SUMMARY OF PROPOSED APPLICATION

Hydro One has initiated a process to discuss potential settlement of the Transmission rate impacts on 2015 and 2016. At the initial discussion on June 25, Ken Rosenberg, who has been retained by Hydro One to facilitate the discussion, described the key elements of this process and established dates for further sharing of supporting data and initiation of negotiations. The communication on the schedule issued by Ken is attached.

At the meeting, Hydro One also introduced Gordon Kaiser who is assisting Hydro One from a strategic perspective. Hydro One shared an overview of the Transmission Revenue Requirement and Rates that the company requires for 2015 and 2016. The power point presentation used on June 24 is also included. When establishing the dates for further discussion, Hydro One clearly indicated that while it is hopeful that a settlement can be reached, it needs to file an application in September with or without a settlement.

To assist parties to better understand the costing underlying Hydro One’s requirements for 2015 and 2016 rates, the parties at the June 25th meeting requested that the company provide key information supporting the 2015 and 2016 revenue requirement and rates. The company has included the scope of the proposed application in the following section which also provides a guide to where additional details are provided. In addition, at the June 25th meeting, Hydro One was requested by Bill Harper to identify which capital projects were directed by the OPA, IESO or Government. This list is included below.

The materials have been organized in a format that is consistent with previous Transmission revenue requirement and rate applications including the exhibit numbers used. As part of this process there may be areas where additional or clarifying information would be beneficial to the parties, Hydro One proposes that it will update the exhibits to improve the quality of the information prior to preparing the application. If a settlement is not reached the attached exhibits might be updated to capture these improvements or other developments that occur in the interim.
1.0 SCOPE OF PROPOSED APPLICATION

The scope of this Proposed Application includes:

- the review of Hydro One Transmission’s evidence in support of the revenue requirements for 2015 and 2016, and
- the review of the charge determinants by rate pools to assist in the development of Uniform Transmission Rates.

This proposal reflects Hydro One Transmission’s plan to invest in its network assets to meet objectives regarding public and employee safety; regulatory and legislative compliance; maintenance of system security and reliability; system growth requirements; and initiatives to facilitate renewable generation connection. Details of Hydro One Transmission’s capital expenditures are provided in schedules within Exhibit D1, Tab 3.

Hydro One Transmission’s OM&A expenditures have been determined on the basis of an examination of required work programs to ensure the most appropriate, cost-effective solutions are undertaken to meet public and employee safety objectives, maintain transmission reliability at targeted performance levels, and to comply with regulatory requirements, environmental requirements and Government direction. These expenditures are provided in Exhibit C1.

Hydro One assesses the condition of its Transmission assets on an ongoing basis, and the results of these assessments are used to determine the Sustainment OM&A and capital plans set out in Exhibits C and D. Sustainment planning is described at Exhibit C1, Tab 2, Schedule 2 and at D1, Tab 3, Schedule 2.

This Proposed Application by Hydro One Transmission is substantively consistent with the Filing Requirements for Transmission Applications (the “Filing Requirements”) issued by the Board on January 2, 2014.
This Proposed Application addresses all outstanding Board directives with respect to its Transmission Business.

Hydro One has used the Corporate Cost Allocation Methodology as accepted by the Board in previous Hydro One Distribution and Transmission Applications and updated for this current filing, to allocate the costs of shared services of OM&A and Common Assets between Transmission and Distribution.

The 2015-2016 overhead capitalization rate has been calculated consistent with the methodology accepted in previous Hydro One Distribution and Transmission Applications and updated for this current filing.

Hydro One has incorporated the methodologies of the Lead Lag study, based on the methodology accepted by the Board in previous Distribution and Transmission Applications and updated for this current filing.

Hydro One has applied the deemed capital structure of 60% debt and 40% common equity, approved by the Board in its EB-2012-0031, in determining its 2015 and 2016 revenue requirement. Hydro One is currently requesting an equity return of 9.71% for the 2015 test year and 9.96% for 2016. The equity returns have been derived using the latest Board formulaic methodology from the EB-2009-0084 proceeding issued on December 11, 2009, applied using the September 2013 Consensus Forecast and Bank of Canada.

The Company expects that the return on equity (ROE) and other Cost of Capital (CoC) parameters for 2015 and 2016 will be updated to reflect the September 2014 and September 2015 Consensus Forecasts and Bank of Canada data available in October of 2014 and 2015 as described at Exhibit B1, Tab 1, Schedule 1.
This Proposed Application provides information on Hydro One Transmission’s revenue requirement and charge determinants by rate pools to assist in the development of provincial uniform transmission rates at Exhibit H1.

2.0 PROPOSED APPROVALS REQUESTED

2.1 Revenue Requirement

Respecting Hydro One’s revenue requirement in the years 2015 and 2016 for its Transmission Business, the Company is proposing to seek approvals for:

1. A revenue requirement of $1,617 million and $1,689 million for the 2015 and 2016 test years, respectively. Taking into account the increased load forecast, the resulting increase in Hydro One Transmission Rates is 3.2% and 3.3%, respectively. The estimated increase on the average customer’s total bill is 0.2% in 2015 and 0.2% in 2016. The transmission component represents 7.4% of an average distribution connected customer’s total bill.


3. An OM&A cost expenditure forecast of $452 million in 2015 and $458 million in 2016, driven by the need to safely deliver transmission reliability at targeted performance levels.

4. The Proposed Application assumes the existing Export Transmission Service (ETS) rate of $2/MWh to be continued and disbursed through a decrease in revenue requirement for the Network Pool. The forecast for ETS revenue is $33.4 million for 2015 and $34.3 million for 2016. The ETS rate is discussed in Exhibit H1, Tab 5, Schedule 1. Hydro One was directed by the Board to prepare an ETS cost allocation study in its EB-2012-0031 Decision and Order. The completed study is provided in Exhibit H1, Tab 5, Schedule 1, Attachment 1.
5. Hydro One Networks seeks approval of regulatory assets totaling ($36.1) million as at December 31, 2013. Hydro One seeks approval to refund this balance over a two year period and to reduce the annual revenue requirement accordingly as discussed at Exhibit F1, Tab 1, Schedule 3.

6. Hydro One Transmission’s Rate Base of $10,177 million for 2015 and $10,558 million for 2016 is discussed in Exhibit D1, Tab 1, Schedule 1.

2.2 Cost Allocation and Rates

The Company is seeking approvals of:

1. The continuation of the Hydro One Transmission’s cost allocation methodology.

2. The continuation of a wholesale metering services pool.

3. The revenue to be collected by each Rate Pool as discussed in Exhibit G1, Tab 1, Schedule 1.

4. The charge determinant application to each Rate Pool as discussed in Exhibit H1, Tab 3, Schedule 1.

5. Charges for the provision of wholesale metering services and export transmission services performed by the utility as set out at Exhibit H1, Tab 4, Schedule 1 and Exhibit H1, Tab 5, Schedule 1, respectively. The disposition of the balances accumulated in Regulatory Accounts as shown in Exhibit F1, Tab 1, Schedule 3.

6. Hydro One Networks will request that the Board amend the Uniform Transmission Rates to allow for recovery of the proposed revenue requirements for 2015 and 2016, effective January 1st of each year.
2.3 Other Proposed Approvals

1. Hydro One Networks seeks approval to continue the following deferral accounts including: the Excess Export Service Revenue Account; the External Secondary Land Use Revenue Variance Account; the External Station Maintenance, E&CS and Other Revenue Variance Account; the Tax Rate Changes Account; the Rights Payments Variance Account; the Pension Cost Differential Account; the External Revenue – Partnership Transmission Projects Account; the East West Tie Deferral Account; the LDC CDM and Demand Response Variance Account (for settling 2013 and 2014 balances) and the Long Term Future Corridor Account.

3.0 CAUSES OF THE INCREASE IN REVENUE REQUIREMENT

In 2015, there are a number of key operational and financial factors contributing to the increased revenue requirement over 2014. The increase in total rates revenue requirement is largely attributable to the impact of rate base growth reflected in the increase in depreciation, as well as higher cost of debt and allowed ROE. Also contributing to the difference is higher income taxes, lower external revenues, and reduced regulatory account disposition.

The increase in 2016 rates revenue requirement is primarily due to the increase in core rate base as reflected in the increase in return on capital and depreciation. Other contributing factors include higher income taxes and slightly higher OM&A work program requirements. Exhibit G1, Tab 1, Schedule 1 provides information on how the rates revenue requirements will be recovered through rates.

