a portion of the fully burdened costs of its Regulatory and Conservation Analyst to the OPA and recovers these costs through the Program Administration Budget. Other Burlington Hydro employees (e.g. the Director, Regulatory

Compliance and Asset Management) perform duties in fulfillment of the CDM Licence Condition; the costs of these positions are recovered through rates and therefore, not eligible for sharing with the OPA. Based on currently available information Burlington Hydro's sharing of the costs of these staff positions with the OPA will cease as of the December 31, 2014. Effective January 1, 2015 all incumbents will no longer be accountable for CDM activities.

Burlington Hydro provides certain services to the City of Burlington, who owns BHEI. Through good governance practices Burlington Hydro has taken appropriate steps to ensure that there are no cross subsidies between its ratepayers and its owner's corporate parent. In its Decision on Burlington Hydro's 2010 EDR Application (EB-2009-0259) the OEB's found it appropriate to eliminate the recovery through rates of certain costs of BHEI's Board of Directors (fees, insurance costs were identified specifically). The Board's Decision addressed other aspects of Burlington Hydro I's relationship with the City (e.g. its practices with respect to Contributions in Aid of Construction for asset modifications or relocations, to charging for the use of Burlington Hydro owned poles) that are addressed elsewhere in this application. The relevant findings of that Decision are summarized below.

- Half of the incentive pay, being directly related to shareholder value, should be funded by the shareholder.
- the recovery through rates of BHEI's Board of Directors fees was not justified.
- Capital contributions should be required from the City of Burlington.
- Pole rental revenue should be recovered from the City to reflect its use of Burlington's poles.

The OEB Regulatory Audit group conducted an audit of Burlington Hydro's transactions with BESI's GridSmartCity co-operative. The audit did not identify any issues to be addressed by Burlington Hydro's management.

SHARED SERVICES & CORPORATE COST ALLOCATIONS VARIANCE ANALYSIS

Revenues and Expenses related to Incoming and outgoing shared services have remained consistent over the past 4 years. Revenues from Billing Services have decreased by 4% from 2010 Actuals, revenues from Accounting Services have remained since 2010. Expenses related to Sponsorships have decreased by 23% since 2012 and 80% since 2010. Director’s fees have also decreased by 23% since 2010

Table 4-13: Shared Service Variance Table

From	To	Service Offered	Pricing Methodology	Cost for the Service 2010	Cost for the Service 2014	Var 2014
Burlington Electricity Services Inc.	Burlington Hydro Inc.	Billing Service	Rate per Bill	350,774.00	335,623.00	-4%
Burlington Electricity Services Inc.	Burlington Hydro Inc.	Accounting	LumpSum	2,000.00	2,000.00	0%
Burlington Hydro Electric Inc.	Burlington Hydro Inc.	Accounting	LumpSum	2,000.00	2,000.00	0%
Burlington Hydro Inc.	Burlington Electricity Services Inc.	Sponsorship	LumpSum	50,000.00	10,000.00	-80%
Burlington Hydro Inc.	Burlington Hydro Electric Inc.	Directors' Fee	LumpSum	110,882.00	85,000.00	-23%
Burlington Electricity Services Inc.	Burlington Hydro Inc.	Misc Services	LumpSum	0.00	66,460.00	100%

A detailed table of the year over year variances is presented at the next page. The variance analysis shows that *Billing Services* fluctuate year over year but tend to remain within a $50K range. Since *Billing Services* are calculated on a per bill rate, therefore the utility has little control over the year over year variances. Fees received from affiliates for Burlington Hydro’s *Accounting Services* are based on time spent providing services and have not changed since 2010 as activity has remained low *Sponsorship* fees have deceased since 2011. As the host utility, Burlington Hydro originally contributed a higher amount in sponsorship however, as per the new agreement with GridSmartCity, Burlington Hydro now pays a lesser amount. *Director's fees* tend to vary on a year to year basis depending the number of Directors are active in a particular year. The turnover plays a major role in year over year costs. Revenues from Miscellaneous Services are intended to compensate Burlington Hydro's executive team for their time spent on managing and promoting GridSmartCity. Fees, paid in a yearly lumpsum, from GridSmartCity to Burlington Hydro, were implemented in 2012.

Table 4-14: Shared Service and Corporate Cost Allocation

Name of Company		Service Offered	Pricing Methodology	Cost for the Service	Cost for the Service	Cost for the Service	Cost for the Service	Cost for the Service
From	To			2010	2011	2012	2013	2014
Burlington Electricity Services Inc.	Burlington Hydro Inc.	Billing Service	Rate per Bill	350,774.00	323,621.00	316,526.00	320,183.00	335,623.00
Burlington Electricity Services Inc.	Burlington Hydro Inc.	Accounting	LumpSum	2,000.00	2,000.00	2,000.00	2,000.00	2,000.00
Burlington Hydro Inc.	Burlington Electricity Services Inc.	Sponsorship	LumpSum	50,000.00	50,000.00	41,452.00	10,000.00	10,000.00
Burlington Hydro Inc.	Burlington Hydro Electric Inc.	Directors' Fee	LumpSum	110,882.00	94,455.00	99,582.00	79,750.00	85,000.00
Burlington Electricity Services Inc.	Burlington Hydro Inc.	Misc Services	LumpSum			61,610.00	66,460.00	66,460.00

Name of Company		Service Offered	Pricing Methodology	Variances				
From	To			2010	2011	2012	2013	2014
Burlington Electricity Services Inc.	Burlington Hydro Inc.	Billing Service	Rate per Bill		(27,153.00)	(7,095.00)	3,657.00	15,440.00
Burlington Electricity Services Inc.	Burlington Hydro Inc.	Accounting	LumpSum		-	-	-	-
Burlington Hydro Inc.	Burlington Electricity Services Inc.	Sponsorship	LumpSum		-	(8,548.00)	(31,452.00)	-
Burlington Hydro Inc.	Burlington Hydro Electric Inc.	Directors' Fee	LumpSum		(16,427.00)	5,127.00	(19,832.00)	5,250.00
Burlington Electricity Services Inc.	Burlington Hydro Inc.	Misc Services	LumpSum		-	61,610.00	4,850.00	-
					-	-	-	-

THIRD PARTY REPORT OF ALLOCATION METHODOLOGY

Burlington Hydro has not contracted a third party report of its allocation methodology.

Exhibit 4: Operating Costs

Tab 6 (of 8): Purchase of Non-Affiliate Services

PURCHASES FROM SUPPLIERS

Burlington Hydro purchases equipment, materials, and services in a cost effective manner with full consideration given to price as well as product quality, the ability to deliver on time, reliability, compliance with engineering specifications and quality of service. Vendors are screened to ensure knowledge, reputation, and the capability to meet Burlington Hydro's needs. The procurement of goods and/or services for Burlington Hydro is carried out with highest of ethical standards and consideration to the public nature of the expenditures.

Burlington Hydro's 2012-2014 Vendor List and purchasing policy is presented at Exhibit Attachment 1 of this schedule and Exhibit 4 Tab 6 Schedule 1 Attachment 2

Attachment 1 (of 2):

Table of Purchases by Supplier

File Number:	
Exhibit:	
Tab:	
Schedule:	
Page:	
Date:	

2009 SUPPLIER LIST > $150,000

NAME	ACTIVITY	PROCESS/DEPT. RESPONSIBLE	TOTAL
ELSTER METERING	Meters	RFQ Purchases	$ 3,357,084.74
K-LINE MAINTENANCE & CONSTRUCTION LTD	Contracted Labour	Tendered Labour	$ 2,509,562.45
LIGHTWORKS INC	Contracted Labour	Tendered Labour	$ 1,546,145.12
MOLONEY ELECTRIC CORPORATION	Transformers	RFQ Supplier Alliance	$ 1,532,544.99
NBM ENGINEERING INC	Contracted Labour	Tendered Labour	$ 1,247,180.19
M.E.A.R.I.E. - EMPL.BENEFITS	Employee Benefits	Reciprocal Arrangement	$ 917,533.47
HONEYWELL LTD - REMIT TORONTO	CDM Peaksaver Program	Tendered Purchases	$ 684,087.62
HD SUPPLY UTILITIES	Inventory	RFQ Supplier Alliance	$ 655,373.89
TERRA DISCOVERY LTD	Locates	RFQ Labour	$ 557,251.37
S & C ELECTRIC LTD.	Intellirupter Pulse Closer and Vista Switchgear	RFQ Alliance Specialty	$ 513,638.56
ANGUS GEOSOLUTIONS INC.	GIS Mapping Software and Installation	RFI Purchases	$ 497,670.60
BETHLEHEM TRENCHING LTD.	Contracted Labour	Tendered Labour	$ 487,266.07
OLAMETER	Meter Reading and Collections	Tendered Labour	$ 472,339.71
CARILLION CANADA INC.	Installation of Underground Hydro	Tendered Labour	$ 448,539.16
GUELPH UTILITY POLE	Wood Poles	RFQ Supplier Alliance	$ 422,308.12
NEXANS CANADA INC	Wire	RFQ Supplier Alliance	$ 355,259.85
NORAMCO WIRE & CABLE	Wire	RFQ Purchases	$ 277,739.11
M.E.A.R.I.E.-LIAB.&PROPERTY INSURANC	Liability & Property Insurance	Reciprocal Arrangement	$ 250,682.04
WAJAX INDUSTRIES	RBD Fleet Purchase	Tendered Purchases	$ 212,485.20
BESWICK TREE SERVICE LTD.	Tree Trimming	Tendered Labour	$ 206,084.55
DAVEY TREE EXPERT CO	Tree Trimming	Tendered Labour	$ 202,339.00
B.F. CONTRACTING	Contracted Labour	Tendered Labour	$ 190,458.66
L.M. GENERATING POWER CO. LTD.	Rental Power Generator	RFQ Purchases	$ 174,519.21
ALADACO CONSULTING	Contracted Labour	RFQ Labour	$ 169,915.33
SANEXEN (FORMERLY PCB DISPOSAL)	Oil/PCB-Non PBC Waste Management	RFQ Labour	$ 164,809.84

2010 SUPPLIER LIST > $150,000

NAME	ACTIVITY	PROCESS/DEPT. RESPONSIBLE	TOTAL
ELSTER METERING	Smart Meters	RFP Purchases	$ 4,709,479.59
K-LINE MAINTENANCE & CONSTRUCTION LT	Contracted Labour	Tendered Labour	$ 1,749,141.93
M.E.A.R.I.E. - EMPL.BENEFITS	Employee Benefits	Reciprocal Arrangement	$ 920,709.98
NBM ENGINEERING INC	Contracted Labour	Tendered Labour	$ 848,022.54
MOLONEY ELECTRIC CORPORATION	Transformers	RFQ Supplier Alliance	$ 779,042.34
OLAMETER	Meter Reading/Collections and Smart Meter Installs	Tendered Labour	$ 760,158.66
LIGHTWORKS INC	CDM - Direct Install Business Lighting	Tendered Labour	$ 727,011.23
NEXANS CANADA INC	Wire	RFQ Supplier Alliance	$ 618,003.91
HONEYWELL LTD	CDM Peaksaver Program	Tendered Purchases	$ 543,058.73
TERRA DISCOVERY LTD	Locates	RFQ Labour	$ 456,492.27
HD SUPPLY UTILITIES	Inventory	RFQ Supplier Alliance	$ 452,114.23
BESWICK TREE SERVICE LTD.	Tree Trimming	Tendered Labour	$ 417,913.20
BETHLEHEM TRENCHING LTD.	Contracted Labour	Tendered Labour	$ 342,483.97
EL-CON CONSTRUCTION INC	Locates	RFQ Labour	$ 326,281.52
M.E.A.R.I.E.-LIAB.&PROPERTY INSURANC	Liability & Property Insurance	Reciprocal Arrangement	$ 298,115.00
ANGUS GEOSOLUTIONS INC.	GIS Mapping Software and Installation	RFI Purchases	$ 277,700.57
GENERAL ELECTRIC	Towerline Station Transformer Repairs and Rewind	RFQ Labour	$ 271,166.10
B.F. CONTRACTING	Contracted Labour	Tendered Labour	$ 247,891.25
S & C ELECTRIC LTD.	Intellirupter Pulse Closer and Vista Switchgear	RFQ Alliance Specialty	$ 225,101.85
SKY ENERGY CONSULTING	MDM/R Smart Meter Data Flow	RFQ Labour	$ 217,742.53
ALADACO CONSULTING	Contracted Labour	RFQ Labour	$ 203,983.23
GUELPH UTILITY POLE	Wood Poles	RFQ Supplier Alliance	$ 189,889.72
NAYLOR GROUP INC.	HVAC Building Equipment	RFQ Purchases	$ 163,610.45
RODAN METERING	Smart Meter Installs	RFQ Labour	$ 157,100.75

2011 SUPPLIER LIST > $150,000

NAME	ACTIVITY	PROCESS/DEPT. RESPONSIBLE	TOTAL
K-LINE MAINTENANCE & CONSTRUCTION LT	Contracted Labour	Tendered Labour	$ 1,529,666.23
M.E.A.R.I.E. - EMPL.BENEFITS	Employee Benefits	Reciprocal Arrangement	$ 1,014,024.18
MOLONEY ELECTRIC CORPORATION	Transformers	RFQ Supplier Alliance	$ 866,967.64
ELSTER METERING	Meters	RFQ Purchases	$ 803,611.27
NBM ENGINEERING INC	Contracted Labour	Tendered Labour	$ 661,495.69
ANGUS GEOSOLUTIONS INC.	GIS Mapping Software and Installation	RFI Purchases	$ 614,860.72
BETHLEHEM TRENCHING LTD.	Contracted Labour	Tendered Labour	$ 534,873.90

EL-CON CONSTRUCTION INC	Locates	RFQ Labour	$ 447,731.96
NEXANS CANADA INC	Wire	RFQ Supplier Alliance	$ 416,448.48
HD SUPPLY UTILITIES	Inventory	RFQ Supplier Alliance	$ 380,028.20
OLAMETER	Meter Reading/Collections and Smart Meter Installs	RFQ Purchases	$ 374,435.65
SKY ENERGY CONSULTING	MDM/R Smart Meter Data Flow	RFQ Labour	$ 373,235.05
HONEYWELL LTD	CDM Peaksaver Program	Tendered Purchases	$ 353,667.83
ALADACO CONSULTING	Contracted Labour	RFQ Labour	$ 342,199.41
GUELPH UTILITY POLE	Wood Poles	RFQ Supplier Alliance	$ 309,700.23
S & C ELECTRIC LTD.	Intellirupter Pulse Closer and Vista Switchgear	RFQ Alliance Specialty	$ 302,044.05
BESWICK TREE SERVICE LTD.	Tree Trimming	Tendered Labour	$ 271,082.77
M.E.A.R.I.E.-LIAB.&PROPERTY INSURANC	Liability & Property Insurance	Reciprocal Arrangement	$ 264,654.76
NAYLOR GROUP INC.	HVAC Building Equipment	RFQ Purchases	$ 201,693.60
B.F. CONTRACTING	Contracted Labour	Tendered Labour	$ 180,569.81
LIGHTWORKS INC	CDM - Direct Install Business Lighting	Tendered Labour	$ 179,644.64
SUPERSUCKER HYDRO VAC SERVICE INC.	Hydro Vac Services	RFQ Labour	$ 173,997.74
PEGASUS DIRECT MAIL WORX INC.	Paper Stock & Mailing of Customers Bills	RFQ Purchases	$ 159,324.19

2012 SUPPLIER LIST > $150,000

NAME	ACTIVITY	PROCESS/DEPT. RESPONSIBLE	TOTAL
K-LINE MAINTENANCE & CONSTRUCTION LT	Contracted Labour	Tendered Labour	$ 1,686,854.18
MOLONEY ELECTRIC CORPORATION	Transformers	RFQ Supplier Alliance	$ 1,433,450.43
S & C ELECTRIC LTD.	Intellirupter Pulse Closer and Vista Switchgear	RFQ Alliance Specialty	$ 1,293,522.88
NBM ENGINEERING INC	Contracted Labour	Tendered Labour	$ 1,252,637.00
M.E.A.R.I.E. - EMPL.BENEFITS	Employee Benefits	Reciprocal Arrangement	$ 1,105,082.00
NEXANS CANADA INC	Wire	RFQ Supplier Alliance	$ 674,738.31
HONEYWELL LTD	CDM Peaksaver Program	Tendered Purchases	$ 665,600.85
ELSTER METERING	Meters	RFQ Purchases	$ 598,226.69
HD SUPPLY UTILITIES	Inventory	RFQ Supplier Alliance	$ 580,835.24
EL-CON CONSTRUCTION INC	Locates	RFQ Labour	$ 559,502.24
BETHLEHEM TRENCHING LTD.	Contracted Labour	Tendered Labour	$ 532,229.61
ANGUS GEOSOLUTIONS INC.	GIS Mapping Software and Installation	RFI Purchases	$ 481,185.42
ALADACO CONSULTING	Contracted Labour	RFQ Labour	$ 393,754.12
M.E.A.R.I.E.-LIAB.&PROPERTY INSURANC	Liability & Property Insurance	Reciprocal Arrangement	$ 315,888.04
BESWICK TREE SERVICE LTD.	Tree Trimming	Tendered Labour	$ 289,028.58
GUELPH UTILITY POLE	Wood Poles	RFQ Supplier Alliance	$ 272,536.79
B.F. CONTRACTING	Contracted Labour	Tendered Labour	$ 203,108.25
LIGHTWORKS INC	CDM - Direct Install Business Lighting	Tendered Labour	$ 201,875.03
BEL-VOLT SALES LTD	Inventory	RFQ Supplier Alliance	$ 193,239.75
ASEI ACUMEN ENGINEERED SOLUTIONS	Contracted Labour	RFQ Labour	$ 192,148.45
NAYLOR GROUP INC.	HVAC Building Equipment	RFQ Purchases	$ 188,140.58
SUPERSUCKER HYDRO VAC SERVICE INC.	Hydro Vac Services	RFQ Labour	$ 171,526.50
PEGASUS DIRECT MAIL WORX INC.	Paper Stock & Mailing of Customers Bills	RFQ Purchases	$ 155,098.75

2013 SUPPLIER LIST > $150,000

NAME	ACTIVITY	PROCESS/DEPT. RESPONSIBLE	TOTAL
MOLONEY ELECTRIC CORPORATION	Transformers	RFQ Supplier Alliance	$ 1,433,450.43
M.E.A.R.I.E. - EMPL.BENEFITS	Employee Benefits	Reciprocal Arrangement	$ 1,105,082.00
NEXANS CANADA INC	Wire	RFQ Supplier Alliance	$ 674,738.31
HONEYWELL LTD	CDM Peaksaver Program	Tendered Purchases	$ 665,600.85
HD SUPPLY UTILITIES	Inventory	RFQ Supplier Alliance	$ 580,835.24
EL-CON CONSTRUCTION INC	Locates	RFQ Labour	$ 559,502.24
BETHLEHEM TRENCHING LTD.	Contracted Labour	Tendered Labour	$ 532,229.61
BESWICK TREE SERVICE LTD.	Tree Trimming	Tendered Labour	$ 417,913.20
M.E.A.R.I.E.-LIAB.&PROPERTY INSURANC	Liability & Property Insurance	Reciprocal Arrangement	$ 315,888.04
GUELPH UTILITY POLE	Wood Poles	RFQ Supplier Alliance	$ 272,536.79
ELSTER METERING	Meters	RFQ Purchases	$ 250,000.00
B.F. CONTRACTING	Contracted Labour	Tendered Labour	$ 203,108.25
ANGUS GEOSOLUTIONS INC.	GIS Mapping Software and Installation	RFI Purchases	$ 200,000.00
BEL-VOLT SALES LTD	Inventory	RFQ Supplier Alliance	$ 193,239.75
SUPERSUCKER HYDRO VAC SERVICE INC.	Hydro Vac Services	RFQ Labour	$ 171,526.50
PEGASUS DIRECT MAIL WORX INC.	Paper Stock & Mailing of Customers Bills	RFQ Purchases	$ 155,098.75
S & C ELECTRIC LTD.	Intellirupter Pulse Closer and Vista Switchgear	RFQ Alliance Specialty	$ -
NBM ENGINEERING INC	Contracted Labour	RFQ Labour	$ -
ALADACO CONSULTING	Contracted Labour	RFQ Labour	$ -
LIGHTWORKS INC	CDM - Direct Install Business Lighting	Tendered Labour	$ -
ASEI ACUMEN ENGINEERED SOLUTIONS	Contracted Labour	RFQ Labour	$ -
K-LINE MAINTENANCE & CONSTRUCTION LT	Contracted Labour	Tendered Labour	$ -

2014 SUPPLIER LIST > $150,000

NAME	ACTIVITY	PROCESS/DEPT. RESPONSIBLE	TOTAL
MOLONEY ELECTRIC CORPORATION	Transformers	RFQ Supplier Alliance	$ 1,433,450.43
M.E.A.R.I.E. - EMPL.BENEFITS	Employee Benefits	Reciprocal Arrangement	$ 1,105,082.00

NEXANS CANADA INC	Wire	RFQ Supplier Alliance	$ 674,738.31
HONEYWELL LTD	CDM Peaksaver Program	Tendered Purchases	$ 665,600.85
HD SUPPLY UTILITIES	Inventory	RFQ Supplier Alliance	$ 580,835.24
EL-CON CONSTRUCTION INC	Locates	RFQ Labour	$ 559,502.24
BETHLEHEM TRENCHING LTD.	Contracted Labour	Tendered Labour	$ 532,229.61
NAYLOR GROUP INC.	HVAC Building Equipment	RFQ Purchases	$ 350,000.00
M.E.A.R.I.E.-LIAB.&PROPERTY INSURANC	Liability & Property Insurance	Reciprocal Arrangement	$ 315,888.04
BESWICK TREE SERVICE LTD.	Tree Trimming	Tendered Labour	$ 289,028.58
GUELPH UTILITY POLE	Wood Poles	RFQ Supplier Alliance	$ 272,536.79
ELSTER METERING	Meters	RFQ Purchases	$ 250,000.00
B.F. CONTRACTING	Contracted Labour	Tendered Labour	$ 203,108.25
ANGUS GEOSOLUTIONS INC.	GIS Mapping Software and Installation	RFI Purchases	$ 200,000.00
BEL-VOLT SALES LTD	Inventory	RFQ Supplier Alliance	$ 193,239.75
SUPERSUCKER HYDRO VAC SERVICE INC.	Hydro Vac Services	RFQ Labour	$ 171,526.50
PEGASUS DIRECT MAIL WORX INC.	Paper Stock & Mailing of Customers Bills	RFQ Purchases	$ 155,098.75
S & C ELECTRIC LTD.	Intellirupter Pulse Closer and Vista Switchgear	RFQ Alliance Specialty	$ -
NBM ENGINEERING INC	Contracted Labour	RFQ Labour	$ -
ALADACO CONSULTING	Contracted Labour	RFQ Labour	$ -
LIGHTWORKS INC	CDM - Direct Install Business Lighting	Tendered Labour	$ -
ASEI ACUMEN ENGINEERED SOLUTIONS	Contracted Labour	RFQ Labour	$ -
K-LINE MAINTENANCE & CONSTRUCTION LT	Contracted Labour	Tendered Labour	$ -

Note for 2013-2014 *: The vendors may change through the tender process, but activity (see below) will remain the same. The forecasted totals for 2013-2014 take into account historical purchases, forecasted work activities reflecting tighter budget controls and improved operational efficiencies.*

Attachment 2 (of 2):

Procurement Policy

PURCHASING & DISPOSAL POLICY
POLICY #11-15-2004-R1-2011

Purchasing Authorization

A. *All purchases* must be approved by the appropriate Department Head or his/her designate via the "Purchase Requisition Form" prior to a purchase order being prepared. The Purchase requisition must include either the Work Order #, GL #, or Capital Budget # (Capital purchases over $1000 must also include the completed and signed "Capital Expenditure Request").

B. *All computer purchases* must be approved via the I.T. Director to assure system conformability.

C. *Purchase Cards* can be signed out in the Purchasing Department for the following vendors: *Canadian Tire, Home Depot, Future Shop, Office Depot*. Receipts must be immediately sent to the Accounting Department and signed by the immediate supervisor with the appropriate departmental charge or GL number.

D. *All Office Supplies* (Basics Office Supplies) are purchased through the individual departments. The Stationery Requisition forms must be approved by the individual department head's. All forms are faxed by the Purchasing Department once completed.

E. Purchasing Services to consult with appropriate Responsible Manager and/or HR/Health & Safety, prior to the purchase of new equipment, tools or materials to ensure new hazards due to change of process, standards or equipment are considered.

Known quantities/requirements

A. Quotation
- Informal quotations will be administered by the Purchasing Manager.
- The Purchasing Manager may obtain up to three quotes from qualified suppliers in the most expeditious manner possible either by phone, fax, E-mail, or correspondence.

B. Tenders
- The act of tendering is an important segment of the Burlington Hydro Inc.'s Purchasing Policy in that it ensures the following:
    1. that Burlington Hydro Inc. receives the benefits of competitive pricing
- Sealed tenders shall be invited to bid based on either the ability to provide the products or services, due diligence documentation for new businesses, or past business relationships.

- Tenders not received by Burlington Hydro Inc. at the stated time and place stipulated in the tendering document will be returned to the vendor unopened.

Negotiations

A. The Purchasing Manager may negotiate where:
    - there is only one source of supply for the goods or services, or
    - there is merit in purchasing at a public auction, or
    - all tenders or quotations received fail to meet specifications or terms and conditions and it is unreasonable to recall tenders or quotations.

B. The negotiation procedures shall be those accepted as standard negotiating procedures that employ fair and ethical practices.

Emergency purchasing

A. Notwithstanding the provisions of this policy, goods and services required to address an emergency, as defined herein, shall be acquired by the most open market procedure. Selection shall be based on the quality and timeliness of service and where possible at the lowest cost.

B. The following shall apply in the case of an emergency situation which requires the immediate procurement of goods and/or services to prevent serious financial consequences to the Utility, to restore a customer's supply, to ensure the health and safety of employees or customers, or to respond to any environmental emergency:
    - During normal business hours, the Purchasing Manager shall procure any required goods and/or services by the quotation/negotiation method.
    - Outside normal business hours, or in the absence of the Purchasing Manager, a Department Head or his/her designate may purchase directly any required goods or services. Where such purchase occurs the Purchasing Manager shall be notified immediately upon starting normal business hours.

Partnerships

A. Depending on the individual circumstances, Burlington Hydro Inc. believes that it can obtain greater benefits by adopting a strategic procurement alliance for the purchase of goods and services rather than treating individual purchases in isolation. The benefits accruing to the Utility are:
    - reduced total inventory levels arising from closely matching production schedules with actual requirements,

- reduced administrative burden and overall costs due to streamlining the procurement process and taking advantage of economies of scale,
- improved service levels,
- better project estimates and improved ability to control final project costs,
- improved ability to meet project schedules,
- reduced expediting and inspection costs,
- innovation will be encouraged and
- adoption of agreed terms and conditions and specifications will reduce time required in both engineering and purchasing

B. Where it is demonstrated that Burlington Hydro Inc. will realize these benefits, a partnership agreement will be submitted to the Utility for approval. As part of the process, in order to ensure open competition, the Utility may entertain expressions of interest from the marketplace. The ability to add and delete products or services to the agreement will be a requirement of the agreement.

Cooperative purchasing

The Utility encourages cooperative purchasing with other Utilities or public agencies whenever the best interests of the Utility will be served. The policies and procedures of the participant responsible for issuing the call shall apply.

Extensions

Where it is to the Utilities advantage, purchasing arrangements may be extended for successive periods, as defined in the original arrangement.

Exceptions

A. This policy does not apply to the following items:
   - Power purchases from Hydro One.
   - Petty cash items
   - Training and education
   - Refundable employee expenses
   - Refunds
   - Utilities
   - Payroll related expenditures
     - debenture payments
     - insurance payments
     - damage claims
     - tax remittances

B. A purchase order is not required for the following:
   - Professional services
     - counseling fees

- auditing
- consulting fees
- legal fees
- banking
- insurance premiums

Selection criteria

A. The selection criteria for goods shall be based on the following where relevant:
   - Specifications or requirements
   - Quality
   - Service
   - Delivery
   - Place
   - Life cycle costs
   - Price

A. The selection criteria for services shall be based on the following where relevant:
   - the ability, capacity and skill of the vendor to perform the contract,
   - the ability, capacity and skill of the vendor to perform the contract in a safe manner,
   - whether the vendor can perform the service promptly within the time specified without delay or interference,
   - the character, integrity, reputation, judgment, experience and efficiency of the vendor and the proposed staff for this service,
   - the quality of performance provided on previous contracts or services, and
   - all cost to the utility that would result from selecting the vendor.

Disposals

A. The Purchasing Manager's co-operation with Department heads or their designate shall have the authority to sell, exchange or otherwise dispose of all goods declared as surplus to the needs of the Utility. Where it is in the best interest of the Utility, items or groups of items may:
   - Be offered to other public agencies;
   - Be sold by external advertisement, formal request, auction or public sale;

B. In the event that all efforts to dispose of goods by sale are unsuccessful, these items may be offered for refuse or donated to a charity.

C. The Purchasing Manager may sell or trade obsolete or surplus goods to the original supplier or others in that line of business where it is determined that a higher net return will be obtained than by following the procedures set out above.

D. Where it is deemed appropriate by the Purchasing Manager, a reserve price may be established.

Authorization Date: November 15, 2004

Exhibit 4: Operating Costs

Tab 7 (of 8): Depreciation and Amortization

DEPRECIATION RATES AND METHODOLOGY

In accordance with the July 17, 2012 letter from the Board on Regulatory accounting policy direction regarding changes to depreciation expense and capitalization policies and as such, has adopted the Kinectrics proposed useful lives and componentization
In 2010, Burlington Hydro completed an internal analysis which supported the revised average useful lives of various asset categories based on historical evidence and is within the typical useful life bands outlined in the Kinectrics Report “Asset Depreciation Study for the Ontario Energy Board”. The impact of on the utility’s net assets is discussed at Exhibit 2 and the newly adopted depreciation rates are presented at the next page.

Continuity Statements of the historical and forecasted depreciation expenses are presented at the next page or Exhibit 4, Tab 7 Schedule 1 Attachment 1.

Attachment 1 (of 2):

OEB Appendices -Depreciation and Amortization Expense (all)

File Number:	EB-2013-0115
Exhibit:	4
Tab:	7
Schedule:	1
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Date:	

Appendix 2-CR
Depreciation and Amortization Expense
Assumes the applicant made capitalization and depreciation expense accounting policy changes under CGAAP effective January 1, 2013

Year 2012 Former CGAAP - CGAAP without the changes to the policies

Account	Description	Opening Regulatory Gross PP&E as at Jan 1, 2012 (a)	Less Fully Depreciated (b)	Net for Depreciation (c)	Additions (d)	Total for Depreciation (e) = (c) + ½ x (d) [1]	Years (f)	Depreciation Rate (g) = 1 / (f)	2012 Depreciation Expense (h) = (e) / (f)	2012 Depreciation Expense per Appendix 2-B Fixed Assets, Column K (l)	Variance [2] (m) = (h) - (l)
1611	Computer Software (Formally known as Account 1925)	$ 4,972,576.00	$ 2,990,941.00	$ 1,981,635.00	$ 566,350.00	$ 2,264,810.00	5.00	20.00%	$ 476,897.00	$ 476,897.00	$ -
1612	Land Rights (Formally known as Account 1906)	$ 12,933.00	$ 2,130.00	$ 10,803.00		$ 10,803.00	35.00	2.86%	$ 308.66	$ 308.66	$ -
1612	Land Rights (Formally known as Account 1906)	$ 176,418.00		$ 176,418.00		$ 176,418.00	70.00	1.43%	$ 2,520.26	$ 2,520.26	
1805	Land	$ 202,703.00		$ 202,703.00		$ 202,703.00			$ -	$ -	$ -
1808	Buildings	$ 203,258.00	$ 43,131.00	$ 160,127.00	$ 5,450.00	$ 162,852.00	10.00	10.00%	$ 16,285.20	$ 16,285.20	$ -
1808	Buildings	$ 7,599.00		$ 7,599.00		$ 7,599.00	15.00	6.67%	$ 506.60	$ 506.60	$ -
1808	Buildings	$ 9,900.00		$ 9,900.00		$ 9,900.00	20.00	5.00%	$ 495.00	$ 495.00	$ -
1808	Buildings	$ 405,824.00	$ 14,394.00	$ 391,430.00		$ 391,430.00	25.00	4.00%	$ 15,657.20	$ 15,657.20	$ -
1808	Buildings	$ 9,085.00		$ 9,085.00		$ 9,085.00	30.00	3.33%	$ 302.83	$ 302.83	$ -
1808	Buildings	$ 1,655,728.00		$ 1,655,728.00		$ 1,655,728.00	50.00	2.00%	$ 33,114.56	$ 33,114.56	$ -
1810	Leasehold Improvements			$ -		$ -			$ -	$ -	$ -
1815	Transformer Station Equipment >50 kV			$ -		$ -			$ -	$ -	$ -
1820	Distribution Station Equipment <50 kV	$ 13,826,211.00	$ 2,800,272.00	$ 11,025,939.00	$ 594,681.00	$ 11,323,279.50	30.00	3.33%	$ 367,829.00	$ 367,829.00	$ -
1825	Storage Battery Equipment			$ -		$ -			$ -	$ -	$ -
1830	Poles, Towers & Fixtures	$ 28,590,096.00	$ 3,902,970.00	$ 24,687,126.00	$ 2,590,416.00	$ 25,982,334.00	25.00	4.00%	$ 1,039,293.36	$ 1,039,293.36	$ -
1835	Overhead Conductors & Devices	$ 39,722,236.00	$ 6,721,781.00	$ 33,000,455.00	$ 1,634,365.00	$ 33,817,637.50	25.00	4.00%	$ 1,352,705.50	$ 1,352,705.50	$ -
1840	Underground Conduit	$ 14,422,386.00	$ 2,168,316.00	$ 12,254,070.00	$ 1,764,996.00	$ 13,136,568.00	25.00	4.00%	$ 525,462.72	$ 525,462.72	$ -
1845	Underground Conductors & Devices	$ 25,777,253.00	$ 3,686,138.00	$ 22,091,115.00	$ 1,309,497.00	$ 22,745,863.50	25.00	4.00%	$ 909,834.54	$ 909,834.54	$ -
1850	Line Transformers	$ 46,417,593.00	$ 6,514,649.00	$ 39,902,944.00	$ 1,855,125.00	$ 40,830,506.50	25.00	4.00%	$ 1,633,220.26	$ 1,633,220.26	$ -
1855	Services (Overhead & Underground)	$ 30,612,058.00	$ 5,203,960.00	$ 25,408,098.00	$ 1,328,442.00	$ 26,072,319.00	25.00	4.00%	$ 1,042,892.76	$ 1,042,892.76	$ -
1860	Meters	$ 8,476,768.74	$ 2,165,081.00	$ 6,311,687.74	$ 427,116.00	$ 6,525,245.74	25.00	4.00%	$ 261,009.83	$ 261,009.83	$ -
1860	Meters (Smart Meters)			$ -	$ 9,558,982.00	$ 4,779,491.00	15.00	6.67%	$ 1,599,572.73	$ 1,599,572.73	$ -
1905	Land	$ 96,300.00		$ 96,300.00		$ 96,300.00			$ -	$ -	$ -
1908	Buildings & Fixtures			$ -	$ 19,446.00	$ 9,723.00	5.00	20.00%	$ 1,944.60	$ 1,944.60	$ -
1908	Buildings & Fixtures	$ 510,189.00	$ 176,581.00	$ 333,608.00	$ 25,929.00	$ 346,572.50	10.00	10.00%	$ 34,657.25	$ 34,657.25	
1908	Buildings & Fixtures	$ 141,810.00		$ 141,810.00	-$ 19,519.00	$ 132,050.50	15.00	6.67%	$ 8,803.37	$ 8,803.37	
1908	Buildings & Fixtures	$ 648,248.00	$ 161,661.00	$ 486,587.00	$ 22,593.00	$ 497,883.50	20.00	5.00%	$ 24,894.18	$ 24,894.18	
1908	Buildings & Fixtures	$ 749,376.00		$ 749,376.00	$ 178,347.00	$ 838,549.50	25.00	4.00%	$ 33,541.98	$ 33,541.98	
1908	Buildings & Fixtures	$ 6,187,439.00		$ 6,187,439.00		$ 6,187,439.00	50.00	2.00%	$ 123,748.78	$ 123,748.78	
1910	Leasehold Improvements			$ -		$ -			$ -	$ -	$ -
1915	Office Furniture & Equipment (10 years)	$ 1,396,963.00	$ 916,649.00	$ 480,314.00	$ 81,205.00	$ 520,916.50	10.00	10.00%	$ 52,091.65	$ 52,091.65	$ -
1915	Office Furniture & Equipment (5 years)			$ -		$ -			$ -	$ -	$ -
1920	Computer Equipment - Hardware	$ 855,550.00	$ 671,912.00	$ 183,638.00	$ 89,641.00	$ 228,458.50	5.00	20.00%	$ 60,433.70	$ 60,433.70	$ -
1920	Computer Equip.-Hardware(Post Mar. 22/04)			$ -		$ -			$ -	$ -	$ -
1920	Computer Equip.-Hardware(Post Mar. 19/07)			$ -		$ -			$ -	$ -	$ -
1930	Transportation Equipment	$ 864,004.00	$ 545,641.00	$ 318,363.00	$ 64,539.00	$ 350,632.50	5.00	20.00%	$ 70,126.50	$ 70,126.50	$ -
1930	Transportation Equipment	$ 2,800,596.00	$ 1,488,001.00	$ 1,312,595.00		$ 1,312,595.00	8.00	12.50%	$ 164,074.38	$ 164,074.38	
1935	Stores Equipment	$ 292,425.00	$ 292,425.00	$ -		$ -			$ -	$ -	$ -
1940	Tools, Shop & Garage Equipment	$ 1,330,286.00	$ 1,039,162.00	$ 291,124.00	$ 27,128.00	$ 304,688.00	10.00	10.00%	$ 32,039.80	$ 32,039.80	$ -
1945	Measurement & Testing Equipment	$ 368,936.00	$ 316,147.00	$ 52,789.00	$ 2,519.00	$ 54,048.50	10.00	10.00%	$ 5,404.85	$ 5,404.85	$ -
1950	Power Operated Equipment			$ -		$ -			$ -	$ -	$ -
1955	Communications Equipment	$ 191,860.00	$ 191,860.00	$ -		$ -			$ -	$ -	$ -
1955	Communication Equipment (Smart Meters)			$ -		$ -			$ -	$ -	$ -
1960	Miscellaneous Equipment			$ -		$ -			$ -	$ -	$ -

1975	Load Management Controls Utility Premises			$ -		$ -			$ -	$ -	$ -
1980	System Supervisor Equipment	$ 3,021,560.00	$ 2,628,421.00	$ 393,139.00	$ 64,163.00	$ 425,220.50	15.00	6.67%	$ 25,012.00	$ 25,012.00	$ -
1985	Miscellaneous Fixed Assets			$ -		$ -			$ -	$ -	$ -
1995	Contributions & Grants	-$ 24,106,435.00		-$ 24,106,435.00	-$ 3,238,245.00	-$ 25,725,557.50	25.00	4.00%	-$ 1,029,022.30	-$ 1,029,022.30	$ -
1609	Other Tangible Property	$ 943,057.00	$ -	$ 943,057.00	$ 5,855,000.00	$ 3,870,557.00			$ -	$ -	$ -
				$ -		$ -			$ -	$ -	$ -
	Total	$ 211,792,789.74	$ 44,642,223.00	$ 167,150,566.74	$ 24,808,166.00	$ 179,554,649.74			$ 8,885,658.74	$ 8,885,658.74	$ -

Year 2011 Former CGAAP - CGAAP without the changes to the policies

Account	Description	Opening Regulatory Gross PP&E as at Jan 1, 2011 (a)	Less Fully Depreciated (b)	Net for Depreciation (c)	Additions (d)	Total for Depreciation (e) = (c) + ½ x (d) [1]	Years (f)	Depreciation Rate (g) = 1 / (f)	2011 Depreciation Expense (h) = (e) / (f)	2011 Depreciation Expense per Appendix 2-B Fixed Assets, Column K (l)	Variance [2] (m) = (h) - (l)
1611	Computer Software (Formally known as Account 1925)	$ 4,441,146.00	$ 2,807,112.00	$ 1,634,034.00	$ 531,430.00	$ 1,899,749.00	5.00	20.00%	$ 358,411.00	$ 358,411.00	$ -
1612	Land Rights (Formally known as Account 1906)	$ 12,933.00	$ 2,130.00	$ 10,803.00		$ 10,803.00	35.00	2.86%	$ 308.66	$ 308.66	$ -
1612	Land Rights (Formally known as Account 1906)	$ 176,418.00		$ 176,418.00		$ 176,418.00	70.00	1.43%	$ 2,520.26	$ 2,520.26	$ -
1805	Land	$ 202,703.00		$ 202,703.00		$ 202,703.00	-		$ -	$ -	$ -
1808	Buildings - Equipment	$ 185,102.00	$ 27,874.00	$ 157,228.00	$ 18,158.00	$ 166,307.00	10.00	10.00%	$ 16,630.70	$ 16,630.70	$ -
1808	Buildings - Equipment			$ -	$ 7,599.00	$ 3,799.50	15.00	6.67%	$ 253.30	$ 253.30	
1808	Buildings - Equipment	$ 9,900.00		$ 9,900.00		$ 9,900.00	20.00	5.00%	$ 495.00	$ 495.00	
1808	Buildings - Major Repairs	$ 404,394.00	$ 14,394.00	$ 390,000.00	$ 1,430.00	$ 390,715.00	25.00	4.00%	$ 15,628.60	$ 15,628.60	$ -
1808	Buildings - Major Repairs	$ 9,085.00		$ 9,085.00		$ 9,085.00	30.00	3.33%	$ 302.83	$ 302.83	
1808	Buildings - Brick, Stone, Concrete and Steel	$ 1,655,728.00		$ 1,655,728.00		$ 1,655,728.00	50.00	2.00%	$ 33,114.56	$ 33,114.56	$ -
1810	Leasehold Improvements			$ -		$ -	-		$ -	$ -	$ -
1815	Transformer Station Equipment >50 kV			$ -		$ -	-		$ -	$ -	$ -
1820	Distribution Station Equipment <50 kV	$ 13,180,871.00	$ 2,563,889.00	$ 10,616,982.00	$ 645,339.00	$ 10,939,651.50	30.00	3.33%	$ 360,175.00	$ 360,175.00	$ -
1825	Storage Battery Equipment			$ -		$ -	-		$ -	$ -	$ -
1830	Poles, Towers & Fixtures	$ 26,025,505.00	$ 3,292,696.00	$ 22,732,809.00	$ 2,564,592.00	$ 24,015,105.00	25.00	4.00%	$ 960,604.20	$ 960,604.20	$ -
1835	Overhead Conductors & Devices	$ 38,499,884.00	$ 5,670,755.00	$ 32,829,129.00	$ 1,222,353.00	$ 33,440,305.50	25.00	4.00%	$ 1,337,612.22	$ 1,337,612.22	$ -
1840	Underground Conduit	$ 13,529,171.00	$ 1,829,276.00	$ 11,699,895.00	$ 893,215.00	$ 12,146,502.50	25.00	4.00%	$ 485,860.10	$ 485,860.10	$ -
1845	Underground Conductors & Devices	$ 24,767,744.00	$ 3,109,769.00	$ 21,657,975.00	$ 1,009,509.00	$ 22,162,729.50	25.00	4.00%	$ 886,509.18	$ 886,509.18	$ -
1850	Line Transformers	$ 45,814,007.00	$ 5,225,939.00	$ 40,588,068.00	$ 603,586.00	$ 40,889,861.00	25.00	4.00%	$ 1,635,594.44	$ 1,635,594.44	$ -
1855	Services (Overhead & Underground)	$ 29,513,031.00	$ 4,390,262.00	$ 25,122,769.00	$ 1,099,026.00	$ 25,672,282.00	25.00	4.00%	$ 1,026,891.28	$ 1,026,891.28	$ -
1860	Meters	$ 8,202,543.00	$ 1,821,859.00	$ 6,380,684.00	$ 329,818.00	$ 6,545,593.00	25.00	4.00%	$ 261,823.72	$ 261,823.72	$ -
1860	Meters (Smart Meters)			$ -		$ -			$ -	$ -	$ -
1905	Land	$ 96,300.00		$ 96,300.00		$ 96,300.00	-		$ -	$ -	$ -
1908	Buildings & Fixtures - Equipment	$ 453,185.00	$ 141,616.00	$ 311,569.00	$ 57,003.00	$ 340,070.50	10.00	10.00%	$ 34,007.05	$ 34,007.05	$ -
1908	Buildings & Fixtures - Equipment				$ 141,810.00	$ 70,905.00	15.00	6.67%	$ 4,727.00	$ 4,727.00	
1908	Buildings & Fixtures - Driveways	$ 648,249.00	$ 161,661.00	$ 486,588.00		$ 486,588.00	20.00	5.00%	$ 24,329.40	$ 24,329.40	$ -
1908	Buildings & Fixtures - Major Repairs	$ 749,374.00		$ 749,374.00		$ 749,374.00	25.00	4.00%	$ 29,974.96	$ 29,974.96	$ -
1908	Buildings & Fixtures - Brick Store etc	$ 6,187,440.00		$ 6,187,440.00		$ 6,187,440.00	50.00	2.00%	$ 123,748.80	$ 123,748.80	$ -
1910	Leasehold Improvements			$ -		$ -			$ -	$ -	$ -
1915	Office Furniture & Equipment (10 years)	$ 1,325,174.00	$ 899,859.00	$ 425,315.00	$ 71,789.00	$ 461,209.50	10.00	10.00%	$ 46,120.95	$ 46,120.95	$ -
1915	Office Furniture & Equipment (5 years)			$ -		$ -			$ -	$ -	$ -
1920	Computer Equipment - Hardware	$ 813,080.00	$ 603,690.00	$ 209,390.00	$ 42,470.00	$ 230,625.00	5.00	20.00%	$ 46,125.00	$ 46,125.00	$ -
1920	Computer Equip.-Hardware(Post Mar. 22/04)			$ -		$ -			$ -	$ -	$ -
1920	Computer Equip.-Hardware(Post Mar. 19/07)			$ -		$ -			$ -	$ -	$ -
1930	Transportation Equipment - under 3 Tons	$ 951,396.00	$ 507,282.92	$ 444,113.08	$ 64,228.00	$ 476,227.08	5.00	20.00%	$ 95,245.42	$ 95,245.42	$ -
1930	Transportation Equipment - 3 Tons & Over	$ 2,800,596.14	$ 1,226,361.00	$ 1,574,235.14		$ 1,574,235.14	8.00	12.50%	$ 196,779.39	$ 196,779.39	$ -
1935	Stores Equipment	$ 292,425.00	$ 292,425.00	$ -		$ -	10.00	10.00%	$ -	$ -	$ -
1940	Tools, Shop & Garage Equipment	$ 1,314,552.00	$ 1,005,051.00	$ 309,501.00	$ 15,734.00	$ 317,368.00	10.00	10.00%	$ 31,736.80	$ 31,736.80	$ -
1945	Measurement & Testing Equipment	$ 366,214.00	$ 309,936.00	$ 56,278.00	$ 2,722.00	$ 57,639.00	10.00	10.00%	$ 5,763.90	$ 5,763.90	$ -
1950	Power Operated Equipment			$ -		$ -			$ -	$ -	$ -
1955	Communications Equipment	$ 191,861.00	$ 191,861.00	$ -		$ -			$ -	$ -	$ -
1955	Communication Equipment (Smart Meters)			$ -		$ -			$ -	$ -	$ -
1960	Miscellaneous Equipment			$ -		$ -			$ -	$ -	$ -
1975	Load Management Controls Utility Premises			$ -		$ -			$ -	$ -	$ -
1980	System Supervisor Equipment	$ 2,976,201.00	$ 2,626,720.00	$ 349,481.00	$ 45,359.00	$ 372,160.50	15.00	6.67%	$ 22,258.00	$ 22,258.00	$ -
1985	Miscellaneous Fixed Assets			$ -		$ -			$ -	$ -	$ -
1995	Contributions & Grants	-$ 22,658,819.00		-$ 22,658,819.00	-$ 1,447,615.00	-$ 23,382,626.50	25.00	4.00%	-$ 935,305.06	-$ 935,305.06	$ -
1609	Other Tangible Property			$ -	$ 943,057.00	$ 471,528.50			$ -	$ -	$ -
				$ -		$ -			$ -		$ -
	Total	$ 203,137,393.14	$ 38,722,417.92	$ 164,414,975.22	$ 8,862,612.00	$ 168,846,281.22			$ 7,108,246.66	$ 7,108,246.66	$ -