The increases identified within the Proposed Application will ensure that customers within the Province will continue to be supplied in a secure and reliable manner while supporting the Government’s connection of renewable generation initiatives, thereby contributing to the health and competitiveness of the Province’s economy.
JUNE 25th PARTICIPANT PRESENTATION
2015/16 Transmission Rates Application Presentation

*****Confidential*****

Wednesday, June 25, 2014
OEB North Hearing Room
Objectives

- Review Hydro One 2015/16 Rates Proposal
- Determine if participants are interested in pursuing a negotiated settlement
Context

• 2 year cost of service
• Rates primarily driven by increases in rate base for key capital projects/programs
• Focus on sustaining activity in the test years
• Maintaining current reliability levels while becoming more productive
Issues

1. Is the overall revenue requirement increase in 2015 and 2016 reasonable?

2. Is the load forecast methodology appropriate?

3. Are the proposed spending levels for Sustaining, Development, Operations, Common Corporate and Other OM&A in 2015 and 2016 appropriate?

4. Are the amounts proposed for rate base in 2015/16 appropriate?

5. Are the proposed levels for Sustaining, Development, Operations, Common Corporate and Other Capital Expenditures in 2015/16 appropriate?

6. Are the proposed amounts, disposition and continuance of Hydro One's existing Deferral and Variance accounts appropriate?

7. What is the appropriate level for Export Transmission Rates in Ontario?
Proposed 2015 Transmission Revenue - Cost of Service Requirement

Cost of Debt 4.90%

Rate Base $10,177M

Capital Structure 60/40

Cost of Equity ROE – 9.71%

WACC Cost of Capital 6.82%

Return on Capital $699M + Income Tax $72M

Cost of Service $846M

ROE Net Income $395M Debt Interest $304M

OM&A $452M Depreciation $394M

External Revenue and Other $66M

Rates Revenue Requirement $1,551M

Proposed 2015 Rate Schedules
Proposed 2016 Transmission Revenue - Cost of Service Requirement

- **Cost of Debt**: 5.04%
- **Rate Base**: $10,558M
- **Capital Structure**: 60/40
- **Cost of Equity**
  - **ROE**: 9.96%
  - **WACC Cost of Capital**: 7.01%
- **Return on Capital**: $745M
  - **+ Income Tax**: $83M
- **Cost of Service**: $861M
- **External Revenue and Other**: $67M
- **Rates Revenue Requirement**: $1,622M
- **Proposed 2016 Rate Schedules**
Transmission Rate Increase

<table>
<thead>
<tr>
<th>Year</th>
<th>OEB Approved</th>
<th>Proposed</th>
</tr>
</thead>
<tbody>
<tr>
<td>2013</td>
<td>0.0%</td>
<td>3.3%</td>
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<tr>
<td>2014</td>
<td>6.3%</td>
<td>6.4%</td>
</tr>
<tr>
<td>2015</td>
<td>0.3%</td>
<td>5.6%</td>
</tr>
<tr>
<td>2016</td>
<td>0.2%</td>
<td>4.3%</td>
</tr>
</tbody>
</table>

Total Bill Impact: 0.0% 0.5% 0.2% 0.2%
OM&A Expenditures 2013 to 2016 ($ millions)

<table>
<thead>
<tr>
<th></th>
<th>2013</th>
<th>2014</th>
<th>Test Years</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>Actual</td>
<td>OEB</td>
<td>Bridge</td>
</tr>
<tr>
<td>Sustaining</td>
<td>221.0</td>
<td>235.7</td>
<td>236.2</td>
</tr>
<tr>
<td>Development</td>
<td>8.6</td>
<td>13.7</td>
<td>12.9</td>
</tr>
<tr>
<td>Operations</td>
<td>56.7</td>
<td>57.7</td>
<td>57.4</td>
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<tr>
<td>Customer Care</td>
<td>5.3</td>
<td>4.9</td>
<td>5.8</td>
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<tr>
<td>Common Corporate</td>
<td>75.8</td>
<td>61.9</td>
<td>70.6</td>
</tr>
<tr>
<td>and Other OM&amp;A</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Property Taxes &amp;</td>
<td>21.2*</td>
<td>66.0</td>
<td>65.6</td>
</tr>
<tr>
<td>Rights Payments</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td><strong>Total</strong></td>
<td>388.4</td>
<td>440.3</td>
<td>448.6</td>
</tr>
</tbody>
</table>

* Reflects One-time Property Tax Credit of $43 million

- OM&A Increase – Primarily from Sustaining
  - Aging transmission system
  - Expanding transmission system
  - Standard requirements
  - Inflation

- Efficiency and productivity savings – mitigate the increase
# Productivity ($ millions)

<table>
<thead>
<tr>
<th></th>
<th>2014 Bridge</th>
<th>2015 Proposed</th>
<th>2016 Proposed</th>
</tr>
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<tbody>
<tr>
<td>OM&amp;A</td>
<td>$449</td>
<td>$452</td>
<td>$457</td>
</tr>
<tr>
<td>Productivity Savings</td>
<td>$42</td>
<td>$46</td>
<td>$49</td>
</tr>
<tr>
<td>Productivity Savings %</td>
<td>9.30%</td>
<td>10.10%</td>
<td>10.70%</td>
</tr>
<tr>
<td>OM&amp;A without Productivity</td>
<td>$491</td>
<td>$498</td>
<td>$507</td>
</tr>
</tbody>
</table>
# In-Service Capital Additions 2013 to 2016 ($ millions)

<table>
<thead>
<tr>
<th></th>
<th></th>
<th></th>
<th></th>
<th></th>
<th></th>
<th></th>
<th></th>
</tr>
</thead>
<tbody>
<tr>
<td>Sustaining</td>
<td>403.8</td>
<td>443.3</td>
<td>588.4</td>
<td>701.1</td>
<td>572.2</td>
<td>480.9</td>
<td></td>
</tr>
<tr>
<td>Development</td>
<td>231.7</td>
<td>261.8</td>
<td>177.3</td>
<td>205.8</td>
<td>134.7</td>
<td>119.4</td>
<td></td>
</tr>
<tr>
<td>Operations</td>
<td>5.9</td>
<td>15.1</td>
<td>19.0</td>
<td>48.0</td>
<td>50.4</td>
<td>10.0</td>
<td></td>
</tr>
<tr>
<td>Common &amp; Other</td>
<td>62.4</td>
<td>64.0</td>
<td>78.7</td>
<td>68.0</td>
<td>64.1</td>
<td>63.1</td>
<td></td>
</tr>
<tr>
<td><strong>Total</strong></td>
<td><strong>703.8</strong></td>
<td><strong>784.2</strong></td>
<td><strong>863.3</strong></td>
<td><strong>1,023.1</strong></td>
<td><strong>821.3</strong></td>
<td><strong>673.3</strong></td>
<td></td>
</tr>
</tbody>
</table>

## Rate Base

<table>
<thead>
<tr>
<th></th>
<th>2013</th>
<th>2014</th>
<th>2015</th>
<th>2016</th>
</tr>
</thead>
<tbody>
<tr>
<td>Rate Base</td>
<td>9,209</td>
<td>9,353</td>
<td>9,671</td>
<td>10,177</td>
</tr>
</tbody>
</table>

- **In-Service Capital Additions:**
  - Sustaining – Completion of large projects/programs in 2014/15
  - Development – Completion of large projects in recent years
  - Operation – Network Management System (and others) coming in service in 2015
Achieving In-Service Capital Additions

Factors Impacting 2013/14 Performance

• Outages
• Construction
• Shift of priority
• Efficiency savings

Achieving In-Service Capital Additions in 2015/16

• Projects/Programs under way or approved:
  ➢ A significant portion (over 80%) of sustaining projects/programs
  ➢ Midtown Transmission Reinforcement ($62 M in service in 2015)
  ➢ Guelph Area Transmission Reinforcement ($94 M in service in 2016)
  ➢ Network Management System Upgrade ($35 M in service in 2015)

• 2015 and 2016 figures match historical level
Capital Expenditures 2013 to 2016 ($ millions)

<table>
<thead>
<tr>
<th></th>
<th>2013</th>
<th>OEB Approved</th>
<th>2014</th>
<th>OEB Approved</th>
<th>Test Years</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>Actual</td>
<td>Bridge</td>
<td>Actual</td>
<td>Bridge</td>
<td>2015</td>
</tr>
<tr>
<td>Sustaining</td>
<td>480.0</td>
<td>579.3</td>
<td>695.3</td>
<td>581.9</td>
<td>548.6</td>
</tr>
<tr>
<td>Development</td>
<td>171.7</td>
<td>195.6</td>
<td>306.2</td>
<td>209.7</td>
<td>211.8</td>
</tr>
<tr>
<td>Operations</td>
<td>17.7</td>
<td>38.5</td>
<td>56.5</td>
<td>38.4</td>
<td>37.4</td>
</tr>
<tr>
<td>Common &amp; Other</td>
<td>49.1</td>
<td>85.8</td>
<td>63.5</td>
<td>69.4</td>
<td>68.5</td>
</tr>
<tr>
<td><strong>Total</strong></td>
<td>718.5</td>
<td><strong>899.2</strong></td>
<td><strong>1,121.5</strong></td>
<td><strong>899.4</strong></td>
<td><strong>866.3</strong></td>
</tr>
</tbody>
</table>