Year 2010 Former CGAAP - CGAAP without the changes to the policies

Account	Description	Opening Regulatory Gross PP&E as at Jan 1, 2010 (a)	Less Fully Depreciated (b)	Net for Depreciation (c)	Additions (d)	Total for Depreciation (e) = (c) + ½ x (d) [1]	Years (f)	Depreciation Rate (g) = 1 / (f)	2010 Depreciation Expense (h) = (e) / (f)	2010 Depreciation Expense per Appendix 2-B Fixed Assets, Column K (l)	Variance [2] (m) = (h) - (l)
1611	Computer Software (Formally known as Account 1925)	$ 4,191,890.00	$ 2,763,164.00	$ 1,428,726.00	$ 249,256.00	$ 1,553,354.00	5.00	20.00%	$ 305,500.00	$ 305,500.00	$ -
1612	Land Rights (Formally known as Account 1906)	$ 12,933.00	$ 2,130.00	$ 10,803.00		$ 10,803.00	35.00	2.86%	$ 308.66	$ 308.66	$ -
1612	Land Rights (Formally known as Account 1906)	$ 176,418.00		$ 176,418.00		$ 176,418.00	70.00	1.43%	$ 2,520.26	$ 2,520.26	$ -
1805	Land	$ 202,703.00		$ 202,703.00		$ 202,703.00	-		$ -	$ -	$ -
1808	Buildings - Equipment	$ 169,172.00	$ 22,174.00	$ 146,998.00	$ 15,930.00	$ 154,963.00	10.00	10.00%	$ 15,496.30	$ 15,496.30	$ -
1808	Buildings - Equipment			$ -	$ 9,900.00	$ 4,950.00	20.00	5.00%	$ 247.50	$ 247.50	
1808	Buildings - Major Repairs	$ 404,394.00	$ 14,394.00	$ 390,000.00	$ -	$ 390,000.00	25.00	4.00%	$ 15,600.00	$ 15,600.00	$ -
1808	Buildings - Major Repairs			$ -	$ 9,085.00	$ 4,542.50	30.00	3.33%	$ 151.42	$ 151.42	$ -
1808	Buildings - Brick, Stone, Concrete and Steel	$ 1,655,728.00		$ 1,655,728.00		$ 1,655,728.00	50.00	2.00%	$ 33,114.56	$ 33,114.56	$ -
1810	Leasehold Improvements	$ -		$ -		$ -			$ -	$ -	$ -
1815	Transformer Station Equipment >50 kV	$ -		$ -		$ -			$ -	$ -	$ -
1820	Distribution Station Equipment <50 kV	$ 12,965,913.00	$ 2,317,634.00	$ 10,648,279.00	$ 214,958.00	$ 10,755,758.00	30.00	3.33%	$ 357,629.64	$ 357,629.64	$ -
1825	Storage Battery Equipment	$ -		$ -		$ -			$ -	$ -	$ -
1830	Poles, Towers & Fixtures	$ 24,151,388.00	$ 2,815,379.00	$ 21,336,009.00	$ 1,874,117.00	$ 22,273,067.50	25.00	4.00%	$ 890,922.70	$ 890,922.70	$ -
1835	Overhead Conductors & Devices	$ 37,300,263.00	$ 4,848,708.00	$ 32,451,555.00	$ 1,199,621.00	$ 33,051,365.50	25.00	4.00%	$ 1,322,054.62	$ 1,322,054.62	$ -
1840	Underground Conduit	$ 12,088,085.00	$ 1,564,099.00	$ 10,523,986.00	$ 1,441,086.00	$ 11,244,529.00	25.00	4.00%	$ 449,781.16	$ 449,781.16	$ -
1845	Underground Conductors & Devices	$ 23,584,390.00	$ 2,658,969.00	$ 20,925,421.00	$ 1,183,354.00	$ 21,517,098.00	25.00	4.00%	$ 860,683.92	$ 860,683.92	$ -
1850	Line Transformers	$ 43,726,111.00	$ 4,453,185.00	$ 39,272,926.00	$ 2,087,896.00	$ 40,316,874.00	25.00	4.00%	$ 1,612,674.96	$ 1,612,674.96	$ -
1855	Services (Overhead & Underground)	$ 27,927,296.00	$ 3,753,839.00	$ 24,173,457.00	$ 1,585,735.00	$ 24,966,324.50	25.00	4.00%	$ 998,652.98	$ 998,652.98	$ -
1860	Meters	$ 10,063,029.00	$ 5,451,210.00	$ 4,611,819.00	$ 2,106,826.00	$ 5,665,232.00	25.00	4.00%	$ 226,609.28	$ 226,609.28	$ -
1860	Meters (Smart Meters)	$ -		$ -		$ -			$ -	$ -	$ -
1905	Land	$ 96,300.00		$ 96,300.00		$ 96,300.00	-		$ -	$ -	$ -
1908	Buildings & Fixtures - Equipment	$ 380,435.00	$ 133,208.00	$ 247,227.00	$ 72,750.00	$ 283,602.00	10.00	10.00%	$ 28,360.20	$ 28,360.20	$ -
1908	Buildings & Fixtures - Driveways	$ 571,928.00	$ 161,661.00	$ 410,267.00	$ 76,321.00	$ 448,427.50	20.00	5.00%	$ 22,421.38	$ 22,421.38	$ -
1908	Buildings & Fixtures - Major Repairs	$ 707,393.00		$ 707,393.00	$ 41,981.00	$ 728,383.50	25.00	4.00%	$ 29,135.34	$ 29,135.34	$ -
1908	Buildings & Fixtures - Brick Store etc	$ 6,187,439.00		$ 6,187,439.00		$ 6,187,439.00	50.00	2.00%	$ 123,748.78	$ 123,748.78	$ -
1910	Leasehold Improvements	$ -		$ -		$ -			$ -	$ -	$ -
1915	Office Furniture & Equipment (10 years)	$ 1,273,709.00	$ 898,607.21	$ 375,101.79	$ 52,155.00	$ 401,179.29	10.00	10.00%	$ 40,117.93	$ 40,117.93	$ -
1915	Office Furniture & Equipment (5 years)	$ -		$ -		$ -			$ -	$ -	$ -
1920	Computer Equipment - Hardware	$ 738,094.00	$ 530,642.00	$ 207,452.00	$ 74,986.00	$ 244,945.00	5.00	20.00%	$ 48,989.00	$ 48,989.00	$ -
1920	Computer Equip.-Hardware(Post Mar. 22/04)	$ -		$ -		$ -			$ -	$ -	$ -
1920	Computer Equip.-Hardware(Post Mar. 19/07)	$ -		$ -		$ -			$ -	$ -	$ -
1930	Transportation Equipment - under 3 Tons	$ 912,989.00	$ 478,119.00	$ 434,870.00	$ 38,406.00	$ 454,073.00	5.00	20.00%	$ 90,814.60	$ 90,814.60	$ -
1930	Transportation Equipment - 3 Tons & Over	$ 2,979,702.00	$ 1,448,039.00	$ 1,531,663.00	$ 42,572.00	$ 1,552,949.00	8.00		$ 194,118.63	$ 194,118.63	$ -
1935	Stores Equipment	$ 292,425.00	$ 292,425.00	$ -		$ -	10.00	10.00%	$ -	$ -	$ -
1940	Tools, Shop & Garage Equipment	$ 1,292,993.00	$ 971,933.00	$ 321,060.00	$ 21,559.00	$ 331,839.50	10.00	10.00%	$ 33,183.95	$ 33,183.95	$ -
1945	Measurement & Testing Equipment	$ 362,219.00	$ 309,936.00	$ 52,283.00	$ 3,995.00	$ 54,280.50	10.00	10.00%	$ 5,428.05	$ 5,428.05	$ -
1950	Power Operated Equipment	$ -		$ -		$ -			$ -	$ -	$ -
1955	Communications Equipment	$ 191,861.00	$ 191,861.00	$ -		$ -			$ -	$ -	$ -
1955	Communication Equipment (Smart Meters)	$ -		$ -		$ -			$ -	$ -	$ -
1960	Miscellaneous Equipment	$ -		$ -		$ -			$ -	$ -	$ -
1975	Load Management Controls Utility Premises	$ -		$ -		$ -			$ -	$ -	$ -
1980	System Supervisor Equipment	$ 2,883,378.00	$ 150,363.00	$ 2,733,015.00	$ 92,823.00	$ 2,779,426.50	15.00	6.67%	$ 184,143.00	$ 184,143.00	$ -
1985	Miscellaneous Fixed Assets	$ -		$ -		$ -			$ -	$ -	$ -
1995	Contributions & Grants	-$ 19,753,629.00		-$ 19,753,629.00	-$ 2,905,190.00	-$ 21,206,224.00	25.00	4.00%	-$ 848,248.96	-$ 848,248.96	$ -
etc.				$ -		$ -			$ -		$ -
				$ -		$ -			$ -		$ -
	Total	$ 197,736,949.00	$ 36,231,679.21	$ 161,505,269.79	$ 9,590,122.00	$ 166,300,330.79			$ 7,044,159.84	$ 7,044,159.84	$ -

Year 2009 Former CGAAP - CGAAP without the changes to the policies

Account	Description	Opening Regulatory Gross PP&E as at Jan 1, 2009 (a)	Less Fully Depreciated (b)	Net for Depreciation (c)	Additions (d)	Total for Depreciation (e) = (c) + ½ x (d) [1]	Years (f)	Depreciation Rate (g) = 1 / (f)	2009 Depreciation Expense (h) = (e) / (f)	2009 Depreciation Expense per Appendix 2-B Fixed Assets, Column K (l)	Variance [2] (m) = (h) - (l)
1611	Computer Software (Formally known as Account 1925)	$ 3,501,452.00	$ 2,412,214.00	$ 1,089,238.00	$ 782,826.00	$ 1,480,651.00	5.00	20.00%	$ 277,324.00	$ 277,324.00	$ -
1612	Land Rights (Formally known as Account 1906)	$ 12,933.00	$ 2,130.00	$ 10,803.00		$ 10,803.00	35.00	2.86%	$ 308.66	$ 308.66	$ -
1612	Land Rights (Formally known as Account 1906)	$ 176,418.00		$ 176,418.00		$ 176,418.00	70.00	1.43%	$ 2,520.26	$ 2,520.26	$ -
1805	Land	$ 202,703.00		$ 202,703.00		$ 202,703.00	-		$ -	$ -	$ -
1808	Buildings - Equipment	$ 161,977.00	$ 22,174.00	$ 139,803.00	$ 7,195.00	$ 143,400.50	10.00	10.00%	$ 14,340.05	$ 14,340.05	$ -
1808	Buildings - Major Repairs	$ 199,541.00	$ 14,394.00	$ 185,147.00	$ 204,853.00	$ 287,573.50	25.00	4.00%	$ 11,502.94	$ 11,502.94	$ -
1808	Buildings - Brick, Stone, Concrete and Steel	$ 1,655,728.00		$ 1,655,728.00		$ 1,655,728.00	50.00	2.00%	$ 33,114.56	$ 33,114.56	$ -
1810	Leasehold Improvements	$ -		$ -		$ -			$ -	$ -	$ -
1815	Transformer Station Equipment >50 kV	$ -		$ -		$ -			$ -	$ -	$ -
1820	Distribution Station Equipment <50 kV	$ 12,783,395.00	$ 2,317,634.00	$ 10,465,761.00	$ 182,518.00	$ 10,557,020.00	30.00	3.33%	$ 351,900.67	$ 351,900.67	$ -
1825	Storage Battery Equipment	$ -		$ -		$ -			$ -	$ -	$ -
1830	Poles, Towers & Fixtures	$ 22,037,933.00	$ 2,681,053.00	$ 19,356,880.00	$ 2,113,455.00	$ 20,413,607.50	25.00	4.00%	$ 816,544.30	$ 816,544.30	$ -
1835	Overhead Conductors & Devices	$ 35,342,997.00	$ 4,617,368.00	$ 30,725,629.00	$ 1,957,266.00	$ 31,704,262.00	25.00	4.00%	$ 1,268,170.48	$ 1,268,170.48	$ -
1840	Underground Conduit	$ 10,733,310.00	$ 1,489,474.00	$ 9,243,836.00	$ 1,354,775.00	$ 9,921,223.50	25.00	4.00%	$ 396,848.94	$ 396,848.94	$ -
1845	Underground Conductors & Devices	$ 20,652,799.00	$ 2,532,105.00	$ 18,120,694.00	$ 2,931,591.00	$ 19,586,489.50	25.00	4.00%	$ 783,459.58	$ 783,459.58	$ -
1850	Line Transformers	$ 39,911,353.00	$ 4,311,517.00	$ 35,599,836.00	$ 3,814,758.00	$ 37,507,215.00	25.00	4.00%	$ 1,500,288.60	$ 1,500,288.60	$ -
1855	Services (Overhead & Underground)	$ 24,660,397.00	$ 3,574,737.00	$ 21,085,660.00	$ 3,266,899.00	$ 22,719,109.50	25.00	4.00%	$ 908,764.38	$ 908,764.38	$ -
1860	Meters	$ 13,557,072.00	$ 5,369,177.00	$ 8,187,895.00	$ 391,237.00	$ 8,383,513.50	25.00	4.00%	$ 335,340.54	$ 335,340.54	$ -
1860	Meters (Smart Meters)	$ -		$ -		$ -			$ -	$ -	$ -
1905	Land	$ 96,300.00		$ 96,300.00		$ 96,300.00	-		$ -	$ -	$ -
1908	Buildings & Fixtures - Equipment	$ 231,107.00	$ 133,208.00	$ 97,899.00	$ 149,328.00	$ 172,563.00	10.00	10.00%	$ 17,256.30	$ 17,256.30	$ -
1908	Buildings & Fixtures - Driveways	$ 555,994.00	$ 161,661.00	$ 394,333.00	$ 15,934.00	$ 402,300.00	20.00	5.00%	$ 20,115.00	$ 20,115.00	$ -
1908	Buildings & Fixtures - Major Repairs	$ 609,173.00		$ 609,173.00	$ 98,221.00	$ 658,283.50	25.00	4.00%	$ 26,331.34	$ 26,331.34	$ -
1908	Buildings & Fixtures - Brick Store etc	$ 6,187,439.00		$ 6,187,439.00		$ 6,187,439.00	50.00	2.00%	$ 123,748.78	$ 123,748.78	$ -
1910	Leasehold Improvements	$ -		$ -		$ -			$ -	$ -	$ -
1915	Office Furniture & Equipment (10 years)	$ 1,191,252.00	$ 865,122.00	$ 326,130.00	$ 82,457.00	$ 367,358.50	10.00	10.00%	$ 36,735.85	$ 36,735.85	$ -
1915	Office Furniture & Equipment (5 years)	$ -		$ -		$ -			$ -	$ -	$ -
1920	Computer Equipment - Hardware	$ 1,836,832.00	$ 1,543,875.00	$ 292,957.00	$ 28,284.00	$ 307,099.00	5.00	20.00%	$ 61,419.80	$ 61,419.80	$ -
1920	Computer Equip.-Hardware(Post Mar. 22/04)	$ -		$ -		$ -			$ -	$ -	$ -
1920	Computer Equip.-Hardware(Post Mar. 19/07)	$ -		$ -		$ -			$ -	$ -	$ -
1930	Transportation Equipment - under 3 Tons	$ 863,324.00	$ 340,407.00	$ 522,917.00	$ 145,446.00	$ 595,640.00	5.00	20.00%	$ 119,128.00	$ 119,128.00	$ -
1930	Transportation Equipment - 3 Tons & Over	$ 2,609,760.00	$ 1,484,733.00	$ 1,125,027.00	$ 406,635.00	$ 1,328,344.50	8.00		$ 166,043.06	$ 166,043.06	$ -
1935	Stores Equipment	$ 292,425.00	$ 292,425.00	$ -		$ -	10.00	10.00%	$ -	$ -	$ -
1940	Tools, Shop & Garage Equipment	$ 1,277,349.00	$ 947,360.00	$ 329,989.00	$ 15,644.00	$ 337,811.00	10.00	10.00%	$ 33,781.10	$ 33,781.10	$ -
1945	Measurement & Testing Equipment	$ 354,348.00	$ 309,936.00	$ 44,412.00	$ 7,871.00	$ 48,347.50	10.00	10.00%	$ 4,834.75	$ 4,834.75	$ -
1950	Power Operated Equipment	$ -		$ -		$ -			$ -	$ -	$ -
1955	Communications Equipment	$ 191,861.00	$ 191,861.00	$ -		$ -			$ -	$ -	$ -
1955	Communication Equipment (Smart Meters)	$ -		$ -		$ -			$ -	$ -	$ -
1960	Miscellaneous Equipment	$ -		$ -		$ -			$ -	$ -	$ -
1975	Load Management Controls Utility Premises	$ -		$ -		$ -			$ -	$ -	$ -
1980	System Supervisor Equipment	$ 2,759,678.00	$ 150,363.00	$ 2,609,315.00	$ 123,700.00	$ 2,671,165.00	15.00	6.67%	$ 178,077.67	$ 178,077.67	$ -
1985	Miscellaneous Fixed Assets	$ -		$ -		$ -			$ -	$ -	$ -
1995	Contributions & Grants	-$ 13,092,065.00		-$ 13,092,065.00	-$ 6,661,564.00	-$ 16,422,847.00	25.00	4.00%	-$ 656,913.88	-$ 656,913.88	$ -
etc.				$ -		$ -			$ -		$ -
				$ -		$ -			$ -		$ -
	Total	$ 191,554,785.00	$ 35,764,928.00	$ 155,789,857.00	$ 11,419,329.00	$ 161,499,521.50			$ 6,830,985.72	$ 6,830,985.72	$ -

Appendix 2-CS
Depreciation and Amortization Expense

Assumes the applicant made capitalization and depreciation expense accounting policy changes under CGAAP effective January 1, 2013

Year 2013 Former CGAAP - CGAAP without the changes to the policies

Account	Description	Opening Regulatory Gross PP&E as at Jan 1, 2013 (a)	Less Fully Depreciated (b)	Net for Depreciation (c)	Additions (d)	Total for Depreciation (e) = (c) + ½ x (d) [1]	Years (f)	Depreciation Rate (g) = 1 / (f)	2013 Depreciation Expense (h) = (e) / (f)	2013 Depreciation Expense per Appendix 2-B Fixed Assets, Column K (l)	Variance [2] (m) = (h) - (l)
1611	Computer Software (Formally known as Account 1925)	$ 5,538,926	$ 3,209,131	**$ 2,329,795**	$ 345,000	**$ 2,502,295**	6.65	15.05%	**$ 376,489**	$ 376,489	**$ -**
1612	Land Rights (Formally known as Account 1906)	$ 12,933	$ 2,130	**$ 10,803**		**$ 10,803**	35.00	2.86%	**$ 309**	$ 309	**$ -**
1612	Land Rights (Formally known as Account 1906)	$ 176,418		**$ 176,418**		**$ 176,418**	70.00	1.43%	**$ 2,520**	$ 2,520	**$ -**
1805	Land	$ 202,703		**$ 202,703**		**$ 202,703**	0.00		**$ -**	$ -	**$ -**
1808	Buildings	$ 208,708	$ 61,437	**$ 147,272**	$ 5,000	**$ 149,772**	10.00	10.00%	**$ 14,977**	$ 14,977	**$ -**
1808	Buildings	$ 7,599		**$ 7,599**		**$ 7,599**	15.00	6.67%	**$ 507**	$ 507	**$ -**
1808	Buildings	$ 9,900		**$ 9,900**		**$ 9,900**	20.00	5.00%	**$ 495**	$ 495	**$ -**
1808	Buildings	$ 405,824	$ 23,224	**$ 382,600**		**$ 382,600**	25.00	4.00%	**$ 15,304**	$ 15,304	**$ -**
1808	Buildings	$ 9,085		**$ 9,085**		**$ 9,085**	30.00	3.33%	**$ 303**	$ 303	**$ -**
1808	Buildings	$ 1,655,728		**$ 1,655,728**		**$ 1,655,728**	50.00	2.00%	**$ 33,115**	$ 33,115	**$ -**
1810	Leasehold Improvements			**$ -**		**$ -**			**$ -**	$ -	**$ -**
1815	Transformer Station Equipment >50 kV			**$ -**		**$ -**			**$ -**	$ -	**$ -**
1820	Distribution Station Equipment <50 kV	$ 14,420,892	$ 2,978,898	**$ 11,441,995**	$ 229,739	**$ 11,556,864**	30.00	3.33%	**$ 385,229**	$ 385,229	**$ -**
1825	Storage Battery Equipment			**$ -**		**$ -**			**$ -**	$ -	**$ -**
1830	Poles, Towers & Fixtures	$ 31,180,512	$ 4,601,676	**$ 26,578,836**	$ 3,720,151	**$ 28,438,911**	25	3.99%	**$ 1,134,403**	$ 1,134,403	**$ -**
1835	Overhead Conductors & Devices	$ 41,356,601	$ 7,925,109	**$ 33,431,492**	$ 1,205,634	**$ 34,034,309**	25	3.96%	**$ 1,348,246**	$ 1,348,246	**$ -**
1840	Underground Conduit	$ 16,187,382	$ 2,556,487	**$ 13,630,895**	$ 2,113,875	**$ 14,687,832**	25	3.97%	**$ 583,274**	$ 583,274	**$ -**
1845	Underground Conductors & Devices	$ 27,086,750	$ 4,346,027	**$ 22,740,722**	$ 1,710,859	**$ 23,596,152**	25	3.97%	**$ 936,649**	$ 936,649	**$ -**
1850	Line Transformers	$ 48,272,718	$ 7,922,690	**$ 40,350,029**	$ 2,142,678	**$ 41,421,368**	27	3.77%	**$ 1,560,732**	$ 1,560,732	**$ -**
1855	Services (Overhead & Underground)	$ 31,940,499	$ 6,135,568	**$ 25,804,931**	$ 1,210,802	**$ 26,410,332**	25	3.96%	**$ 1,046,252**	$ 1,046,252	**$ -**
1860	Meters	$ 18,462,866	$ 2,617,697	**$ 15,845,170**	$ 670,000	**$ 16,180,170**	18	5.59%	**$ 905,177**	$ 905,177	**$ -**
1860	Meters (Smart Meters)			**$ -**		**$ -**			**$ -**	$ -	**$ -**
1905	Land	$ 96,300		**$ 96,300**		**$ 96,300**	0.00		**$ -**	$ -	**$ -**
1908	Buildings & Fixtures	$ 19,446		**$ 19,446**		**$ 19,446**	5.00	20.00%	**$ 3,889**	$ 3,889	**$ -**
1908	Buildings & Fixtures	$ 536,117	$ 171,261	**$ 364,856**		**$ 364,856**	10.00	10.00%	**$ 36,486**	$ 36,486	**$ -**
1908	Buildings & Fixtures	$ 122,291		**$ 122,291**		**$ 122,291**	15.00	6.67%	**$ 8,153**	$ 8,153	**$ -**
1908	Buildings & Fixtures	$ 670,841	$ 161,661	**$ 509,180**		**$ 509,180**	20.00	5.00%	**$ 25,459**	$ 25,459	**$ -**
1908	Buildings & Fixtures	$ 927,723		**$ 927,723**	$ 35,000	**$ 945,223**	25.00	4.00%	**$ 37,809**	$ 37,809	**$ -**
1908	Buildings & Fixtures	$ 6,187,440		**$ 6,187,440**		**$ 6,187,440**	50.00	2.00%	**$ 123,749**	$ 123,749	**$ -**
1910	Leasehold Improvements			**$ -**		**$ -**			**$ -**	$ -	**$ -**
1915	Office Furniture & Equipment (10 years)	$ 1,478,168	$ 864,006	**$ 614,162**	$ 54,000	**$ 641,162**	10.00	10.00%	**$ 64,116**	$ 64,116	**$ -**
1915	Office Furniture & Equipment (5 years)			**$ -**		**$ -**			**$ -**	$ -	**$ -**
1920	Computer Equipment - Hardware	$ 768,208	$ 545,461	**$ 222,747**	$ 98,000	**$ 271,747**	5.00	20.00%	**$ 54,349**	$ 54,349	**$ -**
1920	Computer Equip.-Hardware(Post Mar. 22/04)			**$ -**		**$ -**			**$ -**	$ -	**$ -**
1920	Computer Equip.-Hardware(Post Mar. 19/07)			**$ -**		**$ -**			**$ -**	$ -	**$ -**
1930	Transportation Equipment	$ 928,543	$ 547,831	**$ 380,712**		**$ 380,712**	5.00	20.00%	**$ 76,142**	$ 76,142	**$ -**
1930	Transportation Equipment	$ 2,601,211	$ 1,282,844	**$ 1,318,367**	$ 46,000	**$ 1,341,367**	8.00	12.50%	**$ 167,671**	$ 167,671	**$ -**
1935	Stores Equipment	$ 292,425	$ 292,425	**$ -**		**$ -**	10.00	10.00%	**$ -**	$ -	**$ -**
1940	Tools, Shop & Garage Equipment	$ 1,357,414	$ 797,695	**$ 559,719**	$ 18,000	**$ 568,719**	10.00	10.00%	**$ 56,872**	$ 56,872	**$ -**
1945	Measurement & Testing Equipment	$ 371,455	$ 300,312	**$ 71,143**	$ 3,000	**$ 72,643**	10.00	10.00%	**$ 7,264**	$ 7,264	**$ -**
1950	Power Operated Equipment			**$ -**		**$ -**			**$ -**	$ -	**$ -**
1955	Communications Equipment	$ 191,861	$ 191,861	**$ -**		**$ -**			**$ -**	$ -	**$ -**
1955	Communication Equipment (Smart Meters)			**$ -**		**$ -**			**$ -**	$ -	**$ -**
1960	Miscellaneous Equipment			**$ -**		**$ -**			**$ -**	$ -	**$ -**
1975	Load Management Controls Utility Premises			**$ -**		**$ -**			**$ -**	$ -	**$ -**
1980	System Supervisor Equipment	$ 3,085,724	$ 2,602,079	**$ 483,645**	$ 95,261	**$ 531,275**	15.00	6.67%	**$ 35,418**	$ 35,418	**$ -**
1985	Miscellaneous Fixed Assets			**$ -**		**$ -**			**$ -**	$ -	**$ -**
1995	Contributions & Grants	-$ 27,344,680		**-$ 27,344,680**	-$ 3,460,000	**-$ 29,074,680**	25.00	4.00%	**-$ 1,162,987**	-$ 1,162,987	**$ -**
1609	Other Tangible Property	$ 6,798,057		**$ 6,798,057**	-$ 1,477,000	**$ 6,059,557**	60.00	1.67%	**$ 44,342**	$ 44,342	**$ -**
				$ -		**$ -**			**$ -**		**$ -**
	Total	**$ 236,224,588**	**$50,137,509**	**$186,087,080**	**$ 8,766,000**	**$ 190,470,080**			**$ 7,922,713**	**$ 7,922,713**	**$ -**

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Appendix 2-CT
Depreciation and Amortization Expense

Assumes the applicant made capitalization and depreciation expense accounting policy changes under CGAAP effective January 1, 2013

Year 2013 Revised CGAAP or ASPE - CGAAP or ASPE with the changes to the policies

Account	Description	Opening NBV as at Jan 1, 2013 [5] (a)	Additions (d)	Average Remaining Life of Opening NBV [4] (i)	Years (new additions only) [3] (f)	Depreciation Rate on New Additions (g) = 1 / (f)	Depreciation Expense on Opening NBV (j) = (a) / (i)	Depreciation Expense on Additions [1] (h)=((d)*0.5)/(f)	2013 Depreciation Expense (k) = (j) + (h)	2013 Depreciation Expense per Appendix 2-B Fixed Assets, Column K (l)	Variance [2] (m) = (k) - (l)	Depreciation Expense on 2013 Full Year Additions (n)=((d))/(f)	Less Depreciation Expense on Assets Fully Depreciated during the year (o)	2013 Full Year Depreciation [6] (p) = (j) + (n) - (o)
1611	Computer Software (Formally known as Account 1925)	$ 1,461,811	$ 345,000	5.88	6.00	16.67%	$ 248,607	$ 29,500	$ 278,107	$ 278,107	$ -	$ 59,000	$ 22,316	$ 341,441
1612	Land Rights (Formally known as Account 1906)	$ 1,537		5.00		0.00%	$ 307	$ -	$ 307	$ 307	$ -	$ -		$ 307
1612	Land Rights (Formally known as Account 1906)	$ 161,297		64.00		0.00%	$ 2,520	$ -	$ 2,520	$ 2,520	$ -	$ -		$ 2,520
1805	Land	$ 202,703				0.00%	$ -	$ -	$ -	$ -	$ -	$ -		$ -
1808	Buildings	$ 145,956	$ 5,000	9.91	10.00	10.00%	$ 14,727	$ 250	$ 14,977	$ 14,977	$ -	$ 500		$ 15,227
1808	Buildings	$ 6,839		13.51			$ 506	$ -	$ 506	$ 506	$ -	$ -		$ 506
1808	Buildings	$ 8,663		17.50			$ 495	$ -	$ 495	$ 495	$ -	$ -		$ 495
1808	Buildings	$ 347,435		22.70			$ 15,304	$ -	$ 15,304	$ 15,304	$ -	$ -		$ 15,304
1808	Buildings	$ 8,328		27.48			$ 303	$ -	$ 303	$ 303	$ -	$ -		$ 303
1808	Buildings	$ 625,709		18.69			$ 33,485	$ -	$ 33,485	$ 33,485	$ -	$ -	$ 2,184	$ 31,301
1810	Leasehold Improvements					0.00%	$ -	$ -	$ -	$ -	$ -	$ -		$ -
1815	Transformer Station Equipment >50 kV					0.00%	$ -	$ -	$ -	$ -	$ -	$ -		$ -
1820	Distribution Station Equipment <50 kV	$ 5,195,553	$ 206,520	24.18	40.00	2.50%	$ 214,893	$ 2,582	$ 217,474	$ 217,474	$ -	$ 5,163		$ 220,056
1820	Distribution Station Equipment <50 kV		$ 7,695		20.00	5.00%	$ -	$ 192	$ 192	$ 192	$ -	$ 385		$ 385
1825	Storage Battery Equipment					0.00%	$ -	$ -	$ -	$ -	$ -	$ -		$ -
1830	Poles, Towers & Fixtures	$ 16,364,710	$ 3,252,295	33.03	40.00	2.50%	$ 495,477	$ 40,654	$ 536,131	$ 536,131	$ -	$ 81,307		$ 576,784
1835	Overhead Conductors & Devices	$ 17,410,602	$ 226,610	31.29	40.00	2.50%	$ 556,406	$ 2,833	$ 559,238	$ 559,238	$ -	$ 5,665		$ 483,954
1835	Overhead Conductors & Devices		$ 401,155		60.00	1.67%		$ 3,343	$ 3,343	$ 3,343	$ -	$ 6,686		$ 6,686
1835	Overhead Conductors & Devices		$ 54,005		20.00	5.00%		$ 1,350	$ 1,350	$ 1,350	$ -	$ 2,700		$ 2,700
1840	Underground Conduit	$ 8,374,179	$ 1,981,565	52.00	60.00	1.67%	$ 161,038	$ 16,513	$ 177,551	$ 177,551	$ -	$ 33,026		$ 194,064
1845	Underground Conductors & Devices	$ 12,959,955	$ 1,399,615	22.24	40.00	2.50%	$ 582,617	$ 17,495	$ 600,112	$ 600,112	$ -	$ 34,990		$ 563,111
1845	Underground Conductors & Devices		$ 204,710		30.00	3.33%		$ 3,412	$ 3,412	$ 3,412	$ -	$ 6,824		$ 6,824
1850	Line Transformers	$ 20,769,135	$ 2,008,135	30.92	40.00	2.50%	$ 671,801	$ 25,102	$ 696,903	$ 696,903	$ -	$ 50,203		$ 722,005
1855	Services (Overhead & Underground)	$ 13,750,012	$ 1,589,650	51.41	60.00	1.67%	$ 267,479	$ 13,247	$ 280,726	$ 280,726	$ -	$ 26,494		$ 293,973
1860	Meters	$ 4,042,025	$ 271,400	11.87	15.00	6.67%	$ 340,662	$ 9,047	$ 349,709	$ 349,709	$ -	$ 18,093		$ 276,419
1860	Meters		$ 304,565		20.00	5.00%		$ 7,614	$ 7,614	$ 7,614	$ -	$ 15,228		$ 15,228
1860	Meters		$ 58,780		45.00	2.22%		$ 653	$ 653	$ 653	$ -	$ 1,306		$ 1,306
1860	Meters (Smart Meters)	$ 7,959,409		12.49		0.00%	$ 637,268	$ -	$ 637,268	$ 637,268	$ -	$ -		$ 637,268
1905	Land	$ 96,300				0.00%	$ -	$ -	$ -	$ -	$ -	$ -		$ -
1908	Buildings & Fixtures	$ 17,502		4.50		0.00%	$ 3,889	$ -	$ 3,889	$ 3,889	$ -	$ -		$ 3,889
1908	Buildings & Fixtures	$ 421,837		11.56		0.00%	$ 36,485	$ -	$ 36,485	$ 36,485	$ -	$ -		$ 36,485
1908	Buildings & Fixtures	$ 108,760		13.34		0.00%	$ 8,152	$ -	$ 8,152	$ 8,152	$ -	$ -		$ 8,152
1908	Buildings & Fixtures	$ 579,081		22.75		0.00%	$ 25,459	$ -	$ 25,459	$ 25,459	$ -	$ -		$ 25,459
1908	Buildings & Fixtures	$ 798,326	$ 35,000	21.51	25.00	4.00%	$ 37,108	$ 700	$ 37,808	$ 37,808	$ -	$ 1,400		$ 38,508
1908	Buildings & Fixtures	$ 2,658,511		19.98		0.00%	$ 133,054	$ -	$ 133,054	$ 133,054	$ -	$ -	$ 2,367	$ 127,251
1910	Leasehold Improvements					0.00%	$ -	$ -	$ -	$ -	$ -	$ -		$ -
1915	Office Furniture & Equipment (10 years)	$ 319,085	$ 54,000	5.55	10.00	10.00%	$ 57,489	$ 2,700	$ 60,189	$ 60,189	$ -	$ 5,400	$ 7,221	$ 55,668
1915	Office Furniture & Equipment (5 years)					0.00%	$ -	$ -	$ -	$ -	$ -	$ -		$ -
1920	Computer Equipment - Hardware	$ 154,526	$ 98,000	3.10	5.00	20.00%	$ 49,868	$ 9,800	$ 59,668	$ 59,668	$ -	$ 19,600	$ 8,973	$ 57,915
1920	Computer Equip.-Hardware(Post Mar. 22/04)					0.00%	$ -	$ -	$ -	$ -	$ -	$ -		$ -
1920	Computer Equip.-Hardware(Post Mar. 19/07)					0.00%	$ -	$ -	$ -	$ -	$ -	$ -		$ -
1930	Transportation Equipment	$ 258,981		14.29		0.00%	$ 18,121	$ -	$ 18,121	$ 18,121	$ -	$ -		$ 18,121
1930	Transportation Equipment	$ 569,810	$ 46,000	11.01	12.00	8.33%	$ 51,731	$ 1,917	$ 53,648	$ 53,648	$ -	$ 3,833		$ 55,565
1935	Stores Equipment					0.00%	$ -	$ -	$ -	$ -	$ -	$ -		$ -
1940	Tools, Shop & Garage Equipment	$ 149,260	$ 18,000	4.94	10.00	10.00%	$ 30,202	$ 900	$ 31,102	$ 31,102	$ -	$ 1,800	$ 5,920	$ 26,082
1945	Measurement & Testing Equipment	$ 53,785	$ 3,000	9.88	10.00	10.00%	$ 5,443	$ 150	$ 5,593	$ 5,593	$ -	$ 300	$ 1,268	$ 4,475
1950	Power Operated Equipment					0.00%	$ -	$ -	$ -	$ -	$ -	$ -		$ -
1955	Communications Equipment					0.00%	$ -	$ -	$ -	$ -	$ -	$ -		$ -
1955	Communication Equipment (Smart Meters)					0.00%	$ -	$ -	$ -	$ -	$ -	$ -		$ -
1960	Miscellaneous Equipment					0.00%	$ -	$ -	$ -	$ -	$ -	$ -		$ -
1970	Load Management Controls - Customer Premises					0.00%	$ -	$ -	$ -	$ -	$ -	$ -		$ -
1975	Load Management Controls Utility Premises					0.00%	$ -	$ -	$ -	$ -	$ -	$ -		$ -
1980	System Supervisor Equipment	$ 480,602	$ 36,195	2.91	30.00	3.33%	$ 165,331	$ 603	$ 165,935	$ 165,935	$ -	$ 1,207	$ 101,961	$ 64,577
1980	System Supervisor Equipment		$ 52,625		10.00	10.00%	$ -	$ 2,631	$ 2,631	$ 2,631	$ -	$ 5,263		$ 5,263
1985	Miscellaneous Fixed Assets					0.00%	$ -	$ -	$ -	$ -	$ -	$ -		$ -
1990	Other Tangible Property					0.00%	$ -	$ -	$ -	$ -	$ -	$ -		$ -
1995	Contributions & Grants	-$ 21,546,388	-$ 3,217,443	41.23	46.66	2.14%	-$ 522,579	-$ 34,480	-$ 557,059	-$ 557,059	$ 0	-$ 68,960		-$ 591,538
1609	Other Tangible Property	$ 6,798,057	-$ 1,477,000		60.00	1.67%	$ -	$ 44,342	$ 44,342	$ 44,342	$ -	$ 88,684		$ 88,684
						0.00%	$ -	$ -	$ -	$ -	$ -	$ -		$ -
	Total	**$ 101,713,893**	**$ 7,965,077**				**$ 4,343,649**	**$ 203,049**	**$ 4,546,699**	**$ 4,546,698**	**$ 0**	**$ 406,099**	**$ 152,210**	**$ 4,432,722**

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Appendix 2-CU
Depreciation and Amortization Expense

Assumes the applicant made capitalization and depreciation expense accounting policy changes under CGAAP effective January 1, 2013

Year 2014 Revised CGAAP or ASPE - CGAAP or ASPE with the changes to the policies

Account	Description	Additions (d)	Years (new additions only) (f)	Depreciation Rate on New Additions (g) = 1 / (f)	2014 Depreciation Expense [1] (h)=2013 Full Year Depreciation + ((d)*0.5)/(f)	2014 Depreciation Expense per Appendix 2-B Fixed Assets, Column K (l)	Variance [2] (m) = (h) - (l)
1611	Computer Software (Formally known as Account 1925)	$ 195,000	5.00	20.00%	**$ 360,941**	$ 360,633	**$ 308**
1611	Computer Software (Formally known as Account 1925)	$ 50,000	10.00	10.00%	**$ 2,807**	$ 2,807	**$ -**
1612	Land Rights (Formally known as Account 1906)	$ 60,000	60.00	1.67%	**$ 807**	$ 807	**$ -**
1612	Land Rights (Formally known as Account 1906)			0.00%	**$ 2,520**	$ 2,520	**$ -**
1805	Land			0.00%	**$ -**	$ -	**$ -**
1808	Buildings	$ 5,000	10.00	10.00%	**$ 15,477**	$ 15,477	**$ -**
1808	Buildings			0.00%	**$ 506**	$ 506	**$ -**
1808	Buildings			0.00%	**$ 495**	$ 495	**$ -**
1808	Buildings			0.00%	**$ 15,304**	$ 15,304	**$ -**
1808	Buildings			0.00%	**$ 303**	$ 303	**$ -**
1808	Buildings			0.00%	**$ 31,301**	$ 31,301	**$ -**
1810	Leasehold Improvements			0.00%	**$ -**	$ -	**$ -**
1815	Transformer Station Equipment >50 kV			0.00%	**$ -**	$ -	**$ -**
1820	Distribution Station Equipment <50 kV	$ 557,619	40.00	2.50%	**$ 227,026**	$ 227,026	**$ -**
1820	Distribution Station Equipment <50 kV	$ 7,693	20.00	5.00%	**$ 577**	$ 577	**$ -**
1825	Storage Battery Equipment			0.00%	**$ -**	$ -	**$ -**
1830	Poles, Towers & Fixtures	$ 1,686,483	40.00	2.50%	**$ 597,865**	$ 597,865	**$ -**
1835	Overhead Conductors & Devices	$ 351,359	40.00	2.50%	**$ 488,346**	$ 488,346	**$ -**
1835	Overhead Conductors & Devices	$ 321,114	60.00	1.67%	**$ 9,362**	$ 9,362	**$ -**
1835	Overhead Conductors & Devices	$ 174,733	20.00	5.00%	**$ 7,069**	$ 7,069	**$ -**
1840	Underground Conduit	$ 1,669,428	60.00	1.67%	**$ 207,976**	$ 207,976	**$ -**
1845	Underground Conductors & Devices	$ 1,293,949	40.00	2.50%	**$ 579,285**	$ 579,285	**$ -**
1845	Underground Conductors & Devices	$ 588,523	30.00	3.33%	**$ 16,632**	$ 16,632	**$ -**
1850	Line Transformers	$ 1,909,205	40.00	2.50%	**$ 745,870**	$ 745,870	**$ -**
1855	Services (Overhead & Underground)	$ 1,261,637	60.00	1.67%	**$ 304,487**	$ 304,487	**$ -**
1860	Meters	$ 240,309	15.00	6.67%	**$ 284,429**	$ 284,429	**$ -**
1860	Meters	$ 347,826	20.00	5.00%	**$ 23,924**	$ 23,924	**$ -**
1860	Meters	$ 18,749	45.00	2.22%	**$ 1,515**	$ 1,515	**$ -**
1860	Meters (Smart Meters)			0.00%	**$ 637,268**	$ 637,268	**$ -**
1905	Land			0.00%	**$ -**	$ -	**$ -**
1908	Buildings & Fixtures			0.00%	**$ 3,889**	$ 3,889	**$ -**
1908	Buildings & Fixtures			0.00%	**$ 36,485**	$ 36,485	**$ -**
1908	Buildings & Fixtures			0.00%	**$ 8,152**	$ 8,152	**$ -**
1908	Buildings & Fixtures			0.00%	**$ 25,459**	$ 25,459	**$ -**
1908	Buildings & Fixtures	$ 327,000	25.00	4.00%	**$ 45,048**	$ 45,048	**$ -**
1908	Buildings & Fixtures			0.00%	**$ 127,251**	$ 127,251	**$ -**
1910	Leasehold Improvements			0.00%	**$ -**	$ -	**$ -**
1915	Office Furniture & Equipment (10 years)	$ 38,000	10.00	10.00%	**$ 57,568**	$ 57,568	**$ -**
1915	Office Furniture & Equipment (5 years)			0.00%	**$ -**	$ -	**$ -**
1920	Computer Equipment - Hardware	$ 70,000	5.00	20.00%	**$ 64,915**	$ 64,915	**$ -**
1920	Computer Equip.-Hardware(Post Mar. 22/04)			0.00%	**$ -**	$ -	**$ -**
1920	Computer Equip.-Hardware(Post Mar. 19/07)			0.00%	**$ -**	$ -	**$ -**
1930	Transportation Equipment	$ 50,000	12.00	8.33%	**$ 20,204**	$ 20,204	**$ -**
1930	Transportation Equipment			0.00%	**$ 55,565**	$ 55,565	**$ -**
1935	Stores Equipment			0.00%	**$ -**	$ -	**$ -**
1940	Tools, Shop & Garage Equipment	$ 9,000	10.00	10.00%	**$ 26,532**	$ 26,532	**$ -**
1945	Measurement & Testing Equipment	$ 3,000	10.00	10.00%	**$ 4,625**	$ 4,625	**$ -**
1950	Power Operated Equipment			0.00%	**$ -**	$ -	**$ -**
1955	Communications Equipment			0.00%	**$ -**	$ -	**$ -**
1955	Communication Equipment (Smart Meters)			0.00%	**$ -**	$ -	**$ -**
1960	Miscellaneous Equipment			0.00%	**$ -**	$ -	**$ -**
1970	Load Management Controls - Customer Premises			0.00%	**$ -**	$ -	**$ -**
1975	Load Management Controls Utility Premises			0.00%	**$ -**	$ -	**$ -**
1980	System Supervisor Equipment	$ 31,104	30.00	3.33%	**$ 65,095**	$ 65,095	**$ -**
1980	System Supervisor Equipment	$ 42,521	10.00	10.00%	**$ 7,389**	$ 7,389	**$ -**
1985	Miscellaneous Fixed Assets	$ -	-	0.00%	**$ -**	$ -	**$ -**
1990	Other Tangible Property			0.00%	**$ -**	$ -	**$ -**
1995	Contributions & Grants	-$ 3,579,205	$ 44.03	2.27%	**-$ 632,186**	-$ 632,186	**$ -**
etc.				0.00%	**$ 88,684**	$ 88,684	**$ -**
				0.00%	**$ -**	$ -	**$ -**
	Total	**$ 7,730,047**			**$ 4,566,768**	**$ 4,566,459**	**$ 308**

Total Depreciation expense to be included in the test year revenue requirement **$ 4,566,768**

Attachment 2 (of 2):

Typical Useful Lives Study

Enersource Corporation, Burlington Hydro, Oakville Hydro, Halton Hills Hydro & Milton Hydro Useful Life of Assets

Kinectrics Inc. Report No: K-418022-RA-0001-R003

December 10, 2009

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Enersource Corporation, Burlington Hydro, Oakville Hydro, Halton Hills Hydro & Milton Hydro Useful Life of Assets

DISCLAIMER

Kinectrics Inc. has prepared this report in accordance with, and subject to, the terms and conditions of the agreement between Kinectrics Inc. and Enersource Corporation, Burlington Hydro, Oakville Hydro, Halton Hills Hydro & Milton Hydro.

Enersource Corporation, Burlington Hydro, Oakville Hydro, Halton Hills Hydro, & Milton Hydro Useful Life of Assets

Kinectrics Inc. Report No: K-418022-RA-0001-R003

December 10, 2009

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Enersource Corporation, Burlington Hydro, Oakville Hydro, Halton Hills Hydro & Milton Hydro Useful Life of Assets

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Revision History

Revision Number	Date	Comments	Approved
R000	October 8, 2009	Initial Draft	N/A
R001	October 28, 2009	Finalized Draft (incorporating Consortium's Comments)	N/A
R002	November 23, 2009	Finalized Report (for Consortium's final comments)	N/A
R003	December 10, 2009	Final Version	Y. Tsimberg

Enersource Corporation, Burlington Hydro, Oakville Hydro, Halton Hills Hydro & Milton Hydro Useful Life of Assets

Table of Contents

1 Executive Summary

1.1 Introduction

One of the aspects of switching to International Financial Reporting Standards (IFRS) methodology that Ontario's Local Distribution Companies (LDCs) are embarking upon is trying to align the time period assets are amortized over with their actual useful life.

This is a rather onerous task because LDCs own and operate a large number of assets that are divided into different asset categories, each with its own degradation mechanism and useful life range. Moreover, some assets are comprised of several components that may have differing useful life than the assets themselves. It is therefore important for LDCs to properly account for the useful lives of assets and their components to facilitate conversion to IFRS.

This report reviews the useful lives of the assets, and their components that are applicable to Enersource Corporation, Burlington Hydro, Oakville Hydro, Halton Hills Hydro and Milton Hydro (the Consortium). The useful life values are compiled from several different sources, namely, industrial statistics, research studies and reports (either by individuals or working groups such as CIGRE), and Kinectrics experience, all listed in Section 35 of this Report. Useful lives of assets are dependent on a number of utilization factors (mechanical stress, electrical loading, environmental factors and operating practices) that are described in more detail in Section 1.4 of this report and it is worth noting that the useful lives of assets do not generally follow standard distribution curves as they are derived from empirical statistics.

1.2 Project Scope

This report provides an in-depth evaluation of the useful lives of the assets that are owned and operated by the Consortium members. The typical parent system(s) to which the asset belongs is provided and these "parent" systems are: *Overhead Lines* (OH), *Transmission Stations* (TS), *Municipal Stations* (MS), *Underground Systems* (UG) and *Monitoring and Control System* (S). The long term degradation mechanism of each asset category is described for each asset category and when applicable assets are sub-categorized into components: components are included when their cost is material enough and, at the same time, component could be replaced without a need to replace the whole asset. For each asset or component, the following information is presented:

- Useful Life Range
- Typical Life
- Typical time-based maintenance intervals, if applicable
- Impact of Utilization Factors

Section 1.4 provides definitions for the above terms, as well as descriptions of typical distribution system assets and asset components.

1.3 Project Execution Process

The project execution process entailed a number of steps to ensure that the industry-based information compiled by Kinectrics not only includes all the relevant assets and components used by Consortium, but also that it addresses the specific needs related to the IFRS review. The procedure is as follows:

- The initial list of assets and components was produced by the Consortium members to Kinectrics for review.
- Upon review of the initial list, Kinectrics generated an intermediate asset list that had a somewhat different background, granularity, and componentization, based on industry practices and Kinectrics experience.
- The intermediate list was reviewed jointly by the Consortium members and Kinectrics to derive a “final” list.
- For each asset and component in the “final” list, Kinectrics then gathered the information described in Section 1.2 from the sources described in Section 1.1 of this report. A Draft Report that summarized the findings and provided detail descriptions, including degradation mechanisms and applicable assumptions for each asset, was then produced.
- This Draft Report was reviewed by the Consortium members and their feedback was incorporated in the Final Report.

1.4 Definition of Terms

1.4.1 *Typical Distribution System Asset*

Typical distribution system assets include transformers, breakers, switches, underground cables, poles, vaults, cable chambers, etc. Some of the assets, such as power transformers, are rather complex systems and include a number of components.

1.4.2 *Component*

For the purposes of this study, component refers to the sub-category of an asset that meets both of the following criteria:

- Its value is significant enough, relative to the asset value.
- A need to replace the component does not necessarily warrant replacing the entire asset.

An *asset* may be comprised of more than one component, each with an independent failure mode and degradation mechanism that may result in a substantially different useful life than the overall asset. A component may also have an independent maintenance and replacement schedule.

1.4.3 *Useful Life*

Useful Life refers to an estimated range of years during which an electric utility asset or its component is expected to operate as designed, without experiencing major functional degradation that requires major refurbishment or replacement.

In this report, the useful life range, in years, is presented in terms of a minimum, maximum, and typical value. An overwhelming number of units within a population will perform their intended design functions for a period of time greater than or equal to the *minimum* life. Conversely, an overwhelming number of units will cease to perform as designed at or beyond the *maximum* life. A majority of the population will have useful lives of around the *typical* life. For example, consider an asset class with a useful life range of 20 to 40 years, and a typical life of 30 years. An overwhelming majority of the units within this class will perform as required for at least 20 years. Very little number units will operate beyond 40 years. Finally, a majority of the units within the population will operate for approximately 30 years. Note that an asset category can have a typical life that is equal to either the maximum or minimum life. This is simply an indication that the majority of the units within a population will be operational for either the minimum or maximum years; i.e. the statistical data is skewed towards either the maximum or minimum values. The range in useful lives reflects differences in Utilization Factors described below.

1.4.4 *Typical Life*

Refers to the typical age at which the asset or component fails. This may vary depending on a utility's maintenance practices, environmental conditions, and operational stresses.

1.4.5 *Typical Time-based Maintenance Intervals*

For the purposes of this report, time-based maintenance refers to either *Routine Inspections* (RI) or *Routine Testing/Maintenance* (RTM). Other maintenance techniques such as Condition Based Maintenance, Reliability Centered Maintenance, and more intrusive periodic overhauls are very much dependent on individual utility's maintenance strategy and practices and, as such, could not be included in compiling industry-wide typical values.

Typical time-based maintenance intervals will be given only for assets that are proactively maintained, i.e. assets for which useful life is affected by regular planned maintenance. This excludes assets that are not routinely maintained.

1.4.6 *Impact of Utilization Factors*

For the purpose of this report, stress that impacts the assets refers to *Mechanical Stress* (MC), *Electrical Loading* (EL), *Environmental Conditions* (EN) and/or *Operating Practices* (OP):

- Mechanical stress includes factors such as wind and ice that leads to degradation over time
- Electrical loading refers to either constant loading that creates long term degradation or temporary overloading that may causes a severe degradation
- Environmental conditions include pollution, salt, acid rain, extreme temperature and detrimental animals (i.e. woodpeckers) that may cause degradation over time
- Operating practices refers to how frequently an asset is subject to operating procedure (automatic or manual) that impacts its useful life, e.g. reclosers operations.

Each asset could be impacted by one or more of these factors resulting in a different degradation rates for the same assets and/or components in different jurisdictions. Therefore, it is expected that some of the utility specific typical life values would be different than the ones provided in this report based on the qualitative assessment of the above factors.

1.5 Summary of Findings

Table 1-1 summarizes useful and typical lives, time based maintenance schedules, and impact of stress for Consortium assets.

Table 1-1 Summary of Componentized Assets

Report Section #	Parent*	Asset Category	Componentization *(sub category)*		Useful Life *(years)* Minimum	Typical	Maximum	Maint. Type**	Time Based Maint. Schedule *(years)*	Impact of Stress***	Reference #
2	OH	Wood Poles	Pole		40	44	50	RI	15	MC, EN	[1], [2], [3], [4], [38],[39], [40]
			Cross Arm	Wood	20	40	50				
				Composite	40	60	80				
				Steel	20	70	100				
			Bracket	Galvanized Steel	20	40	50				
			Insulator	Composite	10	20	45				
				Porcelain	40	40	50				
			Anchors & Guying		20	40	50				
3	OH	Concrete Poles	*Refer to Wood Poles (1)*		50	60	60	RI	15	MC, EN	[5], [6]
4	OH	Steel Poles	*Refer to Wood Poles (1)*		60	60	80	RI	15	MC, EN	[7], [8], [41]
5	OH	Composite Poles	*Refer to Wood Poles (1)*		50	70	100	N/A	N/A	MC	[9]

* OH = Overhead Lines TS=Transmission Stations MS=Municipal Stations UG=Underground Systems S=Monitoring & Control System
** RI=Routine Inspection RTM=Routine Testing/Maintenance
*** MC=Mechanical Stress EL=Electrical Loading EN=Environmental Factors OP=Operating Practices

Report Section #	Parent*	Asset Category	Componentization *(sub category)*		Useful Life *(years)*			Maint. Type**	Time Based Maint. Schedule *(years)*	Impact of Stress***	Reference #
					Minimum	Typical	Maximum				
6	OH	Wires	Conductor	ACSR	50	60	77	N/A	N/A	MC, EL, EN	[5], [10]
			Conductor	AAC	50	60	77				
			Conductor	Cu	50	60	77				
			Conductor	Insulated wire	50	60	77				
			Arrester								
7	OH	Pole Mounted Transformers	Transformer		30	40	60	N/A	N/A	EL, EN	[5]
			Arrester								
8	OH	Manual Overhead Line Switches			30	50	60	RTM	2	EL, EN	[6]
9	OH	Local Motorized Overhead Switches	Switch		30	50	60	RTM	2	EL, EN	[6]
			Motor		15	20	20				
10	OH	Remote Automated Overhead Switches	Switch		30	50	60	RTM	2	EL, EN	[11], [12]
			Motor		15	20	20				
			RTU		15	20	30				
11	OH	Fuse Cutouts			30	40	60	N/A	N/A	EL, EN	[6]
12	OH	Voltage Regulator			15	20	40	N/A	N/A	EL, EN, OP	[5], [42]

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Section #	Parent*	Asset Category	Componentization (sub category)		Useful Life			Maint. Type**	Maint. Schedule	Impact of Stress***	Reference #
					Minimum	Typical	Maximum				
13	OH	Reclosers	Breaker	Vacuum	30	40	40	RTM	10	EL, OP	[5], [6], [11], [12]
				Oil	30	42	60				
			RTU		15	20	30				
14	TS	Station Service Transformers	Dry Type		20	30	40	RTM	3	EL, EN	[1],[13], [45],[46]
			Other		32	45	55				
15	TS	TS Power Transformers	Winding		32	45	55	RTM	2	EL, EN, OP	[1], [13], [14],[15], [16],[43] [44],[48]
			Manual/Automatic On Load Tap Changer		20	20	60				
16	MS	MS Power Transformers	Winding		32	45	55	RTM	2	EL, EN, OP	[1], [13], [14],[15], [16],[43] [44],[48]
			Manual/Automatic On Load Tap Changer		20	20	60				
17	MS	DC Station Service	Battery bank		10	20	30	RTM	1	EL, EN, OP	[6],[17], [18],[19]
			Charger		20	20	30				
18	MS	Air Insulated Switchgear	Breaker	SF6	30	42	60	RTM	6	EL, EN, OP	[1],[6], [20],[21],
				Vacuum	30	40	60				
				Air Magnetic	25	40	60				
			Switchgear assembly		40	50	60				

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Section #	Parent*	Asset Category	Componentization (sub category)		Useful Life Minimum	Useful Life Typical	Useful Life Maximum	Maint. Type**	Maint. Schedule	Impact of Stress***	Reference #
19	MS	Gas Insulated Switchgear	Breaker	SF6	30	42	60	RTM	6	EL, EN, OP	[1],[6], [20],[21],
				Vacuum	30	40	60				
				Air Magnetic	25	40	60				
			Switchgear assembly		40	50	60				
20	MS	Building	Building		30	50	80	RI	1	MC, EN	[13]
			Roof		15	20	20				
			Fence		30	35	45				
21	MS	Station Grounding System			25	40	50	N/A	N/A	EN	[13],[22], [23]
22	UG	UG Primary Cables	TR-XLPE	In Duct	40	40	60	N/A	N/A	EL, EN	[6],[24], [25]
				In Concrete Encased Duct	40	40	60				
				Direct Buried	20	25	40				
			Termination		25	40	60				
			Arrester								
23	UG	UG Secondary Cables	PI (polyethylene insulated)		40	40	60	N/A	N/A	EL, EN	[6],[24], [25]
			PIJ (PVC jacket)		40	40	60				

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Section #	Parent*	Asset Category	Componentization (sub category)		Useful Life Minimum	Useful Life Typical	Useful Life Maximum	Maint. Type**	Maint. Schedule	Impact of Stress***	Reference #
24	UG	Distribution Transformer	Transformer	Pad Mounted	30	40	40	N/A	N/A	EL, EN, OP	[5],[4], [6]
				Vault	30	40	40				
				Submersible	25	35	40				
			Elbows and Inserts		20	40	60				
25	UG	Pad Mounted Switchgear	Air Insulated		20	30	40	RI	3	EL, EN, OP	[26],[27], [28]
			Gas Insulated		30	30	50				
			Solid Dielectric		30	30	50				
26	UG	Vault Switch	Metal Enclosed Switch		20	30	40	RI	3	EL, EN, OP	[6],[26], [27]
			Metal Enclosed Cutout		30	40	60				
27	UG	Utility Chamber			50	60	80	RTM	3	EN	[5],[6], [29]
28	UG	Duct	Duct Bank		30	50	80	N/A	N/A	EN	[5],[6], [30]
			Direct Buried Pipe (PVC)		30	50	75				
			HDPE		50	50	100				
29	UG	Transformer and Switchgear Foundations			30	60	80	RTM	3	EN	[5],[6]
30	UG	Junction Cubicle			25	40	50	N/A	N/A	EN	[5]
31	S	"Classic" SCADA	RTU		15	20	30	N/A	N/A	OP	[1],[11], [12],[32]
			Relay		20	30	50				
			Battery		5	10	10				

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Section #	Parent*	Asset Category	Componentization *(sub category)*		Useful Life Minimum	Useful Life Typical	Useful Life Maximum	Maint. Type**	Maint. Schedule	Impact of Stress***	Reference #
32	S	IED Based SCADA	IED		10	15	15	N/A	N/A	OP	[13],[32], [33]
			Battery		5	10	20				
33	S	Fault Indicators	Overhead		5	10	20	N/A	N/A	EN	[34], [47]
			Underground		10	20	30				
34	S	Metering	Meter	Residential	20	30	45	N/A	N/A	EN	[5],[35], [36]
				Industrial	20	30	60				
				Wholesale	20	30	60				
			CT		30	45	50				
			PT		30	45	50				
35	S	Smart Metering	Smart Meter		15	15	20	N/A	N/A	EN	[5],[37]
			Repeaters		5	10	15				
			Antennas								
			Data Concentrator	Sockets & Poles	10	20	20				
			Powerline Repeaters		5	10	15				
			Sky Pilot Devices								
			WAN Equipment								

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2 Wood Poles

The asset referred to in this category is the fully dressed wood pole ranging in size from 30 to 75 feet. This includes the wood pole, cross arm, bracket, insulator, and anchor & guys. Wood poles are typically the most common form of support for overhead distribution feeders and low voltage secondary lines.

The most significant component of this asset is the wood pole itself. The wood species predominately used for distribution systems are Red Pine, Jack Pine, and Western Red Cedar (WRC), either butt treated or full length treated. Smaller numbers of Larch, Fir, White Pine and Southern Yellow Pine have also been used. Preservative treatments applied prior to 1980, range from none on some WRC poles, to butt treated and full length Creosote or Pentachlorophenol (PCP) in oil. The present day treatment, regardless of species, is CCA-Peg (Chromated Copper Arsenate, in a Polyethylene Glycol solution). Other treatments such as Copper Naphthenate and Ammoniacal Copper Arsenate have also been used, but these are relatively uncommon.

2.1 Degradation Mechanism

The end of life criteria for wood poles includes loss of strength, functionality, or safety (typically due to rot, decay, or physical damage). As wood is a natural material the degradation processes are somewhat different from those which affect other physical assets on the electricity distribution systems. The critical processes are biological, involving naturally occurring fungi that attack and degrade wood, resulting in decay. The nature and severity of the degradation depends both on the type of wood and the environment. Some fungi attack the external surfaces of the pole and some the internal heartwood. Therefore, the mode of degradation can be split into either external rot or internal rot. As a structural item the sole concern when assessing the condition for a wood pole is the reduction in mechanical strength due to degradation or damage.

2.2 System Hierarchy

Wood poles are considered to be a part of the Overhead Lines asset grouping.

2.3 Useful Life and Typical Life

The overall useful life of a wood pole is in the range of 40 to 50 years; the typical life is 44 years.

This asset also has several major components, each with a different useful life:

- Cross Arm (Wood, Composite, Steel)
- Bracket (Galvanized Steel)
- Insulator (Composite, Porcelain)
- Anchor and Guying

2.3.1 *Cross Arm*

The useful life of a wood cross arm is in the range of 20 to 50 years; the typical life is 40 years.

The useful life of a composite cross arm is in the range of 40 to 80 years; the typical life is 60 years.

The useful life of a steel cross arm is in the range of 20 to 100 years; the typical life is 70 years.

2.3.2 *Bracket (Galvanized Steel)*

The useful life of an aluminum bracket component ranges from 20 to 50 years, with a typical value of approximately 40 years.

2.3.3 *Insulator*

The useful life of a composite insulator is in the range of 10 to 45 years; the typical life is 20 years.

The useful life of a porcelain insulator is in the range of 40 to 50 years, with a typical life of 40 years.

2.3.4 *Anchors and Guying*

The useful life of anchors and guying is in the range of 20 to 50 years; the typical life is 40 years.

2.4 Time Based Maintenance Intervals

A typical routine inspection interval for this asset is every 15 years.

2.5 Impact of Utilization Factors

The useful life of this asset is impacted by Mechanical Stress and Environmental Conditions.

3 Concrete Poles

This asset category includes the concrete pole with the same components as for the wood poles, namely cross arm, bracket, insulator, and anchor. These poles range in size from 35 to 80 feet, with the typical pole being 60 feet.

3.1 Degradation Mechanism

The most significant component in this class is the concrete pole itself. Concrete poles age in the same manner as any other concrete structure. Any moisture ingress inside the concrete pores would result in freezing during the winter and damage to concrete surface. Road salt spray can further accelerate the degradation process and lead to concrete spalling. Typical concrete mixes employ a washed-gravel aggregate and have extremely high resistance to downward compressive stresses (about 3,000 lb/sq in), however, any appreciable stretching or bending (tension) will break the microscopic rigid lattice, resulting in cracking and separation of the concrete. The spun concrete process used in manufacturing poles prevents moisture entrapment inside the pores. Spun, pre-stressed concrete is particularly resistant to corrosion problems common in a water-and-soil environment.

3.2 System Hierarchy

Concrete poles are considered to be a part of the Overhead Lines assets grouping.

3.3 Useful Life and Typical Life

The useful life range of the concrete pole component is 50 to 60 years; the typical life is 60 years. For other components, (cross arm, bracket, insulator, and anchor), please refer to Section 2.3.

3.4 Time Based Maintenance Intervals

A typical routine inspection interval for this asset is every 15 years.

3.5 Impact of Utilization Factors

The useful life of this asset is impacted by Mechanical Stress and Environmental Conditions.

4 Steel Poles

This asset category includes the directly buried steel pole, cross arm, bracket, insulator, and anchor.

4.1 Degradation Mechanism

The degradation of directly buried steel poles is mainly due to steel corrosion in-ground. In-ground situations are vastly different because of the wide local variations in soil chemistry, moisture content and conductivity that will affect the way coated or uncoated steel will perform in the ground.

There are two issues that determine the life of buried steel. The first is the life of the protective coating and the second is the corrosion rate of the steel. The item can be deemed to have failed when the steel loss is sufficient to prevent the steel performing its structural function. Where polymer coatings are applied to buried steel items, the failures are rarely caused by general deterioration of the coating. Localized failures due to defects in the coating, pin holing or large-scale corrosion related to electrolysis are common causes of failure in these installations.

Metallic coatings, specifically galvanizing, and to a lesser extent aluminum, fail through progressive consumption of the coating by oxidation or chemical degradation. The rate of degradation is approximately linear, and with galvanized coatings of known thickness, the life of the galvanized coating then becomes a function of the coating thickness and the corrosion rate.

4.2 System Hierarchy

Steel poles are considered a part of the Overhead Lines asset grouping.

4.3 Useful Life and Typical Life

The useful life of steel poles is in the range of 60 to 80 years; the typical life is 60 years. For other components, (cross arm, bracket, insulator, and anchor), please refer to Section 2.3.

4.4 Time Based Maintenance Intervals

A typical routine inspection interval for this asset is every 15 years.

4.5 Impact of Utilization Factors

This asset is impacted by Mechanical Stress and Environmental Conditions.

5 Composite Poles

This asset category includes the composite pole, cross arm, bracket, insulator, and anchor. At Consortium the composite poles are fiberglass.

5.1 Degradation Mechanism

The most significant component in this class is the composite pole itself. The major degradation of composite poles is ultra violet (UV) degradation. It represents an attack from ultra-violet radiation, which might result in crack or disintegration in composite poles. It is a common problem in products exposed to sunlight. Continuous exposure is a more serious problem than intermittent exposure, since attack is dependent on the extent and degree of exposure. In fiber products like composite poles, useful life will be shortened because the outer fibers will be attacked first, and will easily be damaged by abrasion. This will end up with fiber blooming and fading.

5.2 System Hierarchy

Composite poles are considered to be a part of the Overhead Lines assets grouping.

5.3 Useful Life and Typical Life

The useful life range of the composite pole component is 50 to 100 years; the typical life is 70 years. For other components, (cross arm, bracket, insulator, and anchor), please refer to Section 2.3.

5.4 Time Based Maintenance Intervals

. Composite poles are not subject to planned maintenance.

5.5 Impact of Utilization Factors

This asset is impacted by Mechanical Stress.

6 Wires

Overhead conductors along with structures that support them constitute overhead lines or feeders that distribute electrical energy either directly to large customers or from Municipal Stations via distribution transformers to the end users. These conductors are sized to carry a specified maximum current and to meet other design criteria, i.e. mechanical loading.

The overhead conductors typically used by the Consortium are aluminum conductor steel reinforced (ACSR), all aluminum conductor (AAC), copper, and insulated wire.

6.1 Degradation Mechanism

To function properly, conductors must retain both their conductive properties and mechanical (i.e. tensile) strength. Aluminum conductors have three primary modes of degradation: corrosion, fatigue and creep. The rate of each degradation mode depends on several factors, including the size and construction of the conductor, as well as environmental and operating conditions. Most utilities find that corrosion and fatigue present the most critical forms of degradation.

Generally, corrosion represents the most critical life-limiting factor for aluminum-based conductors. Visual inspection cannot detect corrosion readily in conductors. Environmental conditions affect degradation rates from corrosion. Both aluminum and zinc-coated steel core conductors are particularly susceptible to corrosion from chlorine-based pollutants, even in low concentrations.

Fatigue degradation presents greater detection and assessment challenges than corrosion degradation. In extreme circumstances, under high tensions or inappropriate vibration or galloping control, fatigue can occur in very short timeframes. However, under normal operating conditions, with proper design and application of vibration control, fatigue degradation rates are relatively slow. Under normal circumstances, widespread fatigue degradation is not commonly seen in conductors less than 70 years of age. Also, in many cases detectable indications of fatigue may only exist during the last 10% of a conductor’s life.

In designing transmission lines, engineers ensure that conductors receive no more than 60% of their rated tensile strength (RTS) during heaviest anticipated weather loads. The tensile strength of conductors gradually decreases over time. When conductors experience unexpectedly large mechanical loads and tensions beyond 50% of their RTS, they begin to undergo permanent stretching with noticeable increases in sagging.

Overloading lines beyond their thermal capacity causes elevated operating temperatures. When operating at elevated temperatures, aluminum conductors begin to anneal and lose tensile strength. Each elevated temperature event adds further damage to the conductor. After a loss of 10% of a conductor’s RTS, significant sag occurs, requiring either resagging or replacement of the conductor.

Phase to phase power arcs can result from conductor galloping during severe storm events. This can cause localized burning and melting of a conductor’s aluminum strands, reducing strength at those sites and potentially leading to conductor failures. Visual inspection readily detects arcing damage.

Other forms of conductor damage include:

- Broken strands (i.e., outer and inners)
- Strand abrasion
- Elongation (i.e., change in sags and tensions)
- Burn damage (i.e., power arc/clashing)
- Birdcaging

The degradation of copper wire is mostly due to corrosion. Oxidization gives copper a high resistance to corrosion. Derivatives of chlorine and sulfur contained in coastal atmospheres start the oxidation by forming a blackish or greenish film. The film is very dense, has low solubility, high electric resistance and high resistance to the chemical attack and to corrosion. Despite this, mechanical vibrations, abrasion, erosion and thermal variations may cause fissures and faults in this layer. When this happens, the metal is uncovered and corrosion may occur. Also electrolytes with low Cl contents could enter, causing a dislocation of the passivity. This may also be the result of a deficit of oxygen which would make the area anodic.

6.2 System Hierarchy

The Wire asset category belongs to the Overhead Lines assets grouping.

6.3 Useful Life and Typical Life

The useful life of conductors is in the range of 50 to 77 years; the typical life is 60 years.

6.4 Time Based Maintenance Intervals

Overhead conductors are not subject to planned maintenance.

6.5 Impact of Utilization Factors

This asset is impacted by Mechanical Stress, Electrical Loading and Environmental Conditions.

7 Pole Mounted Transformers

Distribution pole top mounted transformers change sub-transmission or primary distribution voltages to 120/240 V or other common voltages for use in residential and commercial applications.

7.1 Degradation Mechanism

It has been demonstrated that the life of the transformer's internal insulation is related to temperature-rise and duration. Therefore, transformer life is affected by electrical loading profiles and length of time in service. Other factors such as mechanical damage, exposure to corrosive salts, and voltage and current surges also have a strong effect. Therefore, a combination of condition, age and load based criteria is commonly used to determine the useful remaining life of distribution transformers.

The impacts of loading profiles, load growth, and ambient temperature on asset condition, loss-of-life, and life expectancy can be assessed using methods outlined in ANSI/IEEE Loading Guides. This also provides an initial baseline for the size of transformer that should be selected for a given number and type of customers to obtain optimal life.

7.2 System Hierarchy

The Pole Mounted Transformer asset category belongs to the Overhead Lines assets grouping.

7.3 Useful Life and Typical Life

The useful life of the pole mounted transformer is in the range of 30 to 60 years, with a typical value close to 40 years.

7.4 Time Based Maintenance Intervals

Pole mounted distribution transformers are not subject to planned maintenance.

7.5 Impact of Utilization Factors

This asset is impacted by Electrical Loading and Environmental Conditions.

8 Manual Overhead Line Switches

This asset class consists of overhead line switches. The primary function of switches is to allow for isolation of line sections or equipment for maintenance, safety or other operating requirements. The operating control mechanism can be either a simple hook stick or manual gang.

8.1 Degradation Mechanism

The main degradation processes associated with manually operated line switches include the following, with rate and severity depending on operating duties and environment:

- Corrosion of steel hardware or operating rod
- Mechanical deterioration of linkages
- Switch blades falling out of alignment
- Loose connections
- Non functioning padlocks
- Insulators damage
- Missing ground connections
- Missing nameplates for proper identification

8.2 System Hierarchy

Overhead Switches asset category belongs to the Overhead Lines assets grouping.

8.3 Useful Life and Typical Life

The useful life of manually operated switches is in the range of 30 to 60 years; the typical life is 50 years.

8.4 Time Based Maintenance Intervals

The typical routine testing/maintenance schedule for manually operated overhead switches is two years.

8.5 Impact of Utilization Factors

This asset is impacted by Electrical Loading and Environmental Conditions.

9 Local Motorized Overhead Line Switches

This asset class consists of overhead line three-phase, gang operated switches and a motor. The primary function of switches is to allow for isolation of line sections or equipment for maintenance, safety or other operating requirements. The operating control mechanism is controlled by a motor.

9.1 Degradation Mechanism

Like the remotely operated switch, the main degradation processes associated with local motorized overhead switches include the following:

- Corrosion of steel hardware or operating rod
- Mechanical deterioration of linkages
- Switch blades falling out of alignment
- Loose connections
- Non functioning padlocks
- Insulators damage
- Missing ground connections
- Missing nameplates for proper identification

The rate and severity of degradation are a function on operating duties and environment.

9.2 System Hierarchy

Local Motorized Overhead Switches category belongs to the Overhead Lines assets grouping.

9.3 Useful Life and Typical Life

The local motorized overhead switch can be componentized into two components:

- Switch
- Motor

9.3.1 *Switch*

The useful life of the switch is in the range of 30 to 60 years; the typical life is 50 years (the same as for Manually Operated Overhead switch in section 8.3 of this report).

9.3.2 *Motor*

The useful life of the motor of local motorized switches is in the range of 15 to 20 years; the typical life is about 20 years.

9.4 Time Based Maintenance Intervals

The typical routine testing/maintenance schedule for local motorized switches is every two years.

9.5 Impact of Utilization Factors

This asset is impacted by Electrical Loading and Environmental Conditions.

10 Remote Automated Overhead Line Switches

This asset class consists of overhead line three-phase, gang operated switches. The primary function of switches is to allow for isolation of line sections or equipment for maintenance, safety or other operating requirements. While some categories of the switches are rated for load interruption, others are designed to operate under no load conditions and operate only when the current through the switch is zero. Most distribution line switches are rated 600 to 900 A continuous rating. Switches when used in conjunction with cutout fuses provide short circuit interruption rating. Disconnect switches are sometimes provided with padlocks to allow staff to obtain work permit clearance with the switch handle locked in open position. This component also consists of a remote terminal unit (RTU) component.

10.1 Degradation Mechanism

The main degradation processes associated with line switches include:

- Corrosion of steel hardware or operating rod
- Mechanical deterioration of linkages
- Switch blades falling out of alignment
- Loose connections
- Non functioning padlocks
- Insulators damage
- Missing ground connections
- Missing nameplates for proper identification

The rate and severity of these degradation processes depends on a number of inter-related factors including the operating duties and environment in which the equipment is installed. In most cases, corrosion or rust represents a critical degradation process. The rate of deterioration depends heavily on environmental conditions in which the equipment operates. Corrosion typically occurs around the mechanical linkages of these switches. Corrosion can cause seizing. When lubrication dries out, the switch operating mechanism may seize making the disconnect switch inoperable. In addition, when blades fall out of alignment, excessive arcing may result. While a lesser mode of degradation, air pollution also can affect support insulators. Typically, this occurs in heavy industrial areas or where road salt is used.

10.2 System Hierarchy

Remote Automated Overhead switches asset category belongs to the Overhead Lines assets grouping.

10.3 Useful Life and Typical Life

The remote automated overhead switch can be componentized into three components:

- Switch
- Motor
- Remote Terminal Unit (RTU)

10.3.1 *Switch*

The useful life of the switch is in the range of 30 to 60 years; the typical life is 50 years (the same as for Manually Operated Overhead Switch in section 8.3 of this report).

10.3.2 *Motor*

The useful life of a motor is in the range of 15 to 20 years; the typical life is 20 years (the same as for Local Motorized Overhead Switch in section 9.3.2 of this report).

10.3.3 *Remote Terminal Unit (RTU)*

The useful life of an RTU is in the range of 15 to 30 years; the typical life is 20 years.

10.4 Time Based Maintenance Intervals

The typical routine testing/maintenance schedule for remote automated overhead switches is every two years.

10.5 Impact of Utilization Factors

This asset is impacted by Electrical Loading and Environmental Conditions.

11 Fuse Cutouts

This asset is applied on overhead transformers, capacitors, cables or lines. Fuse Cutouts will interrupt all faults including low current that will melt the fuse link and high rated interrupting current so long as the system is under realistic transient-recovery-voltage conditions.

11.1 Degradation Mechanism

The major degradation of fuse cutouts is on fuse body. There are several degradation modes in practice including the production of carbon from organic materials in the fuse, generation of water vapor to assist current interruption and electrical breakdown in high stress areas of the core.

The production of carbon from organic materials in the fuse body is one degradation mode in practice. This carbon is not produced until a particular body temperature is reached, and the time for this to occur depends on the fuse design. The most critical factors would appear to include the heat generated in the fulgurite, the distance between the fulgurite and the fuse body, the thermal conductivity of the filler material, and the breakdown temperature of the organic material.

For some fuses that generate water vapor to assist current interruption, the water is deposited on the inside surface of the body. Treeing is observed on the surface, ultimately leading to a steady increase in leakage current until failure.

For the fuse cores that contain organic material, hollow core is developed at high temperature due to release of water molecules, resulting in electrical breakdown in high stress areas of the core in certain designs.

11.2 System Hierarchy

Fuse Cutouts asset category belongs to the Overhead Lines assets grouping.

11.3 Useful Life and Typical Life

The useful life of fuse cutouts is in the range of 30 to 60 years; the typical life is 40 years.

11.4 Time Based Maintenance Intervals

Fuse Cutouts are not subject to planned maintenance

11.5 Impact of Utilization Factors

This asset is impacted by Electrical Loading and Environmental Conditions.

12 Voltage Regulators

Voltage regulators are static devices that perform step-up and step-down voltage change operations. Distribution line transformers change the medium or low distribution voltage to 120/240 V or other common voltages for use in residential and commercial applications.

12.1 Degradation Mechanism

It has been demonstrated that the life of the voltage regulator's internal insulation is related to temperature-rise and duration. Therefore, voltage regulator life is affected by electrical loading profiles and length of time in service. Other factors such as mechanical damage, exposure to corrosive salts, and voltage and current surges also have a strong effect. Therefore, a combination of condition, age and load based criteria is commonly used to determine the useful remaining life of voltage regulators.

The impacts of loading profiles, load growth, and ambient temperature on asset condition, loss-of-life, and life expectancy can be assessed using methods outlined in ANSI/IEEE Loading Guides. This also provides an initial baseline for the size of voltage regulator that should be selected for a given number and type of customers to obtain optimal life. There is also the operating practices affect on voltage regulators. If it is a strong system, the voltage regulator may not need to step-up or step-down the voltage, in which case there would be less stress on the device itself.

12.2 System Hierarchy

Voltage Regulators asset category belongs to the Overhead Lines assets grouping.

12.3 Useful Life and Typical Life

The useful life of voltage regulators is in the range of 15 to 40 years; the typical life is 20 years.

12.4 Time Based Maintenance Intervals

Voltage Regulators are not subject to planned maintenance.

12.5 Impact of Utilization Factors

This asset is impacted by Electrical Loading, Environmental Conditions and Operating Practices.

13 Reclosers

This asset class consists of light duty circuit breakers equipped with interrupters that use controllers. This is where the breaking and making of fault current takes place. The interrupters use oil of vacuum as the insulating agent. The controllers are either hydraulic or electric. It is designed for single phase or three phase use, depending on the model.

13.1 Degradation Mechanism

The degradation processes associated with reclosers involves the effects of making and breaking fault current, the mechanism itself and deterioration of components. The effects of making and breaking fault current affect suppression devices as well as the contacts, the oil, and the arc control. The degradation of these devices depends on the prevailing fault, if it is well below the rated capability of the recloser, the deteriorating effects will be small. For the mechanism itself, deterioration or mal-operation of the mechanism causes deterioration during operation. Typically lack of use, corrosion and poor lubrication are the main causes of mechanism mal-function. For deterioration, exposure to weather is a potentially significant degradation process – primarily corrosion of the tank and other metallic components and deterioration of bushings.

13.2 System Hierarchy

Recloser asset category belongs to the Overhead Lines assets grouping.

13.3 Useful Life and Typical Life

Reclosers can be categorized into two components:

- Breaker (Vacuum, Oil)
- RTU

13.3.1 *Breaker*

The useful life of Vacuum breakers is in the range of 30 to 40 years; the typical life is 40 years.

The useful life of Oil breakers is in the range of 30 to 60 years; the typical life is 42 years.

13.3.2 *RTU*

The useful life of recloser RTUs is in the range of 15 to 30 years; the typical life is 20 years.

13.4 Time Based Maintenance Intervals

The typical routine testing/maintenance schedule for the breaker component of reclosers is every ten years.

13.5 Impact of Utilization Factors

This asset is impacted by Electrical Loading and Operating Practices.

14 Station Service Transformers

The station service transformers are the small transformers are configured to provide power to the auxiliary equipment, such as fans, pumps, heating, or lighting, in the distribution station. The most reliable source of such power is directly from the transmission or distribution lines. This report refers to both to both dry type and other types of transformers.

14.1 Degradation Mechanism

As with most transformers, end of life is typically a result of insulation failure, particularly paper insulation. The oil and paper insulation degrade as oxidation takes place in the presence of oxygen, high temperature, and moisture. Acids, particles, and static electricity also have degrading effects to the insulation.

For dry type transformers, the major degradation factors are dirt and moisture. Dirt will contaminate insulation surfaces allowing the formation of conductive paths along the surfaces and eventually to ground. In the case of ventilated dry type transformers, the windings are in direct contact with the air. External air-carrying contaminants or excessive moisture could reduce winding insulation. Dust and dirt accumulation can also reduce air circulation through windings, which eventually shorten the life expectancy of a dry type transformer.

14.2 System Hierarchy

Station service transformers are considered part of the Transmission Stations assets grouping.

14.3 Useful Life and Typical Life

The useful life of a station service transformer is based on the transformer type:

- Dry Type
- Other

14.3.1 *Dry Type*

The useful life of dry type station service transformers is in the range of 20 to 40 years; the typical life is 30 years.

14.3.2 *Other*

The useful life of other station service transformers is in the range of 32 to 55 years; the typical life is 45 years.

14.4 Time Based Maintenance Intervals

The typical routine testing/maintenance interval for these transformers is three years.

14.5 Impact of Utilization Factors

This asset is impacted by Electrical Loading and Environmental Conditions. If this device is running within an electrically stable system there will be less stress imposed on it.

15 TS Power Transformers

While power transformers can be employed in either step-up or step-down mode, a majority of the applications in transmission and distribution stations involve step down of the transmission or sub-transmission voltage to distribution voltage levels. Power transformers vary in capacity and ratings over a broad range. There are two general classifications of power transformers: transmission station transformers and distribution station transformers. For transformer stations, when step down from 230kV or 115kV to distribution voltage is required, ratings may range from 30MVA to 125 MVA. The Consortium typically uses TS Power Transformers rated 75/125 MVA.

15.1 Degradation Mechanism

Transformers operate under many extreme conditions, and both normal and abnormal conditions affect their aging and breakdown. They are subject to thermal, electrical, and mechanical aging. Overloads cause above-normal temperatures, through-faults can cause displacement of coils and insulation, and lightning and switching surges can cause internal localized over-voltages.

For a majority of transformers, end of life is a result of the failure of insulation, more specifically, the failure of pressboard and paper insulation. While the insulating oil can be treated or changed, it is not practical to change the paper and pressboard insulation. The condition and degradation of the insulating oil, however, plays a significant role in aging and deterioration of the transformer, as it directly influences the speed of degradation of the paper insulation. The degradation of oil and paper in transformers is essentially an oxidation process. The three important factors that impact the rate of oxidation of oil and paper insulation are the presence of oxygen, high temperature, and moisture. Particles and acids, as well as static electricity in oil cooled units, also affect the insulation.

Tap changers and bushing are major components of the power transformer. Tap changers are complex mechanical devices and are therefore prone to failure resulting from either mechanical or electrical degradation. Bushings are subject to aging from both electrical and thermal stresses.

15.2 System Hierarchy

Power Transformers belong to the Transformer Stations assets grouping.

15.3 Useful Life and Typical Life

This asset could be componentized into the following components:

- Winding
- Manual/Automatic On Load Tap Changer

15.3.1 *Winding*

The useful life of the winding can be in the range of 32-55 years, depending on the loading condition and ambient operating temperature, and routine maintenance practices. A typical life of 45 years can be expected for the winding system.

15.3.2 *Manual/Automatic On Load Tap Changer*

The useful life range of the manual or automatic on load tap changer, assuming it is vacuum type, is 20-60 years; the typical life is 20 years.

15.4 Time Based Maintenance Intervals

For TS power transformers, the typical routine testing/maintenance interval is two years.

15.5 Impact of Utilization Factors

This asset is impacted by Electrical Loading, Environmental Conditions and Operating Practices. It is specifically the on load tap changer component that is affected by operating practices. If this device is running within an electrically stable system there will be less stress imposed on it.

16 MS Power Transformers

Power transformers at distribution stations typically step down voltage to distribution levels. Ratings typically range from 5 MVA to 30 MVA. The Consortium typically uses MS Power Transformers rated 20/33.3 MVA.

16.1 Degradation Mechanism

The degradation of the power transformers at municipal stations or at customer sites is similar to that of the transformers at transmission stations. These transformers are subject to electrical, thermal, and mechanical aging. Degradation of the insulating oil, and more significantly, paper insulation, typically results in end of life. Insulation degradation is a result of oxidation, a process that occurs in the presence of oxygen, high temperature, and moisture. For oil cooled transformers, particles, acids, and static electricity will also deteriorate the insulation.

Tap changers and bushing are major components of the power transformer. Tap changers are prone to failure resulting from either mechanical or electrical degradation. Bushings are subject to aging from both electrical and thermal stresses.

16.2 System Hierarchy

MS Power Transformer asset category belongs to the Municipal Stations assets grouping.

16.3 Useful Life and Typical Life

The power transformer also has major components that have different useful lives. Componentization is as follows:

- Winding
- Manual/Automatic On Load Tap Changer

16.3.1 *Winding*

The useful life of windings is 32 to 55 years; the typical life is 45 years.

16.3.2 *Manual/Automatic On Load Tap Changer*

The useful life range of the manual or automatic tap changer, assuming it is vacuum type, is 20 to 60 years; the typical life is 20 years.

16.4 Time Based Maintenance Intervals

The typical routine testing/maintenance interval for these transformers is two years.

16.5 Impact of Utilization Factors

This asset is impacted by Electrical Loading, Environmental Conditions and Operating Practices. It is specifically the on load tap changer component that is affected by operating practices. If this device is running within an electrically sound system there will be less stress imposed on it.

17 DC Station Service

The DC station service asset class includes battery banks and chargers. Equipment within transmission and municipal stations must be provided with a guaranteed source of power to ensure they can be operated under all system conditions, particularly during fault conditions. There is no known way to store AC power so the only guaranteed instantaneous power source must be DC, based on batteries.

17.1 Degradation Mechanism

Effective battery life tends to be much shorter than many of the major components in a station. The deterioration of a battery from an apparently healthy condition to a functional failure can be rapid. This makes condition assessment very difficult. However, careful inspection and testing of individual cells often enables the identification of high risk units in the short term.

It is well understood in the utility industry that regular inspection and maintenance of batteries and battery chargers is necessary. In most cases the explicit reason for carrying out regular maintenance inspection is to detect minor defects and rectify them. However, critical examination of trends in maintenance records can give an early warning of potential failures.

Despite the regular and frequent maintenance and inspection of battery systems, failures in service are still relatively frequent. For this reason, many utilities employ battery monitors and alarm systems. The earlier versions of these are still widely used and are relatively unsophisticated devices that measure basic battery parameters with pre-set alarm levels. More modern monitoring devices have the ability to identify a potential failure as it develops and to provide a warning.

Although battery deterioration is difficult to detect, any changes in the electrical characteristics or observation of significant internal damage can be used as sensitive measures of impending failure. Batteries consist of multiple individual cells. While the significant deterioration/failure of an individual cell may be an isolated incident, detection of deterioration in a number of cells in a battery is usually the precursor to widespread failure and functional failure of the total battery.

Battery chargers are also critical to the satisfactory performance of the whole battery system. Battery chargers are relatively simple electronic devices that have a high degree of reliability and a significantly longer lifetime than the batteries themselves. Nevertheless, problems do occur. As with other electronic devices, it is difficult to detect deterioration prior to failure. It is normal practice during the regular maintenance and inspection process to check the functionality of the battery chargers, in particular the charging rates. Where any functional failures are detected it would be normal to replace the battery charger.

17.2 System Hierarchy

DC station services belong to Municipal Stations assets grouping.

17.3 Useful Life and Typical Life

This asset also has two major components that have differing useful lives:

- Battery Banks
- Charger

17.3.1 *Battery Bank*

The battery bank has a useful life range of 10 to 30 years; typical life is 20 years.

17.3.2 *Charger*

The charger has a useful life range of 20 to 30 years; typical life is 20 years.

17.4 Time Based Maintenance Intervals

Typically, routine testing/maintenance for batteries are conducted annually. The maintenance of schedule battery chargers is typically coordinated with that of the battery.

17.5 Impact of Utilization Factors

This asset is impacted by Electrical Loading, Environmental Conditions and Operating Practices. This device cannot be overloaded, last longer when there is not extreme cold weather conditions and only the battery bank component is affected by operating practices (i.e., it only runs if the AC fails).

18 Air Insulated Switchgear

Air Insulated Switchgear consists of an assembly of retractable/racked switchgear devices that are totally enclosed in a metal envelope (metal-enclosed). These devices operate in the medium voltage range, from 4.16 to 44 kV. The switchgear includes breakers; disconnect switches, or fusegear, current transformers (CTs), voltage transformers (VTs) and occasionally some or all of the following: metering, protective relays, internal DC and AC power, battery charger(s), and AC station service transformation. The gear is modular in that each breaker is enclosed in its own metal envelope (cell). The gear also is compartmentalized with separate compartments for breakers, control, incoming/outgoing cables or bus duct, and bus-bars associated with each cell.

18.1 Degradation Mechanism

Switchgear degradation is a function of a number of different factors: mechanism operation and performance, degradation of solid insulation, general degradation/corrosion, environmental factors, or post fault maintenance (condition of contacts and arc control devices). Degradation of the breaker used is also a factor. However the degradation mechanism differs slightly between switchgear types: air insulated and gas insulated.

Correct operation of the mechanism is critical in devices that make or break fault currents, i.e. the contact opening and closing characteristics must be within specified limits. The greatest cause of mal-operation of switchgear is related to mechanism malfunction. Deterioration due to corrosion or wear due to lubrication failure may compromise mechanism performance by either preventing or slowing down the operation of the breaker. This is a serious issue for all types of switchgear.

In older air filled equipment, degradation of active solid insulation (for example drive links) has been a significant problem for some types of switchgear. Some of the materials used in this equipment, particularly those manufactured using cellulose-based materials (pressboard, SRBP, laminated wood) are susceptible to moisture absorption. This results in a degradation of their dielectric properties that can result in thermal runaway or dielectric breakdown. An increasingly significant area of solid insulation degradation relates to the use of more modern polymeric insulation. Polymeric materials, which are now widely used in switchgear, are very susceptible to discharge damage. These electrical stresses must be controlled to prevent any discharge activity in the vicinity of polymeric material. Failures of relatively new switchgear due to discharge damage and breakdown of polymeric insulation have been relatively common over the past 15 years.

Temperature, humidity and air pollution are also significant degradation factors, so indoor units tend to have better long-term performance. The safe and efficient operation of switchgear and its longevity may all be significantly compromised if the substation environment is not adequately controlled. In addition, the air switchgear can tolerate less number of full fault operations before maintenance is required.

18.2 System Hierarchy

Switchgear asset category belongs to the Municipal Stations assets grouping.

18.3 Useful Life and Typical Life

This asset also has several major components, each with a different useful life:

- Breaker (SF6, Vacuum, Air Magnetic)
- Switchgear Assembly

18.3.1 *Breaker*

The useful life range of SF6 type breaker in air insulated switchgear is 30 to 60 years; typical life is 42 years.

The useful life range of vacuum type breaker in air insulated switchgear is 30 to 60 years; typical life is 40 years.

The useful life range of air magnetic type breaker in air insulated switchgear is 25 to 60 years; typical life is 40 years.

18.3.2 *Switchgear Assembly*

The useful life range of switchgear assembly is 40 to 60 years; typical life is 50 years.

18.4 Time Based Maintenance Intervals

The typical routine testing/maintenance interval for this asset is six years.

18.5 Impact of Utilization Factors

This asset is impacted by Electrical Loading, Environmental Conditions and Operating Practices. It is specifically the breaker component that is affected by operating practices. If this device is running within an electrically system there will be less stress imposed on it. It is specifically the switchgear assembly component that is affected by environmental factors, specifically temperature.

19 Gas Insulated Switchgear

The latest design of metalclad gear is the Gas Insulated Switchgear (GIS), which uses low-pressure SF6 gas as a general insulation medium, as a replacement for the air. The insulation within the metal enclosure is not necessarily the same as the working fluid in the breakers themselves, which presently is either SF6 or vacuum.

19.1 Degradation Mechanism

Switchgear degradation is a function of a number of different factors: mechanism operation and performance, degradation of solid insulation, general degradation/corrosion, environmental factors, or post fault maintenance (condition of contacts and arc control devices). Degradation of the breaker used is also a factor. However the degradation mechanism differs slightly between switchgear types: air insulated and gas insulated.

Generally, mechanism malfunction causes most operational problems in GIS. Corrosion and lubrication failure may compromise mechanism performance by preventing or slowing its operation.

Solid insulation such as that in entrance bushings, internal support insulators, plus breaker and switch operating rods have caused many GIS failures. Manufacturing, shipping, installing, maintaining and operating the GIS can cause defects in the insulation. Defects include voids in epoxy insulators, delamination of epoxy and metallic hardware, and protrusions on conductors. In floating components, fixed and moving particles can lead to failures. Partial discharge (PD) activity usually leads to flashovers.

Corrosion and general deterioration increase risks of moisture ingress and SF6 leaks, particularly in outdoor GIS. If not treated, these factors may cause the end-of-life for GIS.

GIS is designed and manufactured for outdoor use, but it generally has better long-term performance when installed indoors. Outdoor GIS, particularly older ITE designs, have higher than acceptable SF6 gas leaks because of the poor quality of fittings, connectors, valves, by-pass piping, general enclosure porosity and flange corrosion. Indoor installations reduce problems from corrosion, moisture ingress, low ambient temperatures and SF6 leaks.

GIS have more costly, difficult and time-consuming post fault maintenance requirements than air insulated switchgear. Older GIS have even more post-fault maintenance problems. Accessibility, fault location, fault level and duration, degree of compartmentalization, isolation requirements, pressure relief, burn-through protection, parts and service capabilities all help determine post-fault maintenance needs.

19.2 System Hierarchy

Switchgear asset category belongs to the Municipal Stations assets grouping.

19.3 Useful Life and Typical Life

This asset also has several major components, each with a different useful life:

- Breaker (SF6, Vacuum, Air Magnetic)
- Switchgear Assembly

19.3.1 *Breaker*

The useful life range of SF6 type breaker in air insulated switchgear is 30 to 60 years; typical life is 42 years.

The useful life range of vacuum type breaker in air insulated switchgear is 30 to 60 years; typical life is 40 years.

The useful life range of air magnetic type breaker in air insulated switchgear is 25 to 60 years; typical life is 40 years.

19.3.2 *Switchgear Assembly*

The useful life range of switchgear assembly is 40 to 60 years; typical life is 50 years.

19.4 Time Based Maintenance Intervals

The typical routine testing/maintenance interval for this asset is six years.

19.5 Impact of Utilization Factors

This asset is impacted by Electrical Loading, Environmental Conditions and Operating Practices. It is specifically the breaker component that is affected by operating practices. If this device is running within an electrically system there will be less stress imposed on it. It is specifically the switchgear assembly component that is affected by environmental factors, specifically temperature.

20 Building

Buildings at major transformer and municipal stations house the switchgear, relays and controls and serve as a base for administrative and service work. This asset includes the building itself (foundations, walls), roof, and fence.

20.1 Degradation Mechanism

The following contribute to the degradation of this asset:

- Building age
- Structural condition of loading members
- Condition of floors, walls and ceilings
- Protection against weather elements
- Environmental concerns
- Functional requirements

Buildings are a very maintainable asset. The capital cost of replacement is high enough that the lowest long term cost is achieved even with quite high levels of annual maintenance. Age alone is a very poor indicator of end of life. Rather impacts such as environmental rain, wind and snow storms contribute highly to the degradation of buildings. It is the potential water ingress with poses the most danger to the asset due to the presence of electrical equipment. In order to prevent this, the buildings must be weatherproof.

Also, since the foundation materials typically consist of reinforced concrete designed to consider environmental elements including soil conditions and climate. Landscaping is used to control soil erosion, maintain site cleanliness and facilitate an efficient and safe work environment.

Preventative maintenance helps ensure long-term integrity of buildings. This type of maintenance should be done on a regular basis. As well the occasional refurbishment of doors, windows and roofs helps with the viability of the building.

The building roof is the most susceptible to degradation due to environmental factors. The roof is typically level and composed of tar and an aggregate that is designed to keep the wind from wearing at the tar. Nevertheless, the roof is still susceptible to environmental degradation and if not sealed properly can become a source of flooding. The maintenance of the roof is generally the largest undertaking for buildings.

20.2 System Hierarchy

Building asset category belongs to the Municipal Stations assets grouping.

20.3 Useful Life and Typical Life

The overall useful life range of the building itself is 30 to 80 years; the typical life is 50 years.

This asset also has two other major components, each of which has a different useful life. From a maintenance practice perspective, the building can be componentized into the following:

- Roof
- Fence

20.3.1 *Roof*
The useful life of the roof can be in the range of 15 to 20 years, with a typical life of 20 years.

20.3.2 *Fence*
The useful life range of the fence is 30 to 45 years, with a typical life of 35 years.

20.4 Time Based Maintenance Intervals
The typical routine inspection interval for this asset is every year.

20.5 Impact of Utilization Factors
This asset is impacted by Mechanical Stress and Environmental Conditions.

21 Station Grounding System

The station grounding system asset refers to grounding rods and connectors. Grounding systems in stations dissipate maximum ground fault currents without interfering with power system operation or causing voltages dangerous to people or equipment. Safety hazards from inadequate grounding include excessive ground potential rises and excessive step and touch potentials. Generally, grounding system assets provide suitable paths for ground currents to follow from power equipment and conductors into the earth. Consequently, complete grounding systems include buried conductors, ground rods and connections, plus soil and vegetation in the area. Soil and vegetative conditions affect water retention and drainage, which impact overall performance of the grounding system.

21.1 Degradation Mechanism

Station grounding systems keep ground potential rise, step and touch potentials below specified limits when maximum (i.e. worst case) ground faults occur. Under fault conditions, the following factors determine step and touch potentials:

- Magnitude of the fault current
- Resistance of ground combined with the ground grid consisting of station electrodes, transmission line sky wires and distribution neutrals
- Ground resistivity of upper and lower layers of earth.

Increases in system capacity and fault currents at a station may lead to unacceptable performance of the ground grid. Corrosion of buried conductors and connectors, mechanical damage to buried electrodes, plus burning-off of grounding conductors and connectors during heavy fault currents also may lead to unsatisfactory performance. Further, changes in resistivity of upper or lower layers of earth may adversely affect ground grid characteristics.

21.2 System Hierarchy

Station Grounding Systems asset category belongs to the Municipal Stations assets groupings.

21.3 Useful Life and Typical Life

Station grounding systems have a useful life range of 25 to 50 years; the typical life is 40 years.

21.4 Time Based Maintenance Intervals

Station Grounding Systems are not subject to planned maintenance.

21.5 Impact of Utilization Factors

This asset is impacted by Environmental Conditions.

22 Underground Primary Cables

Distribution underground cables are mainly used in urban areas where it is either impossible or extremely difficult to build overhead lines due to aesthetic, legal, environmental and safety reasons. The initial capital cost of a distribution underground cable circuit is three or more times the cost of an overhead line of equivalent capacity and voltage. The cross linked polyethylene (XLPE) cable is the type of underground distribution cables used by Consortium. While XLPE underground cable can be installed in ducts (and concrete enclosed ducts), it can also be directly buried.

Cable terminations are designed to separate the cable ground from the conductor in a safe and controlled manner. Inside the cable, ground and high voltage are separated by only a few millimeters. This distance is much too small to support any voltage. Therefore the termination must increase this separation while being able to withstand the surrounding environment.

22.1 Degradation Mechanism

Over the past 30 years XLPE insulated cables have all but replaced paper-insulated cables. These cables can be manufactured by a simple extrusion of the insulation over the conductor and therefore are much more economic to produce. In normal cable lifetime terms XLPE cables are still relatively young. Therefore, failures that have occurred can be classified as early life failures. Certainly in the early days of polymeric insulated cables their reliability was questionable. Many of the problems were associated with joints and accessories or defects introduced in the manufacturing process. Over the past 30 years many of these problems have been addressed and modern XLPE cables and accessories are generally very reliable.

Polymeric insulation is very sensitive to discharge activity. It is therefore very important that the cable, joints and accessories are discharge free when installed. Discharge testing is, therefore, an important factor for these cables. This type of testing is conducted during commissioning and is not typically used for detection of deterioration of the insulation. These commissioning tests are an area of some concern for polymeric cables because the tests themselves are suspected of causing permanent damage and reducing the life of polymeric cables.

Water treeing is the most significant degradation process for polymeric cables. The original design of cables with polymeric sheaths allowed water to penetrate and come into contact with the insulation. In the presence of electric fields water migration can result in treeing and ultimately breakdown. The rate of growth of water trees is dependent on the quality of the polymeric insulation and the manufacturing process. Any contamination voids or discontinuities will accelerate degradation. This is assumed to be the reason for poor reliability and relatively short lifetimes of early polymeric cables. As manufacturing processes have improved the performance and ultimate life of this type of cable has also improved.

The major degradation problems with the cable terminations concern mostly flashover and tracking associated with the outside and interior surfaces of the accessory. However, there are also problems of overheating at connections and voltage control at the end of the cable shield.

22.2 System Hierarchy

Underground Primary Cables asset category belongs to the Underground Systems assets grouping.

22.3 Useful Life and Typical Life

The overall useful life range of the cable itself is dependent on the cable type and component:

- TR-XLPE (In Duct, In Concrete Encased Duct, Direct Buried)
- Termination

22.3.1 *TR-XLPE*

The useful life range of in duct cable is 40 to 60 years; the typical life is 40 years.

The useful life range of in concrete encased duct cable is 40 to 60 years; the typical life is 40 years.

The useful life range of direct buried cable is 20 to 40 years; the typical life is 25 years.

22.3.2 *Termination*

The useful life range of termination component of underground cable is 25 to 60 years; the typical life is 40 years.

22.4 Time Based Maintenance Intervals

Underground Primary Cables are not subject to planned maintenance.

22.5 Impact of Utilization Factors

This asset is impacted by Electrical Loading and Environmental Conditions.

23 Underground Secondary Cables

Secondary underground cables are used to supply customer premises. The Polyethylene Insulated (PI) and PVC Jacket (PIJ) are similar to the XLPE cables described above, and are assumed to be in duct.

23.1 Degradation Mechanism

Underground secondary conductors are typically insulated with polyethylene. Polyethylene insulation is very sensitive to discharge activity. It is therefore very important that the cable, joints and accessories are discharge free when installed. These commissioning tests are an area of some concern for polyethylene cables because the tests themselves are suspected of causing permanent damage and reducing the life of polymeric cables. However those with the PVC jacket have further insulation to prevent some deterioration of the insulation.

23.2 System Hierarchy

Underground Secondary Cables are used in the Underground system.

23.3 Useful Life and Typical Life

The underground secondary cable can be categorized into two types:

- Polyethylene Insulated
- PVC Jacket

23.3.1 *Polyethylene Insulated*

The useful life range of in polyethylene insulated cable is 40 to 60 years; the average life is 40 years.

23.3.2 *PVC Jacket*

The useful life range of in PVC jacket cable is 40 to 60 years; the average life is 40 years.

23.4 Time Based Maintenance Intervals

Underground Secondary Cables are not subject to planned maintenance

23.5 Impact of Utilization Factors

This asset is impacted by Electrical Loading and Environmental Conditions.

24 Distribution Transformer

This asset class consists of the transformer and elbows and inserts associated with the system. There are three types of transformers that Consortium uses: Pad Mounted, Vault and Submersible.

Pad mounted transformers typically employ sealed tank construction and are liquid filled, with mineral insulating oil being the predominant liquid. Vault transformers typically employ sealed tank construction and are liquid filled with mineral insulating oil. Submersible transformers typically employ sealed tank construction and are liquid filled with mineral insulating oil.

24.1 Degradation Mechanism

The pad-mounted transformer has a similar degradation mechanism to other distribution transformers. It has been demonstrated that the life of the transformer's internal insulation is related to temperature rise and duration. Therefore, the transformer life is affected by electrical loading profiles and length of service life. Other factors such as mechanical damage, exposure to corrosive salts, and voltage current surges also have strong effects. Therefore, a combination of condition, age, and load based criteria is commonly used to determine the useful remaining life.

In general, the following are considered when determining the health of the pad-mounted transformer:

- Tank corrosion, condition of paint
- Extent of oil leaks
- Condition of bushings
- Condition of padlocks, warning signs, etc.
- Transfer operating age and winding temperature profile

The vault transformer and submersible transformer have a similar degradation mechanism to other distribution transformers. The life of the transformer's internal insulation is related to temperature rise and duration, so transformer life is affected by electrical loading profiles and length of service life. Mechanical damage, exposure to corrosive salts, and voltage current surges has strong effects. In general, a combination of condition, age, and load based criteria is commonly used to determine the useful remaining life.

24.2 System Hierarchy

Distribution Transformers asset category belongs to the Underground Systems asset grouping.

24.3 Useful Life and Typical Life

The overall useful life range of the transformer itself is dependent on the component:

- Transformer (Pad Mounted, Vault, Submersible)
- Elbows and Inserts

24.3.1 *Transformer*

The useful life range of pad mounted distribution transformers are 30 to 40 years; the typical life is 40 years.

The useful life range of vault distribution transformers is 30 to 40 years; the typical life is 40 years.

The useful life range of submersible distribution transformers is 25 to 40 years; the typical life is 35 years.

24.3.2 *Elbows and Inserts*

The useful life range of the elbows and inserts component of distribution transformers is 20 to 60 years; the typical life is 40 years.

24.4 Time Based Maintenance Intervals

Distribution Transformers are not subject to planned maintenance.

24.5 Impact of Utilization Factors

This asset is impacted by Electrical Loading, Environmental Conditions and Operating Practices. The operating practices impact only the elbows and inserts component of the asset.

25 Pad Mounted Switchgear

Pad-mounted switchgear is used for protection and switching in the underground distribution system. The switching assemblies can be classified into air insulated, SF6 load break switches and vacuum fault interrupters. A majority of the pad mounted switchgear currently employs air-insulated gang operated load-break switches.

25.1 Degradation Mechanism

The pad-mounted switchgear is very infrequently used for switching and often used to drop loads way below its rating. Therefore, switchgear aging and eventual end of life is often established by mechanical failures, e.g. rusting of the enclosures or ingress of moisture and dirt into the switchgear causing corrosion of operating mechanism and degradation of insulated barriers.

The first generation of pad mounted switchgear was first introduced in early 1970's and many of these units are still in good operating condition. The life expectancy of pad-mounted switchgear is impacted by a number of factors that include frequency of switching operations, load dropped, presence or absence of corrosive environmental and absence of existence of dampness at the installation site.

In the absence of specifically identified problems, the common industry practice for distribution switchgear is running it to end of life, just short of failure. To extend the life of these assets and to minimize in-service failures, a number of intervention strategies are employed on a regular basis: e.g. inspection with thermographic analysis and cleaning with CO2 for air insulated pad-mounted switchgear. If problems or defects are identified during inspection, often the affected component can be replaced or repaired without a total replacement of the switchgear.

Failures of switchgear are most often not directly related to the age of the equipment, but are associated instead with outside influences. For example, pad-mounted switchgear is most likely to fail due to rodents, dirt/contamination, vehicle accidents, rusting of the case, and broken insulators caused by misalignment during switching. All of these causes are largely preventable with good design and maintenance practices. Failures caused by fuse malfunctions can result in a catastrophic switchgear failure.

Aging and end of life is established by mechanical failures, such as corrosion of operating mechanism from rusting of enclosure or moisture and dirt ingress. Switchgear failure is associated more with outside influences rather than age. For example, switchgear failure is more likely to be caused by rodents, dirt or contamination, vehicle accidents, rusting of the case, and broken insulators caused by misalignment during switching.

25.2 System Hierarchy

Pad-Mounted Switchgear belongs to the Underground Systems assets grouping.