- Capital Expenditures in 2015 and 2016 will continue at 2014 level
### Major Sustaining Capital Projects/Programs ($ millions)

<table>
<thead>
<tr>
<th></th>
<th>2013</th>
<th>2014</th>
<th>2015</th>
<th>2016</th>
</tr>
</thead>
<tbody>
<tr>
<td><strong>Station Work</strong></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>$355</td>
<td>$459</td>
<td>$450</td>
<td>$430</td>
<td></td>
</tr>
<tr>
<td>• Station Re-investment</td>
<td>$89</td>
<td>$158</td>
<td>$241</td>
<td>$160</td>
</tr>
<tr>
<td>• Protection, Control, Monitoring &amp; Telecom</td>
<td>$84</td>
<td>$117</td>
<td>$92</td>
<td>$96</td>
</tr>
<tr>
<td><strong>Lines Work</strong></td>
<td>$125</td>
<td>$121</td>
<td>$132</td>
<td>$119</td>
</tr>
</tbody>
</table>
### Major Development Capital Projects ($ millions)

<table>
<thead>
<tr>
<th>Project</th>
<th>2015</th>
<th>2016</th>
</tr>
</thead>
<tbody>
<tr>
<td>Clarington TS: Build new 500/230kV Station (2017)</td>
<td>$92</td>
<td>$101</td>
</tr>
<tr>
<td>Midtown Transmission Reinforcement Plan (2015)</td>
<td>$22</td>
<td>$0</td>
</tr>
<tr>
<td>Guelph Area Transmission Reinforcement (2016)</td>
<td>$48</td>
<td>$30</td>
</tr>
<tr>
<td>Supply to Essex County Transmission Reinforcement (2017)</td>
<td>$25</td>
<td>$38</td>
</tr>
</tbody>
</table>
Capital Projects Not Included

- East West Tie Expansion – Station Work
- Northwest Bulk Transmission Line Project
- GTA Reactors
Other Components

• Depreciation
  – Foster Associates has completed a new Depreciation Study for Hydro One Transmission in support of its 2015 and 2016 application which recommends an increase in depreciation for Transmission Operations and Common Operations.
  – This would increase depreciation by about $16 million in 2015.

• Income Taxes
  – The combined income tax rate continues to be 26.5% for 2015 and 2016, comprised of a Federal rate of 15% and an Ontario rate of 11.5% as a result of the Ontario budget bill enacted on June 20, 2012.
Other Components

• Cost of Capital
  – Hydro One Transmission’s deemed capital structure for rate making purposes is 60% debt and 40% common equity. The capital structure assumptions have not changed.
  – Hydro One Transmission’s application reflects a return of 9.71% for the test year 2015 and 9.96% for the test year 2016, per the Board’s formulaic approach.
  – The return on equity for each test year will be updated in accordance with the Cost of Capital Report, upon the final decision in this case.
## Disposition of Regulatory Account Balances ($ millions)

<table>
<thead>
<tr>
<th>Particulars</th>
<th>Balance as at Dec 31, 2013 (a)</th>
<th>Forecast Balance as at Dec 31, 2014 (b)</th>
</tr>
</thead>
<tbody>
<tr>
<td>Excess Export Service/Deferred Revenue</td>
<td>(41.9)</td>
<td>(23.5)</td>
</tr>
<tr>
<td>External Secondary Land Use Revenue</td>
<td>(32.8)</td>
<td>(18.5)</td>
</tr>
<tr>
<td>External Stations, EC&amp;S Revenue and Other Revenue</td>
<td>(6.4)</td>
<td>(1.3)</td>
</tr>
<tr>
<td>Tax Rate Changes Account</td>
<td>(3.6)</td>
<td>0.8</td>
</tr>
<tr>
<td>Rights Payments</td>
<td>(3.6)</td>
<td>(1.9)</td>
</tr>
<tr>
<td>Pension Cost Differential</td>
<td>20.8</td>
<td>8.2</td>
</tr>
<tr>
<td>Long-Term Transmission Future Corridor Acquisition and Development</td>
<td>0.1</td>
<td>0.1</td>
</tr>
<tr>
<td><strong>Total Regulatory Accounts</strong></td>
<td><strong>(67.4)</strong></td>
<td><strong>(36.1)</strong></td>
</tr>
</tbody>
</table>

(a) 2013 interest is based on the OEB prescribed rates.
(b) 2014 includes disposition amounts ($30.3 M) as approved by the Board in EB 2012-0031 and forecast interest improvement for 2014.

**Annual Credit:** $18 M in 2015 and $18.1 M in 2016
ETS Rate

• Current ETS Rate = $2/MWh
• Stakeholder session held on March 24, 2014 where Elenchus explained their methodology
• Final report completed by Elenchus
• Proposed cost allocation methodology determines the ETS rate based on cost causality principles
• Based on the proposed 2015 and 2016 HONI financial data, Elenchus recommends an ETS rate of $1.70/MWh be implemented for 2015/16
ETS Rate

- ETS revenues in this application ($33.4m in 2015 and $34.3M in 2016) are determined based on the current approved tariff of $2/MWh and the 3 year historical average volume of electricity exported from, or wheeled-through, Ontario over its transmission system.

- Hydro One proposes to revise its rates revenue requirement to reflect the OEB’s decision and order with respect to the ETS tariff as part of the Draft Rate Order to be submitted in connection with finalizing the 2015 UTR to be approved.
Bruce to Milton Partnership

- The Saugeen Ojibway Nation (SON) agreed to purchase from Hydro One an approximately 34% equity interest in the assets of Bruce to Milton Project. The transaction is expected to close in 2014.

- The assets will be removed from Hydro One Networks’ rate base and transferred to a new partnership (to be called B2M LP)

- The net book value of the assets is approximately $530 million.

- Hydro One Networks’ revenue requirement will be reduced by approximately $42 million (-3% transmission rate reduction for Hydro One Networks)

- Next Steps:
  - Finalizing Financing arrangements
  - Rate approval from the OEB
As to the schedule:

- On or before July 2 H1 will deliver an Information Package ("IP") to the Participants (those who have signed a Confidentiality Agreement). It may be as soon as today.

- On or before July 11, the Participants will provide their Interrogatories to H1

- On or before July 17th H1 will provide answers to the Interrogatories

- On July 23rd at 1:30 pm there will be an in-person meeting to discuss and follow-up on the IP and Interrogatories and other relevant matters related to the case.

- July 29th and 30th have been set aside as in-person meeting dates in the nature of a technical conference.

- Tuesday Aug 12 to Friday August 15th --- Negotiations.

Please assume all in-person meetings will be at the OEB. If the OEB is not available, another site will be designated.
List of Capital Projects* that were directed by the Ontario Power Authority, Independent Electricity System Operator or Government

<table>
<thead>
<tr>
<th>Project Name</th>
<th>CAP EX ($ millions)</th>
</tr>
</thead>
<tbody>
<tr>
<td>New 500 kV Bruce to Milton Double Circuit Transmission Line</td>
<td>3.3</td>
</tr>
<tr>
<td>Clarington TS: Build new 500/230kV Station</td>
<td>91.7</td>
</tr>
<tr>
<td>Installation of Shunt Capacitor Banks at Cherrywood TS</td>
<td>0.1</td>
</tr>
<tr>
<td>Guelph Area Transmission Reinforcement</td>
<td>48.3</td>
</tr>
<tr>
<td>Preston TS Transformation</td>
<td>10.0</td>
</tr>
<tr>
<td>Toronto Area Station Upgrades for Short Circuit Capability: Manby TS Equipment Uprate</td>
<td>5.7</td>
</tr>
<tr>
<td>Hawthorne TS: Replace two existing Transformers</td>
<td>1.0</td>
</tr>
<tr>
<td>York Region – Increase Transmission Capability for B82V/B83V Circuits</td>
<td>5.0</td>
</tr>
<tr>
<td>Supply to Essex County Transmission Reinforcement</td>
<td>25.0</td>
</tr>
<tr>
<td>Napanee Gas Generation Connection</td>
<td>1.0</td>
</tr>
<tr>
<td>Transmission Station P&amp;C Upgrades for DG</td>
<td>17.5</td>
</tr>
</tbody>
</table>

* All projects listed are development projects
## 2015-2016 TRANSMISSION RATES PROPOSAL
### INFORMATION PACKAGE CONTENTS

<table>
<thead>
<tr>
<th>Exhibit</th>
<th>Tab</th>
<th>Schedule</th>
<th>Contents</th>
</tr>
</thead>
<tbody>
<tr>
<td>A</td>
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<td>Cost Allocation and Charge Determinants</td>
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<td>Transmission Customers Load Forecast</td>
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<td>Charge Determinants</td>
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<td>Rates for Wholesale Meter Service</td>
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<td>Rates for Export Transmission Service</td>
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<td>Attachment 1 – Elenchus Export Transmission Service Rate – Cost Allocation Methodology</td>
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</table>
FINANCIAL SUMMARY

1.0 INTRODUCTION

Hydro One Transmission is proposing this Application requesting approval of an appropriate revenue requirement in support of just and reasonable transmission rates for 2015 and 2016.