25.3 Useful Life and Typical Life

The overall useful life range of the switchgear itself is dependent on the pad mount switchgear type:

- Air Insulated
- Gas Insulated
- Solid Dielectric

25.3.1 *Air Insulated*

The useful life range of this air insulated pad mount switchgear is 20 to 40 years; the typical life is 30 years.

25.3.2 *Gas Insulated*

The useful life range of this gas insulated pad mount switchgear is 30 to 50 years; the typical life is 30 years.

25.3.3 *Solid Dielectric*

The useful life range of this solid dielectric pad mount switchgear is 30 to 50 years; the typical life is 30 years.

25.4 Time Based Maintenance Intervals

The typical routine inspection interval for this asset is three years.

25.5 Impact of Utilization Factors

This asset is impacted by Electrical Loading, Environmental Conditions and Operating Practices.

26 Vault Switch

The vault switches used by Consortium are metal enclosed switch and metal enclosed cutout. These units are essentially pad mounted switchgear, enclosed in stainless steel containers, with the ability to be wall or ceiling mounted.

26.1 Degradation Mechanism

The degradation mechanism of this asset is similar to that of other types of pad mounted switchgear. Aging and end of life is established by mechanical failures, such as corrosion of operating mechanism from rusting of enclosure or moisture and dirt ingress. Switchgear failure is associated more with outside influences rather than age. For example, switchgear failure is more likely to be caused by rodents, dirt or contamination, vehicle accidents, rusting of the case, and broken insulators caused by misalignment during switching.

26.2 System Hierarchy

Vault Switches asset category belongs to the Underground Systems assets grouping.

26.3 Useful Life and Typical Life

The overall useful life range of the vault switch is dependent on the pad mount switchgear type:

- Metal Enclosed Switch
- Metal Enclosed Cutout

26.3.1 *Metal Enclosed Switch*

The useful life range of metal enclosed switch is 20 to 40 years; the typical life is 30 years.

26.3.2 *Metal Enclosed Cutout*

The useful life range of metal enclosed cutout is 30 to 60 years; the typical life is 40 years.

26.4 Time Based Maintenance Intervals

The typical routine inspection interval for this asset is 3 years.

26.5 Impact of Utilization Factors

This asset is impacted by Electrical Loading, Environmental Conditions and Operating Practices.

27 Utility Chamber

Utility Chambers facilitate cable pulling into underground ducts and provide access to splices and facilities that require periodic inspections or maintenance. They come in different styles, shapes and sizes according to the location and application. Pre-cast cable chambers are normally installed only outside the traveled portion of the road although some end up under the road surface after road widening. Cast-in-place cable chambers are used under the traveled portion of the road because of their strength and also because they are less expensive to rebuild if they should fail. Customer cable chambers are on customer property and are usually in a more benign environment. Although they supply a specific customer, system cables loop through these chambers so other customers could also be affected by any problems.

27.1 Degradation Mechanism

These assets must withstand the heaviest structural loadings that they might be subjected to. For example, when located in streets, utility chambers must withstand heavy loads associated with traffic in the street. When located in driving lanes, utility chamber chimney and collar rings must match street grading. Since utility chambers and vaults often experience flooding, they sometimes include drainage sumps and sump pumps. Nevertheless, environmental regulations in some jurisdictions may prohibit the pumping of utility chambers into sewer systems, without testing of the water for environmentally hazardous contaminants.

Although age is loosely related to the condition of underground civil structures, it is not a linear relationship. Other factors such as mechanical loading, exposure to corrosive salts, etc. have stronger effects. Utility chamber degradation commonly includes corrosion of reinforcing steel, spalling of concrete, and rusting of covers or rings. Acidic salts (i.e. sulfates or chlorides) affect corrosion rates. Utility chamber systems also may experience a number of deficiencies or defects. In roadways, defects exist when covers are not level with street surfaces. Conditions that lead to flooding, clogged sumps, and non-functioning sump-pumps also represent major deficiencies in a utility chamber system. Similarly, utility chamber systems with lights that do not function properly constitute defective systems. Deteriorating ductwork associated with utility chambers also requires evaluation in assessing the overall condition of a utility chamber system.

27.2 System Hierarchy

Utility Chambers asset category belongs to the Underground Systems assets grouping.

27.3 Useful Life and Typical Life

Utility chambers have a useful life range of 50 to 80 years; the typical life range is 60 years.

27.4 Time Based Maintenance Intervals

The typical routine testing/maintenance interval for this asset class is three years.

27 Utility Chamber

27.5 Impact of Utilization Factors

This asset is impacted by Environmental Conditions.

28 Duct

In areas such as road crossings, ducts provide a conduit for underground cables to travel. They are comprised of a number of ducts, in trench, and typically encased in concrete. Ducts are sized as required and are usually two to six inches in diameter.

28.1 Degradation Mechanism

The ducts connecting one utility chamber to another cannot easily be assessed for condition without excavating areas suspected of suffering failures. However, water ingress to a utility chamber that is otherwise in sound condition is a good indicator of a failure of a portion of the ductwork. Since there are no specific tests that can be conducted to determine duct integrity at reasonable cost, the duct system is typically treated on an ad hoc basis and repaired or replaced as is determined at the time of cable replacement or failure.

28.2 System Hierarchy

Ducts asset category belongs to the Underground Systems assets grouping.

28.3 Useful Life and Typical Life

The overall useful life range of the duct is dependent on the type:

- Duct Bank
- Direct Buried Pipe (PVC)
- High Density Polyethylene (HDPE)

28.3.1 *Duct Bank*

The useful life range of the duct bank type is 30 to 80 years; the typical life is 50 years.

28.3.2 *Direct Buried Pipe (PVC)*

The useful life range of the direct buried pipe type is 30 to 75 years; the typical life is 50 years.

28.3.3 *High Density Polyethylene (HDPE)*

The useful life range of the HDPE type is 50 to 100 years; the typical life is 50 years.

28.4 Time Based Maintenance Intervals

Ducts are not subject to planned maintenance.

28.5 Impact of Utilization Factors

This asset is impacted by Environmental Conditions.

29 Transformer and Switchgear Foundations

This asset class is similar to the utility chamber asset. It is a buried pre cast concrete vault on which pad-mounted transformers or switchgear are mounted. The foundation itself is buried; however the top portion is above ground.

29.1 Degradation Mechanism

These assets must withstand the heaviest structural loadings that they might be subjected to. For example, when located in streets, transformer and switchgear foundation must withstand heavy loads associated with traffic in the boulevard. When located in driving lanes, concrete vault must match street grading. Since vaults often experience flooding, they sometimes include drainage sumps and sump pumps. Nevertheless, environmental regulations in some jurisdictions may prohibit the pumping into sewer systems, without testing of the water for environmentally hazardous contaminants.

Although age is loosely related to the condition of underground civil structures, it is not a linear relationship. Other factors such as mechanical loading, exposure to corrosive salts, etc. have stronger effects. Transformer and switchgear foundation degradation commonly includes corrosion of reinforcing steel, spalling of concrete, and rusting of covers or rings. Acidic salts (i.e. sulfates or chlorides) affect corrosion rates. Transformer and switchgear foundation also may experience a number of deficiencies or defects. In roadways, defects exist when covers are not level with street surfaces. Conditions that lead to flooding, clogged sumps, and non-functioning sump-pumps also represent major deficiencies in a transformer and switchgear foundation. Similarly, transformer and switchgear foundation with lights that do not function properly constitute defective systems.

29.2 System Hierarchy

Transformer and Switchgear foundations asset category belongs to the Underground Systems assets grouping.

29.3 Useful Life and Typical Life

The overall useful life range of Transformer and switchgear foundation is 30 to 80 years; the typical life is 60 years.

29.4 Time Based Maintenance Intervals

The typical routine testing/maintenance interval for this asset class is three years.

29.5 Impact of Utilization Factors

This asset is impacted by Environmental Conditions.

30 Junction Cubicle

This asset class consists of a wiring box similar to pad mount switchgear. For the purposes of this study there is only reference to junction casing.

30.1 Degradation Mechanism

The main degradation associated with the junction cubicle casing is caused by outside sources. These include corrosion, vehicle damage, case rusting, and dirt or contamination.

30.2 System Hierarchy

Junction cubicle is used in the Underground Systems assets grouping.

30.3 Useful Life and Typical Life

The overall useful life range of junction cubicle casing is 25 to 50 years; the typical life is 40 years.

30.4 Time Based Maintenance Intervals

Junction Cubicles are not subject to planned maintenance

30.5 Impact of Utilization Factors

This asset is impacted by Environmental Conditions.

31 "Classic" SCADA

Supervisory Control and Data Acquisition (SCADA) refers to the centralized monitoring and control system of a facility. SCADA remote terminal units (RTUs) allow the master SCADA system to communication, often wirelessly, with field equipment. In general, RTUs collect digital and analog data from equipment, exchange information to the master system, and perform control functions on field devices. They are typically comprised of the following: power supply, CPU, I/O Modules, housing and chassis, communications interface, and software.

31.1 Degradation Mechanism

There are many factors that contribute to the end-of-life of RTUs. Utilities may choose to upgrade or replace older units that are no longer supported by vendors or where spare parts are no longer available. Because RTUs are essentially computer devices, they are prone to obsolescence. For example, older units may lack the ability to interface with Intelligent Electronic Devices (IEDs), be unable to support newer or modern communications media and/or protocols, or not allow for the quantity, resolution, and accuracy of modern data acquisition. Legacy units may have limited ability of multiple master communication ports and protocols, or have an inability to segregate data into multiple RTU addresses based on priority.

31.2 System Hierarchy

Classic SCADA asset category belongs to the Monitoring and Control Systems assets grouping.

31.3 Useful Life and Typical Life

This asset has several major components, each of which has a different useful life. From a maintenance practice perspective, classic SCADA can be componentized into the following:

- RTU
- Relay
- Battery

31.3.1 *RTU*

The useful life of the RTU in "classic" SCADA is in the range of 15 to 30 years; the typical life is 20 years.

31.3.2 *Relay*

The useful life of the relay in "classic" SCADA is in the range of 20 to 50 years; the typical life is 30 years.

31.3.3 *Battery*

The useful life of the battery in "classic" SCADA is in the range of 5 to 10 years; the typical life is 10 years.

31 “Classic” SCADA

31.4 Time Based Maintenance Intervals

“Classic” SCADA is not subject to planned maintenance.

31.5 Impact of Utilization Factors

This asset is impacted by Operating Practices. It is specifically the battery and relay components that are affected by operating practices. If this device is running within an electrically stable system there will be less stress imposed on it.

32 IED Based SCADA

Intelligent Electronic Devices (IED) based Supervisory Control and Data Acquisition (SCADA) refers to the centralized monitoring and control system of a facility.

32.1 Degradation Mechanism

Physical degradation of IED Based SCADA happens on hardware part of an IED. Compared to solid state relays, IEDs are not sensitive to ambient environment. The major contributing factor of degradation is the electrical environment, i.e. inrush transient. Since IEDs have built-in self-supervision system, the settings with perfect long time stability is guaranteed.

The failure mode of an IED can be:

- Fail to trip because communication port is held by defective external equipment
- Mal-function due to hardware/firmware/software version mismatch
- Mal-function due to software design flaw causing software latched by external EMI interference
- Will not operate due to power supply failure

To assess the health status of an IED, the following condition parameters are studied:

- Operating mechanism, including power supply, insulation, connection
- Recalibration, including recalibration record and relay functionality (e.g., overcurrent, distance etc.)
- Reliability, including mal-operation count, loading and age

32.2 System Hierarchy

IED Based SCADA asset category belongs to the Monitoring and Control Systems assets grouping.

32.3 Useful Life and Typical Life

This asset has two major components, each of which has a different useful life. From a maintenance practice perspective, classic SCADA can be componentized into the following:

- IED
- Battery

32.3.1 *IED*

The useful life of the IED in IED based SCADA is in the range of 10 to 15 years; the typical life is 15 years.

32.3.2 *Battery*

The useful life of the battery in IED based SCADA is in the range of 5 to 20 years; the typical life is 10 years.

32.4 Time Based Maintenance Intervals

IED based SCADA is not subject to planned maintenance.

32.5 Impact of Utilization Factors

This asset is impacted by Operating Practices. It is specifically the battery component that is affected by operating practices. If this device is running within an electrically stable system there will be less stress imposed on it.

33 Fault Indicators

Fault indicators are used for loaded underground distribution circuits where secondary voltage is available - pad mounted transformers, switchgear and underground vault applications. A sensor monitors the line current. When the trip rating is exceeded, the indicator trips to the fault position. To reset the display the fault indicator uses a secondary voltage source, such as the low-voltage terminals of distribution transformers.

33.1 Degradation Mechanism

Fault indicators have durable Lexan housings, and utilize coated nickel iron sensor laminations encapsulated in a polyurethane potting compound for environmental protection. Overhead fault indicators use batteries, hence their useful life is based primarily on the end of life of the battery itself. The useful life of overhead fault indicators is significantly less than underground fault indicators due to this battery component.

33.2 System Hierarchy

Fault Indicators asset category belongs to the Monitoring and Control Systems assets grouping.

33.3 Useful Life and Typical Life

The overall useful life range of the fault indicator itself is dependent on the type:

- Overhead
- Underground

33.3.1 *Overhead*

The useful life of the overhead fault indicator is based on the useful life of its battery which is in the range of 5 to 20years; the typical life is 10 years.

33.3.2 *Underground*

The useful life of the underground fault indicator is in the range of 10 to 30 years; the typical life is 20 years.

33.4 Time Based Maintenance Intervals

Fault Indicators are not subject to planned maintenance.

33.5 Impact of Utilization Factors

This asset is impacted by Environmental Conditions.

34 Metering

The metering is how electricity providers measure billable services by measuring various aspects of power usage. When used in electricity retailing, the utilities record the values measured by these meters to generate an invoice for the electricity. This report focuses on those meters used for residential meters, industrial/commercial meters and wholesale meters. This asset consists of three components: the meter itself, the current transformer (CT) and the potential transformer (PT).

34.1 Degradation Mechanism

The major degradation mechanism of traditional meters is listed as follows:

- Electronic component aging due to long-term power quality impact, for solid-state meters
- Meter creep due to high temperature for induction type meters. This occurs when the meter disc rotates continuously with potential applied and the load terminals open circuited
- Magnetization alteration due to overload or short-circuited conditions
- Mechanical damage due to vibration of meter mounting
- Other adverse operating environment that might expedite the aging of components, such as humidity or dirt

34.2 System Hierarchy

Metering asset category belongs to the Monitoring and Control Systems assets grouping.

34.3 Useful Life and Typical Life

There are two components of the meter which have their own useful and typical life:

- Meter (Residential, Industrial/Commercial, Wholesale)
- Transformer (Current, Potential)

34.3.1 *Meter*

The useful life range of <u>residential</u> type meter is 20 to 45 years; typical life is 30 years.

The useful life range of <u>industrial/commercial</u> type meter is 20 to 60 years; typical life is 30 years.

The useful life range of <u>wholesale</u> type meter is 20 to 60 years; typical life is 30 years.

34.3.2 *Transformer (Current, Potential)*

The useful life range of the CT component is 30 to 50 years; typical life is 45 years.

The useful life range of the PT component is 30 to 50 years; typical life is 45 years.

34.4 Time Based Maintenance Intervals

Meters are not subject to planned maintenance

34.5 Impact of Utilization Factors

This asset is impacted by Environmental Conditions.

35 Smart Metering

A smart meter is an advanced meter is an electrical meter that identifies consumption in more detail than a conventional meter; and communicates that information via some network back to the local utility for monitoring and billing purposes.

35.1 Degradation Mechanism

The major degradation mechanism of smart metering system is listed as follows:

- Wiring insulation deterioration due to corrosion, moisture or overheating
- Poor electrical connections due to corrosion, vibration or other physical problems
- Cabinetry or rack damage or wear
- Faulty electronic components

The rate and severity of degradation in the equipment depend on its operational duties and environmental factors. Corrosion and moisture ingress, or combinations of these, represent the most critical degradation processes in microwave equipment of smart metering system.

Environmental conditions in relay and switch-rooms can affect microwave equipment's condition and reliability. Humidity, temperature, dust and pollution can cause component degradation. When plant temperatures fall below the dew point condensation can occur. When water enters equipment rooms through roof or other leaks, it can affect performance and aggravate corrosion.

Typically, terminations and connectors experience mechanical degradation. In damp locations it is common for verdigris, which is the green coating or patina formed when copper, brass or bronze is weathered and exposed to air or seawater over a period of time, to form. Typical problems for these components include:

- Failed crimped terminations due to movement
- Cracked terminal blocks
- Stripped threads
- Mechanical damage from over tightening

Typical degradation processes for the cabinets or racks include:

- Corrosion
- Loss of mechanical strength through use (e.g. swing front panels)

Microwave electronics in smart metering system range from capacitors and resistors to solid-state printed circuit boards. All electronic components have finite lifetimes. Modern highly integrated electronic equipment consists of application specific integrated circuits, surface mounted components, and multi-layer boards.

35.2 System Hierarchy

Smart Metering asset category belongs to the Monitoring and Control Systems assets grouping.

35.3 Useful Life and Typical Life

There are several components of the smart meter which have their own useful and typical life:

- Smart Meter
- Repeater
- Data Concentrator
- Powerline Repeaters

35.3.1 *Smart Meter*

The useful life range of the smart meter is 15 to 20 years; typical life is 15 years.

35.3.2 *Repeater*

The useful life range of the repeater is 5 to 15 years; typical life is 10 years.

35.3.3 *Data Concentrator*

The useful life range of the data concentrator is 10 to 20 years; typical life is 20 years.

35.3.4 *Powerline Repeaters*

The useful life range of the powerline repeater is 5 to 15 years; typical life is 10 years.

35.4 Time Based Maintenance Intervals

Smart Meters are not subject to planned maintenance

35.5 Impact of Utilization Factors

This asset is impacted by Environmental Conditions.

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DEPRECIATION EXPENSE ASSOCIATED WITH RETIREMENT OBLIGATION

Burlington Hydro does not have any depreciation expense associated with any asset retirement obligations.

DEPRECIATION POLICY

The Need

An item of property, plant and equipment other than land that normally has an unlimited life, has a limited life. Its useful life is normally the shortest of its physical, technological, commercial and legal life. Amortization is the charge to income that recognizes that life is finite and that the cost less salvage value or residual value of an item of property, plant and equipment is allocated to the periods of service provided by the asset. Amortization may also be termed depreciation or depletion. Policies are required to ensure that amortization is applied rationally and consistently.

Considerations

Factors to be considered in estimating the life and useful life of an item of fixed assets include expected future usage, effects of technological or commercial obsolescence, expected wear and tear from use or the passage of time, the maintenance program, results of studies made regarding the industry, studies of similar items retired, and the condition of existing comparable items. Different methods of amortizing an item of property, plant and equipment result in different patterns of charges to income. The objective is to provide a rational and systematic basis for allocating the amortizable amount of a item of property, plant and equipment over its estimated life and useful life.

POLICY

1.01 Burlington Hydro Inc. will use the straight-line method of amortization for fixed assets.

2 PURPOSE

2.01 This Statement of Policy and Procedure establishes principles and accountabilities for the amortization of fixed assets.

3 SCOPE

3.01 This Statement of Policy and Procedure applies to the Accounting Department.

4 RESPONSIBILITY

4.01 The Accounting Department is responsible for:

- calculating and applying amortization on readily identifiable assets monthly
- calculating and applying amortization on grouped assets annually
- maintaining all fixed asset amortization and Capital Cost Allowance records

5 DEFINITIONS

5.01 “Fixed Asset Group” means a group of assets that share the same characteristics, especially estimated economic life, and may be grouped together in one asset account.

5.02 “Capitalize” means the act of classifying the acquisition value of a major piece of equipment, building or other item of physical plant as an asset in order that its cost may be spread over more than one fiscal period.

5.03 “Amortization” means the spreading of the acquisition cost of fixed assets over their useful economic lives. It is also referred to as depreciation.

5.04 “Straight-Line Method of Depreciation” means the periodic depreciation charge is computed by dividing the service cost by the estimated number of periods of service life.

5.05 “Service Life” means the period over which the operating function of an asset provides benefit to the utility.

6 REFERENCES AND RELATED STATEMENTS OF POLICY AND PROCEDURE

None.

7 PROCEDURES

7.01 Amortization Methods

a) The company will apply a straight-line method of amortization to each group of fixed assets.

b) Land assets must not be amortized.

c) Grouped assets not completed by the end of the year must not be amortized.

d) The Accounting and /or Engineering Department must determine the most appropriate economic life of the asset group.

e) In the year of the acquisition readily identifiable assets shall be amortized at 50% of the annual rate.

f) Amortization for Fixed Asset Groups, (ie) meters, transformers will be based on the net additions for the year and applied on a straight-line method.

g) An estimate of amortization for Fixed Asset Groups will be recorded monthly based on the Capital Expenditure Budget and reconciled at year end.

h) (h Amortization shall be recorded monthly.

i) Periodically, the Accounting Department shall initiate a study to confirm its estimates of most appropriate economic life based on actual experience.

7.02 Amortization Records

a) At the time of calculation, the Accounting Department shall retain a record

b) of the assets on hand to support the amortization calculations.

c) A long-term record of all entries to the Accumulated Amortization Account for each asset group shall be kept.

8 ATTACHMENTS

Appendix A - Amortization Rates

GENERAL LEDEGER ACCOUNTS FOR IFRS COMPONENTS			
OLD ACCOUNT	NEW ACCOUNT	DESCRIPTION	YEARS
540/1980	8701	Scada - RTU	20
540/1980	8702	Scada - Relays	30
540/1980	8703	Scada - Battery	10
1820	8201	Substation - Equipment	40
1820	8202	Substation - Battery Bank and Chargers	20
1830	8301	Overhead Primary - Structures	40
1835	8351	Overhead Primary - Devices	40
1835	8352	Overhead Primary - Conductors	60
1835	8353	Overhead Primary - Switch Motors, Arresters	20
1840	8401	Underground Primary - Conduit	60
1845	8451	Underground Primary - Conductor	40
1845	8452	Underground Primary - Riser Pole Arresters	20
1845	8453	Underground Primary - Devices	30
1850	8501	Transformers	40
1850	8502	Transformers - Arresters	20
1855	8551	Underground Secondary	60
1855	8552	Overhead Secondary	60
1860	8601	Meters - Residential	25
1860	8602	Meters - Industrial and Wholesale	20
1860	8603	Meters - CT and PT	45
1860	8604	Smart Meters, Repeaters, Data Concentrators	15

DEPRECIATION RATES

IFRS, COMPONENT ASSETS					
REVISED SEPTEMBER 21, 2012					
ACCOUNT / WORK ORDER	CAPITAL EXPENDITURE REPORT	Burlington Hydro	KINECTRICS	ACTIVITY INCLUDED	Kinectrics
DESCRIPTION	CLASSIFICATION	LIFE	REPORT		Section No.
Scada - RTU	Scada	20	15 to 30	RTU	31
Scada - Relays	Scada	30	20 to 50	Relays	31
Scada - Transducer	Scada	10	5 to 10	Transducer - ACM Units, ACM Replacements, ACM Recorders	31
Substation - Equipment	Substation - Equipment	40	20 to 40	Station Service Transformers - Dry Type	14
			32 to 55	MS Power Transformers - Winding	16
			20 to 60	MS Power Transformers - Manual/Automatic on Load Tap changer	16
			25 to 60	Air Insulated Switchgear - Air Magnetic Breaker	18
			40 to 60	Switchgear Assembly	18

ACCOUNT / WORK ORDER	CAPITAL EXPENDITURE REPORT	Burlington Hydro	KINECTRICS	ACTIVITY INCLUDED	Kinectrics
			25 to 50	Substation Grounding System	21
Substation - Battery Bank and Chargers	Substation - Equipment	20	10 to 30	DC Service Station - Battery Bank	17
			20 to 30	DC Service Station - Charger	17
Substation - Metalclad Equipment Refurbish	Substation - Equipment	40	40 to 60	Switchgear Assembly	18
Substation - Vacuum Breaker Conversions	Substation - Equipment	40	30 to 60	Air Insulated Switchgear - Vacuum Breaker	18
Overhead Primary - Structures	General Services - Overhead Primary	40	40 to 50	Pole	2
			20 to 50	Cross Arms - Wood	2
			40 to 80	Cross Arms - Composite	2
			20 to 100	Cross Arms - Steel	2
			20 to 50	Bracket (Galvanixed Steel)	2
			20 to 50	Anchors and Guying	2
Overhead Primary - Devices	General Services - Overhead Primary	40	10 to 45	Insulators - Composite	2

1

ACCOUNT / WORK ORDER	CAPITAL EXPENDITURE REPORT	Burlington Hydro	KINECTRICS	ACTIVITY INCLUDED	Kinectrics
			40 to 50	Insulators - Porcelain	2
			30 to 60	Manual Overhead line switches	8
			30 to 60	Local Motorized Overhead Switches	9
			30 to 60	Remote Automated Overhead switches	10
			30 to 60	Fuse Cutouts	11
Overhead Primary - Conductors	General Services - Overhead Primary	60	50 to 77	Conductor - ACSR	6
			50 to 77	Conductor - AAC	6
			50 to 77	Conductor - Copper	6
			50 to 77	Conductor - Insulated Wire	6
Overhead Primary - Switch Controllers, Arresters	General Services - Overhead Primary	20	15 to 20	Overhead Switches - Motor Controllers	9
Underground Primary - Riser Pole Arresters	General Services - Underground Primary		15 to 20	Remote Switch - Motor Controllers	10
Transformers - Arresters	Transformers		15 to 30	Remote switch - RTU	10
				Overhead Wires - Arresters	6

2

3

1

ACCOUNT / WORK ORDER	CAPITAL EXPENDITURE REPORT	Burlington Hydro	KINETRICS	ACTIVITY INCLUDED	Kinetrics
			20 to 40	Underground - Riser Pole Arresters	22
			30 to 60	Pole Mounted Transformer - Arresters	7
Underground Primary - Conduit	General Services - Underground Primary	60	50 to 80	Utility Chamber	27
			30 to 80	Duct Bank	28
			30 to 75	Direct Buried Pipe (PVC)	28
			50 to 100	HDPE	28
			30 to 80	Transformer and Switchgear Foundations	29
Underground Primary - Conductor	General Services - Underground Primary	40	40 to 60	TR-XLPE	22
			25 to 60	Elbows / Terminations	
Underground Primary - Devices	General Services - Undeground Primary	30	20 to 40	Air Insulated - Switchgears	25
			30 to 50	Gas Insulated - Switchgears	25
			20 to 40	Metal Enclosed Switch	26
			30 to 60	Metal Enclosed Cutout	26

			25 to 50	Junction Cable	30
ACCOUNT / WORK ORDER	CAPITAL EXPENDITURE REPORT	Burlington Hydro	KINECTRICS	ACTIVITY INCLUDED	Kinectrics
Transformers	Transformers	40	30 to 60	Transformer - Pole Mounted	7
			30 to 40	Transformer - Pad Mounted	24
			30 to 40	Transformer - Vault	24
			25 to 40	Transformer - Submersible	24
			20 to 60	Inserts, bushings	24
Underground Secondary - Cables	General Services - Underground Secondary	60	40 to 60	PI (Polyethylene insulated)	23
			40 to 60	PIJ (PVC Jacket)	23
Underground Secondary - Conduit	General Services - Underground Secondary	60	30 to 75	Direct Buried Pipe (PVC)	28
Overhead Secondary - Wire	General Services - Overhead Secondary	60	50 to 77	Conductor - Insulated Wire	6
Overhead Secondary - Structures	General Services - Overhead Secondary	40	20 to 50	Poles, Brackets, Anchors	2
Meters - Residential	Meters	15	20 to 45	Meters - Residential	34
Meters - Industrial/Wholesale	Meters	20	20 to 60	Meters - Industrial	34

ACCOUNT / WORK ORDER	CAPITAL EXPENDITURE REPORT	Burlington Hydro	KINECTRICS	ACTIVITY INCLUDED	Kinectrics
			20 to 60	Meters - Wholesale	34
Meters - Current/Potential Transformers	Meters	45	30 to 50	Current Transformers	34
			30 to 50	Potential Transformers	34
Smart Meters	Meters	15	15 to 20	Smart Meters	35
		15	5 to 15	Repeaters	35
		15	10 to 20	Data Concentrator	35
Smart Meters (Overtime)					

ADOPTION OF HALF YEAR RULE

Burlington Hydro confirms that it has applied the half-year rule for the purposes of computing the net book value of Property, Plant and Equipment and General Plant to include in rate base. Under the half-year rule acquisitions and investments made during the year are amortized assuming they entered service at the mid-point of the year.

Exhibit 4: Operating Costs

Tab 8 (of 8): Income & Capital Taxes

OVERVIEW OF PROVISION IN LIEU OF TAXES (PILS)

Burlington Hydro is required to make payments in lieu of income taxes ("taxes") based on its taxable income. Burlington Hydro files Federal/Provincial tax returns annually. There have been no special circumstances that would require specific tax planning measures to minimize taxes payable. There are no outstanding audits, reassessments or disputes relating the tax returns filed by Burlington Hydro.

There are no non-utility activities included in Burlington Hydro's financial results, therefore the entire amount of PILs payable is considered in the proposed allowance to be included in the revenue requirement.

Burlington Hydro has used the OEB Tax Work Form model to calculate the amount of taxes for inclusion in its 2014 rates. This model is included at Exhibit 4, Tab 8, Schedule 3 Attachment 1. PILs have been calculated under CGAAP with changes to accounting policies. The PILS model has been reviewed by Burlington Hydro's external auditor to ensure that the current and proposed tax rates have been applied, that the amount of PILS calculated appears reasonable and that the integrity checks established in the Boards Minimum Filing Requirements have been adhered to.

The Table on the following page summarizes Burlington Hydro's taxes for the 2014 Test Year. Under the new accounting policies, Burlington Hydro's PILs amount to $137,696

Table 4-15: Tax/PILs excerpt form the RRWF

Particulars	Application
Determination of Taxable Income	
Utility net income before taxes	$4,738,640
Adjustments required to arrive at taxable utility income	($4,083,678)
Taxable income	$654,962
Calculation of Utility income Taxes	
Income taxes	$108,565
Total taxes	$108,565
Gross-up of Income Taxes	$29,131
Grossed-up Income Taxes	$137,696
PILs / tax Allowance (Grossed-up Income taxes + Capital taxes)	$137,696
Other tax Credits	$ -
Tax Rates	
Federal tax (%)	15.00%
Provincial tax (%)	6.16%
Total tax rate (%)	21.16%

The major reasons for the drop in PILs in the test year compared to year 2010 are as follows:

a) The corporate tax rate has fallen from 31% to 26.5%
b) The Capital Tax is no longer application now. There was 70K impact in 2010 due to the capital tax.
c) CCA amount is much larger than the depreciation amount
d) Test year accounting income before depreciation and taxes is projected to be smaller than it was in 2010.

Attachment 1 (of 2):

Latest Filed Tax Return

Canada Revenue Agency / Agence du revenu du Canada

Code 1201

SCIENTIFIC RESEARCH AND EXPERIMENTAL DEVELOPMENT (SR&ED) EXPENDITURES CLAIM

Use this form:
- to provide technical information on your SR&ED projects;
- to calculate your SR&ED expenditures; and
- to calculate your qualified SR&ED expenditures for investment tax credits (ITC).

To claim an ITC, use either:
- Schedule T2SCH31, *Investment Tax Credit – Corporations*, or
- Form T2038(IND), *Investment Tax Credit (Individuals)*.

The information requested in this form and documents supporting your expenditures are prescribed information.

Your SR&ED claim must be filed within 12 months of the filing due date of your income tax return.

To help you fill out this form, use the T4088, *Guide to Form T661*, which is available on our Web site: **www.cra.gc.ca/sred**.

Part 1 – General information

010 Name of claimant: BURLINGTON HYDRO INC.	Enter one of the following:
Tax year From: 2012-01-01 (Year Month Day) To: 2012-12-31 (Year Month Day)	Business Number (BN): 86829 1980 RC0001
050 Total number of projects you are claiming this tax year: 1	Social Insurance Number (SIN):

100 Contact person for the financial information: JOHN MAURO	**105** Telephone number/extension: (905) 332-1851	**110** Fax number: (905) 332-8384
115 Contact person for the technical information: Michael Kysley	**120** Telephone number/extension: (905) 332-1851	**125** Fax number:

151 If this claim is filed for a partnership, was Form T5013 filed? . . . . 1 ☐ Yes 2 ☐ No

If you answered **no** to line 151, complete lines 153, 156 and 157.

153 Name of the partners	**156** %	**157** BN or SIN
1		
2		
3		
4		
5		

Part 2 - Project information

CRA internal form identifier 060
Code 1101

Complete a separate Part 2 for each project claimed this year.

Section A - Project identification

200 Project title (and identification code if applicable)

See schedule

Part 3 – Calculation of SR&ED expenditures

What did you spend on your SR&ED projects?

Section A – Select the method to calculate the SR&ED expenditures

I elect (choose) to use the following method to calculate my SR&ED expenditures and related investment tax credits (ITC) for this tax year.
I understand that my election is irrevocable (cannot be changed) for this tax year.

160 [X] I elect to use the proxy method
(Enter "0" on line 360. Complete Part 5 and you do not need to track any expenditure incurred for overhead)

162 [ ] I choose to use the traditional method
(Enter "0" on line 355. Complete line 360, and track any expenditure incurred for overhead)

Section B – Calculation of allowable SR&ED expenditures (to the nearest dollar)

	Line		Amount
• SR&ED portion of salary or wages of employees directly engaged in the SR&ED:			
a) Employees other than specified employees for work performed in Canada	300	+	140,756
b) Specified employees for work performed in Canada	305	+	
Subtotal (add lines 300 and 305)	306	=	140,756
c) Employees other than specified employees for work performed outside Canada (subject to limitations – see guide)	307	+	
d) Specified employees for work performed outside Canada (subject to limitations – see guide)	309	+	
• Salary or wages identified on line 315 in prior years that were paid in this tax year	310	+	
• Salary or wages incurred in the year but not paid within 180 days of the tax year end	315		
• Cost of materials consumed in performing SR&ED	320	+	
• Cost of materials transformed in performing SR&ED	325	+	
• Contract expenditures for SR&ED performed on your behalf:			
a) Arm's length contracts	340	+	244,471
b) Non-arm's length contracts	345	+	
• Lease costs of equipment used:			
a) All or substantially all (90% of the time or more) for SR&ED	350	+	
b) Primarily (more than 50% of the time but less than 90%) for SR&ED. (Enter 50% of lease costs if you use the proxy method or enter "0" if you use the traditional method)	355	+	
• Overhead and other expenditures (enter "0" if you use the proxy method)	360	+	
• Third-party payments (complete Form T1263*)	370	+	
Total current SR&ED expenditures (add lines 306 to 370; do not add line 315) (Corporations need to adjust line 118 of schedule T2SCH1)	380	=	385,227
• **Capital Expenditures** (see guide for what qualifies for SR&ED) (Do not include these capital expenditures on schedule T2SCH8)	390	+	
Total allowable SR&ED expenditures (add lines 380 and 390)	400	=	385,227

Section C – Calculation of pool of deductible SR&ED expenditures (to the nearest dollar)

	Line		Amount
Amount from line 400	420		385,227
Deduct			
• provincial government assistance for expenditures included on line 400	429	–	17,335
• other government assistance for expenditures included on line 400	431	–	
• non-government assistance for expenditures included on line 400	432	–	
• SR&ED ITCs applied and/or refunded in the prior year (see guide)	435	–	96,320
• sale of SR&ED capital assets and other deductions	440	–	
Subtotal (line 420 minus lines 429 to 440)	442	=	271,572
Add			
• repayments of government and non-government assistance that previously reduced the SR&ED expenditure pool	445	+	
• prior year's pool balance of deductible SR&ED expenditures (from line 470 of prior year T661)	450	+	
• SR&ED expenditure pool transfer from amalgamation or wind-up	452	+	
• amount of SR&ED ITC recaptured in the prior year	453	+	
Amount available for deduction (add lines 442 to 453) (enter positive amount only, include negative amount in income)	455	=	271,572
• Deduction claimed in the year (Corporations should enter this amount on line 411 of schedule T2SCH1)	460	–	271,572
Pool balance of deductible SR&ED expenditures to be carried forward to future years (line 455 minus 460)	470	=	

* Form T1263, *Third-Party Payments for Scientific Research and Experimental Development (SR&ED)*

Part 4 – Calculation of qualified SR&ED expenditures for investment tax credit (ITC) purposes

The resulting amount is used to calculate your refundable and/or non refundable ITC.

Enter the breakdown between current and capital expenditures (to the nearest dollar)

	Line	Current Expenditures	Line	Capital Expenditures
Total expenditures for SR&ED (from line 380 and 390)	492	385,227	496	
Add				
• payment of prior years' unpaid amounts (other than salary or wages)	500 +			
• prescribed proxy amount (complete Part 5) (Enter "0" if you use the traditional method)	502 +	89,053		
• expenditures on shared-use equipment (see guide)			504 +	
• qualified expenditures transferred to you (complete Form T1146**)	508 +		510 +	
Subtotal (add lines 492 to 508, and add lines 496 to 510)	511 =	474,280	512 =	
Deduct				
• provincial government assistance	513 –	21,343	514 –	
• other government assistance	515 –		516 –	
• non-government assistance and contract payments	517 –		518 –	
• current expenditures (other than salary or wages) not paid within 180 days of the tax year end	520 –			
• amounts paid in respect of an SR&ED contract to a person or partnership that is not taxable supplier	528 –			
• 20% of expenditures included on lines 340 and 370 that were incurred after December 31, 2012	529 –			
• prescribed expenditures not allowed by regulations (see guide)	530 –		532 –	
• other deductions (see guide)	533 –		535 –	
• non-arm's length transactions				
– assistance allocated to you (complete Form T1145*)	538 –		540 –	
– expenditures for non-arm's length SR&ED contracts (from line 345)	541 –			
– adjustments to purchases (limited to costs) of goods and services from non-arm's length suppliers (see guide)	542 –		543 –	
– qualified expenditures you transferred (complete Form T1146**)	544 –		546 –	
Subtotal (line 511 minus lines 513 to 544 and line 512 minus lines 514 to 546)	557 =	452,937	558 =	
Qualified SR&ED expenditures (add lines 557 and 558)			559 =	452,937
Add				
• repayments of assistance and contract payments made in the year			560 +	
Total qualified SR&ED expenditures for ITC purposes (add lines 559 and 560)			570 =	452,937

* Form T1145, *Agreement to Allocate Assistance for SR&ED Between Persons Not Dealing at Arm's Length*

** Form T1146, *Agreement to Transfer Qualified Expenditures Incurred in Respect of SR&ED Contracts Between Persons Not Dealing at Arm's Length*

Part 5 – Calculation of prescribed proxy amount (PPA)

A notional amount representing your overhead and other expenditures.

This part calculates the PPA to enter on line 502 in Part 4. Do not complete this part if you have chosen to use the traditional method in Part 3 (line 162).
You can only claim a PPA if you elected to use the proxy method for the year in Part 3 (line 160).

Special rules apply for specified employees. Calculate your salary base in Section A and the PPA in section B.

Section A – Salary base

Salary or wages of employees other than specified employees (from line 300 and 307)	**810**	+	140,756
Deduct			
Bonuses, remuneration based on profits, and taxable benefits that were included on line 810	**812**	–	3,752
Subtotal (line 810 minus 812)	**814**	=	137,004

Salary or wages of specified employees

850	852	854	856	858	860
Column 1	**Column 2**	**Column 3**	**Column 4**	**Column 5**	**Column 6**
Name of specified employee	Total salary or wages for the year (SR&ED and non-SR&ED) excluding bonuses, remuneration based on profits, and taxable benefits (to the nearest dollar)	% of time spent on SR&ED (maximum 75%)	Amount in column 2 multiplied by percentage in column 3	2,5 x A x B/365 A = Year's maximum pensionable earnings B = Number of days employed in tax year	Amount in column 4 or 5, whichever amount is less

(Enter total of column 6 on line 816)	**816**	+	
Salary base (total of lines 814 and 816)	**818**	=	137,004

Section B – Prescribed proxy amount (PPA)

Enter 65% of the salary base (line 818) less 5% of the salary base for the number of 2013 calendar days in the tax year (use formula in the guide – line 820)	**820**	=	89,053

Enter the amount from line 820 on line 502 in Part 4 unless the overall cap on PPA applies to you.

(See the guide for explanation and example of the overall cap on PPA)

Part 6 – Project costs

Information requested in this part must be provided for **all** SR&ED projects claimed in the year.
Expenditures should be recorded and allocated on a project basis.

750	752	754	756
Project title or identification code	Salary or wages in the tax year (Total of lines 306 to 309)	Cost of materials in the tax year (Total of lines 320 and 325)	Contract expenditures for SR&ED performed on your behalf in the tax year (Total of lines 340 and 345)
1. BHI2012-04-01 Real-time scalable communication framewo	140,756		244,471
Total	140,756		244,471

Part 7 – Additional information

Expenditures for SR&ED performed by you in Canada (line 400 minus lines 307, 309, 340, 345, and 370) **605** 140,756

From the total you entered on line 605, estimate the percentage of distribution of the sources of funds for SR&ED performed within your organization.

		Canadian (%)		Foreign (%)
Internal	600	100.000		
Parent companies, subsidiaries, and affiliated companies	602		604	
Federal grants (do not include funds or tax credits from SR&ED tax incentives)	606			
Federal contracts	608			
Provincial funding	610			
SR&ED contract work performed for other companies on their behalf	612		614	
Other funding (e.g., universities, foreign governments)	616		618	

Enter the number of SR&ED personnel in full-time equivalents (FTE):

Scientists and engineers	632	1
Technologists and technicians	634	1
Managers and administrators	636	1
Other technical supporting staff	638	1

Part 8 – Claim checklist

To ensure your claim is complete, make sure you have:

1. used the current version of this form . . . X
2. entered the method you have chosen for reporting your SR&ED expenditures in Section A of Part 3 . . . X
3. completed Part 2 for each project . . . X
4. filed a completed Schedule T2SCH31 or Form T2038(IND) to claim ITCs on your qualified SR&ED expenditures . . . X
5. filed a completed Form T1145*, T1146**, T1174*** and/or T1263**** including any required attachments, if applicable . . . X

To expedite the processing of your claim, make sure you have:

1. completed Form T2, *Corporation Income Tax Return* or Form T1, *Income Tax and Benefit Return* . . . X
2. filed the appropriate provincial and/or territorial tax credit forms, if applicable . . . X
3. retained documents to support the SR&ED expenditures you claimed . . . X
4. checked boxes 231 and 232 on page 2 of your T2 return to indicate attachment of Form T661 and Schedule T2SCH31 . . . X

* Form T1145, *Agreement to Allocate Assistance for SR&ED Between Persons Not Dealing at Arm's Length*

** Form T1146, *Agreement to Transfer Qualified Expenditures Incurred in Respect of SR&ED Contracts Between Persons Not Dealing at Arm's Length*

*** Form T1174, *Agreement Between Associated Corporations to Allocate Salary or Wages of Specified Employees for Scientific Research and Experimental Development (SR&ED)*

**** Form T1263, *Third-Party Payments for Scientific Research and Experimental Development (SR&ED)*

PREPARED SOLELY FOR INCOME TAX PURPOSES WITHOUT AUDIT OR REVIEW FROM INFORMATION PROVIDED BY THE TAXPAYER.

Part 9 – Certification

I certify that I have examined the information provided on this form and on the attachments and it is true, correct, and complete.

165 MICHAEL KYSLEY
Name of authorized signing officer of the corporation, or individual

Signature

170
Date

175 KPMG LLP
Name of person/firm who completed this form

Part 2 - Project information (continued)

Project number **1**

CRA internal form identifier 060
Code 1201

Complete a separate Part 2 for each project claimed this year.

Section A – Project identification

200 Project title (and identification code if applicable)

BHI2012-04-01 Real-time scalable communication framework

202 Project start date	**204** Completion or expected completion date	**206** Field of science or technology code (See guide for list of codes)
2011-12 (Year Month)	2014-08 (Year Month)	2.02.01 Electrical and electronic engineering

Project claim history

208 1 [ ] Continuation of a previously claimed project   **210** 1 [X] First claim for the project

218 Was any of the work done jointly or in collaboration with other businesses? . . . . 1 [ ] Yes   2 [X] No

If you answered **yes** to line 218, complete lines 220 and 221.

220 Names of the businesses	**221** BN
1	
2	
3	

The work was carried out (Check any that apply)

223 1 [ ] In a laboratory   **226** 1 [X] In a commercial plant or facility

224 1 [ ] In a dedicated research facility   **228** 1 [ ] Others, specify **229**

Purpose of the work

230 1 [X] To achieve technological advancement for the purpose of creating new or improving existing materials, devices, products or processes. (**Go to Section B** – Experimental development)

232 1 [ ] For the advancement of scientific knowledge (**Go to Section C** – Basic or applied research)

Section B – Experimental development

The technological advancements you were trying to achieve with this work were required for:

	Materials, devices, or products	Processes
The creation of new	**235** 1 [X]	**236** 1 [ ]
The improvement of existing	**237** 1 [X]	**238** 1 [ ]

240 What **technological** advancements were you trying to achieve? (*Maximum 50 lines*)

Burlington Hydro Inc. (Burlington Hydro or the Company) is a company specialized in delivering safe, efficient and reliable electricity to approximately 65,000 residential and commercial customers.

In FY2012, Burlington Hydro sought to develop a flexible framework to integrate various dissimilar systems and improve traceability of load and power distribution characteristics. However, the Company's existing GIS (Geographic Information System) and SCADA (Supervisory Control And Data Acquisition) system were not capable of managing real-time data due to their inherent limitations. In addition, it was challenging to achieve high data integrity, security, and interoperability with hardware/software component that were not designed to work together.

This project represents a technological advancement in the fields of Electrical Engineering and Telecommunications. If this project is successful, Burlington Hydro would have:

- developed a real-time communication framework that provides seamless

240 What **technological** advancements were you trying to achieve? (*Maximum 50 lines*)

integration of various dissimilar systems and reliable signal/fault traceability while ensuring 100% communication accuracy. The framework would enable seamless coordination of mixed entities such as legacy/newer SCADA and PIN Mapping systems to exchange real-time information without the need to redesign their respective interfaces.

- developed dynamic techniques to detect and predict grid anomalies (i.e., power outages) based on trending load patterns, etc. while ensuring real-time rectification response to avoid catastrophic failures.

242 What **technological** obstacles/uncertainties did you have to overcome to achieve the technological advancements described in Line 240? (*Maximum 50 lines*)

In order to achieve these advancements, Burlington Hydro had to resolve the following technological obstacles in FY2012:

- Burlington Hydro sought to develop a real-time communication framework to seamlessly integrate various dissimilar systems and provide reliable signal/fault traceability. The challenge was that the underlying legacy sub-systems had different communication protocols that needed to be dynamically coordinated in real-time. However, there is no existing solution to provide real-time event and signal tracing across entities such as GIS and SCADA sub-systems. With respect to field-devices (e.g., smart switches), the Company hypothesized that a new IP-based radio network could improve the communication performance between the field-devices and the SCADA system. However, there was significant uncertainty as to whether or not the SCADA system could provide real-time MIMO (Multiple input multiple output) for new and legacy radio systems concurrently, while guaranteeing zero-downtime. In addition, Burlington Hydro experienced compatibility challenges between the new radio network and legacy SCADA sub-systems with proprietary interfaces.

- Burlington Hydro sought to develop real-time techniques to detect and predict grid anomalies (i.e., power outages). It was hypothesized that the control data from end devices and sub-systems could be leveraged to accurately locate outage penetrations. However, the Company was uncertain about how to develop reliable communication techniques to collect and interpret data from various systems without negatively impacting real-time control and monitoring performance. In addition, Burlington Hydro was uncertain about whether the new outage management techniques would be compatible with the large number of legacy nodes and devices (such as transformers) while ensuring system stability and reliability.

244 What work did you perform **in the tax year** to overcome the technological obstacles/uncertainties described in Line 242? (Summarize the systematic investigation) (*Maximum 100 lines*)

Throughout FY2012, Burlington Hydro sought to develop a real-time communication framework to seamlessly integrate various disparate sub-systems such as the GIS, AMI (Advanced Metering Infrastructure), SCADA, etc., in order to reliably manage the grid distribution network. To achieve this, the Company developed an architecture that consisted of a middleware to mediate and coordinate control/signal and data (i.e., information) packets between sub-systems. On the backend, the payload was then marshaled to analytic engines that were responsible for computing and updating real-time geo-referenced data related to field devices. However, test results revealed unacceptable response jitter that undermined real-time deterministic performance. To overcome this challenge, the Company developed a protocol to coordinate data handling (i.e., transmissions, transformation, validation, etc.) based on event priorities, periodicity and throughput-rates, while ensuring 100% communication accuracy. The techniques also enabled effective integration between monitoring and control systems, and field devices for real-time load management and distribution planning.

244 What work did you perform **in the tax year** to overcome the technological obstacles/uncertainties described in Line 242? (Summarize the systematic investigation) (*Maximum 100 lines*)

From June to December 2012, Burlington Hydro sought to extend the protocols to support legacy analogue-based radio sub-systems. In this regard, an IP-based communication network was integrated to interface remote field devices with the SCADA system through IP-based radios. To improve the system scalability, the Company performed extensive investigations to characterize wireless signals (i.e., signal to noise ratios) under various conditions (line of sight propagation, network connectivity, etc.). Data gathered from the investigation were subsequently used to design the network topology (i.e., location of repeaters, etc.). Moreover, Burlington Hydro developed generic techniques between the new/legacy switches and the SCADA system to provide concurrent data exchange. However, test result revealed compatibility issues between new and legacy systems that resulted in high rates of packet/signal drops. To overcome this challenge, the Company developed real-time telemetry components to automatically monitor SCADA-enabled switches and detect alarms remotely while ensuring zero system downtime. By the end of the FY, these techniques allowed Burlington Hydro to support reliable concurrent communication for new and legacy radio systems while achieving above 95% data accuracy and zero-downtime. In the upcoming FY, the Company will continue to develop techniques to improve system response performance.

In FY2012, Burlington Hydro sought to develop techniques to detect and predict power outages in real-time. In the first attempt, the Company developed real-time messaging techniques to monitor events such as voltage fluctuations in over 65,000 smart meters. The data/events were then piped through a shared bus that ran across the AMI, SCADA and GIS sub-systems. Subsequently, algorithms were developed to process and analyze the field data for outage detection. In addition, Burlington Hydro integrated the GIS framework with a load analysis model to identify the geographic location of outages. However, the Company observed high occurrences of incomplete data and false negatives which impacted the reliability and accuracy of the outage detection techniques. To address this challenge, Burlington Hydro developed real-time tracing techniques to monitor the status of sub-systems and transfer the updated information to the backend systems. In addition, a distribution system logical connectivity model was developed and the field data was then weighted statistically for potential outages based on various characteristics such as distribution topology, the status of transformers, etc. However, test result revealed unexpected system failure involving over 3,000 end-devices such as smart meters. Further analysis revealed that this was caused by the transformer overloads. As a result, Burlington Hydro developed a self-adaptive component to dynamically add/remove transformers in specific locations to handle the unexpected power load. These techniques allowed the Company to provide reliable outage management, while guaranteeing up to 200% peak-time capacity. In the upcoming FY, Burlington Hydro will continue to improve the reliability of the outage management system.

Section C – Basic or applied research

250 What advancements in scientific knowledge were you trying to achieve? (*Maximum 50 lines*)

252 What work did you perform **in the tax year**, how did that work contribute to the advancements described in Line 250? (Summarize the systematic investigation) (*Maximum 100 lines*)

252 What work did you perform **in the tax year**, how did that work contribute to the advancements described in Line 250? (Summarize the systematic investigation) (*Maximum 100 lines*)	
3.	
4.	

Section D – Additional project information

Who prepared the responses for Section B or Section C?

253 1 [X] Employee directly involved in the project	**254** Name Saunders, Joe	
255 1 [ ] Other employee of the company	**256** Name	
257 1 [X] External consultant	**258** Name KPMG LLP	**259** Firm KPMG LLP

List the key individuals directly involved in the project and indicate their qualifications/experience.

	260 Names	**261** Qualifications/experience and position title
1	Saunders, Joe	Director of Regulatory Compliance and Asset Management, 30 years of experience in Utility Operations
2	Lowry, Dan	Director, Information Technology, College degree in Computer Science, 35 years of experience in IT and software development
3	Young, Jeffrey	Protection & Control and Station Maintenance Supervisor, 27 years of experience inProtection and Control software maintenance and design.

265 Are you claiming any salary or wages for SR&ED performed outside Canada? . . . . 1 [ ] Yes 2 [X] No

266 Are you claiming expenditures for SR&ED carried out on behalf of another party? . . . . 1 [ ] Yes 2 [X] No

267 Are you claiming expenditures for SR&ED performed by people other than your employees? . . . . 1 [X] Yes 2 [ ] No

If you answered **yes** to line 267, complete lines 268 and 269.

	268 Names of individuals or companies	**269** BN
1	AGSI	88787 3784 RC0001

What evidence do you have to support your claim? (Check any that apply)
You do not need to submit these items with the claim. However, you are required to retain them in the event of a review.

270 1 [ ] Project planning documents

271 1 [ ] Records of resources allocated to the project, time sheets

272 1 [ ] Design of experiments

273 1 [X] Project records, laboratory notebooks

274 1 [X] Design, system architecture and source code

275 1 [ ] Records of trial runs

276 1 [ ] Progress reports, minutes of project meetings

277 1 [X] Test protocols, test data, analysis of test results, conclusions

278 1 [ ] Photographs and videos

279 1 [ ] Samples, prototypes, scrap or other artefacts

280 1 [X] Contracts

281 1 [ ] Others, specify **282** ______

Federal Tax Instalments

Federal tax instalments

For the taxation year ended 2013-12-31

Business number 86829 1980 RC0001

The following is a list of federal instalments payable for the current taxation year. The last column indicates the instalments payable to Revenue Canada. The instalments are due no later than on the dates indicated, otherwise non-deductible interest will be charged. A cheque or money order should be made payable to the Receiver General. Payment may be made by cheque or money order payable to the Receiver General either to an authorized financial institution or filed with **the appropriate remittance voucher to the following address**:

Canada Revenue Agency
875 Heron Road
Ottawa ON K1A 1B1

Note that you may also be able to pay by telephone or Internet banking. For more information, consult the *Corporation Instalment Guide*.

Monthly instalment workchart

Date	Monthly tax instalments	Refund transferred to instalments	Instalments paid	Cumulative difference	Instalments payable
2013-01-31	92,541				92,541
2013-02-28	92,541				92,541
2013-03-31	92,541				92,541
2013-04-30	92,541				92,541
2013-05-31	92,541				92,541
2013-06-30	92,541				92,541
2013-07-31	92,541				92,541
2013-08-31	92,541				92,541
2013-09-30	92,541				92,541
2013-10-31	92,541				92,541
2013-11-30	92,541				92,541
2013-12-31	92,535				92,535
Totals	1,110,486				1,110,486

Canada Revenue Agency / Agence du revenu du Canada

T2 Corporation Income Tax Return

200

055 Do not use this area

This form serves as a federal, provincial, and territorial corporation income tax return, unless the corporation is located in Quebec or Alberta. If the corporation is located in one of these provinces, you have to file a separate provincial corporation return.

All legislative references on this return are to the federal *Income Tax Act*. This return may contain changes that had not yet become law at the time of publication.

Send one completed copy of this return, including schedules and the *General Index of Financial Information* (GIFI), to your tax centre or tax services office. You have to file the return within six months after the end of the corporation's tax year.

For more information see **www.cra.gc.ca** or Guide T4012, *T2 Corporation – Income Tax Guide*.

Identification

Business number (BN) **001** 86829 1980 RC0001

Corporation's name

002 BURLINGTON HYDRO INC.

Address of head office

Has this address changed since the last time we were notified? . . . . **010** 1 Yes [ ] 2 No [X]

(If **yes**, complete lines 011 to 018.)

011 1340 BRANT STREET

012

City **015** BURLINGTON — Province, territory, or state **016** ON

Country (other than Canada) **017** — Postal code/Zip code **018** L7R 3Z7

Mailing address (if different from head office address)

Has this address changed since the last time we were notified? . . . . **020** 1 Yes [ ] 2 No [X]

(If **yes**, complete lines 021 to 028.)

021 c/o

022

023

City **025** — Province, territory, or state **026**

Country (other than Canada) **027** — Postal code/Zip code **028**

Location of books and records

Has the location of books and records changed since the last time we were notified? . . . . **030** 1 Yes [ ] 2 No [X]

(If **yes**, complete lines 031 to 038.)

031 1340 BRANT STREET

032

City **035** BURLINGTON — Province, territory, or state **036** ON

Country (other than Canada) **037** — Postal code/Zip code **038** L7R 3Z7

040 **Type of corporation at the end of the tax year**

1 [X] Canadian-controlled private corporation (CCPC)

2 [ ] Other private corporation

3 [ ] Public corporation

4 [ ] Corporation controlled by a public corporation

5 [ ] Other corporation (specify, below)

If the type of corporation changed during the tax year, provide the effective date of the change . . . . **043** ______ YYYY MM DD

To which tax year does this return apply?

Tax year start **060** 2012-01-01 (YYYY MM DD) — Tax year-end **061** 2012-12-31 (YYYY MM DD)

Has there been an acquisition of control to which subsection 249(4) applies since the previous tax year? . . . . **063** 1 Yes [ ] 2 No [X]

If **yes**, provide the date control was acquired . . . . **065** ______ YYYY MM DD

Is the date on line 061 a deemed tax year-end according to:

subparagraph 88(2)(a)(iv)? . . . . **064** 1 Yes [ ] 2 No [X]

subsection 249(3.1)? . . . . **066** 1 Yes [ ] 2 No [X]

Is the corporation a professional corporation that is a member of a partnership? . . . . **067** 1 Yes [ ] 2 No [X]

Is this the first year of filing after:

Incorporation? . . . . **070** 1 Yes [ ] 2 No [X]

Amalgamation? . . . . **071** 1 Yes [ ] 2 No [X]

If **yes**, complete lines 030 to 038 and attach Schedule 24.

Has there been a wind-up of a subsidiary under section 88 during the current tax year? . . . . **072** 1 Yes [ ] 2 No [X]

If **yes**, complete and attach Schedule 24.

Is this the final tax year before amalgamation? . . . . **076** 1 Yes [ ] 2 No [X]

Is this the final return up to dissolution? . . . . **078** 1 Yes [ ] 2 No [X]

If an election was made under section 261, state the functional currency used . . . . **079** ______

Is the corporation a resident of Canada?

080 1 Yes [X] 2 No [ ] If **no**, give the country of residence on line 081 and complete and attach Schedule 97.

081 ______

Is the non-resident corporation claiming an exemption under an income tax treaty? . . . . **082** 1 Yes [ ] 2 No [X]

If **yes**, complete and attach Schedule 91.

If the corporation is exempt from tax under section 149, tick one of the following boxes:

085

1 [ ] Exempt under paragraph 149(1)(e) or (l)

2 [ ] Exempt under paragraph 149(1)(j)

3 [ ] Exempt under paragraph 149(1)(t)

4 [ ] Exempt under other paragraphs of section 149

Do not use this area

095 — **096**

Attachments

Financial statement information: Use GIFI schedules 100, 125, and 141.
Schedules – Answer the following questions. For each **yes** response, **attach** the schedule to the T2 return, unless otherwise instructed.

		Yes	Schedule
Is the corporation related to any other corporations?	150	X	9
Is the corporation an associated CCPC?	160	X	23
Is the corporation an associated CCPC that is claiming the expenditure limit?	161		49
Does the corporation have any non-resident shareholders who own voting shares?	151		19
Has the corporation had any transactions, including section 85 transfers, with its shareholders, officers, or employees, other than transactions in the ordinary course of business? Exclude non-arm's length transactions with non-residents	162		11
If you answered **yes** to the above question, and the transaction was between corporations not dealing at arm's length, were all or substantially all of the assets of the transferor disposed of to the transferee?	163		44
Has the corporation paid any royalties, management fees, or other similar payments to residents of Canada?	164	X	14
Is the corporation claiming a deduction for payments to a type of employee benefit plan?	165	X	15
Is the corporation claiming a loss or deduction from a tax shelter acquired after August 31, 1989?	166		T5004
Is the corporation a member of a partnership for which a partnership account number has been assigned?	167		T5013
Did the corporation, a foreign affiliate controlled by the corporation, or any other corporation or trust that did not deal at arm's length with the corporation have a beneficial interest in a non-resident discretionary trust (without reference to section 94)?	168		22
Did the corporation have any foreign affiliates during the year?	169		25
Has the corporation made any payments to non-residents of Canada under subsections 202(1) and/or 105(1) of the federal *Income Tax Regulations*?	170		29
Has the corporation had any non-arm's length transactions with a non-resident?	171		T106
For private corporations: Does the corporation have any shareholders who own 10% or more of the corporation's common and/or preferred shares?	173	X	50
Has the corporation made payments to, or received amounts from, a retirement compensation plan arrangement during the year?	172		
Is the net income/loss shown on the financial statements different from the net income/loss for income tax purposes?	201	X	1
Has the corporation made any charitable donations; gifts to Canada, a province, or a territory; gifts of cultural or ecological property; or gifts of medicine?	202	X	2
Has the corporation received any dividends or paid any taxable dividends for purposes of the dividend refund?	203	X	3
Is the corporation claiming any type of losses?	204	X	4
Is the corporation claiming a provincial or territorial tax credit or does it have a permanent establishment in more than one jurisdiction?	205	X	5
Has the corporation realized any capital gains or incurred any capital losses during the tax year?	206		6
i) Is the corporation claiming the small business deduction and reporting income from: a) property (other than dividends deductible on line 320 of the T2 return), b) a partnership, c) a foreign business, or d) a personal services business; or ii) does the corporation have aggregate investment income at line 440?	207		7
Does the corporation have any property that is eligible for capital cost allowance?	208	X	8
Does the corporation have any property that is eligible capital property?	210	X	10
Does the corporation have any resource-related deductions?	212		12
Is the corporation claiming deductible reserves (other than transitional reserves under section 34.2)?	213		13
Is the corporation claiming a patronage dividend deduction?	216		16
Is the corporation a credit union claiming a deduction for allocations in proportion to borrowing or an additional deduction?	217		17
Is the corporation an investment corporation or a mutual fund corporation?	218		18
Is the corporation carrying on business in Canada as a non-resident corporation?	220		20
Is the corporation claiming any federal or provincial foreign tax credits, or any federal or provincial logging tax credits?	221		21
Does the corporation have any Canadian manufacturing and processing profits?	227		27
Is the corporation claiming an investment tax credit?	231	X	31
Is the corporation claiming any scientific research and experimental development (SR&ED) expenditures?	232	X	T661
Is the total taxable capital employed in Canada of the corporation and its related corporations over $10,000,000?	233	X	
Is the total taxable capital employed in Canada of the corporation and its associated corporations over $10,000,000?	234	X	
Is the corporation claiming a surtax credit?	237		37
Is the corporation subject to gross Part VI tax on capital of financial institutions?	238		38
Is the corporation claiming a Part I tax credit?	242		42
Is the corporation subject to Part IV.1 tax on dividends received on taxable preferred shares or Part VI.1 tax on dividends paid?	243		43
Is the corporation agreeing to a transfer of the liability for Part VI.1 tax?	244		45
Is the corporation subject to Part II - Tobacco Manufacturers' surtax?	249		46
For financial institutions: Is the corporation a member of a related group of financial institutions with one or more members subject to gross Part VI tax?	250		39
Is the corporation claiming a Canadian film or video production tax credit refund?	253		T1131
Is the corporation claiming a film or video production services tax credit refund?	254		T1177
Is the corporation subject to Part XIII.1 tax? (Show your calculations on a sheet that you identify as Schedule 92.)	255		92

Attachments – continued from page 2

	Line	Yes	Schedule
Did the corporation have any foreign affiliates that are not controlled foreign affiliates?	256		T1134
Did the corporation have any controlled foreign affiliates?	258		T1134
Did the corporation own specified foreign property in the year with a cost amount over $100,000?	259		T1135
Did the corporation transfer or loan property to a non-resident trust?	260		T1141
Did the corporation receive a distribution from or was it indebted to a non-resident trust in the year?	261		T1142
Has the corporation entered into an agreement to allocate assistance for SR&ED carried out in Canada?	262		T1145
Has the corporation entered into an agreement to transfer qualified expenditures incurred in respect of SR&ED contracts?	263		T1146
Has the corporation entered into an agreement with other associated corporations for salary or wages of specified employees for SR&ED?	264		T1174
Did the corporation pay taxable dividends (other than capital gains dividends) in the tax year?	265	X	55
Has the corporation made an election under subsection 89(11) not to be a CCPC?	266		T2002
Has the corporation revoked any previous election made under subsection 89(11)?	267		T2002
Did the corporation (CCPC or deposit insurance corporation (DIC)) pay eligible dividends, or did its general rate income pool (GRIP) change in the tax year?	268	X	53
Did the corporation (other than a CCPC or DIC) pay eligible dividends, or did its low rate income pool (LRIP) change in the tax year?	269		54

Additional information

	Line	1 Yes	2 No
Did the corporation use the International Financial Reporting Standards (IFRS) when it prepared its financial statements?	270		X
Is the corporation inactive?	280		X

What is the corporation's main revenue-generating business activity? 221122 Electric Power Distribution

Specify the principal product(s) mined, manufactured, sold, constructed, or services provided, giving the approximate percentage of the total revenue that each product or service represents.

			%
284	ELECTRICITY DISTRIB.	285	100.000 %
286		287	%
288		289	%

	Line	1 Yes	2 No
Did the corporation immigrate to Canada during the tax year?	291		X
Did the corporation emigrate from Canada during the tax year?	292		X
Do you want to be considered as a quarterly instalment remitter if you are eligible?	293		

If the corporation was eligible to remit instalments on a quarterly basis for part of the tax year, provide the date the corporation ceased to be eligible 294 ______ YYYY MM DD

If the corporation's major business activity is construction, did you have any subcontractors during the tax year? 295 1 Yes ☐ 2 No ☐

Taxable income

Net income or (loss) for income tax purposes from Schedule 1, financial statements, or GIFI.	300		4,879,494	A
Deduct: Charitable donations from Schedule 2	311	9,375		
Gifts to Canada, a province, or a territory from Schedule 2	312			
Cultural gifts from Schedule 2	313			
Ecological gifts from Schedule 2	314			
Gifts of medicine from Schedule 2	315			
Taxable dividends deductible under section 112 or 113, or subsection 138(6) from Schedule 3	320			
Part VI.1 tax deduction*	325			
Non-capital losses of previous tax years from Schedule 4	331			
Net capital losses of previous tax years from Schedule 4	332			
Restricted farm losses of previous tax years from Schedule 4	333			
Farm losses of previous tax years from Schedule 4	334			
Limited partnership losses of previous tax years from Schedule 4	335			
Taxable capital gains or taxable dividends allocated from a central credit union	340			
Prospector's and grubstaker's shares	350			
Subtotal		9,375	9,375	B
Subtotal (amount A **minus** amount B) (if negative, enter "0")			4,870,119	C
Add: Section 110.5 additions or subparagraph 115(1)(a)(vii) additions	355			D
Taxable income (amount C **plus** amount D)	360		4,870,119	
Income exempt under paragraph 149(1)(t)	370			
Taxable income for a corporation with exempt income under paragraph 149(1)(t) (line 360 **minus** line 370)			4,870,119	Z

* This amount is equal to 3.5 times the Part VI.1 tax payable at line 724 on page 8. Use 3.2 for tax years ending before 2012.

Small business deduction

Canadian-controlled private corporations (CCPCs) throughout the tax year

Income from active business carried on in Canada from Schedule 7 . . . . **400** 4,879,494 A

Taxable income from line 360 on page 3, **minus** 100/28* 3.57143 of the amount on line 632** on page 7, **minus** 1/(0.38 - X***) 4 times the amount on line 636**** on page 7, and **minus** any amount that, because of federal law, is exempt from Part I tax . . . . **405** 4,870,119 B

Business limit (see notes 1 and 2 below) . . . . **410** 500,000 C

Notes:

1. For CCPCs that are not associated, enter $ 500,000 on line 410. However, if the corporation's tax year is less than 51 weeks, prorate this amount by the number of days in the tax year divided by 365, and enter the result on line 410.

2. For associated CCPCs, use Schedule 23 to calculate the amount to be entered on line 410.

Business limit reduction:

Amount C 500,000 x $\dfrac{\textbf{415} \text{ ***** } 259{,}369 \text{ D}}{11{,}250}$ = ... 11,527,511 E

Reduced business limit (amount C **minus** amount E) (if negative, enter "0") . . . . **425** F

Small business deduction

Amount A, B, C, or F, whichever is the least x 17 % = ... **430** G

Enter amount G on line 1 on page 7.

* 10/3 for tax years ending before November 1, 2011. The result of the multiplication by line 632 has to be pro-rated based on the number of days in the tax year that are in each period: before November 1, 2011, and after October 31, 2011.

** Calculate the amount of foreign non-business income tax credit deductible on line 632 without reference to the refundable tax on the CCPC's investment income (line 604) and without reference to the corporate tax reductions under section 123.4.

*** General rate reduction percentage for the tax year. It has to be pro-rated based on the number of days in the tax year that are in each calendar year. See page 5.

**** Calculate the amount of foreign business income tax credit deductible on line 636 without reference to the corporation tax reductions under section 123.4.

***** **Large corporations**

- If the corporation is not associated with any corporations in both the current and previous tax years, the amount to be entered on line 415 is: (total taxable capital employed in Canada for the **prior year** minus $10,000,000) x 0.225%.
- If the corporation is not associated with any corporations in the current tax year, but was associated in the previous tax year, the amount to be entered on line 415 is: (total taxable capital employed in Canada for the **current year** minus $10,000,000) x 0.225%.
- For corporations associated in the current tax year, see Schedule 23 for the special rules that apply.

General tax reduction for Canadian-controlled private corporations

Canadian-controlled private corporations throughout the tax year

Taxable income from line 360 on page 3*			4,870,119	A
Lesser of amounts V and Y (line Z1) from Part 9 of Schedule 27		B		
Amount QQ from Part 13 of Schedule 27		C		
Personal service business income**	432	D		
Amount used to calculate the credit union deduction from Schedule 17		E		
Amount from line 400, 405, 410, or 425 on page 4, whichever is the least		F		
Aggregate investment income from line 440 on page 6***		G		
Total of amounts B to G		►		H
Amount A **minus** amount H (if negative, enter "0")			4,870,119	I

Amount I	4,870,119	x	Number of days in the tax year before January 1, 2011 / Number of days in the tax year	/ 366	x 10 %	=	J
Amount I	4,870,119	x	Number of days in the tax year after December 31, 2010, and before January 1, 2012 / Number of days in the tax year	/ 366	x 11.5 %	=	K
Amount I	4,870,119	x	Number of days in the tax year after December 31, 2011 / Number of days in the tax year	366 / 366	x 13 %	= 633,115	L

General tax reduction for Canadian-controlled private corporations – Total of amounts J to L .... 633,115 M
Enter amount M on line 638 on page 7.

* For tax years ending after October 31, 2011, line 360 or amount Z, whichever applies.
** For tax years beginning after October 31, 2011.
*** Except for a corporation that is, throughout the year, a cooperative corporation (within the meaning assigned by subsection 136(2)) or a credit union.

General tax reduction

Do not complete this area if you are a Canadian-controlled private corporation, an investment corporation, a mortgage investment corporation, a mutual fund corporation, or any corporation with taxable income that is not subject to the corporation tax rate of 38%.

Taxable income from page 3 (line 360 or amount Z, whichever applies)				N
Lesser of amounts V and Y (line Z1) from Part 9 of Schedule 27		O		
Amount QQ from Part 13 of Schedule 27		P		
Personal service business income*	434	Q		
Amount used to calculate the credit union deduction from Schedule 17		R		
Total of amounts O to R		►		S
Amount N **minus** amount S (if negative, enter "0")				T

Amount T		x	Number of days in the tax year before January 1, 2011 / Number of days in the tax year	/ 366	x 10 %	=	U
Amount T		x	Number of days in the tax year after December 31, 2010, and before January 1, 2012 / Number of days in the tax year	/ 366	x 11.5 %	=	V
Amount T		x	Number of days in the tax year after December 31, 2011 / Number of days in the tax year	366 / 366	x 13 %	=	W

General tax reduction – Total of amounts U to W X
Enter amount X on line 639 on page 7.

* For tax years beginning after October 31, 2011.

Refundable portion of Part I tax

Canadian-controlled private corporations throughout the tax year

Aggregate investment income from Schedule 7 440	x 26 2 / 3 % =			A
Foreign non-business income tax credit from line 632 on page 7 . . .				
Deduct: Foreign investment income from Schedule 7 445	x 9 1 / 3 % = (if negative, enter "0")			B
Amount A **minus** amount B (if negative, enter "0")				C
Taxable income from line 360 on page 3		4,870,119		
Deduct: Amount from line 400, 405, 410, or 425 on page 4, whichever is the least				
Foreign non-business income tax credit from line 632 on page 7	x 25/9* 100 / 35 =			
Foreign business income tax credit from line 636 on page 7	x 1(0.38 - X**) / 4 =			
		4,870,119		
	x 26 2 / 3 % =		1,298,698	D
Part I tax payable minus investment tax credit refund (line 700 **minus** line 780 from page 8)			637,768	E
Refundable portion of Part I tax – Amount C, D, or E, whichever is the least . . . 450				F

* 100/35 for tax years beginning after October 31, 2011.

** General rate reduction percentage for the tax year. It has to be pro-rated based on the number of days in the tax year that are in each calendar year. See page 5.

Refundable dividend tax on hand

Refundable dividend tax on hand at the end of the previous tax year . . . 460			
Deduct: Dividend refund for the previous tax year . . . 465			G
Add the total of:			
Refundable portion of Part I tax from line 450 above			
Total Part IV tax payable from Schedule 3			
Net refundable dividend tax on hand transferred from a predecessor corporation on amalgamation, or from a wound-up subsidiary corporation . . . 480			H
Refundable dividend tax on hand at the end of the tax year – Amount G **plus** amount H . . . 485			

Dividend refund

Private and subject corporations at the time taxable dividends were paid in the tax year

Taxable dividends paid in the tax year from line 460 on page 2 of Schedule 3	1,750,000 x 1 / 3	583,333	I
Refundable dividend tax on hand at the end of the tax year from line 485 above			J
Dividend refund – Amount I or J, whichever is less (enter this amount on line 784 on page 8)			

Part I tax

Base amount of Part I tax – Taxable income from page 3 (line 360 or amount Z, whichever applies) **multiplied** by 38 %		550	1,850,645	A
Recapture of investment tax credit from Schedule 31		602		B

Calculation for the refundable tax on the Canadian-controlled private corporation's (CCPC) investment income
(if it was a CCPC throughout the tax year)

Aggregate investment income from line 440 on page 6			i
Taxable income from line 360 on page 3	4,870,119		
Deduct:			
Amount from line 400, 405, 410, or 425 on page 4, whichever is the least			
Net amount	4,870,119 ►	4,870,119	ii

Refundable tax on CCPC's investment income – 6 2 / 3 % of whichever is less: amount i or ii	604		C
Subtotal (**add** amounts A to C)		1,850,645	D

Deduct:

Small business deduction from line 430 on page 4			1		
Federal tax abatement	608	487,012			
Manufacturing and processing profits deduction from Schedule 27	616				
Investment corporation deduction	620				
Taxed capital gains 624					
Additional deduction – credit unions from Schedule 17	628				
Federal foreign non-business income tax credit from Schedule 21	632				
Federal foreign business income tax credit from Schedule 21	636				
General tax reduction for CCPCs from amount M on page 5	638	633,115			
General tax reduction from amount X on page 5	639				
Federal logging tax credit from Schedule 21	640				
Federal qualifying environmental trust tax credit	648				
Investment tax credit from Schedule 31	652	92,750			
Subtotal		1,212,877	►	1,212,877	E

Part I tax payable – Amount D **minus** amount E	637,768	F

Enter amount F on line 700 on page 8.

Summary of tax and credits

Federal tax

Part I tax payable from page 7	700	637,768
Part II surtax payable from Schedule 46	708	
Part III.1 tax payable from Schedule 55	710	
Part IV tax payable from Schedule 3	712	
Part IV.1 tax payable from Schedule 43	716	
Part VI tax payable from Schedule 38	720	
Part VI.1 tax payable from Schedule 43	724	
Part XIII.1 tax payable from Schedule 92	727	
Part XIV tax payable from Schedule 20	728	
Total federal tax		637,768

Add provincial or territorial tax:

Provincial or territorial jurisdiction . . . 750 ON
(if more than one jurisdiction, enter "multiple" and complete Schedule 5)

Net provincial or territorial tax payable (except Quebec and Alberta)	760	472,718	
Provincial tax on large corporations (Nova Scotia Schedule 342)	765		
(The Nova Scotia tax on large corporations is eliminated effective July 2012.)		472,718 ▶	472,718
Total tax payable	770		1,110,486 A

Deduct other credits:

Investment tax credit refund from Schedule 31	780		
Dividend refund from page 6	784		
Federal capital gains refund from Schedule 18	788		
Federal qualifying environmental trust tax credit refund	792		
Canadian film or video production tax credit refund (Form T1131)	796		
Film or video production services tax credit refund (Form T1177)	797		
Tax withheld at source	800		
Total payments on which tax has been withheld 801			
Provincial and territorial capital gains refund from Schedule 18	808		
Provincial and territorial refundable tax credits from Schedule 5	812		
Tax instalments paid	840	1,553,604	
Total credits	890	1,553,604 ▶	1,553,604 B

Refund code 894 1 Overpayment 443,118 ◀ Balance (amount A **minus** amount B) -443,118

If the result is negative, you have an **overpayment**.
If the result is positive, you have a **balance unpaid**.
Enter the amount on whichever line applies.

Generally, we do not charge or refund a difference of $2 or less.

Balance unpaid . . . .

Enclosed payment 898

Direct deposit request

To have the corporation's refund deposited directly into the corporation's bank account at a financial institution in Canada, or to change banking information you already gave us, complete the information below:

☐ Start ☐ Change information

910 ______ Branch number

914 ______ Institution number

918 ______ Account number

If the corporation is a Canadian-controlled private corporation throughout the tax year, does it qualify for the one-month extension of the date the balance of tax is due? . . . 896 1 Yes ☐ 2 No ☒

If this return was prepared by a tax preparer for a fee, provide their EFILE number . . . 920 A6698

PREPARED SOLELY FOR INCOME TAX PURPOSES WITHOUT AUDIT OR REVIEW FROM INFORMATION PROVIDED BY THE TAXPAYER.

Certification

I, 950 KYSLEY (Last name (print)) 951 MICHAEL (First name (print)) 954 VICE PRESIDENT, FINANCE (Position, office, or rank),

am an authorized signing officer of the corporation. I certify that I have examined this return, including accompanying schedules and statements, and that the information given on this return is, to the best of my knowledge, correct and complete. I also certify that the method of calculating income for this tax year is consistent with that of the previous tax year except as specifically disclosed in a statement attached to this return.

955 ______ Date (yyyy/mm/dd) ______ Signature of the authorized signing officer of the corporation 956 (905) 332-1851 Telephone number

Is the contact person the same as the authorized signing officer? If **no**, complete the information below . . . 957 1 Yes ☐ 2 No ☒

958 JOHN MAURO Name (print) 959 (905) 332-1851 Telephone number

Language of correspondence – Langue de correspondance

Indicate your language of correspondence by entering **1** for English or **2** for French.
Indiquez votre langue de correspondance en inscrivant **1** pour anglais ou **2** pour français. 990 1

Canada Revenue Agency / Agence du revenu du Canada

Net Income (Loss) for Income Tax Purposes

SCHEDULE 1

Corporation's name	Business Number	Tax year end Year Month Day
BURLINGTON HYDRO INC.	86829 1980 RC0001	2012-12-31

- The purpose of this schedule is to provide a reconciliation between the corporation's net income (loss) as reported on the financial statements and its net income (loss) for tax purposes. For more information, see the T2 *Corporation Income Tax Guide*.
- All legislative references are to the *Income Tax Act*.

Amount calculated on line 9999 from Schedule 125				6,410,383 A
Add:				
Provision for income taxes – current		101	1,310,399	
Provision for income taxes – deferred		102	419,259	
Interest and penalties on taxes		103	3,997	
Amortization of tangible assets		104	7,707,198	
Charitable donations and gifts from Schedule 2		112	9,375	
Scientific research expenditures deducted per financial statements		118	227,707	
Non-deductible meals and entertainment expenses		121	31,460	
Reserves from financial statements – balance at the end of the year		126	3,601,541	
Subtotal of additions			13,310,936 ▶	13,310,936
Other additions:				
Miscellaneous other additions:				
600 SECTION 12(1)(a) income		290	5,540,952	
603				
Inducement - ITA 12(1)(x)	47,909			
Total	47,909	293	47,909	
604 Deferred revenue 12(1)(a)	1,243,653			
Total	1,243,653	294	1,243,653	
Subtotal of other additions		199	6,832,514 ▶	6,832,514
Total additions		500	20,143,450 ▶	20,143,450 B
Amount A **plus** amount B				26,553,833

Deduct:

Gain on disposal of assets per financial statements	401	2,895		
Capital cost allowance from Schedule 8	403	8,674,494		
Cumulative eligible capital deduction from Schedule 10	405	6,580		
SR&ED expenditures claimed in the year from Form T661 (line 460)	411	271,572		
Reserves from financial statements – balance at the beginning of the year	414	3,472,353		
Subtotal of deductions		12,427,894	▶	12,427,894

Other deductions:

Miscellaneous other deductions:

700	SECTION 20(1)(m) reserve		390	5,540,952		
701	Deferred revenue 20(1)(m)		391	1,243,653		
702	Regulatory variance adjustments		392	2,176,291		
704	ITCs booked to accounting income	285,549				
	Total	285,549	394	285,549		
	Subtotal of other deductions		499	9,246,445	▶	9,246,445
	Total deductions		510	21,674,339	▶	21,674,339

Net income (loss) for income tax purposes – enter on line 300 of the T2 return . . . 4,879,494

T2 SCH 1 E (12) Canadä

Attached Schedule with Total

Line 118 – Scientific research expenditures deducted per financial statements

Title Line 118 – Scientific research expenditures deducted per financial statemer

Description	Amount	
TOTAL CURRENT EXPENDITURES FOR SRED PURPOSES	385,227	00
LESS: CURRENT COSTS CAPITALIZED FOR ACCOUNTING PURPOSES	-157,520	00
Total	227,707	00

Attached Schedule with Total

Line 290 – Amount for line 600

Title Line 290 – Amount for line 600

Description	Amount	
Customer deposits	2,989,191	00
Work order deposits	2,551,761	00
Total	5,540,952	00

Inducement

This form is used to calculate inducements that a corporation must add to its income under paragraph 12(1)(x) of the ITA. If an amount reduces the capital cost of a property, this amount will be indicated in Part "Tax credits whose amount should reduce the capital cost of property."

If you want to transfer an amount to Schedule 1 and include it in the corporation's income for tax purposes, select the corresponding check box in column A. You can also select the option **Select this check box to add all the amounts to income calculated in Schedule 1** to transfer all the amounts to Schedule 1. In either case, the column A check box will be selected for that amount and it will therefore be updated to Schedule 1.

Tax credits whose amount should be added to income

Select this check box to add all the amounts to income calculated in Schedule 1. . . . . ☐

Federal

A		
X	Investment tax credit from apprenticeship job creation expenditures	2,000
☐	Investment tax credit from child care spaces expenditures	
☐	Canadian film or video production tax credit* * Please verify if the credit amount relates to depreciable property. For more information, press F1 to consult the Help.	
☐	Film or video production services tax credit* * Please verify if the credit amount relates to depreciable property. For more information, press F1 to consult the Help.	

Ontario

A		
X	Portion of the Ontario research and development tax credit that relates to the prescribed proxy amount (PPA)	5,909
☐	Ontario co-operative education tax credit	
X	Ontario apprenticeship training tax credit	40,000
☐	Ontario computer animation and special effects tax credit* * Please verify if the credit amount relates to depreciable property. For more information, press F1 to consult the Help.	
☐	Ontario film and television tax credit* * Please verify if the credit amount relates to depreciable property. For more information, press F1 to consult the Help.	
☐	Ontario production services tax credit* * Please verify if the credit amount relates to depreciable property. For more information, press F1 to consult the Help.	
☐	Ontario interactive digital media tax credit* * Please verify if the credit amount relates to depreciable property. For more information, press F1 to consult the Help.	
☐	Ontario sound recording tax credit* * Please verify if the credit amount relates to depreciable property. For more information, press F1 to consult the Help.	
☐	Ontario book publishing tax credit	
☐	Portion of the Ontario innovation tax credit that relates to the prescribed proxy amount (PPA)	
☐	Ontario business-research institute tax credit	
☐	Ontario public transit expense tax credit	

Tax credits whose amount should reduce the capital cost of property

Canada Revenue Agency / Agence du revenu du Canada

SCHEDULE 2

CHARITABLE DONATIONS AND GIFTS

Name of corporation	Business Number	Tax year-end Year Month Day
BURLINGTON HYDRO INC.	86829 1980 RC0001	2012-12-31

- For use by corporations to claim any of the following:
  - charitable donations;
  - gifts to Canada, a province, or a territory;
  - gifts of certified cultural property;
  - gifts of certified ecologically sensitive land; or
  - additional deduction for gifts of medicine.
- The donations and gifts are eligible for a five-year carryforward.
- Use this schedule to show a credit transfer following an amalgamation or the wind-up of a subsidiary as described under subsections 87(1) and 88(1) of the *Income Tax Act*.
- For donations and gifts made after March 22, 2004, subsection 110.1(1.2) of the *Income Tax Act* provides as follows:
  - Where a particular corporation has undergone an acquisition of control, for tax years that end on or after the acquisition of control, no corporation can claim a deduction for a gift made by the particular corporation to a qualified donee before the acquisition of control
  - If a particular corporation makes a gift to a qualified donee pursuant to an arrangement under which both the gift and the acquisition of control is expected, no corporation can claim a deduction for the gift unless the person acquiring control of the particular corporation is the qualified donee.
- Under proposed changes, the eligible amount of a charitable gift is the amount by which the fair market value of the gift exceeds the amount of an advantage, if any, for the gift.
- Under proposed changes, a gift of medicine made after March 18, 2007, to qualifying organizations for activities outside of Canada, may be eligible for an additional deduction if the gift is an eligible medical gift. This additional deduction is calculated in Part 6.
- File one completed copy of this schedule with your *T2 Corporation Income Tax Return*.
- For more information, see the *T2 Corporation – Income Tax Guide*.

Part 1 – Charitable donations

Charity/Recipient	Amount ($100 or more only)
United Way	100
Conservation Halton	1,200
Halton Women's Place	300
YMCA of Hamilton/Burlington	1,000
Burlington Community Foundation	2,500
Breast Cancer Support Services	3,300
Burlington Art Centre Foundation	275
Brain Tumor Foundation of Canada	100
Reformation Luther Church	100
Canadian Red Cross	500
Subtotal	9,375
Add: Total donations of less than $100 each	
Total donations in current tax year	9,375

		Federal		Québec	Alberta
Charitable donations at the end of the previous tax year					
Deduct: Charitable donations expired after five tax years*	239				
Charitable donations at the beginning of the tax year	240				
Add:					
Charitable donations transferred on an amalgamation or the wind-up of a subsidiary	250				
Total current-year charitable donations made (enter this amount on line 112 of Schedule 1) 210: 9,375				9,375	
Subtotal (line 250 **plus** line 210)		9,375		9,375	9,375
Deduct: Adjustment for an acquisition of control (for donations made after March 22, 2004)	255				
Total charitable donations available		9,375	A	9,375	9,375
Deduct: Amount applied against taxable income (cannot be more than amount K in Part 2) (enter this amount on line 311 of the T2 return)	260	9,375		9,375	9,375
Charitable donations closing balance	280				

* For the federal and Alberta, the gifts expire after five tax years. For Québec, gifts made in a tax year that ended before March 24, 2006, expire after five tax years and gifts made in a tax year that ended after March 23, 2006, expire after twenty tax years.

Amounts carried forward – Charitable donations

Year of origin:		Federal	Québec	Alberta
1st prior year	2011-12-31			
2nd prior year	2010-12-31			
3rd prior year	2009-12-31			
4th prior year	2008-12-31			
5th prior year	2007-12-31			
6th prior year*	2006-12-31			
7th prior year	2005-12-31			
8th prior year	2004-12-31			
9th prior year	2003-12-31			
10th prior year	2002-12-31			
11th prior year	2001-12-31			
12th prior year	2001-09-30			
13th prior year	2000-09-30			
14th prior year	1999-09-30			
15th prior year	1998-09-30			
16th prior year	1997-09-30			
17th prior year	1996-09-30			
18th prior year	1995-09-30			
19th prior year	1994-09-30			
20th prior year	1993-09-30			
21st prior year*	1992-09-30			
Total (to line A)				

* For the federal and Alberta, the 6th prior year gifts expire in the current year. For Québec, the 6th prior year gifts made in a tax year that ended before March 24, 2006, expire in the current year and the 21st prior year gifts made in a tax year that ended after March 23, 2006, expire in the current year.

Part 2 – Calculation of the maximum allowable deduction for charitable donations

Net income for tax purposes* **multiplied** by 75 % .... 3,659,621 B

Taxable capital gains arising in respect of gifts of capital property included in Part 1** .... **225** ______ C

Taxable capital gain in respect of deemed gifts of non-qualifying securities per subsection 40(1.01) .... **227** ______ D

The amount of the recapture of capital cost allowance in respect of charitable gifts .... **230** ______

Proceeds of disposition, less outlays and expenses** .... ______ E

Capital cost** .... ______ F

Amount E or F, whichever is less .... **235** ______

Amount on line 230 or 235, whichever is less .... ______ G

Subtotal (**add** amounts C, D, and G) ______ H

Amount H **multiplied** by 25 % ______ I

Subtotal (amount B **plus** amount I) 3,659,621 J

Maximum allowable deduction for charitable donations (enter amount A from Part 1, amount J, or net income for tax purposes, whichever is less) .... 9,375 K

* For credit unions, this amount is before the deduction of payments pursuant to allocations in proportion to borrowing and bonus interest.

** This amount must be prorated by the following calculation: eligible amount of the gift **divided by** the proceeds of disposition of the gift.

Part 3 – Gifts to Canada, a province, or a territory

Gifts to Canada, a province, or a territory at the end of the previous tax year			
Deduct: Gifts to Canada, a province, or a territory expired after five tax years	339		
Gifts to Canada, a province, or a territory at the beginning of the tax year	340		▶
Add: Gifts to Canada, a province, or a territory transferred on an amalgamation or the windup of a subsidiary	350		
Total current-year gifts made to Canada, a province, or a territory*	310		
Subtotal (line 350 **plus** line 310)			
Deduct: Adjustment for an acquisition of control (for gifts made after March 22, 2004)		355	
Total gifts to Canada, a province, or a territory available			
Deduct: Amount applied against taxable income (enter this amount on line 312 of the T2 return).		360	
Gifts to Canada, a province, or a territory closing balance		380	

* Not applicable for gifts made after February 18, 1997, unless a written agreement was made before this date. If no written agreement exists, enter the amount on line 210 and complete Part 2.

Part 4 – Gifts of certified cultural property

		Federal	Québec	Alberta
Gifts of certified cultural property at the end of the previous tax year				
Deduct: Gifts of certified cultural property expired after five tax years*	439			
Gifts of certified cultural property at the beginning of the tax year	440			
Add: Gifts of certified cultural property transferred on an amalgamation or the windup of a subsidiary	450			
Total current-year gifts of certified cultural property	410			
Subtotal (line 450 **plus** line 410)				
Deduct: Adjustment for an acquisition of control (for gifts made after March 22, 2004)	455			
Total gifts of certified cultural property available				
Deduct: Amount applied against taxable income (enter this amount on line 313 of the T2 return)	460			
Gifts of certified cultural property closing balance	480			

* For the federal and Alberta, the gifts expire after five tax years. For Québec, gifts made in a tax year that ended before March 24, 2006, expire after five tax years and gifts made in a tax year that ended after March 23, 2006, expire after twenty tax years.

Amount carried forward – Gifts of certified cultural property

Year of origin:		Federal	Québec	Alberta
1st prior year	2011-12-31			
2nd prior year	2010-12-31			
3rd prior year	2009-12-31			
4th prior year	2008-12-31			
5th prior year	2007-12-31			
6th prior year*	2006-12-31			
7th prior year	2005-12-31			
8th prior year	2004-12-31			
9th prior year	2003-12-31			
10th prior year	2002-12-31			
11th prior year	2001-12-31			
12th prior year	2001-09-30			
13th prior year	2000-09-30			
14th prior year	1999-09-30			
15th prior year	1998-09-30			
16th prior year	1997-09-30			
17th prior year	1996-09-30			
18th prior year	1995-09-30			
19th prior year	1994-09-30			
20th prior year	1993-09-30			
21st prior year*	1992-09-30			
Total				

* For the federal and Alberta, the 6th prior year gifts expire in the current year. For Québec, the 6th prior year gifts made in a tax year that ended before March 24, 2006, expire in the current year and the 21st prior year gifts made in a tax year that ended after March 23, 2006, expire in the current year.

Part 5 – Gifts of certified ecologically sensitive land

		Federal	Québec	Alberta
Gifts of certified ecologically sensitive land at the end of the previous tax year				
Deduct: Gifts of certified ecologically sensitive land expired after five tax years*	539			
Gifts of certified ecologically sensitive land at the beginning of the tax year	540			
Add: Gifts of certified ecologically sensitive land transferred on an amalgamation or the windup of a subsidiary	550			
Total current-year gifts of certified ecologically sensitive land	510			
Subtotal (line 550 **plus** line 510)				
Deduct: Adjustment for an acquisition of control (for gifts made after March 22, 2004)	555			
Total gifts of certified ecologically sensitive land available				
Deduct: Amount applied against taxable income (enter this amount on line 314 of the T2 return)	560			
Gifts of certified ecologically sensitive land closing balance	580			

* For the federal and Alberta, the gifts expire after five tax years. For Québec, gifts made in a tax year that ended before March 24, 2006, expire after five tax years and gifts made in a tax year that ended after March 23, 2006, expire after twenty tax years.

Amounts carried forward – Gifts of certified ecologically sensitive land

Year of origin:		Federal	Québec	Alberta
1st prior year	2011-12-31			
2nd prior year	2010-12-31			
3rd prior year	2009-12-31			
4th prior year	2008-12-31			
5th prior year	2007-12-31			
6th prior year*	2006-12-31			
7th prior year	2005-12-31			
8th prior year	2004-12-31			
9th prior year	2003-12-31			
10th prior year	2002-12-31			
11th prior year	2001-12-31			
12th prior year	2001-09-30			
13th prior year	2000-09-30			
14th prior year	1999-09-30			
15th prior year	1998-09-30			
16th prior year	1997-09-30			
17th prior year	1996-09-30			
18th prior year	1995-09-30			
19th prior year	1994-09-30			
20th prior year	1993-09-30			
21st prior year*	1992-09-30			
Total				

* For the federal and Alberta, the 6th prior year gifts expire in the current year. For Québec, the 6th prior year gifts made in a tax year that ended before March 24, 2006, expire in the current year and the 21st prior year gifts made in a tax year that ended after March 23, 2006, expire in the current year.

Part 6 – Additional deduction for gifts of medicine

	Line	Federal		Québec		Alberta	
Additional deduction for gifts of medicine at the end of the previous tax year							
Deduct: Additional deduction for gifts of medicine expired after five tax years	639						
Additional deduction for gifts of medicine at the beginning of the tax year	640						
Add: Additional deduction for gifts of medicine transferred on an amalgamation or the wind-up of a subsidiary	650						
Additional deduction for gifts of medicine for the current year:							
Proceeds of disposition	602		1		1		1
Cost of gifts of medicine	601		2		2		2
Subtotal (line 1 **minus** line 2)			3		3		3
Line 3 **multiplied** by 50 %			4		4		4
Eligible amount of gifts	600		5		5		5

Federal

A ______ x (B ______ / C) = Additional deduction for gifts of medicine for the current year **610** ______

Québec

A ______ x (B ______ / C) = Additional deduction for gifts of medicine for the current year ______

Alberta

A ______ x (B ______ / C) = Additional deduction for gifts of medicine for the current year ______

where:

A is the **lesser** of line 2 and line 4

B is the eligible amount of gifts (line 600)

C is the proceeds of disposition (line 602)

	Line	Federal	Québec	Alberta
Subtotal (line 650 **plus** line 610)				
Deduct: Adjustment for an acquisition of control	655			
Total additional deduction for gifts of medicine available				
Deduct: Amount applied against taxable income (enter this amount on line 315 of the T2 return)	660			
Additional deduction for gifts of medicine closing balance	680			

Amounts carried forward – Additional deduction for gifts of medicine

Year of origin:		Federal	Québec	Alberta
1st prior year	2011-12-31			
2nd prior year	2010-12-31			
3rd prior year	2009-12-31			
4th prior year	2008-12-31			
5th prior year	2007-12-31			
6th prior year*	2006-12-31			
Total				

***** These donations expired in the current year.

Québec – Gifts of musical instruments

Gifts of musical instruments at the end of the previous tax year		A
Deduct: Gifts of musical instruments expired after twenty tax years		B
Gifts of musical instruments at the beginning of the tax year		C
Add:		
Gifts of musical instruments transferred on an amalgamation or the wind-up of a subsidiary		D
Total current-year gifts of musical instruments		E
Subtotal (line D **plus** line E)		F
Deduct: Adjustment for an acquisition of control		G
Total gifts of musical instruments available		H
Deduct: Amount applied against taxable income		I
Gifts of musical instruments closing balance		J

Amounts carried forward – Gifts of musical instruments

Year of origin:		Québec
1st prior year	2011-12-31	
2nd prior year	2010-12-31	
3rd prior year	2009-12-31	
4th prior year	2008-12-31	
5th prior year	2007-12-31	
6th prior year*	2006-12-31	
7th prior year	2005-12-31	
8th prior year	2004-12-31	
9th prior year	2003-12-31	
10th prior year	2002-12-31	
11th prior year	2001-12-31	
12th prior year	2001-09-30	
13th prior year	2000-09-30	
14th prior year	1999-09-30	
15th prior year	1998-09-30	
16th prior year	1997-09-30	
17th prior year	1996-09-30	
18th prior year	1995-09-30	
19th prior year	1994-09-30	
20th prior year	1993-09-30	
21st prior year*	1992-09-30	
Total		

* These gifts expired in the current year.

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DIVIDENDS RECEIVED, TAXABLE DIVIDENDS PAID, AND PART IV TAX CALCULATION

SCHEDULE 3

Name of corporation	Business Number	Tax year-end Year Month Day
BURLINGTON HYDRO INC.	86829 1980 RC0001	2012-12-31

- This schedule is for the use of any corporation to report:
  - non-taxable dividends under section 83;
  - deductible dividends under subsection 138(6);
  - taxable dividends deductible from income under section 112, subsection 113(2) and paragraphs 113(1)(a), (b) or (d); or
  - taxable dividends paid in the tax year that qualify for a dividend refund.
- The calculations in this schedule apply only to private or subject corporations.
- Parts, sections, subsections, and paragraphs referred to on this schedule are from the federal *Income Tax Act.*
- A recipient corporation is connected with a payer corporation at any time in a tax year, if at that time the recipient corporation:
  - controls the payer corporation, other than because of a right referred to in paragraph 251(5)(b); or
  - owns more than 10% of the issued share capital (with full voting rights), and shares that have a fair market value of more than 10% of the fair market value of all shares of the payer corporation.
- File one completed copy of this schedule with your *T2 Corporation Income Tax Return*.
- Column A – Enter "X" if dividends received from a foreign source (connected corporation only).
- Column F1 – Enter the amount of dividends received reported in column 240 that are eligible.
- Column F2 – Enter the code that applies to the deductible taxable dividend.
- Column F3 – Enter if dividends have been received or not after December 20, 2012. This information is required for corporations that must complete Schedules 71 and 72. For more details with regards to this column, consult the Help.

Part 1 – Dividends received in the tax year

Do not include dividends received from foreign non-affiliates.

Name of payer corporation (from which the corporation received the dividend) 200	A	B Enter 1 if payer corporation is connected 205	C Business Number of connected corporation 210	D Tax year-end of the payer corporation in which the sections 112/113 and subsection 138(6) dividends in column F were paid YYYY/MM/DD (See note) 220	E Non-taxable dividend under section 83 230
				Total (enter on line 402 of Schedule 1)	

Columns B to D: Complete if payer corporation is connected

Note: If your corporation's tax year-end is different than that of the connected payer corporation, your corporation could have received dividends from more than one tax year of the payer corporation. If so, use a separate line to provide the information for each tax year of the payer corporation.
For more details, consult the Help.

F Taxable dividends deductible from taxable income under section 112, subsections 113(2) and 138(6), and paragraphs 113(1)(a), (b), or (d)* 240	F1 Eligible dividends (included in column F)	F2	F3	G Total taxable dividends paid by connected payer corporation (for tax year in column D) 250	H Dividend refund of the connected payer corporation (for tax year in column D)** 260	I Part IV tax before deductions F x 1 / 3 *** 270
						J

Columns G and H: Complete if payer corporation is connected

Total (enter the amount from column F on line 320 of the T2 return and amount J in Part 2)

* If taxable dividends are received, enter the amount in column 240, but if the corporation is not subject to Part IV tax (such as a public corporation other than a subject corporation as defined in subsection 186(3)), enter "0" in column 270. Life insurers are not subject to Part IV tax on subsection 138(6) dividends.

** If the connected payer corporation's tax year ends after the corporation's balance-due day for the tax year (two or three months, as applicable), you have to estimate the payer's dividend refund when you calculate the corporation's Part IV tax payable.

*** For dividends received from connected corporations: Part IV tax = $\frac{\text{Column F x Column H}}{\text{Column G}}$

Part 2 – Calculation of Part IV tax payable

Part IV tax before deductions (amount J in Part 1)			
Deduct:			
Part IV.I tax payable on dividends subject to Part IV tax		320	
		Subtotal	
Deduct:			
Current-year non-capital loss claimed to reduce Part IV tax	330		
Non-capital losses from previous years claimed to reduce Part IV tax	335		
Current-year farm loss claimed to reduce Part IV tax	340		
Farm losses from previous years claimed to reduce Part IV tax	345		
Total losses applied against Part IV tax		x 1 / 3 =	
Part IV tax payable (enter amount on line 712 of the T2 return)		360	

Part 3 – Taxable dividends paid in the tax year that qualify for a dividend refund

	A	B	C	D	D1
	Name of connected recipient corporation	Business Number	Tax year end of connected recipient corporation in which the dividends in column D were received YYYY/MM/DD (See note)	Taxable dividends paid to connected corporations	Eligible dividends (included in column D)
	400	410	420	430	
1	The City of Burlington	NR	2012-12-31	1,750,000	

Note

If your corporation's tax year-end is different than that of the connected recipient corporation, your corporation could have paid dividends in more than one tax year of the recipient corporation. If so, use a separate line to provide the information for each tax year of the recipient corporation. For more details, consult the Help.

		Total	1,750,000
Total taxable dividends paid in the tax year to other than connected corporations		450	
Eligible dividends (included in line 450)	450a		
Total taxable dividends paid in the tax year that qualify for a dividend refund (total of column D above **plus** line 450)		460	1,750,000

Part 4 – Total dividends paid in the tax year

Complete this part if the total taxable dividends paid in the tax year that qualify for a dividend refund (line 460 above) is different from the total dividends paid in the tax year.

Total taxable dividends paid in the tax year for the purposes of a dividend refund (from above)			1,750,000
Other dividends paid in the tax year (total of 510 to 540)			
Total dividends paid in the tax year		500	1,750,000
Deduct:			
Dividends paid out of capital dividend account	510		
Capital gains dividends	520		
Dividends paid on shares described in subsection 129(1.2)	530		
Taxable dividends paid to a controlling corporation that was bankrupt at any time in the year	540		
Subtotal		▶	
Total taxable dividends paid in the tax year that qualify for a dividend refund			1,750,000

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SCHEDULE 4

CORPORATION LOSS CONTINUITY AND APPLICATION

Name of corporation	Business number	Tax year-end Year Month Day
BURLINGTON HYDRO INC.	86829 1980 RC0001	2012-12-31

- Use this form to determine the continuity and use of available losses; to determine a current-year non-capital loss, farm loss, restricted farm loss, or limited partnership loss; to determine the amount of restricted farm loss and limited partnership loss that can be applied in a year; and to ask for a loss carryback to previous years.
- A corporation can choose whether or not to deduct an available loss from income in a tax year. The corporation can deduct losses in any order. However, for each type of loss, deduct the oldest loss first.
- According to subsection 111(4) of the *Income Tax Act*, when control has been acquired, no amount of capital loss incurred for a tax year ending (TYE) before that time is deductible in computing taxable income in a TYE after that time. Also, no amount of capital loss incurred in a TYE after that time is deductible in computing taxable income of a TYE before that time.
- When control has been acquired, subsection 111(5) provides for similar treatment of non-capital and farm losses, except as listed in paragraphs 111(5)(a) and (b).
- For information on these losses, see the *T2 Corporation – Income Tax Guide.*
- File one completed copy of this schedule with the T2 return, or send the schedule by itself to the tax centre where the return is filed.
- Parts, sections, subsections, paragraphs, and subparagraphs mentioned in this schedule refer to the Act.