This proposed Application provides information required to support revenue requirement and related transmission rates for the test years 2015 and 2016. The submission also provides historical information for 2011, 2012 and 2013, along with 2014 bridge year information.

The Company is proposing to recover a total revenue requirement of $1,617.1 million from its customers for the 2015 test year and $1,689.2 million for the 2016 test year.

Hydro One Transmission’s capital structure was approved by the Board as part of its November 8, 2012 Decision on Hydro One's Transmission Rate Application (EB-2012-0031). This is consistent with the Board’s report on the cost of capital: see the Report of the Board on the Cost of Capital for Ontario’s Regulated Utilities dated December 11, 2009 (EB-2009-0084). Hydro One Transmission’s evidence reflects a return of 9.71% in 2015 and 9.96% in 2016, as specified by the formula in the report above. Hydro One Transmission’s evidence in support of its Cost of Capital and Cost of Third Party Long Term Debt appears at Exhibit B1, Tab 1, Schedule 1 and Exhibit B1, Tab 2, Schedule 1.

Hydro One Transmission’s OM&A expenditures have been determined through an examination of required work programs to ensure the most appropriate, cost-effective solutions are employed to meet corporate objectives. The proposed OM&A expenditures
are $452.0 million in 2015 and $457.4 million in 2016, driven by the need to safely deliver transmission reliability at targeted performance levels. These expenditures are discussed throughout Exhibit C1. Hydro One has used the Corporate Cost Allocation Methodology, based on the methodology accepted in EB-2012-0031 and previous proceedings and updated for this current filing, to allocate the costs of shared services OM&A between Transmission and Distribution. The 2012 update is described in Exhibit C1, Tab 6, Schedule 1.

Depreciation and amortization expense of $394.2 million for 2015 and $404.0 million for 2016 have been determined based on the results of the Foster’s methodology accepted by the Board in Hydro One’s Transmission’s previous proceedings. An update to the depreciation study has been completed in 2013 for Hydro One Transmission in support of its 2015 and 2016 proposed application. These costs are described in Exhibit C1, Tab 7, Schedule 1.

The Company has also incorporated the methodology of the Lead Lag study, submitted and accepted by the Board in previous proceedings, in its derivation of Rate Base in 2015 and 2016.

Hydro One Transmission's forecast Rate Base of $10,176.5 million for 2015 and $10,558.0 million for 2016 is discussed in Exhibit D1, Tab 1, Schedule 1.

This submission reflects Hydro One Transmission’s plan to invest its network assets to meet objectives regarding public and employee safety, regulatory and legislative compliance, maintenance of system security and reliability, and meeting system growth requirements. The Company is forecasting total capital expenditures of $899.4 million in 2015 and $866.3 million in 2016. Details of Hydro One Transmission’s capital budget are provided in schedules filed at Exhibit D1, Tab 3.
Hydro One Transmission earns approximately 2% of its revenues from sources other than its transmission tariff. As the costs incurred to generate these revenues are included in the Company's cost of service, these external revenues of $28.4 million in 2015 and $28.8 million in 2016 are recorded as an offset to the respective revenue requirement. External revenues are discussed at Exhibit E1, Tab 2, Schedule 1.

In accordance with standard regulatory practice, Hydro One Transmission has incurred prior costs for which it is requesting approval in this submission. Hydro One Transmission is requesting approval of actual Regulatory Asset values of $(36.1) million as at December 31, 2014 which includes the principal balances as at December 31, 2013 and forecasted interest and dispositions for 2014. The Company's submissions regarding these account balances and their proposed disposition appear at Exhibit F1, Tab 1, Schedule 1 and Exhibit F1, Tab 1, Schedule 3, respectively.

Tables 1 and 2 below, summarize the financial highlights for the 2015 and 2016 Test Years.
## Financial Highlights 2015

<table>
<thead>
<tr>
<th>Line No.</th>
<th>Deemed Capital Structure ($ millions)</th>
<th>Total Rate Base Percent</th>
<th>Cost Rate (%)</th>
<th>Exhibit</th>
</tr>
</thead>
<tbody>
<tr>
<td>1</td>
<td>Total Debt</td>
<td>6,105.9</td>
<td>60.0%</td>
<td>4.90%</td>
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<td>2</td>
<td>Common Equity</td>
<td>4,070.6</td>
<td>40.0%</td>
<td>9.71%</td>
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<td>3</td>
<td>Total Rate Base</td>
<td>10,176.5</td>
<td>100.0%</td>
<td>6.82%</td>
</tr>
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</table>

<table>
<thead>
<tr>
<th>Line No.</th>
<th>$ millions</th>
<th>Exhibit</th>
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</thead>
<tbody>
<tr>
<td>1</td>
<td>Total OM&amp;A Expense</td>
<td>452.0</td>
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<td>2</td>
<td>Depreciation &amp; Amortization</td>
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<td>3</td>
<td>Capital Expenditures</td>
<td>899.4</td>
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<td>4</td>
<td>Rate Base</td>
<td>10,176.5</td>
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<tr>
<td>5</td>
<td>Revenue Requirement</td>
<td>1,617.1</td>
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<td>6</td>
<td>External Revenues</td>
<td>28.4</td>
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<td>7</td>
<td>Return on Capital</td>
<td>694.3</td>
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<tr>
<td>8</td>
<td>Regulatory Assets Recovery</td>
<td>(18.0)</td>
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</table>
## Table 2
### Financial Highlights 2016

<table>
<thead>
<tr>
<th>Line No.</th>
<th>Deemed Capital Structure ($ millions)</th>
<th>Total Rate Base (%), Cost Rate (%)</th>
<th>Exhibit</th>
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</thead>
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<td>Total Debt</td>
<td>6,334.8</td>
<td>60.0%, 5.04%</td>
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<td>2</td>
<td>Common Equity</td>
<td>4,223.2</td>
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<td>3</td>
<td>Total Rate Base</td>
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<td>100.0%, 7.01%</td>
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<table>
<thead>
<tr>
<th>Line No.</th>
<th>$ millions</th>
<th>Exhibit</th>
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<td>1</td>
<td>Total OM&amp;A Expense</td>
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<td>Depreciation &amp; Amortization</td>
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<td>Capital Expenditures</td>
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<td>4</td>
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<td>Revenue Requirement</td>
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<td>7</td>
<td>Return on Capital</td>
<td>739.9</td>
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<td>8</td>
<td>Regulatory Assets Recovery</td>
<td>(18.1)</td>
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SUMMARY OF TRANSMISSION BUSINESS

1.0 INTRODUCTION

Hydro One Networks Inc. is licensed by the Ontario Energy Board (the “OEB” or the “Board”) to own, operate and maintain transmission facilities in the Province of Ontario. Hydro One’s transmission system is one of the largest in North America based on net book value and includes facilities that service connected customers and other transmitters’ province wide. These facilities comprise approximately 97% of the licensed transmission facilities in Ontario and are used to serve customers province wide.

The purpose of the transmission system is to transmit electricity between supply points (such as generators, interconnections with other jurisdictions, and load customers with sufficient embedded generation to result in injections into the transmission system) and delivery points (load customers, including Local Distribution Companies (“LDCs”), end-use transmission customers and interconnections with other jurisdictions) and integrated with electrical storage facilities (flywheel and battery technology).

This exhibit provides a summary of Hydro One Transmission’s (the “company”) business in Section 4, a discussion of the business model implemented within the company in Section 5, and the manner in which investment programs are managed is set out in Section 6.

2.0 HYDRO ONE’S VALUES

Hydro One is driven by the values of Health & Safety, Stewardship, Excellence and Innovation. The company works in an environment that can be dangerous for both workers and the public, and so safety is of the utmost importance. The stewardship of critical provincial assets is a serious responsibility. The company demonstrates sound
stewardship in a manner that respects both customers’ needs, as well as the environment. Excellence is achieved through continuous improvement and staff development to ensure the company is prepared and equipped to deliver high quality and affordable service. The company values innovation and views it as a key success factor for its future, allowing the company to find better ways to meet the needs of our customers.

Customers expect and deserve reliable power at reasonable rates. Hydro One Transmission’s strategy and business plan must ensure rates that can balance the financing of investment in infrastructure while maintaining affordable and reliable service. While customer satisfaction with the company’s performance remains strong, customers face a growing array of changes and challenges, and they increasingly look to Hydro One Transmission to help them manage use of power, maintain high levels of service reliability and keep prices reasonable. The company is prepared to meet customers’ expectations, continue its commitment to asset stewardship, and ensure alignment with new policy objectives brought forth by the Government.

3.0 STRATEGIC GOALS AND PERFORMANCE TARGETS

The company’s strategic objectives commit it to:

- Creating an injury-free workplace and maintaining public safety;
- Satisfying our customers;
- Focusing on continuous innovation to ensure a modern, flexible and advanced distribution system;
- Building and maintaining reliable, cost-effective transmission and distribution systems;
- Protecting and sustaining the environment for future generations;
- Championing people and culture;
- Maintaining a commercial culture that increases value for our shareholder; and
- Achieving productivity improvements and cost-effectiveness.
These strategic objectives are inextricably linked. They drive the fulfillment of the Company’s mandate and the achievement of its mission and vision, which is:

“Hydro One will be an innovative and trusted company delivering electricity safely, reliably and efficiently to create value for our customers.”

The company will operate with clear operational and financial performance targets. Where data is available, Hydro One will benchmark its performance against that of other North American utilities and implement plans and programs to achieve its vision. The five year goals associated with the company’s strategic objectives are shown in Table 1.
## Table 1

<table>
<thead>
<tr>
<th>STRATEGIC OBJECTIVES</th>
<th>FIVE-YEAR VISION</th>
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<tbody>
<tr>
<td>Creating an injury-free workplace and maintaining public safety</td>
<td>Achieve world-class standing for medical attentions for utilities</td>
</tr>
<tr>
<td>Satisfying our customers</td>
<td>Achieve an on average of 90% customer satisfaction across all segments</td>
</tr>
<tr>
<td>Focusing on continuous innovation to ensure a modern, flexible and advanced distribution system</td>
<td>Meet 100% of advanced distribution system plan</td>
</tr>
<tr>
<td>Building and maintaining reliable, affordable transmission and distribution systems</td>
<td>Maintain the current levels of reliability relative to comparable utilities, while we improve customer service and satisfaction</td>
</tr>
<tr>
<td>Protecting and sustaining the environment for future generations</td>
<td>Reduce our environmental footprint</td>
</tr>
<tr>
<td>Championing people and culture</td>
<td>Achieve and maintain employee engagement at top quartile of comparable utilities</td>
</tr>
<tr>
<td>Maintaining a commercial culture that increases value for our shareholder</td>
<td>Achieve the Return on Equity allowed by the Ontario Energy Board and maintain an “A” credit rating</td>
</tr>
<tr>
<td>Achieving productivity improvements and cost-effectiveness</td>
<td>Achieve top-quartile unit costs against comparable utilities</td>
</tr>
</tbody>
</table>
The strategic objectives identified in Table 1 underpin and drive the Company’s business planning process and all of its activities going forward.

4.0 HYDRO ONE’S TRANSMISSION BUSINESS

4.1 Transmission System Background

Hydro One Transmission’s business comprises a high voltage system that operates at 500 kV, 230 kV and 115 kV with minor lengths operating at 345 kV and 69 kV. There are 103 generating stations, 47 LDCs and 92 end-use transmission customers connected directly to Hydro One’s Transmission system, as of the end of December, 2013. In 2013, Hydro One transmitted approximately 141 TWh of electricity, directly or indirectly, to substantially all consumers of electricity in Ontario.

A simplified figure of the Transmission System is provided in Figure 1 below.

Figure 1
Hydro One’s Transmission System

The Hydro One Transmission system includes approximately 29,000 circuit kilometers of high voltage transmission lines and 289 transmission stations. These lines are located in

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1 For illustrative purposes only, actual configuration may vary from case to case and may include generators within LDCs and end-use transmission customer facilities.
lands owned by the Ontario government, Hydro One Transmission or by other parties with whom Hydro One Transmission has agreements regarding occupancy and access rights. The major components of the transmission lines are overhead conductors, underground cables, wood or steel support structures, foundations, insulators, connecting hardware and grounding systems. The major components of transmission stations are transformers, circuit breakers, switches, bus bars, insulators, reactors, capacitors, connecting hardware, associated protection and control equipment, grounding systems and revenue meters.

A summary of the key physical assets on Hydro One Transmission’s system is provided in Table 2.

<table>
<thead>
<tr>
<th>Fixed Assets (Net Book Value)</th>
<th>$11.8 Billion</th>
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<tr>
<td>Operating Centres</td>
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<tr>
<td>Transmission System Voltages (kV)</td>
<td>500, 345, 230, 115, 69</td>
</tr>
<tr>
<td>Overhead Transmission Lines (circuit km)</td>
<td>28,636</td>
</tr>
<tr>
<td>Underground Transmission Cables (circuit km)</td>
<td>291</td>
</tr>
<tr>
<td>Transmission Stations</td>
<td>289</td>
</tr>
<tr>
<td>Breakers</td>
<td>4,490</td>
</tr>
<tr>
<td>Step-down Power Transformers²</td>
<td>572</td>
</tr>
<tr>
<td>Auto-Transformers³</td>
<td>134</td>
</tr>
<tr>
<td>Other Transformers</td>
<td>13</td>
</tr>
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</table>

Transmission assets also include facilities required for operation, protection, control, and monitoring functions necessary for the effective and efficient operation of the transmission system. These facilities include extensive telecommunication system, protection and control equipment, the Ontario Grid Control Centre (“OGCC”) and the

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² Includes 25- and 60-cycle systems for transmission circuit km
³ One Ontario Grid Control Centre (OGCC) and one Integrated Telecommunication Management Centre (ITMC)
⁴ 254 Transformer Stations & 35 Switching Stations
⁵ The number of transformers and circuit breakers are at the equivalent three-phase banks
⁶ Excludes lower voltage station service, grounding and operating spare transformers
⁷ Other transformers include 5 phase shifters and 8 high-voltage regulators.
back-up operating facilities which serve as a fully redundant back-up to the OGCC. The OGCC monitors and controls the operation of the transmission system.

As shown in Figure 2, Hydro One Transmission is linked to five adjoining jurisdictions (Manitoba, Quebec, Minnesota, Michigan and New York) through 26 interconnections, through which we can accommodate imports of about 6510MW and exports of approximately 6,070 MW of electricity in the summer. These interconnection facilities are designed to facilitate the transfer of electrical energy between Ontario and these jurisdictions. Actual import and export capabilities of the interconnections depend on limitations at the interface as well as within Hydro One Transmission’s system and transmission systems in other jurisdictions.

**Figure 2**

**Existing Ontario Interconnections**

Hydro One Transmission’s system is also connected to other transmitters, namely Great Lakes Power, Canadian Niagara Power and Five Nations Energy, representing the remaining 3% of licensed transmission facilities in Ontario. Due to a change in policy in
Ontario that enabled competitive transmission (see section 4.3.2), a number of new licensed transmitters emerged in Ontario including: AltaLink Ontario Management Ltd., Iccon Transmission Inc., Oncor Electric Delivery Company LLC, RES Canada Transmission LP, TransCanada Power Transmission Ontario LP, Upper Canada Transmission, and EWT LP (East-West Tie partnership is an equally-shared limited partnership of Great Lakes Transmission, Bamkushwada LP (a number of First Nations in the area of the East-West Tie), and Hydro One).

4.2 Transmission Business Activities

Hydro One Transmission’s business activities are regulated and consist of expanding, maintaining, operating and sustaining assets to meet reliability standards and satisfy regulatory, environmental and legal requirements. In particular, Hydro One Transmission implements system expansion to:

- accommodate load growth and connection of new generation;
- accommodate distributed generation resulting from the feed-in tariff program and other green initiatives advocated through the Ontario Government’s Green Energy and Green Economy Act, 2009 (GEGEA).
- alleviate internal system constraints,
- increase interconnection capabilities with neighbouring utilities; and
- facilitate the development of a modern and smart grid.

The Company’s regulated business activities include the management of its transmission assets, which includes operations, maintenance, construction and engineering services, customer service activities and supporting research, environmental, and public/employee health and safety programs. The costs of all these activities are included in the revenue requirements for Hydro One Transmission.
These activities are performed by a multi-disciplined workforce capable of performing tasks related to operating, maintaining and expanding the transmission business. A number of service centers are located throughout the Province to provide the required operating, maintenance, construction and restoration services. In order to carry out the work, these service centers provide base locations for the mobile workforce and contain essential infrastructure components such as:

- land and buildings for staff accommodation,
- transport and work equipment, including large work vehicles, off-road vehicles, small vehicles (trucks, cars and vans), and specialized units (snowmobiles, chippers, trailers), and
- minor fixed assets, including computers, test equipment, construction and maintenance tools and office furniture.

Included in the regulated transmission business revenue requirement are expenditures for common services that are shared with the distribution business (for the purpose of cost efficiency), such as internal audit, human resources, asset management, legal, general counsel and secretary, finance, information management, performance management, regulatory, environment, planning and corporate affairs. The nature and costs associated with these corporate functions and services are discussed in Exhibit C1, Tab 3, Schedules 1 to 7.