Part 1 – Non-capital losses

Determination of current-year non-capital loss

Net income (loss) for income tax purposes			4,879,494	A
Deduct: (increase a loss)				
Net capital losses deducted in the year (enter as a positive amount)		a		
Taxable dividends deductible under sections 112, 113(1), or subsection 138(6)		b		
Amount of Part VI.1 tax deductible		c		
Amount deductible as prospector's and grubstaker's shares – Paragraph 110(1)(d.2)		d		
Subtotal (total of amounts a to d)		▶		B
Subtotal (amount A **minus** amount B; if positive, enter "0")				C
Deduct: (increase a loss)				
Section 110.5 or subparagraph 115(1)(a)(vii) – Addition for foreign tax deductions				D
Subtotal (amount C **minus** amount D)				E
Add: (decrease a loss)				
Current-year farm loss (whichever is less: the net loss from farming or fishing included in the income, or the non-capital loss before deducting the farm loss. Enter amount F on line 310)				F
Current-year non-capital loss (amount E **plus** amount F; if positive, enter "0"; if negative, enter amount G on line 110 as a positive)				G

Continuity of non-capital losses and request for a carryback

Non-capital loss at the end of the previous tax year			e		
Deduct: Non-capital loss expired*	100		f		
Non-capital losses at the beginning of the tax year (amount e **minus** amount f)	102		▶		H
Add:					
Non-capital losses transferred on an amalgamation or the wind-up of a subsidiary corporation	105		g		
Current-year non-capital loss (amount G above)	110		h		
Subtotal (amount g **plus** amount h)			▶		I
Subtotal (amount H **plus** amount I)					J

* A non-capital loss expires as follows:
- after **7** tax years if it arose in a tax year ending before March 23, 2004;
- after **10** tax years if it arose in a tax year ending after March 22, 2004, and before 2006; and
- after **20** tax years if it arose in a tax year ending after 2005.

An allowable business investment loss becomes a net capital loss as follows:
- after **7** tax years if it arose in a tax year ending before March 23, 2004; and
- after **10** tax years if it arose in a tax year ending after March 22, 2004.

Part 1 – Non-capital losses (continued)

		Amount J from page 1				
Deduct:						
Other adjustments (includes adjustments for an acquisition of control)	150		i			
Section 80 – Adjustments for forgiven amounts	140		j			
Subsection 111(10) – Adjustments for fuel tax rebate			j.1			
Non-capital losses of previous tax years applied in the current tax year (enter on line 331 of the T2 Return)	130		k			
Current and previous year non-capital losses applied against current-year taxable dividends subject to Part IV tax (enter on lines 330 and 335 of Schedule 3, *Dividends Received, Taxable Dividends Paid, and Part IV Tax Calculation*, respectively)	135		l			
Subtotal (total of amounts i to l)			▶			K
Non-capital losses before any request for a carryback (amount J **minus** amount K)						L
Deduct – Request to carry back non-capital loss to:						
First previous tax year to reduce taxable income	901		m			
Second previous tax year to reduce taxable income	902		n			
Third previous tax year to reduce taxable income	903		o			
First previous tax year to reduce taxable dividends subject to Part IV tax	911		p			
Second previous tax year to reduce taxable dividends subject to Part IV tax	912		q			
Third previous tax year to reduce taxable dividends subject to Part IV tax	913		r			
Total of requests to carry back non-capital losses to previous tax years (total of amounts m to r)			▶			M
Closing balance of non-capital losses to be carried forward to future tax years (amount L **minus** amount M)				180		N

Part 2 – Capital losses

Continuity of capital losses and request for a carryback

Capital losses at the end of the previous tax year	200	85,869	a			
Capital losses transferred on the amalgamation or the wind-up of a subsidiary corporation	205		b			
Subtotal (amount a **plus** amount b)		85,869	▶		85,869	A
Deduct:						
Other adjustments (includes adjustments for an acquisition of control)	250		c			
Section 80 – Adjustments for forgiven amounts	240		d			
Subtotal (amount c **plus** amount d)			▶			B
Subtotal (amount A **minus** amount B)					85,869	C
Add: Current-year capital loss (from the calculation on Schedule 6)				210		D
Unused non-capital losses that expired in the tax year*			e			
Allowable business investment losses (ABIL) that expired as non-capital losses in the tax year**			f			
Enter amount e or f, whichever is less	215					
ABILs expired as non-capital loss: line 215 **divided** by 0.500000				220		E
Subtotal (total of amounts C to E)					85,869	F

Note

If there has been an amalgamation or a windup of a subsidiary, do a separate calculation of the ABIL expired as non-capital loss for each predecessor or subsidiary. Add all these amounts and enter the total on line 220 above.

* If the losses were incurred in a tax year ending before March 23, 2004, enter the losses from the 8th previous tax year. If the losses were incurred in a tax year ending after March 22, 2004, and before 2006, enter the losses from the 11th previous tax year. Enter the losses from the 21st previous tax year if the losses were incurred in a tax year ending after 2005. Enter the part that was not used in previous years and the current year on line e.

** If the losses were incurred in a tax year ending before March 23, 2004, enter the losses from the 8th previous tax year. If the losses were incurred in a tax year ending after March 22, 2004, enter the losses from the 11th previous tax year. Enter the full amount on line f.

Part 2 – Capital losses (continued)

Amount F from page 2			85,869	
Deduct: Capital losses from previous tax years applied against the current-year net capital gain (see Note 1)	225			G
Capital losses before any request for a carryback (amount F **minus** amount G)			85,869	H

Deduct – **Request to carry back capital loss to** (see Note 2):

	Capital gain (100%)		Amount carried back (100%)	
First previous tax year		951		g
Second previous tax year		952		h
Third previous tax year		953		i
Subtotal (total of amounts g to i)			▶	I
Closing balance of capital losses to be carried forward to future tax years (amount H **minus** amount I)		280	85,869	J

Note 1
To get the net capital losses required to reduce the taxable capital gain included in the net income (loss) for the purpose of current-year tax, enter the amount from line 225 **multiplied** by 50% on line 332 of the T2 return.

Note 2
On line 225, 951, 952, or 953, whichever applies, enter the actual amount of the loss. When the loss is applied, **multiply** this amount by the 50% inclusion rate.

Part 3 – Farm losses

Continuity of farm losses and request for a carryback

Farm losses at the end of the previous tax year			a	
Deduct: Farm loss expired*	300		b	
Farm losses at the beginning of the tax year (amount a **minus** amount b)	302		▶	A
Add:				
Farm losses transferred on the amalgamation or the windup of a subsidiary corporation	305		c	
Current-year farm loss	310		d	
Subtotal (amount c **plus** amount d)			▶	B
Subtotal (amount A **plus** amount B)				C
Deduct:				
Other adjustments (includes adjustments for an acquisition of control)	350		e	
Section 80 – Adjustments for forgiven amounts	340		f	
Farm losses of previous tax years applied in the current tax year (enter on line 334 of the T2 Return)	330		g	
Current and previous year farm losses applied against current-year taxable dividends subject to Part IV tax (enter on lines 340 and 345 of Schedule 3, *Dividends Received, Taxable Dividends Paid, and Part IV Tax Calculation*, respectively)	335		h	
Subtotal (total of amounts e to h)			▶	D
Farm losses before any request for a carryback (amount C **minus** amount D)				E

Deduct – **Request to carry back farm loss to:**

First previous tax year to reduce taxable income	921		i	
Second previous tax year to reduce taxable income	922		j	
Third previous tax year to reduce taxable income	923		k	
First previous tax year to reduce taxable dividends subject to Part IV tax	931		l	
Second previous tax year to reduce taxable dividends subject to Part IV tax	932		m	
Third previous tax year to reduce taxable dividends subject to Part IV tax	933		n	
Subtotal (total of amounts i to n)			▶	F
Closing balance of farm losses to be carried forward to future tax years (amount E **minus** amount F)	380			G

* A farm loss expires as follows:
- after **10** tax years if it arose in a tax year ending before 2006; and
- after **20** tax years if it arose in a tax year ending after 2005.

Part 4 – Restricted farm losses

Current-year restricted farm loss

Total losses for the year from farming business		485			A
Minus the deductible farm loss:					
(amount A above – $2,500) **divided** by 2 =			a		
Amount a or $ 6,250 , whichever is less					b
			2,500		c
Subtotal (amount b **plus** amount c)			2,500	2,500	B
Current-year restricted farm loss (amount A **minus** amount B; enter amount C on line 410)					C

Continuity of restricted farm losses and request for a carryback

Restricted farm losses at the end of the previous tax year			d	
Deduct: Restricted farm loss expired*	400		e	
Restricted farm losses at the beginning of the tax year (amount d **minus** amount e)	402			D
Add:				
Restricted farm losses transferred on the amalgamation or the wind-up of a subsidiary corporation	405		f	
Current-year restricted farm loss (enter on line 233 of Schedule 1)	410		g	
Subtotal (amount f **plus** amount g)				E
Subtotal (amount D **plus** amount E)				F
Deduct:				
Restricted farm losses from previous tax years applied against current farming income (enter on line 333 of the T2 Return)	430		h	
Section 80 – Adjustments for forgiven amounts	440		i	
Other adjustments	450		j	
Subtotal (total of amounts h to j)				G
Restricted farm losses before any request for a carryback (amount F **minus** amount G)				H
Deduct – **Request to carry back restricted farm loss to:**				
First previous tax year to reduce farming income	941		k	
Second previous tax year to reduce farming income	942		l	
Third previous tax year to reduce farming income	943		m	
Subtotal (total of amounts k to m)				I
Closing balance of restricted farm losses to be carried forward to future tax years (amount H **minus** amount I)	480			J

Note

The total losses for the year from all farming businesses are calculated without including scientific research expenses.

* A restricted farm loss expires as follows:

- after **10** tax years if it arose in a tax year ending before 2006; and
- after **20** tax years if it arose in a tax year ending after 2005.

Part 5 – Listed personal property losses

Continuity of listed personal property loss and request for a carryback

Listed personal property losses at the end of the previous tax year			a			
Deduct: Listed personal property loss expired after seven tax years	500		b			
Listed personal property losses at the beginning of the tax year (amount a **minus** amount b)	502		▶			A
Add: Current-year listed personal property loss (from Schedule 6)				510		B
Subtotal (amount A **plus** amount B)						C
Deduct:						
Previous year personal property losses applied in the current tax year against listed personal property gains (enter on line 655 of Schedule 6)	530		c			
Other adjustments	550		d			
Subtotal (amount c **plus** amount d)			▶			D
Listed personal property losses remaining before any request for a carryback (amount C **minus** amount D)						E
Deduct – Request to carry back listed personal property loss to:						
First previous tax year to reduce listed personal property gains	961		e			
Second previous tax year to reduce listed personal property gains	962		f			
Third previous tax year to reduce listed personal property gains	963		g			
Subtotal (total of amounts e to g)			▶			F
Closing balance of listed personal property losses to be carried forward to future tax years (amount E **minus** amount F)				580		G

Part 7 – Limited partnership losses

Current-year limited partnership losses

1	2	3	4	5	6	7
Partnership identifier 600	Tax year ending YYYY/MM/DD 602	Corporation's share of limited partnership loss 604	Corporation's at-risk amount 606	Total of corporation's share of partnership investment tax credit, farming losses, and resource expenses 608	Column 4 **minus** column 5 (if negative, enter "0")	Current-year limited partnership losses (column 3 **minus** 6) 620
					Total (enter this amount on line 222 of Schedule 1)	

Limited partnership losses from previous tax years that may be applied in the current year

1	2	3	4	5	6	7
Partnership identifier 630	Tax year ending YYYY/MM/DD 632	Limited partnership losses at the end of the previous tax year 634	Corporation's at-risk amount 636	Total of corporation's share of partnership investment tax credit, business or property losses, and resource expenses 638	Column 4 **minus** column 5 (if negative, enter "0")	Limited partnership losses that may be applied in the year (the lesser of columns 3 and 6) 650

Continuity of limited partnership losses that can be carried forward to future tax years

1	2	3	4	5	6
Partnership identifier 660	Limited partnership losses at the end of the previous tax year 662	Limited partnership losses transferred on an amalgamation or the windup of a subsidiary 664	Current-year limited partnership losses (from column 620) 670	Limited partnership losses applied in the current year (cannot be more than column 650) 675	Current year limited partnership losses closing balance to be carried forward to future years (662 + 664 + 670 – 675) 680
			Total (enter this amount on line 335 of the T2 return)		

Note

If you have any current–or previous–year losses, enter your partnership identifier on line 600, 630, or 660.

Part 8 – Election under paragraph 88(1.1)(f)

If you are making an election under paragraph 88(1.1)(f), check the box . . . . 190 Yes

Further to a winding-up of a subsidiary, the portion of a non-capital loss, restricted farm loss, farm loss, or limited partnership loss from a wholly-owned subsidiary is deemed to be the loss of a parent from its tax year starting after the commencement of the winding-up.

Note

This election is only applicable for wind-ups under 88(1) that are reported on Schedule 24, *First-Time Filer after Incorporation, Amalgamation, or Winding-up of a Subsidiary into a Parent*, and the deemed provision is only for the tax years that start after the commencement of the wind-up.

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Schedule 5

TAX CALCULATION SUPPLEMENTARY – CORPORATIONS

Corporation's name	Business Number	Tax year-end Year Month Day
BURLINGTON HYDRO INC.	86829 1980 RC0001	2012-12-31

- Use this schedule if, during the tax year, the corporation:
  - had a permanent establishment in more than one jurisdiction (corporations that have no taxable income should only complete columns A, B and D in Part 1);
  - is claiming provincial or territorial tax credits or rebates (see Part 2); or
  - has to pay taxes, other than income tax, for Newfoundland and Labrador, or Ontario (see Part 2).
- Regulations mentioned in this schedule are from the *Income Tax Regulations.*
- For more information, see the *T2 Corporation – Income Tax Guide.*
- Enter the regulation number in field 100 of Part 1.

Part 1 – Allocation of taxable income

100 ______ Enter the Regulation that applies (402 to 413).

A Jurisdiction Tick yes if the corporation had a permanent establishment in the jurisdiction during the tax year. *		B Total salaries and wages paid in jurisdiction	C (B x taxable income**) / G	D Gross revenue	E (D x taxable income**) / H	F Allocation of taxable income (C + E) x 1/2*** (where either G or H is nil, do not multiply by 1/2)
Newfoundland and Labrador	003 1 Yes	103		143		
Newfoundland and Labrador offshore	004 1 Yes	104		144		
Prince Edward Island	005 1 Yes	105		145		
Nova Scotia	007 1 Yes	107		147		
Nova Scotia offshore	008 1 Yes	108		148		
New Brunswick	009 1 Yes	109		149		
Quebec	011 1 Yes	111		151		
Ontario	013 1 Yes	113		153		
Manitoba	015 1 Yes	115		155		
Saskatchewan	017 1 Yes	117		157		
Alberta	019 1 Yes	119		159		
British Columbia	021 1 Yes	121		161		
Yukon	023 1 Yes	123		163		
Northwest Territories	025 1 Yes	125		165		
Nunavut	026 1 Yes	126		166		
Outside Canada	027 1 Yes	127		167		
Total		129 G		169 H		

* "Permanent establishment" is defined in Regulation 400(2).

** If the corporation has income or loss from an international banking centre: the taxable income is the amount on line 360 or line Z of the T2 return **plus** the total amount not required to be included, or **minus** the total amount not allowed to be deducted, in calculating the corporation's income under section 33.1 of the federal *Income Tax Act*.

*** For corporations other than those described under Regulation 402, use the appropriate calculation described in the Regulations to allocate taxable income.

Notes:

1. After determining the allocation of taxable income, you have to calculate the corporation's provincial or territorial tax payable. For more information on how to calculate the tax for each province or territory, see the instructions for Schedule 5 in the *T2 Corporation – Income Tax Guide*.
2. If the corporation has provincial or territorial tax payable, complete Part 2.

Part 2 – Ontario tax payable, tax credits, and rebates

Total taxable income	Income eligible for small business deduction	Provincial or territorial allocation of taxable income	Provincial or territorial tax payable before credits
4,870,119		4,870,119	525,064

	Line	Amount		Total	
Ontario basic income tax (from Schedule 500)	270	560,064			
Deduct: Ontario small business deduction (from Schedule 500)	402	35,000			
Subtotal		525,064	▶	525,064	A6
Add:					
Ontario additional tax re Crown royalties (from Schedule 504)	274				
Ontario transitional tax debits (from Schedule 506)	276				
Recapture of Ontario research and development tax credit (from Schedule 508)	277				
Subtotal			▶		B6
Subtotal (amount A6 **plus** amount B6)				525,064	C6
Deduct:					
Ontario resource tax credit (from Schedule 504)	404				
Ontario tax credit for manufacturing and processing (from Schedule 502)	406				
Ontario foreign tax credit (from Schedule 21)	408				
Ontario credit union tax reduction (from Schedule 500)	410				
Ontario transitional tax credits (from Schedule 506)	414	1,084			
Ontario political contributions tax credit (from Schedule 525)	415				
Subtotal		1,084	▶	1,084	D6
Subtotal (amount C6 **minus** amount D6) (if negative, enter "0")				523,980	E6
Deduct: Ontario research and development tax credit (from Schedule 508)			416	21,343	
Ontario corporate income tax payable before Ontario corporate minimum tax credit (amount E6 **minus** amount on line 416) (if negative, enter "0")				502,637	F6
Deduct: Ontario corporate minimum tax credit (from Schedule 510)			418		
Ontario corporate income tax payable (amount F6 **minus** amount on line 418) (if negative, enter "0")				502,637	G6
Add:					
Ontario corporate minimum tax (from Schedule 510)	278				
Ontario special additional tax on life insurance corporations (from Schedule 512)	280				
Subtotal			▶		H6
Total Ontario tax payable before refundable credits (amount G6 **plus** amount H6)				502,637	I6
Deduct:					
Ontario qualifying environmental trust tax credit	450				
Ontario co-operative education tax credit (from Schedule 550)	452				
Ontario apprenticeship training tax credit (from Schedule 552)	454	29,919			
Ontario computer animation and special effects tax credit (from Schedule 554)	456				
Ontario film and television tax credit (from Schedule 556)	458				
Ontario production services tax credit (from Schedule 558)	460				
Ontario interactive digital media tax credit (from Schedule 560)	462				
Ontario sound recording tax credit (from Schedule 562)	464				
Ontario book publishing tax credit (from Schedule 564)	466				
Ontario innovation tax credit (from Schedule 566)	468				
Ontario business-research institute tax credit (from Schedule 568)	470				
Other Ontario tax credits					
Subtotal		29,919	▶	29,919	J6
Net Ontario tax payable or refundable credit (amount I6 **minus** amount J6) (if a credit, enter a negative amount) Include this amount on line 255.			290	472,718	K6

Summary

Enter the total net tax payable or refundable credits for all provinces and territories on line 255.

Net provincial and territorial tax payable or refundable credits	**255**	472,718

If the amount on line 255 is positive, enter the net provincial and territorial tax payable on line 760 of the T2 return.
If the amount on line 255 is negative, enter the net provincial and territorial refundable tax credits on line 812 of the T2 return.

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SCHEDULE 8

CAPITAL COST ALLOWANCE (CCA)

Name of corporation	Business Number	Tax year end Year Month Day
BURLINGTON HYDRO INC.	86829 1980 RC0001	2012-12-31

For more information, see the section called "Capital Cost Allowance" in the *T2 Corporation Income Tax Guide*.

Is the corporation electing under regulation 1101(5q)? **101** 1 Yes ☐ 2 No ☒

	1 Class number (See Note) 200	Description	2 Undepreciated capital cost at the beginning of the year (undepreciated capital cost at the end of last year) 201	3 Cost of acquisitions during the year (new property must be available for use)* 203	4 Net adjustments** 205	5 Proceeds of dispositions during the year (amount not to exceed the capital cost) 207	6 50% rule (1/2 of the amount, if any, by which the net cost of acquisitions exceeds column 5)*** 211	7 Reduced undepreciated capital cost	8 CCA rate % **** 212	9 Recapture of capital cost allowance (line 107 of Schedule 1) 213	10 Terminal loss (line 404 of Schedule 1) 215	11 Capital cost allowance (for declining balance method, column 7 **multiplied** by column 8, or a lower amount) (line 403 of Schedule 1) ***** 217	12 Undepreciated capital cost at the end of the year (column 6 **plus** column 7 **minus** column 11) 220
1.	1		74,051,489	232,245		0	116,123	74,167,611	4	0	0	2,966,704	71,317,030
2.	8		10,079,841	527,492		0	263,746	10,343,587	20	0	0	2,068,717	8,538,616
3.	10		648,571	64,539		0	32,270	680,840	30	0	0	204,252	508,858
4.	12		265,715	260,636		0	130,318	396,033	100	0	0	396,033	130,318
5.	45		10,180			0		10,180	45	0	0	4,581	5,599
6.	47	distribution equipment post Feb	33,489,911	8,002,945		0	4,001,473	37,491,383	8	0	0	2,999,311	38,493,545
7.	50	Computers	34,130	58,635		0	29,318	63,447	55	0	0	34,896	57,869
8.	95		943,057	5,855,000		0	2,927,500	3,870,557	0	0	0		6,798,057
		Totals	119,522,894	15,001,492			7,500,748	127,023,638				8,674,494	125,849,892

Note: Class numbers followed by a letter indicate the basic rate of the class taking into account the additional deduction allowed. Class 1a: 4% + 6% = 10% (class 1 to 10%), class 1b: 4% + 2% = 6% (class 1 to 6%).

* Include any property acquired in previous years that has now become available for use. This property would have been previously excluded from column 3. List separately any acquisitions that are not subject to the 50% rule, see Regulation 1100(2) and (2.2).

** Include amounts transferred under section 85, or on amalgamation and winding-up of a subsidiary. See the *T2 Corporation Income Tax Guide* for other examples of adjustments to include in column 4.

*** The net cost of acquisitions is the cost of acquisitions (column 3) **plus** or **minus** certain adjustments from column 4. For exceptions to the 50% rule, see Interpretation Bulletin IT-285, *Capital Cost Allowance – General Comments*.

**** Enter a rate only, if you are using the declining balance method. For any other method (for example the straight-line method, where calculations are always based on the cost of acquisitions), enter N/A. Then enter the amount you are claiming in column 11.

***** If the tax year is shorter than 365 days, prorate the CCA claim. Some classes of property do not have to be prorated. See the *T2 Corporation Income Tax Guide* for more information.

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SCHEDULE 9

RELATED AND ASSOCIATED CORPORATIONS

Name of corporation	Business Number	Tax year end Year Month Day
BURLINGTON HYDRO INC.	86829 1980 RC0001	2012-12-31

- Complete this schedule if the corporation is related to or associated with at least one other corporation.
- For more information, see the *T2 Corporation Income Tax Guide*.

	Name 100	Country of residence (other than Canada) 200	Business number (see note 1) 300	Relationship code (see note 2) 400	Number of common shares you own 500	% of common shares you own 550	Number of preferred shares you own 600	% of preferred shares you own 650	Book value of capital stock 700
1.	BURLINGTON ELECTRICITY SERVIC		86829 1782 RC0001	3					
2.	BURLINGTON HYDRO ELECTRIC IN		88361 4927 RC0001	1					
3.	THE CITY OF BURLINGTON		NR	3					

Note 1: Enter "NR" if the corporation is not registered or does not have a business number.

Note 2: Enter the code number of the relationship that applies from the following order: 1 - Parent 2 - Subsidiary 3 - Associated 4 - Related but not associated

T2 SCH 9 (11)

Canada

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SCHEDULE 10

CUMULATIVE ELIGIBLE CAPITAL DEDUCTION

Name of corporation	Business Number	Tax year-end Year Month Day
BURLINGTON HYDRO INC.	86829 1980 RC0001	2012-12-31

- For use by a corporation that has eligible capital property. For more information, see the *T2 Corporation Income Tax Guide*.
- A separate cumulative eligible capital account must be kept for each business.

Part 1 – Calculation of current year deduction and carry-forward

Cumulative eligible capital - Balance at the end of the preceding taxation year (if negative, enter "0")			200	94,006	A
Add: Cost of eligible capital property acquired during the taxation year	222				
Other adjustments	226				
Subtotal (line 222 plus line 226)		x 3 / 4 =			B
Non-taxable portion of a non-arm's length transferor's gain realized on the transfer of an eligible capital property to the corporation after December 20, 2002	228	x 1 / 2 =			C
amount B minus amount C (if negative, enter "0")			▶		D
Amount transferred on amalgamation or wind-up of subsidiary			224		E
Subtotal (add amounts A, D, and E)			230	94,006	F
Deduct: Proceeds of sale (less outlays and expenses not otherwise deductible) from the disposition of all eligible capital property during the taxation year	242		G		
The gross amount of a reduction in respect of a forgiven debt obligation as provided for in subsection 80(7)	244		H		
Other adjustments	246		I		
(add amounts G,H, and I)		x 3 / 4 =	248		J
Cumulative eligible capital balance (amount F minus amount J)				94,006	K
(if amount K is negative, enter "0" at line M and proceed to Part 2)					
Cumulative eligible capital for a property no longer owned after ceasing to carry on that business		249			
amount K	94,006				
less amount from line 249					
Current year deduction	94,006	x 7.00 % =	250	6,580 *	
(line 249 plus line 250) (enter this amount at line 405 of Schedule 1)		6,580	▶	6,580	L
Cumulative eligible capital – Closing balance (amount K minus amount L) (if negative, enter "0")			300	87,426	M

* You can claim any amount up to the maximum deduction of 7%. The deduction may not exceed the maximum amount prorated by the number of days in the taxation year divided by 365.

Part 2 – Amount to be included in income arising from disposition

(complete this part only if the amount at line K is negative)

Amount from line K (show as positive amount)							N
Total of cumulative eligible capital (CEC) deductions from income for taxation years beginning after June 30, 1988			400		1		
Total of all amounts which reduced CEC in the current or prior years under subsection 80(7)			401		2		
Total of CEC deductions claimed for taxation years beginning before July 1, 1988	402	3					
Negative balances in the CEC account that were included in income for taxation years beginning before July 1, 1988	408	4					
Line 3 minus line 4 (if negative, enter "0")		►			5		
Total of lines 1, 2 and 5					6		
Amounts included in income under paragraph 14(1)(b), as that paragraph applied to taxation years ending after June 30, 1988 and before February 28, 2000, to the extent that it is for an amount described at line 400		7					
Amounts at line T from Schedule 10 of previous taxation years ending after February 27, 2000		8					
Subtotal (line 7 plus line 8)	409	►			9		
Line 6 minus line 9 (if negative, enter "0")					►		O
Line N minus line O (if negative, enter "0")							P
			Line 5		x 1 / 2 =		Q
Line P minus line Q (if negative, enter "0")							R
			Amount R		x 2 / 3 =		S
Amount N or amount O, whichever is less							T
Amount to be included in income (amount S plus amount T) (enter this amount on line 108 of Schedule 1)					410		

Continuity of financial statement reserves (not deductible)

Financial statement reserves (not deductible)

	Description	Balance at the beginning of the year	Transfer on an amalgamation or the wind-up of a subsidiary	Add	Deduct	Balance at the end of the year
1	LIABILITY FOR FUTURE BENEF	3,172,353		3,352,255	3,172,353	3,352,255
2	AFDA	300,000		245,000	300,000	245,000
3	Accrued bonues > 180 days			4,286		4,286
4						
	Reserves from Part 2 of Schedule 13					
	Totals	3,472,353		3,601,541	3,472,353	3,601,541

The total opening balance plus the total transfers should be entered on line 414 of Schedule 1 as a deduction.
The total closing balance should be entered on line 126 of Schedule 1 as an addition.

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SCHEDULE 14

MISCELLANEOUS PAYMENTS TO RESIDENTS

Name of corporation	Business Number	Tax year end Year Month Day
BURLINGTON HYDRO INC.	86829 1980 RC0001	2012-12-31

- This schedule must be completed by all corporations who made the following payments to residents of Canada: royalties for which the corporation has not filed a T5 slip; research and development fees; management fees; technical assistance fees; and similar payments.
- Please enter the name and address of the recipient and the amount of the payment in the applicable column. If several payments of the same type (i.e., management fees) were made to the same person, enter the total amount paid. If similar types of payments have been made, but do not fit into any of the categories, enter these amounts in the column entitled "Similar payments".

	Name of recipient 100	Address of recipient 200	Royalties 300	Research and development fees 400	Management fees 500	Technical assistance fees 600	Similar payments 700
1	BURLINGTON HYDRO ELECTF	1340 BRANT STREET BURLINGTON ON L7R 3Z7			99,582		

T2 SCH 14 (99)

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SCHEDULE 15

DEFERRED INCOME PLANS

Name of corporation	Business Number	Tax year end Year Month Day
BURLINGTON HYDRO INC.	86829 1980 RC0001	2012-12-31

- Complete the information below if the corporation deducted payments from its income made to a registered pension plan (RPP), a registered supplementary unemployment benefit plan (RSUBP), a deferred profit sharing plan (DPSP), or an employee profit sharing plan (EPSP).
- If the trust that governs an employee profit sharing plan is **not resident** in Canada, please indicate if the T4PS, *Statement of Employees Profit Sharing Plan Allocations and Payments,* Supplementary slip(s) were filed for the last calendar year, and whether they were filed by the trustee or the employer.

	Type of plan (see note 1) 100	Amount of contribution $ (see note 2) 200	Registration number (RPP, RSUBP, and DPSP only) 300	Name of EPSP trust 400	Address of EPSP trust 500	T4PS slip(s) filed by: (see note 3) (EPSP only) 600
1	1	801,195	0345983			

Note 1: Enter the applicable code number:

1 – RPP
2 – RSUBP
3 – DPSP
4 – EPSP

Note 2: You do not need to add to Schedule 1 any payments you made to deferred income plans. To reconcile such payments, calculate the following amount:

Total of all amounts indicated in column 200 of this schedule	801,195	A
Less:		
Total of all amounts for deferred income plans deducted in your financial statements	801,195	B
Deductible amount for contributions to deferred income plans (amount A **minus** amount B) (if negative, enter "0")		C

Enter amount C on line 417 of Schedule 1

Note 3: T4PS slip(s) filed by: 1 – Trustee
2 – Employer

T2 SCH 15 (06)

Canada

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SCHEDULE 23

AGREEMENT AMONG ASSOCIATED CANADIAN-CONTROLLED PRIVATE CORPORATIONS TO ALLOCATE THE BUSINESS LIMIT

- For use by a Canadian-controlled private corporation (CCPC) to identify all associated corporations and to assign a percentage for each associated corporation. This percentage will be used to allocate the business limit for purposes of the small business deduction. Information from this schedule will also be used to determine the date the balance of tax is due and to calculate the reduction to the business limit.
- An associated CCPC that has more than one tax year ending in a calendar year, is required to file an agreement for each tax year ending in that calendar year.

Column 1: Enter the legal name of each of the corporations in the associated group. Include non-CCPCs and CCPCs that have filed an election under subsection 256(2) of the *Income Tax Act* (ITA) not to be associated for purposes of the small business deduction.

Column 2: Provide the Business Number for each corporation (if a corporation is not registered, enter "NR").

Column 3: Enter the association code that applies to each corporation:

1 – Associated for purposes of allocating the business limit (unless code 5 applies)
2 – CCPC that is a "third corporation" that has elected under subsection 256(2) not to be associated for purposes of the small business deduction
3 – Non-CCPC that is a "third corporation" as defined in subsection 256(2)
4 – Associated non-CCPC
5 – Associated CCPC to which code 1 does not apply because of a subsection 256(2) election made by a "third corporation"

Column 4: Enter the business limit for the year of each corporation in the associated group. The business limit is computed at line 4 on page 4 of each respective corporation's T2 return.

Column 5: Assign a percentage to allocate the business limit to each corporation that has an association code 1 in column 3. The total of all percentages in column 5 cannot exceed 100%.

Column 6: Enter the business limit allocated to each corporation by multiplying the amount in column 4 by the percentage in column 5. Add all business limits allocated in column 6 and enter the total at line A. Ensure that the total at line A falls within the range for the calendar year to which the agreement applies:

Calendar year	Acceptable range
2006	maximum $300,000
2007	$300,001 to $400,000

Calendar year	Acceptable range
2008	maximum $400,000
2009	$400,001 to $500,000

If the calendar year to which this agreement applies is after 2009, ensure that the total at line A does not exceed $500,000.

Allocating the business limit

Date filed (do not use this area) . . . . **025** Year Month Day

Enter the calendar year to which the agreement applies . . . . **050** Year 2012

Is this an amended agreement for the above-noted calendar year that is intended to replace an agreement previously filed by any of the associated corporations listed below? . . . . **075** 1 Yes [ ] 2 No [X]

	1 Names of associated corporations **100**	2 Business Number of associated corporations **200**	3 Association code **300**	4 Business limit for the year (before the allocation) $	5 Percentage of the business limit % **350**	6 Business limit allocated* $ **400**	
1	BURLINGTON HYDRO INC.	86829 1980 RC0001	1	500,000	100.0000	500,000	
2	BURLINGTON ELECTRICITY SERVICES INC.	86829 1782 RC0001	1	500,000			
3	BURLINGTON HYDRO ELECTRIC INC.	88361 4927 RC0001	1	500,000			
4	THE CITY OF BURLINGTON	NR	4				
				Total	100.0000	500,000	**A**

Business limit reduction under subsection 125(5.1) of the ITA

The business limit reduction is calculated in the small business deduction area of the T2 return. One of the factors used in this calculation is the "Large corporation amount" at line 415 of the T2 return. If the corporation is a member of an associated group** of corporations in the current tax year, the amount at line 415 of the T2 return is equal to 0.225% x (A - $10,000,000) where, "A" is the total of taxable capital employed in Canada*** of each corporation in the associated group for its last tax year ending in the preceding calendar year.

* Each corporation will enter on line 410 of the T2 return, the amount allocated to it in column 6. However, if the corporation's tax year is less than 51 weeks, prorate the amount in column 6 by the number of days in the tax year divided by 365, and enter the result on line 410 of the T2 return.

Special rules apply if a CCPC has more than one tax year ending in a calendar year and is associated in more than one of those years with another CCPC that has a tax year ending in the same calendar year. If the tax year straddles January 1, 2009, the business limit for the second (or subsequent) tax year(s) will be equal to the lesser of the business limit that would have been determined for the first tax year ending in the calendar year, if $500,000 was used in allocating the amounts among associated corporations and the business limit determined for the second (or subsequent) tax year(s) ending in the same calendar year. Otherwise, the business limit for the second (or subsequent) tax year(s) will be equal to the lesser of the business limit determined for the first tax year ending in the calendar year and the business limit determined for the second (or subsequent) tax year(s) ending in the same calendar year.

** The associated group includes the corporation filing this schedule and each corporation that has an "association code" of 1 or 4 in column 3.

*** "Taxable capital employed in Canada" has the meaning assigned by subsection 181.2(1) or 181.3(1) or section 181.4 of the ITA.

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Schedule 31

Investment Tax Credit – Corporations

General information

- Use this schedule:
  - to calculate an investment tax credit (ITC) earned during the tax year;
  - to claim a deduction against Part I tax payable;
  - to claim a refund of credit earned during the current tax year;
  - to claim a carryforward of credit from previous tax years;
  - to transfer a credit following an amalgamation or wind-up of a subsidiary, as described under subsections 87(1) and 88(1) of the federal *Income Tax Act*;
  - to request a credit carryback to one or more previous years; or
  - if you are subject to a recapture of ITC.
- The ITC is eligible for a three-year carryback (if not deductible in the year earned). It is also eligible for a twenty-year carryforward.
- All legislative references are to the federal *Income Tax Act* and *Income Tax Regulations*.
- Investments or expenditures, described in subsection 127(9) of the Act and Part XLVI of the Regulations, that earn an ITC are:
  - qualified property and qualified resource property (Parts 4 to 7 of this schedule);
  - expenditures that are part of the SR&ED qualified expenditure pool (Parts 8 to 17). File Form T661, *Scientific Research and Experimental Development (SR&ED) Expenditures Claim;*
  - pre-production mining expenditures (Parts 18 to 20);
  - apprenticeship job creation expenditures (Parts 21 to 23); and
  - child care spaces expenditures (Parts 24 to 28).
- Include a completed copy of this schedule with the *T2 Corporation Income Tax Return*. If you need more space, attach additional schedules.
- For more information on ITCs, see the section called "Investment Tax Credit" in Guide T4012, *T2 Corporation – Income Tax Guide*, Information Circular IC 78-4, *Investment Tax Credit Rates*, and its related Special Release*.*
- For more information on SR&ED, see Brochure RC4472, *Overview of the Scientific Research and Experimental Development Program (SR&ED) Tax Incentive Program*; Brochure RC4467, *Support for your R&D in Canada*, and T4088*, Guide to Form T661 – Scientific Research and Experimental Development (SR&ED) Expenditures Claim.* Also see the *Eligibility of Work for SR&ED Investment Tax Credits Policy* at **www.cra.gc.ca//txcrdt/sred-rsde/clmng/lgbltywrkfrsrdnvstmnttxcrdts-eng.html**.

Detailed information

- For the purpose of this schedule, **investment** means the capital cost of the property (excluding amounts added by an election under section 21 of the Act), determined without reference to subsections 13(7.1) and 13(7.4), minus the amount of any government or non-government assistance that the corporation has received, is entitled to receive, or can reasonably be expected to receive for that property when it files the income tax return for the year in which the property was acquired.
- An ITC deducted or refunded in a tax year for a depreciable property, other than a depreciable property deductible under paragraph 37(1)(b), reduces the capital cost of that property in the next tax year. It also reduces the undepreciated capital cost of that class in the next tax year. An ITC for SR&ED deducted or refunded in a tax year will reduce the balance in the pool of deductible SR&ED expenditures and the adjusted cost base (ACB) of an interest in a partnership in the next tax year. An ITC from pre-production mining expenditures deducted in a tax year reduces the balance in the pool of deductible cumulative Canadian exploration expenses in the next tax year.
- Property acquired has to be **available for use** before a claim for an ITC can be made. See subsections 127(11.2) and 248(19) for more information.
- Expenditures for SR&ED and capital costs for a property qualifying for an ITC must be identified by the claimant on Form T661 and Schedule 31 no later than 12 months after the claimant's income tax return is due for the tax year in which it incurred the expenditures or capital costs.
- Partnership allocations – Subsection 127(8) provides for the allocation of the amount that may reasonably be considered to be a partner's share of the ITCs of the partnership at the end of the fiscal period of the partnership. An allocation of ITCs is generally considered to be the partner's reasonable share of the ITCs if it is made in the same proportion in which the partners have agreed to share any income or loss and if section 103 is not applicable for the agreement to share any income or loss. Special rules apply to specified and limited partners. For more information, see Guide T4068, *Guide for the Partnership Information Return*.
- For SR&ED expenditures, the expression **in Canada** includes the "exclusive economic zone" (as defined in the *Oceans Act* to generally consist of an area that is within 200 nautical miles from the Canadian coastline), including the airspace, seabed and subsoil for that zone.
- For the purpose of this schedule, the expression **Atlantic Canada** includes the Gaspé Peninsula and the provinces of Newfoundland and Labrador, Prince Edward Island, Nova Scotia, and New Brunswick, as well as their respective offshore regions (prescribed in Regulation 4609).
- For the purpose of this schedule, **qualified property** means property in Atlantic Canada that is used primarily for manufacturing and processing, farming or fishing, logging, storing grain, or harvesting peat. Property in Atlantic Canada that is used primarily for oil and gas, and mining activities is considered qualified property only if acquired by the taxpayer **before** March 29, 2012. Qualified property includes new buildings and new machinery and equipment (prescribed in Regulation 4600), and if acquired by the taxpayer **after** March 28, 2012, new energy generation and conservation property (prescribed in Regulation 4600). Qualified property can also be used primarily to produce or process electrical energy or steam in a prescribed area (as described in Regulation 4610). See the definition of **qualified property** in subsection 127(9) of the Act for more details.
- For the purpose of this schedule, **qualified resource property** means property in Atlantic Canada that is used primarily for oil and gas, and mining activities, if acquired by the taxpayer **after** March 28, 2012, and **before** January 1, 2016. Qualified resource property includes new buildings and new machinery and equipment (prescribed in Regulation 4600). See the definition of **qualified resource property** in subsection 127(9) of the Act for more details.

Detailed information (continued)

- For the purpose of this schedule, **pre-production mining exploration expenditures** are expenses incurred **after** March 28, 2012, by the taxpayer to determine the existence, location, extent, or quality of certain mineral resources in Canada, excluding expenses incurred in the exploration of an oil or gas well. See subparagraph (a)(i) of the definition of **pre-production mining expenditure** in subsection 127(9) for more details.
- For the purpose of this schedule, **pre-production mining development expenditures** are expenses incurred **after** March 28, 2012, by the taxpayer to bring a new mineral resource mine in Canada into production, excluding expenses in the development of a bituminous sands deposit or an oil shale deposit. See subparagraph (a)(ii) of the definition of **pre-production mining expenditure** in subsection 127(9) for more details.

Part 1 – Investments, expenditures and percentages

Investments	**Specified percentage**
Qualified property acquired primarily for use in Atlantic Canada	10 %
Qualified resource property acquired primarily for use in Atlantic Canada and acquired:	
– after March 28, 2012, and before 2014	10 %
– after 2013 and before 2016	5 %
– after 2015*	0 %
Expenditures	
If you are a Canadian-controlled private corporation (CCPC), this percentage may apply to the portion that you claim of the SR&ED qualified expenditure pool that does not exceed your expenditure limit (see Part 10)	35 %
Note: If your current year's qualified expenditures are more than the corporation's expenditure limit (see Part 10), the excess is eligible for an ITC calculated at the 20 % rate**.	
If you are a corporation that is not a CCPC and have incurred qualified expenditures for SR&ED in any area in Canada:	
– before 2014**	20 %
– after 2013**	15 %
If you are a taxable Canadian corporation that incurred pre-production mining expenditures before March 29, 2012	10 %
If you are a taxable Canadian corporation that incurred pre-production mining exploration expenditures***:	
– after March 28, 2012, and before 2013	10 %
– in 2013	5 %
– after 2013***	0 %
If you are a taxable Canadian corporation that incurred pre-production mining development expenditures****:	
– after March 28, 2012, and before 2014****	10 %
– in 2014	7 %
– in 2015	4 %
– after 2015****	0 %
If you paid salary and wages to apprentices in the first 24 months of their apprenticeship contract for employment	10 %
If you incurred eligible expenditures after March 18, 2007, for the creation of licensed child care spaces for the children of your employees and, potentially, for other children	25 %

* A transitional relief rate of 10% may apply to property acquired after 2013 and before 2017, if the property is acquired under a written agreement entered into before March 29, 2012, or the property is acquired as part of a phase of a project where the construction or the engineering and design work for the construction started before March 29, 2012. See paragraph (a.1) of the definition of **specified percentage** in subsection 127(9) for more details.

** The reduction of the rate from 20% to 15% applies to 2014 and later tax years, except that, for 2014 tax years that start before 2014, the reduction is pro-rated based on the number of days in the tax year that are after 2013.

*** Pre-production mining exploration expenditures are described in subparagraph (a)(i) of the definition of **pre-production mining expenditure** in subsection 127(9).

**** A transitional relief rate of 10% may apply to expenditures incurred after 2013 and before 2016, if the expenditure is incurred under a written agreement entered into before March 29, 2012, or the expenditure is incurred as part of the development of a new mine where the construction or the engineering and design work for the construction of the new mine started before March 29, 2012. See subparagraph (k)(ii) of the definition of **specified percentage** in subsection 127(9) for more details. Pre-production mining development expenditures are described in subparagraph (a)(ii) of the definition of **pre-production mining expenditure** in subsection 127(9).

Corporation's name	Business number	Tax year-end Year Month Day
BURLINGTON HYDRO INC.	86829 1980 RC0001	2012-12-31

Part 2 – Determination of a qualifying corporation

Is the corporation a qualifying corporation? . . . . **101** 1 Yes [ ] 2 No [X]

For the purpose of a refundable ITC, a **qualifying corporation** is defined under subsection 127.1(2). The corporation has to be a CCPC and its taxable income (before any loss carrybacks) for its previous tax year cannot be more than its **qualifying income limit** for the particular tax year. If the corporation is associated with any other corporations during the tax year, the total of the taxable incomes of the corporation and the associated corporations (before any loss carrybacks), for their last tax year ending in the previous calendar year, cannot be more than their qualifying income limit for the particular tax year.

Note: A CCPC calculating a refundable ITC, is considered to be associated with another corporation if it meets any of the conditions in subsection 256(1), except where:

- one corporation is associated with another corporation solely because one or more persons own shares of the capital stock of both corporations; and
- one of the corporations has at least one shareholder who is not common to both corporations.

If you are a **qualifying** corporation, you will earn a **100%** refund on your share of any ITCs earned at the 35% rate on qualified **current** expenditures for SR&ED, up to the allocated expenditure limit. The 100% refund does not apply to qualified **capital** expenditures eligible for the 35% credit rate. They are only eligible for the **40%** refund*.

Some CCPCs that are **not qualifying** corporations may also earn a **100%** refund on their share of any ITCs earned at the 35% rate on qualified **current** expenditures for SR&ED, up to the allocated expenditure limit. The expenditure limit can be determined in Part 10. The 100% refund does not apply to qualified **capital** expenditures eligible for the 35% credit rate. They are only eligible for the **40%** refund*.

The 100% refund will not be available to a corporation that is an **excluded corporation** as defined under subsection 127.1(2). A corporation is an excluded corporation if, at any time during the year, it is a corporation that is either controlled by (directly or indirectly, in any manner whatever) or is related to:

a) one or more persons exempt from Part I tax under section 149;

b) Her Majesty in right of a province, a Canadian municipality, or any other public authority; or

c) any combination of persons referred to in a) or b) above.

* Capital expenditures incurred after December 31, 2013, including lease payments for property that would have been a capital expenditure if purchased directly, are **not** qualified SR&ED expenditures and are **not** eligible for an ITC on SR&ED expenditures.

Part 3 – Corporations in the farming industry

Complete this area if the corporation is making SR&ED contributions.

Is the corporation claiming a contribution in the current year to an agricultural organization whose goal is to finance SR&ED work (for example, check-off dues)? . . . . **102** 1 Yes [ ] 2 No [X]

Contributions to agricultural organizations for SR&ED* . . . . **103** ______

If **yes**, complete Schedule 125, *Income Statement Information*, to identify the type of farming industry the corporation is involved in. For more information on Schedule 125, see the *Guide to the General Index of Financial Information (GIFI) for Corporations*. Enter contributions on line 350 of Part 8.

* Enter only contributions not already included on Form T661. Include all of the contributions made before 2013 and 80% of the contributions made after 2012.

Qualified Property and Qualified Resource Property

Part 4 – Eligible investments for qualified property and qualified resource property from the current tax year

CCA* class number **105**	Description of investment **110**	Date available for use **115**	Location used (province or territory) **120**	Amount of investment **125**

Total of investments for qualified property and qualified resource property ______ A

* CCA: capital cost allowance

Part 5 – Current-year credit and account balances – ITC from investments in qualified property and qualified resource property

ITC at the end of the previous tax year . . . . B

Deduct:

Credit deemed as a remittance of co-op corporations **210**

Credit expired **215**

Subtotal (line 210 **plus** line 215) ▶ C

ITC at the beginning of the tax year (amount B **minus** amount C) **220**

Add:

Credit transferred on amalgamation or wind-up of subsidiary **230**

ITC from repayment of assistance **235**

Qualified property; and qualified resource property acquired after March 28, 2012, and before January 1, 2014* (applicable part of amount A from Part 4) . . . . . . x 10 % = **240**

Qualified resource property acquired after December 31, 2013, and before January 1, 2016 (applicable part of amount A from Part 4) . . . . . . x 5 % = **242**

Credit allocated from a partnership **250**

Subtotal (total of lines 230 to 250) ▶ D

Total credit available (line 220 **plus** amount D) . . . . . . E

Deduct:

Credit deducted from Part I tax (enter at amount D in Part 30) **260**

Credit carried back to the previous year(s) (amount H from Part 6) . . . . . . a

Credit transferred to offset Part VII tax liability **280**

Subtotal (total of line 260, amount a, and line 280) ▶ F

Credit balance before refund (amount E **minus** amount F) . . . . . . G

Deduct:

Refund of credit claimed on investments from qualified property and qualified resource property (from Part 7) **310**

ITC closing balance of investments from qualified property and qualified resource property (amount G **minus** line 310) **320**

* Include investments acquired after 2013 and before 2017 that are eligible for transitional relief.

Part 6 – Request for carryback of credit from investments in qualified property and qualified resource property

	Year	Month	Day			
1st previous tax year				Credit to be applied	**901**	
2nd previous tax year				Credit to be applied	**902**	
3rd previous tax year				Credit to be applied	**903**	

Total (enter at amount a in Part 5) H

Part 7 – Refund for qualifying corporations on investments from qualified property and qualified resource property

Current-year ITCs (total of lines 240, 242, and 250 from Part 5) I

Credit balance before refund (amount G from Part 5) . . . . . . J

Refund (40 % of amount I or J, whichever is less) . . . . . . K

Enter amount K or a lesser amount on line 310 in Part 5 (also enter it on line 780 of the T2 return if the corporation does not claim an SR&ED ITC refund).

SR&ED

Part 8 – Qualified SR&ED expenditures

Current expenditures

Current expenditures (from line 557 on Form T661)	452,937		
Add:			
Contributions to agricultural organizations for SR&ED*			
Current expenditures (line 557 on Form T661 **plus** line 103 from Part 3)*	452,937 ►	350	452,937
Capital expenditures incurred **before** 2014 (from line 558 on Form T661)**		360	
Repayments made in the year (from line 560 on Form T661)		370	
Qualified SR&ED expenditures (total of lines 350 to 370)		380	452,937

* If you are claiming only contributions made to agricultural organizations for SR&ED, line 350 should equal line 103 in Part 3. Do not file Form T661.

** Capital expenditures incurred after December 31, 2013, are not qualified SR&ED expenditures.

Part 9 – Components of the SR&ED expenditure limit calculation

Part 9 only applies if the corporation is a CCPC.

Note: A CCPC that calculates SR&ED expenditure limit is considered to be associated with another corporation if it meets any of the conditions in subsection 256(1), except where:

- one corporation is associated with another corporation solely because one or more persons own shares of the capital stock of the corporation; and
- one of the corporations has at least one shareholder who is not common to both corporations.

Is the corporation associated with another CCPC for the purpose of calculating the SR&ED expenditure limit? 385 — 1 Yes [X] 2 No [ ]

Complete lines 390 and 398, if you answered **no** to the question at line 385 above or if the corporation is not associated with any other corporations (the amounts for associated corporations will be determined on Schedule 49).

Enter your taxable income for the previous tax year* (prior to any loss carry-backs applied) 390 ______

Enter your taxable capital employed in Canada for the previous tax year minus $10 million. If this amount is nil or negative, enter "0". If this amount is over $40 million, enter $40 million 398 ______

* If either of the tax years referred to at line 390 is less than 51 weeks, **multiply** the taxable income by the following result: 365 **divided** by the number of days in these tax years.

Part 10 – SR&ED expenditure limit for a CCPC

For a stand-alone corporation: $ 8,000,000

Deduct:

Taxable income for the previous tax year (line 390 from Part 9) or $500,000, whichever is more ______ x 10 = ______ A

Excess ($8,000,000 **minus** amount A; if negative, enter "0") ______ B

$ 40,000,000 **minus** line 398 from Part 9 ______ a

Amount a **divided** by $ 40,000,000 ______ C

Expenditure limit for the stand-alone corporation (amount B **multiplied** by amount C) ______ D*

For an associated corporation:

If associated, the allocation of the SR&ED expenditure limit as provided on Schedule 49 400 ______ E*

Where the tax year of the corporation is less than 51 weeks, calculate the amount of the expenditure limit as follows:

Amount D or E ______ x (Number of days in the tax year 366) / 365 = ______ F

Your SR&ED expenditure limit for the year (enter the amount from line D, E, or F, whichever applies) 410 ______

* Amount D or E cannot be more than $3,000,000.

Part 11 – Investment tax credits on SR&ED expenditures

Current expenditures (line 350 from Part 8) or the expenditure limit (line 410 from Part 10), whichever is less*	420		x	35 %	=		G
Line 350 **minus** line 410 (if negative, enter "0")**	430	452,937	x	20 %	=	90,587	H
Line 410 **minus** line 350 (if negative, enter "0")			b				
Capital expenditures (line 360 from Part 8) or amount b above, whichever is less*	440		x	35 %	=		I
Line 360 **minus** amount b above (if negative, enter "0")**	450		x	20 %	=		J
Repayments (amount from line 370 in Part 8)							

If a corporation makes a repayment of any government or non-government assistance, or contract payments that reduced the amount of qualified expenditures for ITC purposes, the amount of the repayment is eligible for a credit at the rate that would have applied to the repaid amount. Enter the amount of the repayment on the line that corresponds to the appropriate rate.**

460		x	35 %	=		c
480		x	20 %	=		d

Subtotal (amount c **plus** amount d) ▶ K

Current-year SR&ED ITC (total of amounts G to K; enter on line 540 in Part 12) 90,587 L

* For corporations that are not CCPCs, enter "0" for amounts G and I.

** For tax years that end after 2013, the general SR&ED rate is reduced from 20% to 15%, except that, for 2014 tax years that start before 2014, the reduction is pro-rated based on the number of days in the tax year that are after 2013.

Part 12 – Current-year credit and account balances – ITC from SR&ED expenditures

ITC at the end of the previous tax year				M
Deduct:				
Credit deemed as a remittance of co-op corporations	510			
Credit expired	515			
Subtotal (line 510 **plus** line 515)			▶	N
ITC at the beginning of the tax year (amount M **minus** amount N)			520	
Add:				
Credit transferred on amalgamation or wind-up of subsidiary	530			
Total current-year credit (from amount L in Part 11)	540	90,587		
Credit allocated from a partnership	550			
Subtotal (total of lines 530 to 550)		90,587	▶ 90,587	O
Total credit available (line 520 **plus** amount O)			90,587	P
Deduct:				
Credit deducted from Part I tax (enter at amount E in Part 30)	560	90,587		
Credit carried back to the previous year(s) (amount S from Part 13)			e	
Credit transferred to offset Part VII tax liability	580			
Subtotal (total of line 560, amount e, and line 580)		90,587	▶ 90,587	Q
Credit balance before refund (amount P **minus** amount Q)				R
Deduct:				
Refund of credit claimed on SR&ED expenditures (from Part 14 or 15, whichever applies)			610	
ITC closing balance on SR&ED (amount R **minus** line 610)			620	

Part 13 – Request for carryback of credit from SR&ED expenditures

	Year	Month	Day				
1st previous tax year				Credit to be applied	911		
2nd previous tax year				Credit to be applied	912		
3rd previous tax year				Credit to be applied	913		
				Total (enter at amount e in Part 12)			S

Part 14 – Refund of ITC for qualifying corporations – SR&ED

Complete this part only if you are a qualifying corporation as determined at line 101 in Part 2.

Is the corporation an excluded corporation as defined under subsection 127.1(2)? . . . 650 1 Yes [ ] 2 No [X]

Current-year ITC (lines 540 **plus** 550 from Part 12 **minus** amount K from Part 11) . . . ______ f

Refundable credits (amount f above or amount R from Part 12, whichever is less)* . . . ______ T

Deduct:

Amount T or amount G from Part 11, whichever is less . . . ______ U

Net amount (amount T **minus** amount U; if negative, enter "0") . . . ______ V

Amount V **multiplied** by 40 % . . . ______ W

Add:

Amount U . . . ______ X

Refund of ITC (amount W **plus** amount X – enter this, or a lesser amount, on line 610 in Part 12) . . . ______ Y

Enter the total of lines 310 from Part 5 and 610 from Part 12 on line 780 of the T2 return.

* If you are also an excluded corporation [as defined in subsection 127.1(2)], this amount must be multiplied by 40%. Claim this, or a lesser amount, as your refund of ITC for amount Y.

Part 15 – Refund of ITC for CCPCs that are not qualifying or excluded corporations – SR&ED

Complete this box only if you are a CCPC that is not a qualifying or excluded corporation as determined at line 101 in Part 2.

Credit balance before refund (amount R from Part 12) . . . ______ Z

Deduct:

Amount Z or amount G from Part 11, whichever is less . . . ______ AA

Net amount (amount Z **minus** amount AA; if negative, enter "0") . . . ______ BB

Amount BB or amount I from Part 11, whichever is less . . . ______ CC

Amount CC **multiplied** by 40 % . . . ______ DD

Add :

Amount AA . . . ______ EE

Refund of ITC (amount DD **plus** amount EE) . . . ______ FF

Enter FF, or a lesser amount, on line 610 in Part 12 and also on line 780 of the T2 return.

Recapture – SR&ED

Part 16 – Recapture of ITC for corporations and corporate partnerships – SR&ED

You will have a recapture of ITC in a year when **all** of the following conditions are met:

- you acquired a particular property in the current year or in any of the 20 previous tax years, if the credit was earned in a tax year ending after 1997 and did not expire before 2008;
- you claimed the cost of the property as a qualified expenditure for SR&ED on Form T661;
- the cost of the property was included in calculating your ITC or was the subject of an agreement made under subsection 127(13) to transfer qualified expenditures; and
- you disposed of the property or converted it to commercial use after February 23, 1998. This condition is also met if you disposed of or converted to commercial use a property that incorporates the particular property previously referred to.

Note:

The recapture **does not apply** if you disposed of the property to a non-arm's-length purchaser who intended to use it all or substantially all for SR&ED. When the non-arm's-length purchaser later sells or converts the property to commercial use, the recapture rules will apply to the purchaser based on the historical ITC rate of the original user.

You will report a recapture on the T2 return for the year in which you disposed of the property or converted it to commercial use. In the following tax year, add the amount of the ITC recapture to the SR&ED expenditure pool.

If you have more than one disposition for calculations 1 and 2, complete the columns for each disposition for which a recapture applies, using the calculation formats below.

Calculation 1 – If you meet all of the above conditions

Amount of ITC you originally calculated for the property you acquired, or the original user's ITC where you acquired the property from a non-arm's length party, as described in the note above 700	Amount calculated using ITC rate at the date of acquisition (or the original user's date of acquisition) on either the proceeds of disposition (if sold in an arm's length transaction) or the fair market value of the property (in any other case) 710	Amount from column 700 or 710, whichever is less

Subtotal (enter this amount at amount C in Part 17) ______ A

Calculation 2 – Only if you transferred all or a part of the qualified expenditure to another person under an agreement described in subsection 127(13); otherwise, enter nil in amount B in Part 16 on page 9.

A Rate that the transferee used in determining its ITC for qualified expenditures under a subsection 127(13) agreement 720	B Proceeds of disposition of the property if you dispose of it to an arm's length person; or, in any other case, enter the fair market value of the property at conversion or disposition 730	C Amount, if any, already provided for in Calculation 1 (This allows for the situation where only part of the cost of a property is transferred under a subsection 127(13) agreement.) 740

Calculation 2 (continued) – Only if you transferred all or a part of the qualified expenditure to another person under an agreement described in subsection 127(13); otherwise, enter nil in amount B below.

D Amount determined by the formula (A x B) – C	E ITC earned by the transferee for the qualified expenditures that were transferred 750	F Amount from column D or E, whichever is less

Subtotal (enter this amount at amount D in Part 17) ______ B

Calculation 3

As a member of the partnership, you will report your share of the SR&ED ITC of the partnership after the SR&ED ITC has been reduced by the amount of the recapture. If this amount is a positive amount, you will report it on line 550 in Part 12. However, if the partnership does not have enough ITC otherwise available to offset the recapture, then the amount by which reductions to ITC exceed additions (the excess) will be determined and reported on line 760 below.

Corporate partner's share of the excess of SR&ED ITC (amount to be reported at amount E in Part 17) **760** ______

Part 17 – Total recapture of SR&ED investment tax credit

Recaptured ITC for calculation 1 from amount A in Part 16		C
Recaptured ITC for calculation 2 from amount B in Part 16		D
Recaptured ITC for calculation 3 from line 760 in Part 16		E
Total recapture of SR&ED investment tax credit – total of amounts C to E		F

Enter amount F at amount A in Part 29.

Pre-Production Mining

Part 18 – Pre-production mining expenditures

Exploration information

A mineral resource that qualifies for the credit means a mineral deposit from which the principal mineral to be extracted is diamond, a base or precious metal deposit, or a mineral deposit from which the principal mineral to be extracted is an industrial mineral that, when refined, results in a base or precious metal.

In column 800, list all minerals for which pre-production mining expenditures have taken place in the tax year.

For each of the minerals reported in column 800, identify each project (in column 805), mineral title (in column 806), and mining division (in column 807) where title is registered. If there is no mineral title, identify only the project and mining division.

List of minerals 800	Project name 805

Mineral title 806	Mining division 807

Pre-production mining expenditures*

Exploration:

Pre-production mining expenditures that the corporation incurred in the tax year for the purpose of determining the existence, location, extent, or quality of a mineral resource in Canada:

Prospecting	810	
Geological, geophysical, or geochemical surveys	811	
Drilling by rotary, diamond, percussion, or other methods	812	
Trenching, digging test pits, and preliminary sampling	813	

Development:

Pre-production mining expenditures incurred in the tax year for bringing a new mine in a mineral resource in Canada into production in reasonable commercial quantities and incurred before the new mine comes into production in such quantities:

Clearing, removing overburden, and stripping	820	
Sinking a mine shaft, constructing an adit, or other underground entry	821	

Other pre-production mining expenditures incurred in the tax year:

Description 825	Amount 826

Add amounts in column 826 ► A

Total pre-production mining expenditures (total of lines 810 to 821 and amount A)	830	

Deduct:

Total of all assistance (grants, subsidies, rebates, and forgivable loans) or reimbursements that the corporation has received or is entitled to receive in respect of the amounts referred to at line 830 above	832	
Excess (line 830 **minus** line 832) (if negative, enter "0")		B

Add:

Repayments of government and non-government assistance	835	
Pre-production mining expenditures (amount B **plus** line 835)		C

* A pre-production mining expenditure is defined under subsection 127(9).

Part 19 – Current-year credit and account balances – ITC from pre-production mining expenditures

ITC at the end of the previous tax year			D
Deduct:			
Credit deemed as a remittance of co-op corporations	841		
Credit expired	845		
Subtotal (line 841 **plus** line 845)			E
ITC at the beginning of the tax year (amount D **minus** amount E)	850		
Add:			
Credit transferred on amalgamation or wind-up of subsidiary	860		
Pre-production mining expenditures* incurred before January 1, 2013 (applicable part of amount C from Part 18)	870	x 10 % =	a
Pre-production mining exploration expenditures incurred in 2013 (applicable part of amount C from Part 18)	872	x 5 % =	b
Pre-production mining development expenditures incurred in 2014 (applicable part of amount C from Part 18)	874	x 7 % =	c
Pre-production mining development expenditures incurred in 2015 (applicable part of amount C from Part 18)	876	x 4 % =	d
Current year credit (total of amounts a to d)	880		F
Total credit available (total of lines 850, 860, and amount F)			G
Deduct:			
Credit deducted from Part I tax (enter at amount F in Part 30)	885		
Credit carried back to the previous year(s) (amount I from Part 20)			e
Subtotal (line 885 **plus** amount e)			H
ITC closing balance from pre-production mining expenditures (amount G **minus** amount H)	890		

* Also include pre-production mining development expenditures incurred before 2014 and pre-production mining development expenditures incurred after 2013 and before 2016 that are eligible for transitional relief.

Part 20 – Request for carryback of credit from pre-production mining expenditures

	Year	Month	Day		
1st previous tax year				Credit to be applied	921
2nd previous tax year				Credit to be applied	922
3rd previous tax year				Credit to be applied	923

Total (enter at amount e in Part 19) I

Apprenticeship Job Creation

Part 21 – Total current-year credit – ITC from apprenticeship job creation expenditures

If you are a related person as defined under subsection 251(2), has it been agreed in writing that you are the only employer who will be claiming the apprenticeship job creation tax credit for this tax year for each apprentice whose contract number (or social insurance number or name) appears below? (If not, you cannot claim the tax credit.) 611 1 Yes ☐ 2 No ☐

For each apprentice in their first 24 months of the apprenticeship, enter the apprenticeship contract number registered with Canada, or a province or territory, under an apprenticeship program designed to certify or license individuals in the trade. For the province, the trade must be a Red Seal trade. If there is no contract number, enter the social insurance number (SIN) or the name of the eligible apprentice.

	A Contract number (SIN or name of apprentice) 601	B Name of eligible trade 602	C Eligible salary and wages* 603	D Column C x 10 % 604	E Lesser of column D or $ 2,000 605
1.	Michael Dunlop	Powerline Technician	90,855	9,086	2,000

A Contract number (SIN or name of apprentice) 601	B Name of eligible trade 602	C Eligible salary and wages* 603	D Column C x 10 % 604	E Lesser of column D or $ 2,000 605
2. Eliot Heywood	Powerline Technician	1,631	163	163

Total current-year credit (enter at line 640 in Part 22) 2,163 A

* Net of any other government or non-government assistance received or to be received.

Part 22 – Current-year credit and account balances – ITC from apprenticeship job creation expenditures

ITC at the end of the previous tax year				B
Deduct:				
Credit deemed as a remittance of co-op corporations	612			
Credit expired after 20 tax years	615			
Subtotal (line 612 **plus** line 615)			▶	C
ITC at the beginning of the tax year (amount B **minus** amount C)			625	
Add:				
Credit transferred on amalgamation or wind-up of subsidiary	630			
ITC from repayment of assistance	635			
Total current-year credit (amount A from Part 21)	640	2,163		
Credit allocated from a partnership	655			
Subtotal (total of lines 630 to 655)		2,163	▶	2,163 D
Total credit available (line 625 **plus** amount D)				2,163 E
Deduct:				
Credit deducted from Part I tax (enter at amount G in Part 30)	660	2,163		
Credit carried back to the previous year(s) (amount G from Part 23)			a	
Subtotal (line 660 **plus** amount a)		2,163	▶	2,163 F
ITC closing balance from apprenticeship job creation expenditures (amount E **minus** amount F)			690	

Part 23 – Request for carryback of credit from apprenticeship job creation expenditures

	Year	Month	Day			
1st previous tax year				Credit to be applied	931	
2nd previous tax year				Credit to be applied	932	
3rd previous tax year				Credit to be applied	933	
				Total (enter at amount a in Part 22)		G

Child Care Spaces

Part 24 – Eligible child care spaces expenditures

Enter the eligible expenditures that the corporation incurred to create licensed child care spaces for the children of the employees and, potentially, for other children. The corporation cannot be carrying on a child care services business. The eligible expenditures include:

- the cost of depreciable property (other than specified property); and
- the specified child care start-up expenditures;

acquired or incurred only to create new child care spaces at a licensed child care facility.

Cost of depreciable property from the current tax year

	CCA* class number 665	Description of investment 675	Date available for use 685	Amount of investment 695
1.				

Total cost of depreciable property from the current tax year 715 ______

Add:

Specified child care start-up expenditures from the current tax year . . . . . 705 ______

Total gross eligible expenditures for child care spaces (line 715 **plus** line 705) . . . . . ______ A

Deduct:

Total of all assistance (including grants, subsidies, rebates, and forgivable loans) or reimbursements that the corporation has received or is entitled to receive in respect of the amounts referred to at line A) . . . . . 725 ______

Excess (amount A **minus** line 725) (if negative, enter "0") . . . . . ______ B

Add:

Repayments of government and non-government assistance . . . . . 735 ______

Total eligible expenditures for child care spaces (amount B **plus** line 735) . . . . . 745 ______

* CCA: capital cost allowance

Part 25 – Current-year credit – ITC from child care spaces expenditures

The credit is equal to 25% of eligible child care spaces expenditures incurred to a maximum of $10,000 per child care space created in a licensed child care facility.

Eligible expenditures (from line 745) . . . . . ______ x 25 % = ______ C

Number of child care spaces . . . . . 755 ______ x $ 10,000 = ______ D

ITC from child care spaces expenditures (amount C or D, whichever is less) . . . . . ______ E

Part 26 – Current-year credit and account balances – ITC from child care spaces expenditures

ITC at the end of the previous tax year				F
Deduct:				
Credit deemed as a remittance of co-op corporations	765			
Credit expired after 20 tax years	770			
Subtotal (line 765 **plus** line 770)			▶	G
ITC at the beginning of the tax year (amount F **minus** amount G)			775	
Add:				
Credit transferred on amalgamation or wind-up of subsidiary	777			
Total current-year credit (amount E from Part 25)	780			
Credit allocated from a partnership	782			
Subtotal (total of lines 777 to 782)			▶	H
Total credit available (line 775 **plus** amount H)				I
Deduct:				
Credit deducted from Part I tax (enter at amount H in Part 30)	785			
Credit carried back to the previous year(s) (amount K from Part 27)			a	
Subtotal (line 785 **plus** amount a)			▶	J
ITC closing balance from child care spaces expenditures (amount I **minus** amount J)			790	

Part 27 – Request for carryback of credit from child care space expenditures

	Year Month Day			
1st previous tax year	2011-12-31	Credit to be applied	941	
2nd previous tax year	2010-12-31	Credit to be applied	942	
3rd previous tax year	2009-12-31	Credit to be applied	943	
		Total (enter at amount a in Part 26)		K

Recapture – Child Care Spaces

Part 28 – Recapture of ITC for corporations and corporate partnerships – Child care spaces

The ITC will be recovered against the taxpayer's tax otherwise payable under Part I of the Act if, at any time within 60 months of the day on which the taxpayer acquired the property:

- the new child care space is no longer available; or
- property that was an eligible expenditure for the child care space is:
  - disposed of or leased to a lessee; or
  - converted to another use.

If the property disposed of is a child care space, the amount that can reasonably be considered to have been included in the original ITC (paragraph 127(27.12)(a))	792		
In the case of eligible expenditures (paragraph 127(27.12)(b)), the lesser of:			
The amount that can reasonably be considered to have been included in the original ITC	795		
25% of either the proceeds of disposition (if sold in an arm's length transaction) or the fair market value (in any other case) of the property	797		
Amount from line 795 or line 797, whichever is less			A

Corporate partnerships

As a member of the partnership, you will report your share of the child care spaces ITC of the partnership after the child care spaces ITC has been reduced by the amount of the recapture. If this amount is a positive amount, you will report it on line 782 in Part 26. However, if the partnership does not have enough ITC otherwise available to offset the recapture, then the amount by which reductions to ITC exceed additions (the excess) will be determined and reported on line 799 below.

Corporate partner's share of the excess of ITC	799		
Total recapture of child care spaces investment tax credit (total of line 792, amount A, and line 799)			B

Enter amount B at amount B in Part 29.

Summary of Investment Tax Credits

Part 29 – Total recapture of investment tax credit

Recaptured SR&ED ITC (from amount F in Part 17)		A
Recaptured child care spaces ITC (from amount B in Part 28)		B
Total recapture of investment tax credit (amount A **plus** amount B)		C

Enter amount C on line 602 of the T2 return.

Part 30 – Total ITC deducted from Part I tax

ITC from investments in qualified property deducted from Part I tax (from line 260 in Part 5)		D
ITC from SR&ED expenditures deducted from Part I tax (from line 560 in Part 12)	90,587	E
ITC from pre-production mining expenditures deducted from Part I tax (from line 885 in Part 19)		F
ITC from apprenticeship job creation expenditures deducted from Part I tax (from line 660 in Part 22)	2,163	G
ITC from child care space expenditures deducted from Part I tax (from line 785 in Part 26)		H
Total ITC deducted from Part I tax (total of amounts D to H)	92,750	I

Enter amount I at line 652 of the T2 return.

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Summary of Investment Tax Credit Carryovers

Continuity of investment tax credit carryovers

CCA class number 97 Apprenticeship job creation ITC

Current year

Addition current year (A)	Applied current year (B)	Claimed as a refund (C)	Carried back (D)	ITC end of year (A-B-C-D)
2,163	2,163			

Prior years

Taxation year	ITC beginning of year (E)	Adjustments (F)	Applied current year (G)	ITC end of year (E-F-G)
2011-12-31				
2010-12-31				
2009-12-31				
2008-12-31				
2007-12-31				
2006-12-31				
2005-12-31				
2004-12-31				
2003-12-31				
2002-12-31				*
2001-12-31				
2001-09-30				
2000-09-30				
1999-09-30				
1998-09-30				
1997-09-30				
1996-09-30				
1995-09-30				
1994-09-30				
1993-09-30				*
Total				

B+C+D+G **Total ITC utilized** 2,163

* The **ITC end of year** includes the amount of ITC expired from the 10th preceding year if it is before January 1, 1998, or the amount of ITC expired from the 20th preceding year if it is after December 31, 1997. Note that this credit will only expire at the beginning of the subsequent fiscal period. Consequently, this amount will be posted on line 215, 515, 615, 770 or 845, as applicable, in Schedule 31 of the subsequent fiscal year.

Summary of Investment Tax Credit Carryovers

Continuity of investment tax credit carryovers

CCA class number 99 Cur. or cap. R&D for ITC

Current year

Addition current year (A)	Applied current year (B)	Claimed as a refund (C)	Carried back (D)	ITC end of year (A-B-C-D)
90,587	90,587			

Prior years

Taxation year	ITC beginning of year (E)	Adjustments (F)	Applied current year (G)	ITC end of year (E-F-G)
2011-12-31				
2010-12-31				
2009-12-31				
2008-12-31				
2007-12-31				
2006-12-31				
2005-12-31				
2004-12-31				
2003-12-31				
2002-12-31				*
2001-12-31				
2001-09-30				
2000-09-30				
1999-09-30				
1998-09-30				
1997-09-30				
1996-09-30				
1995-09-30				
1994-09-30				
1993-09-30				*
Total				

B+C+D+G **Total ITC utilized** 90,587

* The **ITC end of year** includes the amount of ITC expired from the 10th preceding year if it is before January 1, 1998, or the amount of ITC expired from the 20th preceding year if it is after December 31, 1997. Note that this credit will only expire at the beginning of the subsequent fiscal period. Consequently, this amount will be posted on line 215, 515, 615, 770 or 845, as applicable, in Schedule 31 of the subsequent fiscal year.

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SCHEDULE 50

SHAREHOLDER INFORMATION

Name of corporation	Business Number	Tax year end Year Month Day
BURLINGTON HYDRO INC.	86829 1980 RC0001	2012-12-31

All private corporations must complete this schedule for any shareholder who holds 10% or more of the corporation's common and/or preferred shares.

		Provide only one number per shareholder				
	Name of shareholder (after name, indicate in brackets if the shareholder is a corporation, partnership, individual, or trust) 100	Business Number (If a corporation is not registered, enter "NR") 200	Social insurance number 300	Trust number 350	Percentage common shares 400	Percentage preferred shares 500
1	BURLINGTON HYDRO ELECTRIC INC.	88361 4927 RC0001			100.000	
2						
3						
4						
5						
6						
7						
8						
9						
10						

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SCHEDULE 55

PART III.1 TAX ON EXCESSIVE ELIGIBLE DIVIDEND DESIGNATIONS

Name of corporation	Business Number	Tax year-end Year Month Day
BURLINGTON HYDRO INC.	86829 1980 RC0001	2012-12-31

Do not use this area

- Every corporation resident in Canada that pays a taxable dividend (other than a capital gains dividend within the meaning assigned by subsection 130.1(4) or 131(1)) in the tax year must file this schedule.
- Canadian-controlled private corporations (CCPC) and deposit insurance corporations (DIC) must complete Part 1 of this schedule. All other corporations must complete Part 2.
- Every corporation that has paid an eligible dividend must also file Schedule 53, *General Rate Income Pool (GRIP) Calculation*, or Schedule 54, *Low Rate Income Pool (LRIP) Calculation*, whichever is applicable.
- File the completed schedules with your *T2 Corporation Income Tax Return* no later than six months from the end of the tax year.
- All legislative references on this schedule are to the federal *Income Tax Act*.
- Subsection 89(1) defines the terms eligible dividend, excessive eligible dividend designation, general rate income pool (GRIP), and low rate income pool (LRIP).
- The calculations in Part 1 and Part 2 do not apply if the excessive eligible dividend designation arises from the application of paragraph (c) of the definition of excessive eligible dividend designation in subsection 89(1). This paragraph applies when an eligible dividend is paid to artificially maintain or increase the GRIP or to artificially maintain or decrease the LRIP.

Part 1 – Canadian-controlled private corporations and deposit insurance corporations

Taxable dividends paid in the tax year **not included** in Schedule 3				
Taxable dividends paid in the tax year **included** in Schedule 3		1,750,000		
Total taxable dividends paid in the tax year	100	1,750,000		
Total eligible dividends paid in the tax year	150			A
GRIP at the end of the tax year (line 590 on Schedule 53) (if negative, enter "0")	160		34,131,828	B
Excessive eligible dividend designation (line 150 **minus** line 160)				C
Deduct:				
Excessive eligible dividend designations elected under subsection 185.1(2) to be treated as ordinary dividends*	180			D
Subtotal (amount C **minus** amount D)				E
Part III.1 tax on excessive eligible dividend designations – CCPC or DIC (amount E **multiplied** by 20 %)	190			F

Enter the amount from line 190 on line 710 of the T2 return.

Part 2 – Other corporations

Taxable dividends paid in the tax year **not included** in Schedule 3				
Taxable dividends paid in the tax year **included** in Schedule 3				
Total taxable dividends paid in the tax year	200			
Total excessive eligible dividend designations in the tax year (amount from line A of Schedule 54)				G
Deduct:				
Excessive eligible dividend designations elected under subsection 185.1(2) to be treated as ordinary dividends*	280			H
Subtotal (amount G **minus** amount H)				I
Part III.1 tax on excessive eligible dividend designations – Other corporations (amount I **multiplied** by 20 %)	290			J

Enter the amount from line 290 on line 710 of the T2 return.

* You can elect to treat all or part of your excessive eligible dividend designation as a separate taxable dividend in order to eliminate or reduce the Part III.1 tax otherwise payable. You must file the election on or before the day that is 90 days **after** the day the notice of assessment for Part III.1 tax was sent. We will accept an election before the assessment of the tax. For more information on how to make this election, go to **www.cra.gc.ca/eligibledividends**.

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Schedule 500

Ontario Corporation Tax Calculation

Corporation's name	Business number	Tax year-end Year Month Day
BURLINGTON HYDRO INC.	86829 1980 RC0001	2012-12-31

- Use this schedule if the corporation had a permanent establishment (as defined in section 400 of the federal *Income Tax Regulations*) in Ontario at any time in the tax year and had Ontario taxable income in the year.
- All legislative references are to the federal *Income Tax Act* and *Income Tax Regulations*.
- This schedule is a worksheet only. You do not have to file it with your *T2 Corporation Income Tax Return*.

Part 1 – Calculation of Ontario basic rate of tax for the year

Number of days in the tax year before July 1, 2011 / Number of days in the tax year	/ 366	x	12.00 %	=	%	A1
Number of days in the tax year after June 30, 2011 / Number of days in the tax year	366 / 366	x	11.50 %	=	11.50000 %	A2

Ontario basic rate of tax for the year (rate A1 **plus** A2) 11.50000 ► 11.50000 % A3

Part 2 – Calculation of Ontario basic income tax

Ontario taxable income * . . . . . 4,870,119 B

Ontario basic income tax: amount B **multiplied** by Ontario basic rate of tax for the year (rate A3 from Part 1) . . . . . 560,064 C

If the corporation has a permanent establishment in more than one jurisdiction, or is claiming an Ontario tax credit in addition to Ontario basic income tax, or has Ontario corporate minimum tax or Ontario special additional tax on life insurance corporations payable, enter amount C on line 270 of Schedule 5, *Tax Calculation Supplementary – Corporations*. Otherwise, enter it on line 760 of the T2 return.

* If the corporation has a permanent establishment only in Ontario, enter the amount from line 360 or line Z, whichever applies, of the T2 return. Otherwise, enter the taxable income allocated to Ontario from column F in Part 1 of Schedule 5.

Part 3 – Ontario small business deduction (OSBD)

Complete this part if the corporation claimed the federal small business deduction under subsection 125(1) or would have claimed it if subsection 125(5.1) had not been applicable in the tax year.

Income from active business carried on in Canada (amount from line 400 of the T2 return)	4,879,494	1
Federal taxable income, less adjustment for foreign tax credit (amount from line 405 of the T2 return)	4,870,119	2
Federal business limit before the application of subsection 125(5.1) (amount from line 410 of the T2 return)	500,000	3
Enter the least of amounts 1, 2, and 3	500,000	D

Ontario domestic factor: Ontario taxable income * / Taxable income earned in all provinces and territories ** = 4,870,119.00 / 4,870,119 = 1.00000 E

Amount D x factor E	500,000	a
Ontario taxable income (amount B from Part 2)	4,870,119	b

Ontario small business income (lesser of amount a and amount b) ..... 500,000 F

Number of days in the tax year before July 1, 2011 / Number of days in the tax year: ___ / 366 x 7.50 % = ___ % G1

Number of days in the tax year after June 30, 2011 / Number of days in the tax year: 366 / 366 x 7.00 % = 7.00000 % G2

OSBD rate for the year (rate G1 **plus** G2) ..... 7.00000 % G3

Ontario small business deduction: amount F **multiplied** by OSBD rate for the year (rate G3) ..... 35,000 H

Enter amount H on line 402 of Schedule 5.

* Enter amount B from Part 2.

** Includes the offshore jurisdictions for Nova Scotia and Newfoundland and Labrador.

Part 4 – Ontario adjusted small business income

Complete this part if the corporation was a Canadian-controlled private corporation throughout the tax year and is claiming the Ontario tax credit for manufacturing and processing or the Ontario credit union tax reduction.

Ontario adjusted small business income (lesser of amount D and amount b from Part 3) ..... 500,000 I

Enter amount I on line K in Part 5 of this schedule or on line B in Part 2 of Schedule 502, *Ontario Tax Credit for Manufacturing and Processing*, whichever applies.

Part 5 – Calculation of credit union tax reduction

Complete this part and Schedule 17, *Credit Union Deductions*, if the corporation was a credit union throughout the tax year.

Amount D from Part 3 of Schedule 17		J	
Deduct:			
Ontario adjusted small business income (amount I from Part 4)		K	
Subtotal (amount J **minus** amount K) (if negative, enter "0")		L	
OSBD rate for the year (rate G3 from Part 3)	7.00000 %		
Amount L **multiplied** by the OSBD rate for the year			M
Ontario domestic factor (factor E from Part 3)		1.00000	N
Ontario credit union tax reduction (amount M **multiplied** by factor N)			O

Enter amount O on line 410 of Schedule 5.

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SCHEDULE 506

ONTARIO TRANSITIONAL TAX DEBITS AND CREDITS

Name of corporation	Business Number	Tax year-end Year Month Day
BURLINGTON HYDRO INC.	86829 1980 RC0001	2012-12-31

- Complete this schedule if you are a specified corporation that is subject to the Ontario transitional tax debit or are claiming the Ontario transitional tax credit.
- Unless otherwise noted, all legislative references are to the federal *Income Tax Act*.
- File this schedule with the *T2 Corporation Income Tax Return*.
- Unless otherwise noted, terms on this page are defined under subsection 46(1) of the *Taxation Act, 2007* (Ontario).
- **Specified corporation** is defined under subsection 46(5) of the *Taxation Act, 2007* (Ontario) as a corporation:
  - that is not exempt at or immediately before its transition time from tax payable under Part I of the federal Act;
  - that has a tax year that ends before 2009 and a tax year that includes January 1, 2009; or has a tax year that begins after 2008 and a tax year that is deemed to end on December 31, 2008, under subsection 249(3) of the federal Act;
  - that has a permanent establishment (PE) in Ontario at its transition time;
  - that had a PE in Ontario at any time in its last tax year ending before 2009, and was subject to tax under Part II of the *Corporations Tax Act* (Ontario) for that tax year; and
  - whose assets have not been distributed in an eligible pre-2009 windup.
- A specified corporation also includes, under subsection 51(1) of *the Taxation Act, 2007* (Ontario), the parent corporation of an eligible post-2008 windup and the new corporation of an eligible amalgamation.
- A specified corporation may be subject to the Ontario transitional tax debit if:
  - the corporation's total federal balance is more than the total Ontario balance at the end of the tax year; or
  - the corporation has a post-2008 scientific research and experimental development (SR&ED) balance, as defined under subsection 49(2) of the *Taxation Act, 2007* (Ontario), and a federal SR&ED transitional balance, as defined under subsection 49(4) of the *Taxation Act, 2007* (Ontario), at the end of the tax year.
- A specified corporation may be able to claim the Ontario transitional tax credit if:
  - the corporation's total Ontario balance is more than the total federal balance at the end of the tax year; or
  - the corporation has an unused transitional tax credit balance from previous tax years.
- **Transition time** means:
  - the beginning of the corporation's first tax year that starts after 2008 if the previous tax year is deemed under subsection 249(3) of the federal Act to end on December 31, 2008, or
  - the beginning of the corporation's tax year that includes January 1, 2009, in any other case.
- An **eligible amalgamation** means an amalgamation or merger of a particular corporation and one or more other corporations to form a new corporation where:
  - the amalgamation or merger occurs after December 31, 2008, and does not occur at the new corporation's transition time;
  - the new corporation has a PE in Ontario immediately after the amalgamation or merger;
  - the particular corporation has a PE in Ontario immediately before the amalgamation or merger;
  - the particular corporation is a specified corporation at its transition time or at any time before the amalgamation or merger;
  - the amalgamation or merger occurs in the amortization period of the new corporation;
  - the amortization period of the new corporation does not end immediately after the beginning of its reference period; and
  - the amortization period of the particular corporation does not end before the amalgamation or merger.
- An **eligible post-2008 windup** means the windup of a subsidiary corporation into its parent corporation under subsection 88(1) where:
  - the completion time of the windup is after December 31, 2008, and the time immediately after the completion time is within the amortization periods of the subsidiary and parent;
  - the parent's tax year (during which it received the assets of the subsidiary) ends after December 31, 2008;
  - the subsidiary has a PE in Ontario during its tax year ending at the completion time; and
  - the parent has a PE in Ontario during its tax year in which it received the assets from the subsidiary.
- An **eligible pre-2009 windup** means the windup of a subsidiary under subsection 88(1) where:
  - the completion time of the windup is after December 31, 2008, and the parent's tax year (during which it received the assets of the subsidiary) ended before January 1, 2009; or
  - the completion time of the windup is before January 1, 2009, and the parent's tax year (during which it received the assets of the subsidiary) ended after December 31, 2008.
- The **completion time** of a windup means the end of the tax year of the subsidiary during which the subsidiary distributes its assets to the parent for the purposes of paragraph 88(1)(e.2).
- A **specified pre-2009 transfer** under section 52 of the *Taxation Act, 2007* (Ontario) means a transfer of property between corporations not at arm's length that changes the total federal or Ontario balance of either the transferee or the transferor and that occurs:
  - before 2009;
  - at different values under the *Corporations Tax Act* (Ontario) and the federal Act;
  - in a tax year ending after 2008 for either the transferee or the transferor corporation, and that corporation is a specified corporation; and
  - in a tax year of the other corporation ending before 2009, in which the other corporation has a PE in Ontario.

Part 1 – Total federal balance

Complete this part if:

- the tax year includes January 1, 2009; or
- the previous tax year-end is deemed to be December 31, 2008, under subsection 249(3).

If this is the first year after amalgamation, include the total of all amounts from the predecessor corporations that had a PE in Ontario immediately before the amalgamation.

If the corporation is a life insurer or a non-resident corporation, do not include the amounts under the additional rules in subsection 48(8) of the *Taxation Act, 2007* (Ontario).

For other tax years, go to Part 3.

Federal balances at the end of the previous tax year (tax year ending in 2008)

Total undepreciated capital cost of depreciable properties (total of column 220 from Schedule 8, *Capital Cost Allowance (CCA)*)	110	
Charitable donations not yet deducted from income (from line 280 of Schedule 2, *Charitable Donations and Gifts*) (see Note 1)	112	
Gifts to Canada, a province, or a territory (from line 380 of Schedule 2) (see Note 1)	114	
Gifts of certified cultural property (from line 480 of Schedule 2) (see Note 1)	116	
Gifts of certified ecologically sensitive land (from line 580 of Schedule 2) (see Note 1)	118	
Gifts of medicine (from line 680 of Schedule 2) (see Note 1)	120	
Cumulative eligible capital (from line 300 of Schedule 10, *Cumulative Eligible Capital Deduction*)	122	
Federal SR&ED expenditure pool (from line 470 of Form T661, *Scientific Research and Experimental Development (SR&ED) Expenditures Claim*) (see Note 2 and Note 3)	124	
Cumulative Canadian exploration expense (from line 249 of Schedule 12, *Resource-Related Deductions*) (see Note 2)	128	
Cumulative Canadian development expense (from line 349 of Schedule 12) (see Note 2)	130	
Cumulative Canadian oil and gas property expense (from line 449 of Schedule 12) (see Note 2)	132	

Federal balances at the beginning of the current tax year

Non-capital losses (line 102 of Schedule 4, *Corporation Loss Continuity and Application*, of the current tax year) (see Note 2 and Note 4)	134	
Net capital losses (from line 200 of Schedule 4 of the current tax year x 50 %) (see Note 2 and Note 4)	136	

Amounts included in the calculation of the Ontario income tax in the previous tax year

Total reserves deducted under paragraph 20(1)(l), (l.1), (m), (m.1), (n), or (o), subsection 32(1), section 61.4 or subparagraph 138(3)(a)(i), (ii), or (iv) of the federal Act, as it applies for the purposes of the *Corporations Tax Act* (Ontario)	150	
One half of the total reserves deducted under subparagraph 40(1)(a)(iii) or 44(1)(e)(iii) of the federal Act, as it applies under the *Corporations Tax Act* (Ontario)	152	
Other discretionary deductions claimed for Ontario income tax, but not claimed federally in the tax years ending after December 12, 2006, and before the transition time	154	

Other amounts

Total adjusted cost base of partnership interests owned by the corporation, under the federal Act, at the beginning of the tax year (see Note 5)	160		
Gain from a negative adjusted cost base of a partnership interest under subsection 40(3) of the federal Act, as it applies under the *Corporations Tax Act* (Ontario), as if all partnership interests were disposed of at the beginning of the tax year	162		
Amount of farming income specified under paragraph 28(1)(b) in the previous tax year	164		
Federal balance before election (total of lines 110 to 164)			A

Deduct:

Lesser of amount D or amount E from Part 4, if an election is made	170	
Total federal balance (amount A **minus** line 170)	180	

Enter amount on line 300 in Part 3.

Note 1: Enter "0" if the corporation was non-resident immediately before its transition time.

Note 2: Enter "0" if control of the corporation was acquired at transition time.

Note 3: Do not include the SR&ED expenditure pool earned before control of the corporation was last acquired.

Note 4: Do not include losses that arose before control of the corporation was last acquired.

Note 5: The adjusted cost base of any particular partnership interest cannot be less than "0".

Part 2 – Total Ontario balance

Complete this part if:

- the tax year includes January 1, 2009; or
- the previous tax year-end is deemed to be December 31, 2008, under subsection 249(3).

If this is the first year after amalgamation, include the total of all amounts from the predecessor corporations that had a PE in Ontario immediately before the amalgamation.

If the corporation is a life insurer or a non-resident corporation, do not include the amounts under the additional rules in subsection 48(8) of the *Taxation Act, 2007* (Ontario).

For other tax years, go to Part 3.

Ontario balances at the end of the previous tax year (tax year ending in 2008)

Total undepreciated capital cost of depreciable properties (total of column 13 from Ontario Schedule 8, *Ontario Capital Cost Allowance*)	210	
Charitable donations (amount I from Ontario *Schedule 2, Ontario Charitable Donations and Gifts*) (see Note 1)	212	
Gifts to Canada, a province, or a territory (total of closing balance amounts from parts 3 and 5 of Ontario Schedule 2) (see Note 1)	214	
Gifts of certified cultural property (closing balance amount from Part 6 of Ontario Schedule 2) (see Note 1)	216	
Gifts of certified ecologically sensitive land (closing balance amount from Part 7 of Ontario Schedule 2) (see Note 1)	218	
Gifts of medicine (see Note 1)	220	
Cumulative eligible capital (amount Q from Ontario *Schedule 10, Ontario Cumulative Eligible Capital Deduction*)	222	
Ontario SR&ED expenditure pool (line 480 from Ontario *CT23 Schedule 161, Ontario Scientific Research and Experimental Development Expenditures*) (see Note 2 and Note 3)	224	
Adjusted Ontario SR&ED incentive balance (see Note 2 and Note 5)	226	
Cumulative Canadian exploration expense (closing balance of Regular Expenses from Part 2 of Ontario *Schedule 12, Ontario Exploration Expenses*) (see Note 2)	228	
Cumulative Canadian development expense (closing balance of Regular Expenses, Canadian CCDE Expenses, from Part 3 of Ontario Schedule 12) (see Note 2)	230	
Cumulative Canadian oil and gas property expense (closing balance of Regular Expenses from Part 4 of Ontario Schedule 12) (see Note 2)	232	
Non-capital losses (from line 709 of Ontario *Corporations Tax Return CT8* or *CT23 Corporations Tax and Annual Return*) (see Note 2 and Note 4)	234	
Net capital losses (from line 719 of CT8 or CT23 x 50 %) (see Note 2 and Note 4)	236	

Amounts included In the calculation of the federal income tax in the previous tax year

Total reserves deducted under paragraph 20(1)(l), (l.1), (m), (m.1), (n), or (o), subsection 32(1), section 61.4 or subparagraph 138(3)(a)(i), (ii), or (iv)	250	
One half of the total reserves deducted under subparagraph 40(1)(a)(iii) or 44(1)(e)(iii)	252	

Other amounts

Total adjusted cost base of partnership interests owned by the corporation, for the purposes of the *Corporations Tax Act* (Ontario), at the beginning of the tax year (see Note 6)	260	
Gain from a "negative" adjusted cost base of a partnership interest under subsection 40(3) determined as if all partnership interests were disposed of at the beginning of the tax year	262	
Amount of farming income in the previous tax year specified under paragraph 28(1)(b) of the federal Act, as it applies for the purposes of the *Corporations Tax Act* (Ontario)	264	
Total Ontario balance (total of lines 210 to 264)	280	

Enter amount on line 340 in Part 3.

Note 1: Enter "0" if the corporation was non-resident immediately before its transition time.

Note 2: Enter "0" if control of the corporation was acquired at transition time.

Note 3: Do not include the SR&ED expenditure pool earned before control of the corporation was last acquired.

Note 4: Do not include losses that arose before control of the corporation was last acquired.

Note 5: The adjusted Ontario SR&ED incentive balance under subsection 49(7) of the *Taxation Act, 2007* (Ontario) is the total of federal investment tax credits that:

– have been earned and are available without restriction to the corporation;

– are attributable to qualifying Ontario SR&ED expenditures;

– have not been deducted under subsection 127(5) or (6) of the federal Act at the end of the corporation's tax year ending immediately before its transition time; and

– do not expire in the first tax year ending in 2009 under the 10-year carryforward limit,

divided by the relevant Ontario allocation factor as calculated in Part 11.

Note 6: The adjusted cost base of any particular partnership interest cannot be less than "0".

Part 3 – Total federal balance and total Ontario balance at the end of the tax year

Total federal balance:

Total federal balance (amount from line 180 in Part 1, or amount from line 330 in Part 3 of Schedule 506 for the previous tax year)	300	106,409,224		
Add:				
Amount from eligible amalgamation*	310			
Amount from eligible post-2008 windup*	315			
Amount from eligible pre-2009 windup*	320			
Amount from specified pre-2009 transfers*	325			
Total federal balance at the end of the tax year		106,409,224 ►	330	106,409,224

Total Ontario balance:

Total Ontario balance (amount from line 280 in Part 2, or amount from line 370 in Part 3 of Schedule 506 for the previous tax year)	340	106,432,549		
Add:				
Amount from eligible amalgamation*	350			
Amount from eligible post-2008 windup*	355			
Amount from eligible pre-2009 windup*	360			
Amount from specified pre-2009 transfers*	365			
Total Ontario balance at the end of the tax year		106,432,549 ►	370	106,432,549
Transitional balance at the end of the tax year (line 330 **minus** line 370)			390	-23,325

If line 390 is positive, the corporation may be subject to a transitional tax debit. Complete Part 7 of this schedule.
If line 390 is negative, the corporation may be eligible to claim a transitional tax credit. Complete Part 8 of this schedule.

* See page 1 for definitions of eligible amalgamation, eligible post-2008 windup, eligible pre-2009 windup, and specified pre-2009 transfers. To calculate these amounts, you can use *Schedule 507, Ontario Transitional Tax Debits and Credits Calculation*.

Part 4 – Election to reduce federal SR&ED expenditure pool

The corporation may make this election if:

– the tax year includes January 1, 2009; or
– the previous tax year-end is deemed to be December 31, 2008, under subsection 249(3).

Are you making an election under clause (b) of the definition of "I" in paragraph 1 of subsection 48(4) of the *Taxation Act, 2007* (Ontario)? **400** 1 Yes ☐ 2 No ☒

If you answered **no** to the question at line 400, go to Part 5. If you answered **yes** to the question at line 400, complete the following calculation:

Federal SR&ED expenditure pool closing balance at the end of the previous tax year (amount from line 124 in Part 1)				B
Deduct:				
Adjusted Ontario SR&ED incentive balance at the end of the previous tax year (amount from line 226 in Part 2)		1		
Ontario SR&ED expenditure pool closing balance at the end of the previous tax year (amount from line 224 in Part 2)		2		
Subtotal (amount 1 **plus** amount 2)		►		C
Subtotal (amount B **minus** amount C) (if negative, enter "0")				D
Federal balance before election (amount A from Part 1)				
Deduct:				
Total Ontario balance (amount from line 280 in Part 2)				
Subtotal (if negative, enter "0")				E

Enter the lesser of amount D and amount E on line 170 in Part 1.

Part 5 – Reference period and amortization period

Reference period

The reference period starts at the beginning of the corporation's first tax year ending after December 31, 2008, and ends on whichever date is earlier:

– five calendar years after the time immediately before the start of the corporation's reference period; or
– December 31, 2013.

Number of days in the corporation's reference period* (do not include February 29, 2008, and February 29, 2012) . . **410** 1,825

* The number of days in the corporation's reference period is 1825 unless:
– the previous tax year-end is deemed to be December 31, 2008, under subsection 249(3). In this case, count the number of days from the beginning of the 2009 tax year to December 31, 2013; or
– the corporation was incorporated or amalgamated after January 1, 2009. In this case, count the number of days from the date of incorporation or date of amalgamation to December 31, 2013.

Amortization period

The amortization period starts at the beginning of the corporation's reference period and ends on whichever date is earlier:

– the end of the corporation's reference period; or
– the early termination date as indicated under line 430.

Number of days in the amortization period that are in the tax year** (do not include February 29, 2008, or February 29, 2012) **420** 365

** The number of days in the amortization period that are in the tax year is the number of days in the tax year unless:
– the tax year-end is later than the end of the reference period. In this case, count the number of days from the beginning of the tax year to the end of the reference period; or
– the corporation terminates the amortization period before the end of the tax year. In this case, count the number of days from the beginning of the tax year to the day of early termination.

Early termination of the amortization period

The amortization period of the corporation usually coincides with the corporation's reference period. However, if the corporation's amortization period ends in the tax year and before the reference period ends, tick the applicable box below to indicate the reason for the early termination.

430 The corporation:

1 ☐ – ceases to have a PE in Ontario in the tax year for any reason other than an eligible amalgamation or eligible post-2008 windup.

2 ☐ – becomes exempt from tax under Part I of the federal Act immediately after the end of the tax year.

3 ☐ – elects under subsection 47(2) of the *Taxation Act, 2007* (Ontario) to prepay the transitional tax debit.
Note: The Ontario Allocation Factor, calculated in Part 6, has to be at least 90% or the amount on line 390 in Part 3 is not more than $10,000.

4 ☐ – does not object to early termination of the amortization period and accelerated payment of the transitional tax credit, under subsection 46(3) of the *Taxation Act, 2007* (Ontario).
Note: Amount T in Part 8 cannot be more than $1,000.

If you ticked one of the above boxes:
– enter the date of the early termination, if the date is different from the tax year-end and you ticked box 1 at line 430 . . . . **435** ______
– enter the number of days from the first day of the tax year to the end of the corporation's reference period (do not include February 29, 2008, or February 29, 2012) . . . . **440** ______

Part 6 – Calculation of Ontario allocation factor (OAF)

If the provincial or territorial jurisdiction entered on line 750 of the T2 return is "Ontario," enter "1" on line F.

If the provincial or territorial jurisdiction entered on line 750 of the T2 return is "multiple," complete the following calculation and enter the result on line F:

$$\frac{\text{Ontario taxable income*}}{\text{Taxable income**}} \quad \_\_\_\_\_\_ = \_\_\_\_\_\_$$

Ontario allocation factor (OAF) . . . . 1.00000 F

* Enter the amount allocated to Ontario from column F in Part 1 of Schedule 5, *Tax Calculation Supplementary – Corporations*. If taxable income is nil, calculate the amount in column F as if taxable income were $1,000.

** Enter taxable income from line 360 or amount Z of the T2 return, whichever applies. If taxable income is nil, enter "1,000."

Part 7 – Transitional tax debits

Complete this part if the amount on line 390 in Part 3 is positive.

Amount from line 390 in Part 3			G
Amount G x Ontario basic rate of tax*	11.5 % =		H
Amount H x OAF (from line F in Part 6)	1.00000		I

Number of days from line 440 (if applicable) or line 420 in Part 5 / Number of days in the corporation's reference period from line 410 in Part 5 = 365 / 1,825 = 0.20000 J

Transitional tax debit before tax on elected reduced SR&ED pool (amount I **multiplied** by amount J)		K
Post-2008 SR&ED balance at the end of the year (amount HH from Part 12)	**460**	
Federal SR&ED transitional balance at the end of the year (amount QQ from Part 14)	**470**	
Tax on elected reduced SR&ED pool (the lesser of lines 460 and 470)		L
Total transitional tax debits (amount K **plus** amount L)		M

Enter amount M on line 276 of Schedule 5.

Part 8 – Transitional tax credits

Complete this part if the amount on line 390 in Part 3 is negative.

Amount C6 from Schedule 5 ... 525,064 N

Deduct:

Ontario resource tax credit (from line 404 of Schedule 5)			
Ontario tax credit for manufacturing and processing (from line 406 of Schedule 5)			
Ontario foreign tax credit (from line 408 of Schedule 5)			
Ontario credit union tax reduction (from line 410 of Schedule 5)			
Subtotal		►	O
Subtotal (amount N **minus** amount 0)		525,064	P

Number of days from line 420 in Part 5 / Number of days in the tax year (do not include February 29, 2008, or February 29, 2012) = 365 / 365 = 1.00000 Q

Ontario tax payable for purposes of the current year transitional tax credit (amount P **multiplied** by amount Q) **510** 525,064

Amount from line 390 in Part 3 (enter as a positive amount)		23,325	R
Amount R x Ontario basic rate of tax*	11.5 % =	2,682	S
Amount S x OAF (from line F in Part 6)		2,682	T

Number of days from line 440 (if applicable) or line 420 in Part 5 / Number of days in the corporation's reference period on line 410 in Part 5 = 365 / 1,825 = 0.20000 U

Current-year transitional tax credit (amount T **multiplied** by amount U)	**520**	536	
Ontario tax payable for purposes of the unused transitional tax credit carryforward (line 510 **minus** line 520) (if negative, enter "0")	**530**	524,528	

Transitional tax credit:

Lesser of amounts on line 510 and 520	536	V
Lesser of unused transitional tax credit available (amount Y from Part 9) and amount on line 530	548	W
Transitional tax credits (amount V **plus** amount W)	1,084	X

Enter amount X on line 414 of Schedule 5.

* Enter the rate calculated in Part 1 of Schedule 500, *Ontario Corporation Tax Calculation*.

Part 9 – Unused transitional tax credit

Unused transitional tax credit carryforward from previous year (amount from line 580 of the previous year)*		548	1		
Add:					
Unused transitional tax credit transferred from a predecessor corporation or a subsidiary on an eligible amalgamation or an eligible post-2008 windup*	560		2		
Unused transitional tax credit available (amount 1 **plus** amount 2)		548	▶	548	Y
Add:					
Current-year transitional tax credit (amount from line 520 in Part 8)				536	Z
Subtotal (amount Y **plus** amount Z)				1,084	3
Deduct:					
Transitional tax credit applied (amount X from Part 8)				1,084	AA
Unused transitional tax credit (available for later years) (amount 3 **minus** amount AA)	580				

* Enter "0" if this is the first tax year ending after 2008.

Complete parts 10 to 14 if the corporation or a predecessor made an election in Part 4 at the transition time.

Part 10 – Federal current SR&ED limit and federal current SR&ED deficit

Current SR&ED expenditures in the year under paragraph 37(1)(a)	610				
Capital SR&ED expenditures in the year under paragraph 37(1)(b)	614				
Repayment of assistance under paragraph 37(1)(c)	618				
Investment tax credit recaptured under subsections 127(27), (29), and (34) in the previous tax year	624				
Subtotal (total of lines 610 to 624)			▶		BB
Deduct:					
Assistance under paragraph 37(1)(d)	638				
Investment tax credits deducted under paragraph 37(1)(e)	644				
Subtotal (line 638 **plus** line 644)			▶		CC
Federal current SR&ED limit or federal current SR&ED deficit (amount BB **minus** amount CC)	650				

If the amount on line 650 is positive, enter it on line II In Part 13.

If the amount on line 650 is negative, enter it as a positive amount on line DD in Part 12.