4.3 **Electricity Industry and Regulatory Framework**

4.3.1 **Industry and Regulatory Environment in Ontario**

In the restructured Ontario electricity industry the Ministry of Energy sets legislative and regulatory requirements through changes to the *Electricity Act, 1998* and the *Ontario*
Energy Board Act, 1998. The OEB sets transmission rates, issues codes and licenses, and grants approval for construction of new transmission lines greater than two kilometers.

The Independent Electricity System Operator (“IESO”) administers the electricity market and directs the operation of the power system in Ontario. The transmission assets owned by Hydro One Transmission form approximately 97% of the IESO controlled transmission grid, which is essential for the operation of the IESO administered markets. The IESO controlled grid provides the infrastructure for transmitting large volumes of electrical energy from major generation sources to major load centers. In the restructured Ontario electricity industry, Hydro One Transmission provides transmission capacity. The IESO makes that capacity available to market participants.

The Ontario Power Authority (“OPA”) establishes new electricity supply contracts, sets provincial Conservation and Demand Management targets, forecasts long-term demand/supply requirements and identifies the new or upgraded transmission required to incorporate new generation, relieve constraints on the transmission system and accommodate increasing electricity demand on an area supply basis.

The Transmission System Code (“TSC”), issued by the OEB, sets out the obligations of electricity transmitters with respect to their customers. It includes a Connection Agreement which covers the technical and commercial responsibilities of both transmitters and their customers. The Code also addresses standards for the operation, maintenance, management and expansion of transmission systems.

The TSC and the market rules require all customers directly connected to the transmission system to enter into a connection agreement with their transmitter. Accordingly, Hydro One Transmission has established Connection Agreements with its transmission customers. Each Connection Agreement is comprised of two main parts; general information, such as equipment standards, operational and maintenance
requirements, reporting protocol, dispute resolution methodology and disconnection process, and specific information, including connection point description (diagrams, protection requirements, technical specification for customer’s equipment), contact data for both the customer and appropriate Hydro One Networks’ staff, and description of applicable transmission charges. In addition, the TSC requires Hydro One Transmission to enter into commercial agreements with directly connected load and generation customers to provide new or modified Hydro One Transmission owned connection facilities and to recover the related costs.

Depending on the configuration and ownership of facilities, Hydro One Transmission provides customers with one or more of the four main types of transmission service: network, line connection, transformation connection and wholesale meter service.

4.3.2 Competitive Transmission

On August 26, 2010, the OEB released its new policy entitled “Framework for Transmission Project Development Plans”. This policy sets out a framework for new transmission investment in Ontario by introducing competition for transmission development through an open process.

On March 29, 2011, the Minister expressed the Province’s interest in the OEB commencing a designation process for the East–West Tie Line. The East-West Tie project is the first network line expansion covered under the new approach. The OPA’s proposed route is a 400 km, 230 kV double-circuit line to run beside an existing Hydro One transmission corridor along the north shore of Lake Superior between Hydro One’s transformer stations at Wawa in the east and Lakehead in the west.

On August 7, 2013, the OEB issued its Decision (EB-2011-0140) that the designated transmitter for the development phase of the proposed East-West Tie line is Upper
Canada Transmission Inc. (UCT) a partnership of NextEra Energy Canada (a wholly owned subsidiary of NextEra Energy Resources LLC), Enbridge Inc. and Borealis Infrastructure Management. Hydro One will coordinate with UCT to effect the connection to the bulk transmission system in Northern Ontario at transformer stations owned by Hydro One.

4.3.3 North American Reliability Framework

The National Electric Reliability Council (“NERC”) was established in the United States in 1968 in response to the 1965 blackout. On January 1, 2007, the National Electric Reliability Council became the North American Electric Reliability Corporation (same acronym). NERC’s mission is to ensure the reliability of the bulk power system in North America. To achieve this, NERC develops and enforces reliability standards; monitors the bulk power system; assesses and reports on future transmission and generation adequacy; and offers education and certification programs to industry personnel. NERC is a non-profit, self-regulatory organization that relies on the diverse and collective expertise of industry participants. NERC is subject to oversight by governmental authorities in Canada and the U.S.

NERC works with eight Regional Entities to improve the reliability of the bulk power system, the North East Power Coordinating Council (NPCC) being one of them. Hydro One is a member of NERC and NPCC and is registered with NERC’s compliance registry.

The U.S. Energy Policy Act of 2005 authorized the creation of a self-regulatory Electricity Reliability Organization (ERO) that would span North America, with the Federal Energy Regulatory Commission (FERC) oversight in the U.S. The legislation stated that compliance with reliability standards would be mandatory and enforceable. In July 2006 FERC certified NERC as the ERO in the United States. In October 2006 the
OEB signed a Memorandum of Understanding with NERC recognizing NERC as the ERO in Ontario.

Voluntary compliance was expected as a matter of good utility practice through the first set of NERC standards (effective January 2005). The standards later became mandatory and enforceable in the United States in June 2007.

As a licensed Transmitter, Hydro One is required to comply with the IESO Market Rules. Those Rules require compliance with applicable reliability standards adopted by NERC and NPCC.

According to the regulatory framework in the Province of Ontario, Hydro One is not subject to the Compliance Monitoring and Enforcing Program (CMEP) of NERC and NPCC. The Ontario Market Rules and the Memorandum of Understanding (MOU) signed by the IESO, NERC and NPCC (October 2006), assign the IESO as the only entity in Ontario that is subject to the CMEP. The IESO, by way of its Market Assessment and Compliance Division (MACD), is responsible for monitoring and enforcing the reliability standards in Ontario. Under the Market Rules, MACD can apply monetary sanctions for breaches, which include violations of reliability standards.

To date, NERC has developed 113 standards including 550 requirements. 46 of these standards apply to Hydro One.

4.3.4 Regional Planning for Electricity Infrastructure

The OEB, in 2011, launched a consultation (EB-2011-0043) aimed at “promoting the cost-effective development of electricity infrastructure through coordinated planning on a regional basis between licensed distributors and transmitters.” The Board held a consultation with stakeholders which resulted in a Board Staff Discussion Paper in November, 2011.
In response to inquiries received by the Board, the Ontario Power Authority (OPA) provided an explanation of their regional planning process. It described that transmitters were represented on each Study Team that develops a regional plan. As well, regional plans can be initiated by transmitters. Hydro One is often a participant in regional planning development by the OPA.

In May 2013, the Board issued a Notice of Proposal to Amend the Transmission System Code (TSC) and the Distribution System Code (DSC) to enable:

- the establishment of a process in order to move to a more structured approach to regional infrastructure planning; and
- the determination of the appropriate redefinition of certain line connection assets and modifications to the TSC cost responsibility rules to facilitate regional planning and the execution of regional infrastructure plans.

Following the comment period, the Board issued in August, 2013 its Notice of Amendments to both TSC and DSC to implement the Board’s policies related to Regional Infrastructure Planning. The Board also issued a Supplementary Proposed Amendment to a Code related to the TSC cost responsibility rules.

Hydro One’s participation in Regional Planning is discussed in Exhibit A, Tab 16, Schedule 9.

5.0 ASSET MANAGEMENT MODEL

Hydro One has adopted an Asset Management model in designing the processes used to plan, approve and implement work. The key principles include having functions primarily responsible for defining the work requirements (Asset Management functions) and functions primarily responsible for delivering asset and customer based services in accordance with the defined work (Work Execution functions). Primary responsibility for planning and decision making associated with the management of transmission and
distribution assets falls under the Asset Management functions, whereas primary responsibility for providing engineering, design, estimating, construction, maintenance, operating, and customer care services falls under the Work Execution functions.

Both components of the business actively participate in all phases of work planning and implementation. However, the focus created by this approach allows Hydro One Transmission to better create the competencies and cost-efficiencies to effectively plan and implement the work.

5.1 Asset-Centric Investment Reviews to Improve Investment Planning (IP)

Continuing improvements in Asset Analytics have improved our ability to consider the needs of an asset fleet in its entirety - especially as it regards the performance and demographics of the fleet, providing a comprehensive overview of all work impacting that particular asset fleet. This has facilitated the development of a more comprehensive investment strategy for each asset fleet.

5.2 Asset Management Function

Hydro One’s transmission business strives to continually improve the efficiency and effectiveness of the regulated wires assets. The Asset Management function is responsible for effectively operating, maintaining and upgrading existing transmission and distribution assets and ensuring consistent, cost-efficient and effective decision making that balances customer needs and stakeholder expectations with Hydro One objectives for its assets and systems.

In preparing investment plans and prioritizing work activities, the Asset Management function utilizes tools and planning procedures outlined in Exhibit A, Tab 16, Schedules 3 to 6.
In addition to maintaining a strong stewardship role of Hydro One assets, the asset management strategies, processes and policies are evolving to proactively plan for and invest in the necessary system infrastructure to accommodate increased levels of renewable energy development. These objectives align with the green energy initiatives set forth by the GEGEA and ensure that necessary operational and planning flexibilities are in place to respond to changing system needs.

A more detailed account of the roles and responsibilities of the Asset Management function as a shared service can be found in Exhibit C1, Tab 3, Schedule 4.

### 5.3 Work Execution Functions

The work execution functions provide engineering, design, estimating, construction, maintenance and operating services. Customer relationship management and support services and supporting research, environmental, and public/employee health and safety programs are also provided by these functions. These activities are performed by a multi-disciplined workforce capable of performing tasks related to operating, maintaining and expanding the transmission business. There are three primary work execution functions within Hydro One: Customer Operations, Grid Operations and Engineering and Construction.

#### 5.3.1 Customer Operations

The Customer Operations function is responsible for line construction and maintenance work, including forestry and customer care support services. As well, the Customer Operations function has accountability for planning and connecting new retail customers to the transmission system and to address local system planning issues.

Lines and Forestry services provide for the maintenance of overhead and underground
transmission lines and for vegetation management. The vegetation management program is necessary to ensure that clearances to energized equipment are maintained and that these clearances provide a sustainable level of reliability.

Customer care services can be divided into the following high-level functions: meter reading; billing; settlements; customer contact handling and collections.

5.3.2 Grid Operations

The Grid Operations function provides maintenance and technical services for stations and protection and control, as well as central operations and services for the transmission operating function which includes operation from the OGCC.

The OGCC monitors the integrity of the transmission system in real time to ensure reliable performance of the network under present conditions while recognizing potential contingencies and providing immediate response to customers. The OGCC also reviews, approves, performs and/or authorizes all switching and control actions on Hydro One’s Transmission system and issues work permits in accordance with the Utility Work Protection Code to provide employees with a safe working area. In addition, the OGCC coordinates an extensive outage program with various internal stakeholders and external customers to support Hydro One’s distribution expansion and maintenance programs. Required outages are assessed and coordinated to minimize their impact on reliability and customer operation.

Grid Operations also maintains back-up operating facilities which serve as a fully redundant back-up to the OGCC.
5.3.3 Engineering and Construction

The Engineering and Construction function provides services ranging from engineering and design to the construction and commissioning of new or enhanced facilities. These projects include engineering, estimating, project management and construction of stations, system protection and control, as well as engineering services as required.

6.0 INVESTMENT CATEGORIES

In organizing and planning its work programs, Hydro One Transmission has three main investment categories of work: Sustainment, Development and Operations, which are described below. These categories are used for both the OM&A and Capital components of the investment plan.

6.1 Sustainment

Sustainment work is defined as the work required by the transmission business to maintain the existing infrastructure and facilities at their required performance level. The OM&A component of the sustainment work addresses preventative and breakdown (corrective) maintenance within the useful life span of the asset including mid life overhauls which are required to achieve the expected life span of the equipment. The capital component of the sustainment work deals with replacement of assets at end of life.

Sustainment work is designed to maintain customer delivery reliability system-wide while meeting all legislative, regulatory, safety and environmental requirements. The strategy uses a life cycle management approach, which aims at optimizing performance and cost over the service life of assets.
The Sustainment OM&A and Capital components of the investment plan are described in Exhibit C1, Tab 2, Schedule 2 and Exhibit D1, Tab 3, Schedule 2 respectively.

6.2 Development

Development work is defined as the work required by the transmission business to increase the capacity and capability of the transmission system by constructing additional transmission facilities or upgrading existing facilities. Development work provides the additional capacity and enhanced capability:

- to meet the needs of load or generation customers, including connecting new loads or new generating plants, adding capacity to supply increases in existing loads or output of existing generating plants;
- to reinforce the transmission networks in Ontario or on the interconnections with neighbouring utilities in order to maintain adequate customer supply and system security and to alleviate restrictions to power transfers in accordance with approved plans and directives; and
- to meet customer reliability/power quality service standards, system security standards, or equipment/facilities design standards in a manner consistent with the transmission business asset management strategy and regulatory obligations.
- to facilitate the modernization of a smart grid in Ontario and enhance transmission infrastructure to effectively deliver renewable power from distributed generation.

The Development OM&A and Capital components of the investment plan are described in Exhibit C1, Tab 2, Schedule 3 and Exhibit D1, Tab 3, Schedule 3 respectively.
6.3 Operations

Transmission operating activities are carried out centrally at the OGCC. The Operations function manages the transmission assets to ensure day to day flow of electricity within the capability of the transmission system, coordinates and schedules planned outages, and monitors and reports on the performance of the transmission system.

Capital investments are required to enhance, refurbish and replace transmission system computer management systems and data acquisition systems, including automatic system controls, which monitor and control the operation of the transmission system.

OM&A expenditures are required to maintain transmission system computer management systems and data acquisition systems, including automatic system controls, and to fund the resources required to perform the activities necessary for centralized operation of the transmission system.

The Operations OM&A and Capital components of the investment plan are described in Exhibit C1, Tab 2, Schedule 4 and Exhibit D1, Tab 3, Schedule 4, respectively.
ECONOMIC INDICATORS

1.0 INTRODUCTION

This exhibit provides the costing assumptions underlying the 2013 Business Plan.

2.0 ECONOMIC INDICATORS

2.1 Transmission Cost Escalation for Construction, Operations and Maintenance

The Transmission Cost Escalation for Construction, Operations & Maintenance provides a broad average measure of the industry-wide yearly price changes by tracking a representative basket of equipment and labour for these areas of business. This basket of goods is comprised of the following types of equipment and labour:

- Operation;
- Supervision and Engineering;
- Load Dispatching;
- Station Expenses;
- Lines;
- Meters;
- Customer Installations;
- Maintenance;
- Structures;
- Station Equipment;
- Overhead Lines;
- Underground Lines;
• Line Transformers; and
• Miscellaneous.

The data in Table 1 was provided by Global Insight’s January 2013 forecast.

Table 1
Global Insight’s January 2013 forecast

<table>
<thead>
<tr>
<th>Historical Years</th>
<th>Bridge Year</th>
<th>Test Years</th>
</tr>
</thead>
<tbody>
<tr>
<td>Transmission Cost Escalation for Construction</td>
<td>1.9 3.7 1.6 1.9</td>
<td>2.1 2.4 1.6</td>
</tr>
<tr>
<td>Transmission Cost Escalation for Operations &amp; Maintenance</td>
<td>1.6 3.7 2.1 1.5</td>
<td>2.0 2.4 2.9</td>
</tr>
</tbody>
</table>

The Transmission Cost Escalation for Construction, Operations & Maintenance is used as a planning tool to predict expenditure level changes for transmission materials and services.

2.2 Consumer Price Index

The Consumer Price Index (“CPI”) provides a broad measure of the cost of living. Through the monthly CPI, Statistics Canada tracks the change in retail price of a
representative shopping basket of about 600 goods and services from an average household's expenditure: food, housing, transportation, furniture, clothing, and recreation. Hydro One Transmission operates wholly in the Province of Ontario, Canada. As a result, the CPI–Ontario exhibits the inflationary environment in which Hydro One Transmission operates. The CPI forecast is from Global Insight’s February 2013 forecast and can be found in Table 2.

Table 2

<table>
<thead>
<tr>
<th>Historical Years</th>
<th>Bridge Year</th>
<th>Test Years</th>
</tr>
</thead>
<tbody>
<tr>
<td>CPI – Ontario</td>
<td>2.4</td>
<td>3.1</td>
</tr>
</tbody>
</table>

The CPI is used as a planning tool to forecast expenditure level changes for items such as fleet and sundry costs.

2.3 Exchange Rate (CDNS per US$)

The historic rates in Table 3 are the average exchange rates for 2010, 2011 and 2012 from the Bank of Canada. The exchange rate forecasts for 2013 to 2016 are based on the February 2013 edition of the Global Insight Forecast.
Table 3
Exchange Rate
(CDN$ per US$)

<table>
<thead>
<tr>
<th>Description</th>
<th>Historical Years</th>
<th>Bridge Year</th>
<th>Test Years</th>
</tr>
</thead>
<tbody>
<tr>
<td>Exchange Rate</td>
<td>1.030</td>
<td>0.989</td>
<td>1.000</td>
</tr>
</tbody>
</table>

While the exchange rate forecast is not directly used to forecast costs or other variables, it is an important variable affecting the performance of the Canadian and Ontario economies.

3.0 INTEREST RATES

Interest rate forecasts are used to determine the cost of capital for Hydro One Transmission. Please refer to Exhibit B2, Tab 1, Schedule 2 for historical and forecast debt rates.

3.1 Interest Capitalized

Consistent with the Board’s decisions in EB-2008-0408, effective January 1, 2012, no allowance for funds used during construction (AFUDC) rate is specified for use by Hydro One. In place of the AFUDC rate, Hydro One will base its interest capitalization rate on its embedded cost of debt used to finance the capital expenditures made. This is consistent with Hydro One’s adoption of United States Generally Accepted Accounting Principles (US GAAP) per the Board’s decision in EB-2011-0399 and US GAAP requirements for determination of interest capitalized. The rates used in calculating
capitalized interest for the bridge and test years represent the effective rate of Hydro One Transmission’s forecasted average debt portfolio during the year.