Part 11 – Relevant OAF

Enter on line 660 whichever of the following amounts is greatest:

– the corporation's OAF for the tax year that includes its transition time (from line F in Part 6)		%
– the greatest of the corporation's OAFs for a tax year ending in 2006, 2007, and 2008 as determined under subsection 12(1) of the *Corporations Tax Act* (Ontario)		%
– the greatest of the weighted OAFs* of the corporation and its designated corporations** for 2006, 2007, and 2008		%
Relevant OAF	660	%

* The weighted OAF for two or more corporations for their tax years ending in 2006, 2007, or 2008 is the total of the following for each corporation:

– the corporation's OAF as determined under subsection 12(1) of the *Corporations Tax Act* (Ontario) for the tax year **multiplied** by the corporation's and its share of partnerships' qualified Ontario SR&ED expenditures in the tax year, **divided** by the total of all the corporations' and their shares of partnerships' qualified Ontario SR&ED expenditures in the tax year.

Qualified Ontario SR&ED expenditure is defined in section 11.2 of the *Corporations Tax Act* (Ontario).

** A designated corporation in respect of a particular corporation is:

1) a corporation that amalgamated with the particular corporation under section 87;

2) a corporation that wound up into the particular corporation under subsection 88(1); or

3) a designated corporation to a corporation identified in 1) or 2).

Part 12 – Post-2008 SR&ED balance

Federal current SR&ED deficit for the year (amount from line 650 in Part 10, if negative) (enter as a positive amount) . . . . ______ DD

SR&ED expenditure amount deducted in the year under subsection 37(1) . . . . **670** ______

Deduct:

Cumulative post-2008 SR&ED limit at the end of the year (amount LL from Part 13) . . . . . **675** ______

Subtotal (line 670 **minus** line 675) (if negative, enter "0") ______ ► ______ EE

Subtotal (amount DD **plus** amount EE) ______ FF

Amount FF x 14 % ______ GG

Post-2008 SR&ED balance at the end of the year (amount GG **multiplied** by line 660 from Part 11) . . . . ______ HH

Enter amount HH on line 460 in Part 7.

Part 13 – Cumulative post-2008 SR&ED limit at the end of the year

Federal current SR&ED limit for the year (amount from line 650 in Part 10, if positive) . . . . ______ II

Total of all federal SR&ED limits from previous tax years ending after December 31, 2008 . . . . **700** ______

Subtotal (line II **plus** line 700) ______ JJ

Total of all amounts deducted under subsection 37(1) for previous tax years ending after December 31, 2008 . . . . **705** ______

Total of all transitional tax debits on elected reduced SR&ED pool calculated under subsection 48(3) of the *Taxation Act, 2007* (Ontario) in the previous years (total of line L in Part 7 for previous years) . . . . **710** ______

Deduct:

Amounts included in line 710 that are reasonably attributable to the federal current SR&ED deficit for the year . . . . **715** ______

Subtotal (line 710 **minus** line 715) **720** ______

Line 720	______ = ... ______ KK
Relevant OAF (from line 660 in Part 11) x 14 %	

Subtotal (line 705 **minus** amount KK) ______ ► **730** ______

Cumulative post-2008 SR&ED limit at the end of the year (amount JJ **minus** line 730) (if negative, enter "0") . . . . ______ LL

Enter amount LL on line 675 in Part 12.

Part 14 – Federal SR&ED transitional balance at the end of the year

Amount from line 170 in Part 1 (see Note) . . . . **735** ______ MM

Relevant OAF (from line 660) (see Note) **multiplied** by amount MM . . . . ______ NN

Amount NN x 14 % . . . . ______ ► ______ OO

Federal SR&ED transitional balance transferred on an eligible amalgamation or an eligible post-2008 wind-up . . . . **740** ______

Subtotal (amount OO **plus** line 740) ______ PP

Deduct:

Total of all transitional tax debits on elected reduced SR&ED pool calculated under subsection 48(3) of the *Taxation Act, 2007* (Ontario) in the previous years (total of line L in Part 7 for previous years) . . . . **750** ______

Federal SR&ED transitional balance at the end of the year (amount PP **minus** line 750) . . . . ______ QQ

Enter amount QQ on line 470 in Part 7.

Note: For tax years ending after 2009, enter the amount from line 170 and the relevant OAF from the 2009 tax year.

Canada Revenue Agency / Agence du revenu du Canada

SCHEDULE 508

ONTARIO RESEARCH AND DEVELOPMENT TAX CREDIT

Name of corporation	Business Number	Tax year-end Year Month Day
BURLINGTON HYDRO INC.	86829 1980 RC0001	2012-12-31

- Use this schedule to:
  - calculate an Ontario research and development tax credit (ORDTC);
  - claim an ORDTC earned in the tax year or carried forward from any of the 20 previous tax years that are a tax year ending after December 31, 2008, to reduce Ontario corporate income tax payable in the current tax year;
  - carry back an ORDTC to reduce Ontario corporate income tax payable in any of the three previous tax years, but not to a tax year that ends before January 1, 2009;
  - add an ORDTC that was allocated to the corporation by a partnership of which it was a member;
  - transfer an ORDTC after an amalgamation or windup; or
  - calculate a recapture of the ORDTC.
- The ORDTC is a 4.5% non-refundable tax credit on eligible expenditures incurred by a corporation in a tax year that ends after December 31, 2008.
- An eligible expenditure is an expenditure for a permanent establishment in Ontario of a corporation, that is a qualified expenditure for the purposes of section 127 of the federal *Income Tax Act* for scientific research and experimental development (SR&ED) carried on in Ontario.
- Only corporations that are not exempt from Ontario corporate income tax and none of whose income is exempt income can claim the ORDTC.
- Attach a completed copy of this schedule to the *T2 Corporation Income Tax Return.*

Part 1 – Ontario SR&ED expenditure pool

Total eligible expenditures incurred by the corporation in Ontario in the tax year	100	474,280 A		
Deduct: Government assistance, non-government assistance, or a contract payment for eligible expenditures	105	B		
Net eligible expenditures for the tax year (amount A **minus** amount B) (if negative, enter "0")		474,280 C		
Add: Eligible expenditures transferred to the corporation by another corporation	110	D		
Subtotal (amount C **plus** amount D)		474,280	►	474,280 E
Deduct: Eligible expenditures the corporation transferred to another corporation			115	F
Ontario SR&ED expenditure pool (amount E **minus** amount F) (if negative, enter "0")			120	474,280 G

Part 2 – Calculation of the current part of the ORDTC

Ontario SR&ED expenditure pool (amount G in Part 1)		474,280	x	4.50 %	= 200	21,343 H
ORDTC allocated to a corporation by a partnership of which it is a member (other than a specified member) for a fiscal period that ends in the corporation's tax year *					205	I
Repayment made in the tax year of government or non-government assistance or a contract payment that reduced an eligible expenditure other than for first term or second term shared-use equipment	210		x	4.50 %	= 215	J
Repayment made in the tax year of government or non-government assistance or a contract payment that reduced an eligible expenditure for first term or second term shared-use equipment	220	x 1 / 4 =	x	4.50 %	= 225	K
Current part of the ORDTC (total of amounts H to K)					230	21,343 L

* If there is a disposal or change of use of eligible property, see Part 6

T2 SCH 508 E

Canada

Part 3 – Calculation of ORDTC available for deduction and ORDTC balance

ORDTC balance at the end of the previous tax year				M	
Deduct: ORDTC expired after 20 tax years	300			N	
ORDTC at the beginning of the tax year (amount M **minus** amount N)	305			O	
Add:					
ORDTC transferred on amalgamation or windup	310			P	
Current part of ORDTC (amount L in Part 2)		21,343 Q			

Are you waiving all or part of the current part of the ORDTC? 315 Yes 1 [ ] No 2 [X]

If you answered **yes** at line 315, enter the amount of the tax credit waived on line 320.

If you answered **no** at line 315, enter "0" on line 320.

Deduct: Waiver of the current part of the ORDTC	320	R			
Subtotal (amount Q **minus** amount R)		21,343 ▶	21,343	S	
ORDTC available for deduction (total of amounts O, P and S)			21,343 ▶		21,343 T
Deduct:					
ORDTC claimed * (Enter amount U on line 416 of Schedule 5, *Tax Calculation Supplementary – Corporations*)			21,343	U	
ORDTC carried back to a previous tax year (from Part 4)				V	
Subtotal (amount U **plus** amount V)			21,343 ▶		21,343 W
ORDTC balance at the end of the tax year (amount T **minus** amount W)				325	X

* This amount cannot be more than the lesser of the following amounts:
- ORDTC available for deduction (amount T); or
- Ontario corporate income tax payable before the ORDTC and the Ontario corporate minimum tax credit (amount from line E6 of Schedule 5).

Part 4 – Request for carryback of tax credit

	Year Month Day			
1st previous tax year	2011-12-31	Credit to be applied	901	
2nd previous tax year	2010-12-31	Credit to be applied	902	
3rd previous tax year	2009-12-31	Credit to be applied	903	
		Total (enter amount on line V in Part 3)		

Part 5 – Analysis of tax credit available for carryforward by tax year of origin

You can complete this part to show all the credits from preceding tax years available for carryforward, by year of origin. This will help you determine the amount of credit that could expire in following years.

Tax year of origin (earliest tax year first) Year Month Day	Credit available		Tax year of origin (earliest tax year first) Year Month Day	Credit available
1993-09-30			2002-12-31	
1994-09-30			2003-12-31	
1995-09-30			2004-12-31	
1996-09-30			2005-12-31	
1997-09-30			2006-12-31	
1998-09-30			2007-12-31	
1999-09-30			2008-12-31	
2000-09-30			2009-12-31	
2001-09-30			2010-12-31	
2001-12-31			2011-12-31	
		Current tax year	2012-12-31	

Total (equals line 325 in Part 3) ____________

The amount available from the 20th preceding tax year will expire after this year. When you file your return for the next year, you will enter the expired amount on line 300 of Schedule 508 for that year.

Part 6 – Calculation of a recapture of ORDTC

You will have a recapture of ORDTC in a tax year when you meet **all** of the following conditions:

- you acquired a particular property in the current year or in any of the 20 previous tax years if the ORDTC was earned in a tax year ending after 2008;
- you claimed the cost of the property as an eligible expenditure for the ORDTC;
- the cost of the property was included in computing your ORDTC or was subject to an agreement made under subsection 127(13) of the federal Act to transfer qualified expenditures and section 42 of the *Taxation Act, 2007* (Ontario) applied; and
- you disposed of the property or converted it to commercial use in a tax year ending after December 31, 2008. You also meet this condition if you disposed of or converted to commercial use a property which incorporates the particular property previously referred to.

  Note: The recapture **does not apply** if you disposed of the property to a non-arm's length purchaser who intended to use it all or substantially all for SR&ED in Ontario. When the non-arm's length purchaser later sells or converts the property to commercial use, the recapture rules will apply to the purchaser based on the historical federal investment tax credit (ITC) rate * of the original user in Calculation 1 below.

You have to report the recapture on Schedule 5 for the year in which you disposed of the property or converted it to commercial use. If the corporation is a member of a partnership, report its share of the recapture.

If you have more than one disposition for calculations 1 and 2, complete the columns for each disposition for which a recapture applies, using the calculation formats below.

* Federal ITC in calculations 1 and 2 should be determined without reference to paragraph (e) of the definition **investment tax credit** in subsection 127(9) of the federal Act.

Calculation 1 – If you meet all of the above conditions

	Y Amount of federal ITC you originally calculated for the property you acquired, or the original user's federal ITC where you acquired the property from a non-arm's length party, as described in the note above 700	Z Amount calculated using the federal ITC rate at the date of acquisition (or the original user's date of acquisition) on either the proceeds of disposition (if sold in an arm's length transaction) or the fair market value of the property (in any other case) 710	AA Amount from column 700 or 710, whichever is less
1.			

Subtotal (enter amount BB, on line KK in Part 7) ____________ BB

Calculation 2 – If the corporation is deemed by subsection 42(1) of the *Taxation Act, 2007* (Ontario) to have transferred all or part of the eligible expenditure to another corporation as a consequence of an agreement described in subsection 127(13) of the federal Act complete Calculation 2. Otherwise, enter nil on line II.

	CC	DD	EE
	The rate percentage that the transferee used to determine its federal ITC for a qualified expenditure that was transferred under an agreement under subsection 127(13) of the federal Act	The proceeds of disposition of the property if you dispose of it to a person at arm's length; or, in any other case, the fair market value of the property at conversion or disposition	The amount, if any, already provided for in Calculation 1 (this allows for the situation where only part of the cost of a property is transferred for an agreement under subsection 127(13) of the federal Act)
	720	730	740
1.			

	FF	GG	HH
	Amount determined by the formula (CC x DD) – EE (using the columns above)	The federal ITC earned by the transferee for the qualified expenditure that was transferred	Amount from column FF or GG, whichever is less
		750	
1.			

Subtotal (enter amount II on line LL below) ______ II

Calculation 3

As a member of a partnership, you will report your share of the ORDTC of the partnership after the ORDTC has been reduced by the amount of the recapture. If this is a positive amount, you will report it on line 205 in Part 2. However, if the partnership does not have enough ORDTC otherwise available to offset the recapture, then the amount by which reductions to the ORDTC exceeds additions (the excess) will be determined and reported on line JJ.

Corporate partner's share of the excess of ORDTC (enter amount JJ at line NN below) . . . . 760 ______ JJ

Part 7 – Total recapture of ORDTC

Recaptured federal ITC for Calculation 1 (amount from line BB) . . . . ______ KK

Recaptured federal ITC for Calculation 2 (amount from line II above) . . . . ______ LL

Amount KK **plus** amount LL . . . . ______ x 23.56 % = ______ MM

Add: Corporate partner's share of the excess of ORDTC for Calculation 3 (amount from line JJ above) . . . . ______ NN

Recapture of ORDTC (amount MM **plus** amount NN) (enter amount OO on line 277 of Schedule 5) . . . . ______ OO

Schedule A - Worksheet for eligible expenditures incurred by the corporation in Ontario for the current taxation year

This worksheet allows you to report the amount of eligible expenditures entered on Form T661, *Scientific Research and Experimental Development (SR&ED) Expenditures Claim* which represents eligible expenditures as defined in section 127 of the *Income Tax Act* (ITA) with regard to scientific research and experimental development (SR&ED) **carried on in Ontario and attributable to a permanent establishment in Ontario of a corporation**.

Data on the worksheet is calculated based on the amounts on Form T661, but will have to be adjusted according to the rules of Ontario, if applicable, in particular when the corporation has had a permanent establishment in more than one jurisdiction. This data will be used when calculating Schedule 508 and Schedule 566.

Enter the breakdown between current and capital expenditures

	Current Expenditures		Capital Expenditures	
Total expenditures for SR&ED	385,227			
Add				
• payment of prior years' unpaid expenses (other than salary or wages)	+			
• prescribed proxy amount (Enter "0" if you use the traditional method)	+ 89,053			
• expenditures on shared-use equipment			+	
• other additions	+		+	
Subtotal	= 474,280		=	
Less				
• current expenditures (other than salary or wages) not paid within 180 days of the tax year end	–			
• amounts paid in respect of an SR&ED contract to a person or partnership that is not taxable supplier	–			
• prescribed expenditures not allowed by regulations	–		–	
• other deductions	–		–	
• non-arm's length transactions				
– expenditures for non-arm's length SR&ED contracts	–			
– purchases (limited to costs) of goods and services from non-arm's length suppliers	–		–	
Subtotal	= 474,280	I	=	II
Total eligible expenditures incurred by the corporation in Ontario in the tax year (add amount I and II)			= 474,280	III

Enter amount III on line 100 of Schedule 508.

Canada Revenue Agency / Agence du revenu du Canada

Schedule 510

Ontario Corporate Minimum Tax

Corporation's name	Business number	Tax year-end Year Month Day
BURLINGTON HYDRO INC.	86829 1980 RC0001	2012-12-31

- File this schedule if the corporation is subject to Ontario corporate minimum tax (CMT). CMT is levied under section 55 of the *Taxation Act, 2007* (Ontario), referred to as the "Ontario Act".
- Complete Part 1 to determine if the corporation is subject to CMT for the tax year.
- A corporation not subject to CMT in the tax year is still required to file this schedule if it is deducting a CMT credit, has a CMT credit carryforward, or has a CMT loss carryforward or a current year CMT loss.
- A corporation that has Ontario special additional tax on life insurance corporations (SAT) payable in the tax year must complete Part 4 of this schedule even if it is not subject to CMT for the tax year.
- A corporation is exempt from CMT if, throughout the tax year, it was one of the following:
  1) a corporation exempt from income tax under section 149 of the federal *Income Tax Act*;
  2) a mortgage investment corporation under subsection 130.1(6) of the federal Act;
  3) a deposit insurance corporation under subsection 137.1(5) of the federal Act;
  4) a congregation or business agency to which section 143 of the federal Act applies;
  5) an investment corporation as referred to in subsection 130(3) of the federal Act; or
  6) a mutual fund corporation under subsection 131(8) of the federal Act.
- File this schedule with the *T2 Corporation Income Tax Return*.

Part 1 – Determination of CMT applicability

Total assets of the corporation at the end of the tax year *	112	161,462,997
Share of total assets from partnership(s) and joint venture(s) *	114	
Total assets of associated corporations (amount from line 450 on Schedule 511)	116	48,298,569
Total assets (total of lines 112 to 116)		209,761,566
Total revenue of the corporation for the tax year **	142	194,322,369
Share of total revenue from partnership(s) and joint venture(s) **	144	
Total revenue of associated corporations (amount from line 550 on Schedule 511)	146	3,932,146
Total revenue (total of lines 142 to 146)		198,254,515

The corporation is subject to CMT if:
- for tax years ending before July 1, 2010, the total assets at the end of the year of the corporation or the associated group of corporations are more than $5,000,000, or the total revenue for the year of the corporation or the associated group of corporations is more than $10,000,000.
- for tax years ending after June 30, 2010, the total assets at the end of the year of the corporation or the associated group of corporations are equal to or more than $50,000,000, and the total revenue for the year of the corporation or the associated group of corporations is equal to or more than $100,000,000.

If the corporation is not subject to CMT, do not complete the remaining parts unless the corporation is deducting a CMT credit, or has a CMT credit carryforward, a CMT loss carryforward, a current year CMT loss, or SAT payable in the year.

* **Rules for total assets**
- Report total assets according to generally accepted accounting principles, adjusted so that consolidation and equity methods are not used.
- Do not include unrealized gains and losses on assets and foreign currency gains and losses on assets that are included in net income for accounting purposes but not in income for corporate income tax purposes.
- The amount on line 114 is determined at the end of the last fiscal period of the partnership or joint venture that ends in the tax year of the corporation. Add the proportionate share of the assets of the partnership(s) and joint venture(s), and deduct the recorded asset(s) for the investment in partnerships and joint ventures.
- A corporation's share in a partnership or joint venture is determined under paragraph 54(5)(b) of the Ontario Act and, if the partnership or joint venture had no income or loss, is calculated as if the partnership's or joint venture's income were $1 million. For a corporation with an indirect interest in a partnership or joint venture, determine the corporation's share according to paragraph 54(5)(c) of the Ontario Act.

** **Rules for total revenue**
- Report total revenue in accordance with generally accepted accounting principles, adjusted so that consolidation and equity methods are not used.
- If the tax year is less than 51 weeks, **multiply** the total revenue of the corporation or the partnership, whichever applies, by 365 and **divide** by the number of days in the tax year.
- The amount on line 144 is determined for the partnership or joint venture fiscal period that ends in the tax year of the corporation. If the partnership or joint venture has 2 or more fiscal periods ending in the filing corporation's tax year, **multiply** the sum of the total revenue for each of the fiscal periods by 365 and **divide** by the total number of days in all the fiscal periods.
- A corporation's share in a partnership or joint venture is determined under paragraph 54(5)(b) of the Ontario Act and, if the partnership or joint venture had no income or loss, is calculated as if the partnership's or joint venture's income were $1 million. For a corporation with an indirect interest in a partnership or joint venture, determine the corporation's share according to paragraph 54(5)(c) of the Ontario Act.

Part 2 – Adjusted net income/loss for CMT purposes

	Line	Amount		Line	Total	
Net income/loss per financial statements *				210	6,410,383	
Add (to the extent reflected in income/loss):						
Provision for current income taxes/cost of current income taxes	220	1,310,399				
Provision for deferred income taxes (debits)/cost of future income taxes	222	419,259				
Equity losses from corporations	224					
Financial statement loss from partnerships and joint ventures	226					
Dividends deducted on financial statements (subsection 57(2) of the Ontario Act), excluding dividends paid by credit unions under subsection 137(4.1) of the federal Act	230					
Other additions (see note below):						
Share of adjusted net income of partnerships and joint ventures **	228					
Total patronage dividends received, not already included in net income/loss	232					
281	282					
283	284					
Subtotal		1,729,658	▶		1,729,658	A
Deduct (to the extent reflected in income/loss):						
Provision for recovery of current income taxes/benefit of current income taxes	320					
Provision for deferred income taxes (credits)/benefit of future income taxes	322					
Equity income from corporations	324					
Financial statement income from partnerships and joint ventures	326					
Dividends deductible under section 112, section 113, or subsection 138(6) of the federal Act	330					
Dividends not taxable under section 83 of the federal Act (from Schedule 3)	332					
Gain on donation of listed security or ecological gift	340					
Accounting gain on transfer of property to a corporation under section 85 or 85.1 of the federal Act ***	342					
Accounting gain on transfer of property to/from a partnership under section 85 or 97 of the federal Act ****	344					
Accounting gain on disposition of property under subsection 13(4), subsection 14(6), or section 44 of the federal Act *****	346					
Accounting gain on a windup under subsection 88(1) of the federal Act or an amalgamation under section 87 of the federal Act	348					
Other deductions (see note below):						
Share of adjusted net loss of partnerships and joint ventures **	328					
Tax payable on dividends under subsection 191.1(1) of the federal Act **multiplied** by 3	334					
Interest deducted/deductible under paragraph 20(1)(c) or (d) of the federal Act, not already included in net income/loss	336					
Patronage dividends paid (from Schedule 16) not already included in net income/loss	338					
381	382					
383	384					
385	386					
387	388					
389	390					
Subtotal			▶			B
Adjusted net income/loss for CMT purposes (line 210 **plus** amount A **minus** amount B)				490	8,140,041	

If the amount on line 490 is positive and the corporation is subject to CMT as determined in Part 1, enter the amount on line 515 in Part 3.

If the amount on line 490 is negative, enter the amount on line 760 in Part 7 (enter as a positive amount).

Note

In accordance with *Ontario Regulation 37/09*, when calculating net income for CMT purposes, accounting income should be adjusted to:

– exclude unrealized gains and losses due to mark-to-market changes or foreign currency changes on specified mark-to-market property (assets only);
– include realized gains and losses on the disposition of specified mark-to-market property not already included in the accounting income, if the property is not a capital property or is a capital property disposed in the year or in a previous tax year ended after March 22, 2007.

"Specified mark-to-market property" is defined in subsection 54(1) of the Ontario Act.

These rules also apply to partnerships. A corporate partner's share of a partnership's adjusted income flows through on a proportionate basis to the corporate partner.

* **Rules for net income/loss**

– Banks must report net income/loss as per the report accepted by the Superintendent of Financial Institutions under the federal *Bank Act*, adjusted so consolidation and equity methods are not used.

Part 2 – Adjusted net income/loss for CMT purposes (continued)

– Life insurance corporations must report net income/loss as per the report accepted by the federal Superintendent of Financial Institutions or equivalent provincial insurance regulator, before SAT and adjusted so consolidation and equity methods are not used. If the life insurance corporation is resident in Canada and carries on business in and outside of Canada, **multiply** the net income/loss by the ratio of the Canadian reserve liabilities **divided** by the total reserve liability. The reserve liabilities are calculated in accordance with Regulation 2405(3) of the federal Act.

– Other corporations must report net income/loss in accordance with generally accepted accounting principles, except that consolidation and equity methods must not be used. When the equity method has been used for accounting purposes, equity losses and equity income are removed from book income/loss on lines 224 and 324 respectively.

– Corporations, other than insurance corporations, should report net income from line 9999 of the GIFI (Schedule 125) on line 210.

** The share of the adjusted net income of a partnership or joint venture is calculated as if the partnership or joint venture were a corporation and the tax year of the partnership or joint venture were its fiscal period. For a corporation with an indirect interest in a partnership through one or more partnerships, determine the corporation's share according to clause 54(5)(c) of the Ontario Act.

*** A joint election will be considered made under subsection 60(1) of the Ontario Act if there is an entry on line 342, and an election has been made for transfer of property to a corporation under subsection 85(1) of the federal Act.

**** A joint election will be considered made under subsection 60(2) of the Ontario Act if there is an entry on line 344, and an election has been made under subsection 85(2) or 97(2) of the federal Act.

***** A joint election will be considered made under subsection 61(1) of the Ontario Act if there is an entry on line 346, and an election has been made under subsection 13(4) or 14(6) and/or section 44 of the federal Act.

For more information on how to complete this part, see the *T2 Corporation – Income Tax Guide*.

Part 3 – CMT payable

Adjusted net income for CMT purposes (line 490 in Part 2, if positive)		515	8,140,041	
Deduct:				
CMT loss available (amount R from Part 7)				
Minus: Adjustment for an acquisition of control *	518			
Adjusted CMT loss available		▶		C
Net income subject to CMT calculation (if negative, enter "0")		520	8,140,041	

Amount from line 520	8,140,041	x	Number of days in the tax year before July 1, 2010 / Number of days in the tax year	/ 366	x 4 % =	1
Amount from line 520	8,140,041	x	Number of days in the tax year after June 30, 2010 / Number of days in the tax year	366 / 366	x 2.7 % = 219,781	2

Subtotal (amount 1 **plus** amount 2) 219,781 3

Gross CMT: amount on line 3 above x OAF **	540	219,781	
Deduct:			
Foreign tax credit for CMT purposes ***	550		
CMT after foreign tax credit deduction (line 540 **minus** line 550) (if negative, enter "0")		219,781	D
Deduct:			
Ontario corporate income tax payable before CMT credit (amount F6 from Schedule 5)		502,637	
Net CMT payable (if negative, enter "0")			E

Enter amount E on line 278 of Schedule 5, *Tax Calculation Supplementary – Corporations*, and complete Part 4.

* Enter the portion of CMT loss available that exceeds the adjusted net income for the tax year from carrying on a business before the acquisition of control. See subsection 58(3) of the Ontario Act.

*** Enter "0" on line 550 for life insurance corporations as they are not eligible for this deduction. For all other corporations, enter the cumulative total of amount J for the province of Ontario from Part 9 of Schedule 21 on line 550.

** **Calculation of the Ontario allocation factor (OAF):**

If the provincial or territorial jurisdiction entered on line 750 of the T2 return is "Ontario," enter "1" on line F.

If the provincial or territorial jurisdiction entered on line 750 of the T2 return is "multiple," complete the following calculation, and enter the result on line F:

Ontario taxable income **** / Taxable income ***** =

Ontario allocation factor ..... 1.00000 F

**** Enter the amount allocated to Ontario from column F in Part 1 of Schedule 5. If the taxable income is nil, calculate the amount in column F as if the taxable income were $1,000.

***** Enter the taxable income amount from line 360 or amount Z of the T2 return, whichever applies. If the taxable income is nil, enter "1,000."

Part 4 – CMT credit carryforward

CMT credit carryforward at the end of the previous tax year *			G	
Deduct:				
CMT credit expired *	600			
CMT credit carryforward at the beginning of the current tax year * (see note below)			620	
Add:				
CMT credit carryforward balances transferred on an amalgamation or the windup of a subsidiary (see note below)			650	
CMT credit available for the tax year (amount on line 620 **plus** amount on line 650)				H
Deduct:				
CMT credit deducted in the current tax year (amount P from Part 5)				I
Subtotal (amount H **minus** amount I)				J
Add:				
Net CMT payable (amount E from Part 3)				
SAT payable (amount O from Part 6 of Schedule 512)				
Subtotal			▶	K
CMT credit carryforward at the end of the tax year (amount J **plus** amount K)			670	L

* For the first harmonized T2 return filed with a tax year that includes days in 2009:
- do not enter an amount on line G or line 600;
- for line 620, enter the amount from line 2336 of Ontario CT23 Schedule 101, *Corporate Minimum Tax (CMT)*, for the last tax year that ended in 2008.

For other tax years, enter on line G the amount from line 670 of Schedule 510 from the previous tax year.

Note: If you entered an amount on line 620 or line 650, complete Part 6.

Part 5 – CMT credit deducted from Ontario corporate income tax payable

CMT credit available for the tax year (amount H from Part 4)				M
Ontario corporate income tax payable before CMT credit (amount F6 from Schedule 5)		502,637	1	
For a corporation that is not a life insurance corporation:				
CMT after foreign tax credit deduction (amount D from Part 3)	219,781	2		
For a life insurance corporation:				
Gross CMT (line 540 from Part 3)		3		
Gross SAT (line 460 from Part 6 of Schedule 512)		4		
The **greater** of amounts 3 and 4		5		
Deduct: line 2 or line 5, whichever applies:		219,781	6	
Subtotal (if negative, enter "0")		282,856	▶	282,856 N
Ontario corporate income tax payable before CMT credit (amount F6 from Schedule 5)		502,637		
Deduct:				
Total refundable tax credits excluding Ontario qualifying environmental trust tax credit (amount J6 **minus** line 450 from Schedule 5)		29,919		
Subtotal (if negative, enter "0")		472,718	▶	472,718 O
CMT credit deducted in the current tax year (least of amounts M, N, and O)				P

Enter amount P on line 418 of Schedule 5 and on line I in Part 4 of this schedule.

Is the corporation claiming a CMT credit earned before an acquisition of control? 675 1 Yes ☐ 2 No ☒

If you answered **yes** to the question at line 675, the CMT credit deducted in the current tax year may be restricted. For information on how the deduction may be restricted, see subsections 53(6) and (7) of the Ontario Act.

Part 6 – CMT credit available for carryforward by year of origin

Complete this part if:
- the tax year includes January 1, 2009; or
- the previous tax year-end is deemed to be December 31, 2008, under subsection 249(3) of the federal Act.

Year of origin	CMT credit balance *
10th previous tax year	680
9th previous tax year	681
8th previous tax year	682
7th previous tax year	683
6th previous tax year	684
5th previous tax year	685
4th previous tax year	686
3rd previous tax year	687
2nd previous tax year	688
1st previous tax year	689
Total **	

* CMT credit that was earned (by the corporation, predecessors of the corporation, and subsidiaries wound up into the corporation) in each of the previous 10 tax years and has not been deducted.

** Must equal the total of the amounts entered on lines 620 and 650 in Part 4.

Part 7 – CMT loss carryforward

CMT loss carryforward at the end of the previous tax year * . . . . Q

Deduct:

CMT loss expired * 700

CMT loss carryforward at the beginning of the tax year * (see note below) . . . . ► 720

Add:

CMT loss transferred on an amalgamation under section 87 of the federal Act ** (see note below) 750

CMT loss available (line 720 **plus** line 750) . . . . R

Deduct:

CMT loss deducted against adjusted net income for the tax year (lesser of line 490 (if positive) and line C in Part 3) . . . .

Subtotal (if negative, enter "0") S

Add:

Adjusted net loss for CMT purposes (amount from line 490 in Part 2, if **negative**) (enter as a positive amount) 760

CMT loss carryforward balance at the end of the tax year (amount S **plus** line 760) . . . . 770 T

* For the first harmonized T2 return filed with a tax year that includes days in 2009:
- do not enter an amount on line Q or line 700;
- for line 720, enter the amount from line 2214 of Ontario CT23 Schedule 101, *Corporate Minimum Tax (CMT)*, for the last tax year that ended in 2008.

For other tax years, enter on line Q the amount from line 770 of Schedule 510 from the previous tax year.

** Do not include an amount from a predecessor corporation if it was controlled at any time before the amalgamation by any of the other predecessor corporations.

Note: If you entered an amount on line 720 or line 750, complete Part 8.

Part 8 – CMT loss available for carryforward by year of origin

Complete this part if:
- the tax year includes January 1, 2009; or
- the previous tax year-end is deemed to be December 31, 2008, under subsection 249(3) of the federal Act.

Year of origin	Balance earned in a tax year ending before March 23, 2007 *	Balance earned in a tax year ending after March 22, 2007 **
10th previous tax year	810	820
9th previous tax year	811	821
8th previous tax year	812	822
7th previous tax year	813	823
6th previous tax year	814	824
5th previous tax year	815	825
4th previous tax year	816	826
3rd previous tax year	817	827
2nd previous tax year	818	828
1st previous tax year		829
Total ***		

* Adjusted net loss for CMT purposes that was earned (by the corporation, by subsidiaries wound up into or amalgamated with the corporation before March 22, 2007, and by other predecessors of the corporation) in each of the previous 10 tax years that ended before March 23, 2007, and has not been deducted.

** Adjusted net loss for CMT purposes that was earned (by the corporation and its predecessors, but not by a subsidiary predecessor) in each of the previous 20 tax years that ended after March 22, 2007, and has not been deducted.

*** The total of these two columns must equal the total of the amounts entered on lines 720 and 750.

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SCHEDULE 511

ONTARIO CORPORATE MINIMUM TAX – TOTAL ASSETS AND REVENUE FOR ASSOCIATED CORPORATIONS

Name of corporation	Business Number	Tax year-end Year Month Day
BURLINGTON HYDRO INC.	86829 1980 RC0001	2012-12-31

- For use by corporations to report the total assets and total revenue of all the Canadian or foreign corporations with which the filing corporation was associated at any time during the tax year. These amounts are required to determine if the filing corporation is subject to corporate minimum tax.
- Total assets and total revenue include the associated corporation's share of any partnership(s)/joint venture(s) total assets and total revenue.
- Attach additional schedules if more space is required.
- File this schedule with the *T2 Corporation Income Tax Return.*

	Names of associated corporations 200	Business number (Canadian corporation only) (see Note 1) 300	Total assets* (see Note 2) 400	Total revenue** (see Note 2) 500
1	BURLINGTON ELECTRICITY SERVICES INC.	86829 1782 RC0001	2,253,404	1,825,544
2	BURLINGTON HYDRO ELECTRIC INC.	88361 4927 RC0001	46,045,165	2,106,602
3	THE CITY OF BURLINGTON	NR	0	0
		Total	450 48,298,569	550 3,932,146

Enter the total assets from line 450 on line 116 in Part 1 of Schedule 510, *Ontario Corporate Minimum Tax*.
Enter the total revenue from line 550 on line 146 in Part 1 of Schedule 510.

Note 1: Enter ¨NR¨ if a corporation is not registered.

Note 2: If the associated corporation does not have a tax year that ends in the filing corporation's current tax year but was associated with the filing corporation in the previous tax year of the filing corporation, enter the total revenue and total assets from the tax year of the associated corporation that ends in the previous tax year of the filing corporation.

* **Rules for total assets**

- Report total assets in accordance with generally accepted accounting principles, adjusted so that consolidation and equity methods are not used.
- Include the associated corporation's share of the total assets of partnership(s) and joint venture(s) but exclude the recorded asset(s) for the investment in partnerships and joint ventures.
- Exclude unrealized gains and losses on assets that are included in net income for accounting purposes but not in income for corporate income tax purposes.

** **Rules for total revenue**

- Report total revenue in accordance with generally accepted accounting principles, adjusted so that consolidation and equity methods are not used.
- If the associated corporation has 2 or more tax years ending in the filing corporation's tax year, **multiply** the sum of the total revenue for each of those tax years by 365 and **divide** by the total number of days in all of those tax years.
- If the associated corporation's tax year is less than 51 weeks and is the only tax year of the associated corporation that ends in the filing corporation's tax year, **multiply** the associated corporation's total revenue by 365 and **divide** by the number of days in the associated corporation's tax year.
- Include the associated corporation's share of the total revenue of partnerships and joint ventures.
- If the partnership or joint venture has 2 or more fiscal periods ending in the associated corporation's tax year, **multiply** the sum of the total revenue for each of the fiscal periods by 365 and **divide** by the total number of days in all the fiscal periods.

Canada Revenue Agency / Agence du revenu du Canada

SCHEDULE 546

CORPORATIONS INFORMATION ACT ANNUAL RETURN FOR ONTARIO CORPORATIONS

Name of corporation	Business Number	Tax year-end Year Month Day
BURLINGTON HYDRO INC.	86829 1980 RC0001	2012-12-31

- This schedule should be completed by a corporation that is incorporated, continued, or amalgamated in Ontario and subject to the Ontario *Business Corporations Act* (BCA) or Ontario *Corporations Act* (CA), except for registered charities under the federal *Income Tax Act*. This completed schedule serves as a *Corporations Information Act* Annual Return under the *Ontario Corporations Information Act*.
- Complete parts 1 to 4. Complete parts 5 to 7 only to report change(s) in the information recorded on the Ontario Ministry of Government Services (MGS) public record.
- This schedule must set out the required information for the corporation as of the date of delivery of this schedule.
- A completed Ontario *Corporations Information Act* Annual Return must be delivered within six months after the end of the corporation's tax year-end. The MGS considers this return to be delivered on the date that it is filed with the Canada Revenue Agency (CRA) together with the corporation's income tax return.
- It is the corporation's responsibility to ensure that the information shown on the MGS public record is accurate and up-to-date. To review the information shown for the corporation on the public record maintained by the MGS, obtain a Corporation Profile Report. Visit **www.ServiceOntario.ca** for more information.
- This schedule contains non-tax information collected under the authority of the Ontario *Corporations Information Act*. This information will be sent to the MGS for the purposes of recording the information on the public record maintained by the MGS.

Part 1 – Identification

100 Corporation's name (exactly as shown on the MGS public record)
BURLINGTON HYDRO INC.

Jurisdiction incorporated, continued, or amalgamated, whichever is the most recent	**110** Date of incorporation or amalgamation, whichever is the most recent (Year Month Day)	**120** Ontario Corporation No.
Ontario	1999-12-01	1388234

Part 2 – Head or registered office address (P.O. box not acceptable as stand-alone address)

200 Care of (if applicable)
Michael Kysley

210 Street number	**220** Street name/Rural route/Lot and Concession number	**230** Suite number
1340	Brant Street	

240 Additional address information if applicable (line 220 must be completed first)

250 Municipality (e.g., city, town)	**260** Province/state	**270** Country	**280** Postal/zip code
Burlington	ON	CA	L7R 3Z7

Part 3 – Change identifier

Have there been any changes in any of the information most recently filed for the public record maintained by the MGS for the corporation with respect to names, addresses for service, and the date elected/appointed and, if applicable, the date the election/appointment ceased of the directors and five most senior officers, or with respect to the corporation's mailing address or language of preference? To review the information shown for the corporation on the public record maintained by the MGS, obtain a Corporation Profile Report. For more information, visit **www.ServiceOntario.ca**.

300 1 If there have been no changes, enter **1** in this box and then go to "Part 4 – Certification."
If there are changes, enter **2** in this box and complete the applicable parts on the next page, and then go to "Part 4 – Certification."

Part 4 – Certification

I certify that all information given in this *Corporations Information Act* Annual Return is true, correct, and complete.

450 KYSLEY (Last name) **451** MICHAEL (First name)

454 ______________________, (Middle name(s))

460 2 Please enter one of the following numbers in this box for the above-named person: **1** for director, **2** for officer, or **3** for other individual having knowledge of the affairs of the corporation. If you are a director and officer, enter **1** or **2**.

Note: Sections 13 and 14 of the Ontario *Corporations Information Act* provide penalties for making false or misleading statements or omissions.

Complete the applicable parts to report changes in the information recorded on the MGS public record.

Part 5 – Mailing address

500 ☐ Please enter one of the following numbers in this box:

1 - Show no mailing address on the MGS public record.
2 - The corporation's mailing address is the same as the head or registered office address in Part 2 of this schedule.
3 - The corporation's complete mailing address is as follows:

510 Care of (if applicable)		
520 Street number	**530** Street name/Rural route/Lot and Concession number	**540** Suite number
550 Additional address information if applicable (line 530 must be completed first)		

560 Municipality (e.g., city, town)	**570** Province/state	**580** Country	**590** Postal/zip code

Part 6 – Language of preference

600 ☐ Indicate your language of preference by entering **1** for English or **2** for French. This is the language of preference recorded on the MGS public record for communications with the corporation. It may be different from line 990 on the T2 return.

Canada Revenue Agency / Agence du revenu du Canada

SCHEDULE 552

ONTARIO APPRENTICESHIP TRAINING TAX CREDIT

Name of corporation	Business Number	Tax year-end Year Month Day
BURLINGTON HYDRO INC.	86829 1980 RC0001	2012-12-31

- Use this schedule to claim an Ontario apprenticeship training tax credit (ATTC) under section 89 of the *Taxation Act, 2007* (Ontario).
- The ATTC is a refundable tax credit that is equal to a specified percentage (25% to 45%) of the eligible expenditures incurred by a corporation for a qualifying apprenticeship. Before March 27, 2009, the maximum credit for each apprentice is $5,000 per year to a maximum credit of $15,000 over the first 36-month period of the qualifying apprenticeship. After March 26, 2009, the maximum credit for each apprentice is $10,000 per year to a maximum credit of $40,000 over the first 48-month period of the qualifying apprenticeship. The maximum credit amount is prorated for an employment period of an apprentice that straddles March 26, 2009.
- Eligible expenditures are salaries and wages (including taxable benefits) paid to an apprentice in a qualifying apprenticeship or fees paid to an employment agency for the provision of services performed by the apprentice in a qualifying apprenticeship. These expenditures must be:
  - paid on account of employment or services, as applicable, at a permanent establishment of the corporation in Ontario;
  - for services provided by the apprentice during the first 36 months of the apprenticeship program, if incurred before March 27, 2009; and
  - for services provided by the apprentice during the first 48 months of the apprenticeship program, if incurred after March 26, 2009.
- An expenditure is not eligible for an ATTC if:
  - the same expenditure was used, or will be used, to claim a co-operative education tax credit; or
  - it is more than an amount that would be paid to an arm's length apprentice.
- An apprenticeship must meet the following conditions to be a qualifying apprenticeship:
  - the apprenticeship is in a qualifying skilled trade approved by the Ministry of Training, Colleges and Universities (Ontario); and
  - the corporation and the apprentice must be participating in an apprenticeship program in which the training agreement has been registered under the *Ontario College of Trades and Apprenticeship Act, 2009 or* the *Apprenticeship and Certification Act, 1998* or in which the contract of apprenticeship has been registered under the *Trades Qualification and Apprenticeship Act*.
- Make sure you keep a copy of the training agreement or contract of apprenticeship to support your claim. Do not submit the training agreement or contract of apprenticeship with your *T2 Corporation Income Tax Return*.
- File this schedule with your *T2 Corporation Income Tax Return*.

Part 1 – Corporate information (please print)

110 Name of person to contact for more information	120 Telephone number including area code
JOHN MAURO	(905) 332-1851

Is the claim filed for an ATTC earned through a partnership? * . . . . . **150** 1 Yes [ ] 2 No [X]

If **yes** to the question at line 150, what is the name of the partnership? . . . . . **160** ______

Enter the percentage of the partnership's ATTC allocated to the corporation . . . . . **170** ______ %

* When a corporate member of a partnership is claiming an amount for eligible expenditures incurred by a partnership, complete a Schedule 552 for the partnership as if the partnership were a corporation. Each corporate partner, other than a limited partner, should file a separate Schedule 552 to claim the partner's share of the partnership's ATTC. The total of the partners' allocated amounts can never exceed the amount of the partnership's ATTC.

Part 2 – Eligibility

1. Did the corporation have a permanent establishment in Ontario in the tax year? . . . . . **200** 1 Yes [X] 2 No [ ]
2. Was the corporation exempt from tax under Part III of the *Taxation Act, 2007* (Ontario)? . . . . . **210** 1 Yes [ ] 2 No [X]

If you answered **no** to question 1 or **yes** to question 2, then you are **not eligible** for the ATTC.

Part 3 – Specified percentage

Corporation's salaries and wages paid in the previous tax year * **300** 4,103,271

For eligible expenditures incurred before March 27, 2009:
- If line 300 is $400,000 or less, enter 30% on line 310.
- If line 300 is $600,000 or more, enter 25% on line 310.
- If line 300 is more than $400,000 and less than $600,000, enter the percentage on line 310 using the following formula:

$$\text{Specified percentage} = 30\,\% - \left[5\,\% \times \left(\frac{\text{amount on line 300} \textbf{ minus } 400{,}000}{200{,}000} \right) \right]$$

Specified percentage . . . . . **310** 25.000 %

For eligible expenditures incurred after March 26, 2009:
- If line 300 is $400,000 or less, enter 45% on line 312.
- If line 300 is $600,000 or more, enter 35% on line 312.
- If line 300 is more than $400,000 and less than $600,000, enter the percentage on line 312 using the following formula:

$$\text{Specified percentage} = 45\,\% - \left[10\,\% \times \left(\frac{\text{amount on line 300} \textbf{ minus } 400{,}000}{200{,}000} \right) \right]$$

Specified percentage . . . . . **312** 35.000 %

* If this is the first tax year of an amalgamated corporation and subsection 89(6) of the *Taxation Act, 2007* (Ontario) applies, enter salaries and wages paid in the previous tax year by the predecessor corporations.

Part 4 – Calculation of the Ontario apprenticeship training tax credit

Complete a **separate entry** for each apprentice that is in a qualifying apprenticeship with the corporation. When claiming an ATTC for repayment of government assistance, complete a **separate entry** for each repayment, and complete columns A to G and M and N with the details for the employment period in the previous tax year in which the government assistance was received.

	A Trade code 400	B Apprenticeship program/ trade name 405	C Name of apprentice 410
1.	434a	Powerline Technician	Michael Dunlop
2.	434a	Powerline Technician	Eliot Heywood
3.	434a	Powerline Technician	Joey Fournier

	D Original contract or training agreement number 420	E Original registration date of apprenticeship contract or training agreement (see note 1 below) 425	F Start date of employment as an apprentice in the tax year (see note 2 below) 430	G End date of employment as an apprentice in the tax year (see note 3 below) 435
1.	PB1680	2009-04-14	2012-01-01	2012-12-31
2.	PB1681	2010-01-07	2012-01-01	2012-12-31
3.	PB1682	2009-05-04	2012-01-01	2012-12-31

Note 1: Enter the original registration date of the apprenticeship contract or training agreement in all cases, even when multiple employers employed the apprentice.

Note 2: When there are multiple employment periods as an apprentice in the tax year with the corporation, enter the date that is the first day of employment as an apprentice in the tax year with the corporation. When claiming an ATTC for repayment of government assistance, enter the start date of employment as an apprentice for the tax year in which the government assistance was received.

Note 3: When there are multiple employment periods as an apprentice in the tax year with the corporation, enter the date that is the last day of employment as an apprentice in the tax year with the corporation. When claiming an ATTC for repayment of government assistance, enter the end date of employment as an apprentice for the tax year in which the government assistance was received.

Part 4 – Calculation of the Ontario apprenticeship training tax credit (continued)

	H1 Number of days employed as an apprentice in the tax year before March 27, 2009 (see note 1 below) 441	H2 Number of days employed as an apprentice in the tax year after March 26, 2009 (see note 1 below) 442	H3 Number of days employed as an apprentice in the tax year (column H1 **plus** column H2) 440	I Maximum credit amount for the tax year (see note 2 below) 445
1.		365	365	9,973
2.		365	365	9,973
3.		365	365	9,973

	J1 Eligible expenditures before March 27, 2009 (see note 3 below) 451	J2 Eligible expenditures after March 26, 2009 (see note 3 below) 452	J3 Eligible expenditures for the tax year (column J1 **plus** column J2) 450	K Eligible expenditures **multiplied** by specified percentage (see note 4 below) 460
1.		90,855	90,855	31,799
2.		85,044	85,044	29,765
3.		91,160	91,160	31,906

	L ATTC on eligible expenditures (lesser of columns I and K) 470	M ATTC on repayment of government assistance (see note 5 below) 480	N ATTC for each apprentice (column L or column M, whichever applies) 490
1.	9,973		9,973
2.	9,973		9,973
3.	9,973		9,973

Ontario apprenticeship training tax credit (total of amounts in column N) 500 29,919 **O**

or, if the corporation answered **yes** at line 150 in Part 1, determine the partner's share of amount O:

Amount O ________ x percentage on line 170 in Part 1 ________ % = ... ________ **P**

Enter amount O or P, whichever applies, on line 454 of Schedule 5, *Tax Calculation Supplementary – Corporations*. If you are filing more than one Schedule 552, add the amounts from line O or P, whichever applies, on all the schedules, and enter the total amount on line 454 of Schedule 5.

Note 1: When there are multiple employment periods as an apprentice in the tax year with the corporation, do not include days in which the individual was not employed as an apprentice.
For H1: The days employed as an apprentice must be within 36 months of the registration date provided in column E.
For H2: The days employed as an apprentice must be within 48 months of the registration date provided in column E.

Note 2: Maximum credit = ($5,000 x H1/365*) + ($10,000 x H2/365*)
* 366 days, if the tax year includes February 29

Note 3: Reduce eligible expenditures by all government assistance, as defined under subsection 89(19) of the *Taxation Act, 2007* (Ontario), that the corporation has received, is entitled to receive, or may reasonably expect to receive, in respect of the eligible expenditures, on or before the filing due date of the *T2 Corporation Income Tax Return* for the tax year.
For J1: Eligible expenditures before March 27, 2009, must be for services provided by the apprentice during the first 36 months of the apprenticeship program.
For J2: Eligible expenditures after March 26, 2009, must be for services provided by the apprentice during the first 48 months of the apprenticeship program.

Note 4: Calculate the amount in column K as follows:
Column K = (J1 x line 310) + (J2 x line 312)

Note 5: Include the amount of government assistance repaid in the tax year multiplied by the specified percentage for the tax year in which the government assistance was received, to the extent that the government assistance reduced the ATTC in that tax year.
Complete a **separate entry** for each repayment of government assistance.

Attachment 2 (of 2):

Tax Assessments and Correspondence

Ontario

Ministry of Finance
33 King St W
PO Box 622
Oshawa ON L1H 8H6

HPL - tL059

Issue Date 28-Jun-2013

000004

BURLINGTON HYDRO INC.
ATTENTION: C/O JOHN MAURO, CONTROLLER
1340 BRANT ST
BURLINGTON ON L7R 3Z7

Business No. 868291980TW0001
Reference No. L0981665856

Notice of Assessment - Hydro Payment in Lieu

Electricity Act, 1998, Corporations Tax Act

Your account has been assessed resulting in a balance as indicated below.

Period Ending: 31-Dec-2012	**Return As Filed**
Total Federal Tax	$637,768.00
Total Ontario Tax	$502,637.00
Total Credits	($29,919.00)
Loss Carry-back	$0.00
Total Tax Payable	$1,110,486.00
Interest	$0.00
Current Penalty	$0.00
Credits/Payments	($1,110,486.00)
Total Assessment	**$0.00**

As of 28-Jun-2013, including the amount assessed above, you have an overall credit balance on your account of ($443,118.00).

If you have any questions concerning this Notice of Assessment, please call the number listed below. After discussion with a ministry representative, if you still do not agree with this assessment you have the right to file a Notice of Objection with the Objections and Appeals Branch within 180 days of the issue date of this form. Any taxes, interest and penalties that are outstanding as a result of the assessment are due and payable even if you have filed, or intend to file, a Notice of Objection.

If you have any questions or require additional information, please visit our website or call the Ministry of Finance at the number listed below.

Ministry use only

ALLOWANCE FOR PILS

The PILs model is being filed in conjunction with this application. The integrity checklist is presented at the next section.

NON-RECOVERABLE AND DISALLOWED EXPENSES

Burlington Hydro confirms that expenses that are deemed non-recoverable in the revenue requirement (e.g. certain charitable donations) or disallowed for regulatory purposes, have been excluded from the regulatory tax calculation.

INTEGRITY CHECKLIST

Burlington Hydro and its external auditors attest that the following integrity checks have been completed in its application and provide a statement to this effect

- ✓ The depreciation and amortization added back in the application's PILs model agree with the numbers disclosed in the rate base section of the application;

- ✓ The capital additions and deductions in the UCC/ CCA Schedule 8 agree with the rate base section for historic, bridge and test years;

- ✓ Schedule 8 of the most recent federal T2 tax return filed with the application has a closing December 31st historic year UCC that agrees with the opening bridge year UCC at January 1st. If the amounts do not agree, then Burlington Hydro must

- ✓ provide a reconciliation with explanations for the reasons;

- ✓ The CCA deductions in the application's PILs tax model for historic, bridge and test years agree with the numbers in the UCC schedules for the same years filed in the application;

- ✓ Loss carry-forwards, if any, from the tax returns (Schedule 4) agree with those disclosed in the application;

- ✓ CCA is maximized even if there are tax loss carry-forwards;

- ✓ A statement is included in the application as to when the losses, if any, will be fully utilized;

- ✓ Accounting OPEB and pension amounts added back on Schedule 1 reconciliation of accounting income to net income for tax purposes, must agree with the OM&A analysis for compensation. The amounts deducted must be reasonable when compared with the notes in the audited financial statements, FSCO reports, and the actuarial valuations; and

- ✓ The income tax rate used to calculate the tax expense must be consistent with the utility's actual tax facts and evidence filed in the proceeding.