Prior to 2012, consistent with its Decision in EB-2006-0117, the OEB prescribed that the AFUDC rate to use for CWIP would be the Scotia Capital All-Corporate Mid-Term Yield, as published on the Bank of Canada website and updated quarterly. As a result, the 2010 to 2011 historical years reflect the average quarterly prescribed AFUDC interest rate.

The interest capitalization/AFUDC rates underlying Hydro One’s Business Plan are filed at Exhibit D1, Tab 6, Schedule 1.

4.0 INCOME AND CAPITAL TAX RATES

Please refer to Exhibit C1, Tab 8, Schedule 1 for the historical and forecast tax rates.

5.0 LABOUR ESCALATION RATES

(a) Society Staff and PWU Staff

Planned salary increases are consistent with ratified collective agreement over the length of the agreement. Years following the effective collective agreement are assumed to be 2% net annual increase.
(b) MCP staff

2% annual increase per year in base pay for the entire period. Details regarding management compensation are provided in Exhibit C1, Tab 4, Schedule 2.

(c) Incentive Plan Payouts

All incentive plans have been discontinued, with the exception of the MCP Short Term Incentive Plan. Payout under that plan is assumed to be 15% in all years.

6.0 COST RATES FOR BENEFITS

These rates are applied to the forecast labour rates.
### Table 4

**Burden Rates**

<table>
<thead>
<tr>
<th></th>
<th></th>
<th></th>
<th></th>
<th></th>
<th></th>
</tr>
</thead>
<tbody>
<tr>
<td>Networks</td>
<td>Non-Regular Staff</td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td></td>
<td>% of total earnings*</td>
<td>6.34%</td>
<td>6.35%</td>
<td>6.45%</td>
<td>6.39%</td>
</tr>
<tr>
<td></td>
<td>Regular Staff</td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td></td>
<td>% of total earnings*</td>
<td>6.34%</td>
<td>6.35%</td>
<td>6.45%</td>
<td>6.39%</td>
</tr>
<tr>
<td></td>
<td>% of base pensionable earnings**</td>
<td>29.30%</td>
<td>29.51%</td>
<td>27.88%</td>
<td>25.12%</td>
</tr>
<tr>
<td></td>
<td>% of base pensionable earnings***</td>
<td>0.39%</td>
<td>0.41%</td>
<td>0.38%</td>
<td>0.37%</td>
</tr>
<tr>
<td></td>
<td></td>
<td>29.69%</td>
<td>29.92%</td>
<td>28.27%</td>
<td>25.49%</td>
</tr>
<tr>
<td>Pension</td>
<td>% of base pensionable earnings</td>
<td>30.97%</td>
<td>30.91%</td>
<td>30.84%</td>
<td>30.78%</td>
</tr>
</tbody>
</table>

*CPP, Emp, Insurance, Emp. Health Tax, Workers’ Compensation Schedule 1 Premiums

**Health, Dental, Life Insurance, Maternity, Retirement Bonus, Post-Retirement Health, dental, Life Insurance, OPRB (for Inergi where applicable), Ontario Health Premiums (OHP)

*** OPRB - Inergi

- Base Pensionable Earnings includes pensionable bonus.
- Total Earnings includes base pay, bonus, overtime, taxable benefits and taxable allowances.
- Payroll burden rates exclude Powerflex benefits for MCP employees

The "burden rate," expressed as a percentage, estimates employee current and future cost rates for benefits which are attributable to labour in the current period, and allocates such costs across Hydro One legal entities. The benefit costs include:

- a) Other post-retirement benefits (“OPRB”), such as future health and dental costs;
- b) Other post-employment benefits (“OPEB”), such as long-term disability;
- c) Supplementary pension plan (“SPP”);
- d) Pension (funding) contributions;
e) Employee benefit costs during active employment; and

f) Statutory benefit payments, such as CPP, EI, etc.

Cost items a) through d) are actuarially determined by Hydro One Inc.'s external actuaries, Mercer Consulting Inc., using assumptions recommended by the actuaries and accepted by Hydro One Inc.’s management. Assumptions are determined with reference to past experience and industry norms.

Cost item e) is based on estimates from Mercer, and from Hydro One Inc.'s insurance provider Great West Life, as to anticipated escalation factors of health and dental costs. These estimates are compared to past experience.

Cost item f) is based on government schedules of premium rates for CPP, EI, etc.
BUSINESS LOAD FORECAST AND METHODOLOGY

1.0 INTRODUCTION

This Exhibit discusses Hydro One Transmission system load forecast and the related methodology. The key load forecast supporting Hydro One Networks’ Transmission rate case is the hourly demand load forecast by customer delivery point. This forecast is used to prepare the charge determinant forecast for the following rate categories: network pool, line connection pool, and transformation connection pool. The load forecast in support of this proposed application was prepared in April, 2014 using economic and forecast information that was available in March, 2014.

Hydro One Transmission forecast of average 12-month peak load for 2015 and 2016 for Ontario as a whole and for its three rate categories are shown in Table 1. The impacts of conservation and demand management (CDM) and embedded generation (EG) are included.

<table>
<thead>
<tr>
<th></th>
<th>Hydro One Rate Categories (Charge Determinants)</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>Network Connection</td>
</tr>
<tr>
<td><strong>Ontario Demand</strong></td>
<td></td>
</tr>
<tr>
<td>2015</td>
<td>20,595</td>
</tr>
<tr>
<td>2016</td>
<td>20,814</td>
</tr>
</tbody>
</table>

Hydro One worked with the Ontario Power Authority (OPA) and used their latest CDM assumptions in preparing the load forecast in this proposed rate application. A detailed report was prepared and is provided as Attachment 1 to this Exhibit and the summary results are discussed in Section 3.6.
2.0 A SUMMARY OF HYDRO ONE’S LOAD FORECAST METHODOLOGY AND ASSUMPTIONS

Hydro One Transmission uses a number of methods, such as econometric models, end-use models; customer forecast surveys and hourly load shape analyses to produce the forecasts required for its transmission business. This is the same load forecast methodology used and approved by the Board in previous Hydro One Networks’ Transmission rate cases (EB-2006-0501, EB-2008-0272, EB-2010-0002, and EB-2012-0031). All forecasts presented in this Exhibit are weather-normal, that is, abnormal weather effects are removed from the base year for load forecasting purposes so that the forecast assumes typical weather conditions based on the average of the last 31 years.

All forecasts produced are internally consistent. Therefore forecasts for all customer delivery points add up to the total for the entire customer base served by Hydro One Transmission’s system. Hydro One Transmission’s forecasting methodology comprises a combination of elements that include consensus input, updates to changes in economic forecasts, energy prices, population and household trends, industrial development and production, residential and commercial building activities, and efficiency improvement standards.

The forecasts presented in this Exhibit are consistent with the economic assumptions used in the business planning process and described in Exhibit A, Tab 15, Schedule 1. Section 3 discusses in detail, the various economic inputs taken into consideration when applying the methodology for deriving the load forecasts. Economic inputs are based on analyses prepared by major economic establishments in the country, such as IHS Global Insight, the Conference Board of Canada, the Centre for Spatial Economics and the University of Toronto. Efficiency standard assumptions used in the end-use models are based on discussions with the OPA staff. Specific customer development is based on forecast
survey results from major customers. Inputs from these entities form the economic
database (referred to henceforth as the economic forecast) that is used to establish Hydro
One Transmission’s load forecast.

3.0 KEY ASSUMPTIONS THAT INFLUENCE HYDRO ONE NETWORKS’
LOAD FORECASTS

Key assumptions must be taken into account in the process of developing load forecasts
and in the application of forecasting methodologies. The elements of the forecasting
process used by Hydro One Transmission are based on the knowledge of how the major
economic drivers that affect the usage of electricity demand are likely to evolve over the
forecast period of 2014 to 2016. Consequently for the purpose of this Proposed
Application, the focus is on the short term and the load forecast will reflect those impacts
that are likely to have a major effect in this respect. The key assumptions used in the
analysis are summarized in Figure 1.
Key information used in the analysis includes Ontario GDP, provincial demographic, industrial production and commercial floor space forecasts and regional analysis included in the economic forecast. Also taken into consideration are the provincial CDM plans and by-pass risks, which have a direct impact on Networks’ system energy demands.

### 3.1 Provincial GDP Forecast

The provincial GDP forecast is a key driver for the load forecast. The high Canadian dollar, the recent recession and the slow recovery of the U.S. economy and the European Union had an adverse impact on the provincial manufacturing sector. Nearly all manufacturing segments were negatively affected in recent years. In the last two years, the GDP grew by 1.3 percent in 2012 and 1.2 percent in 2013. Based on the consensus
forecast, the Ontario GDP is expected to grow by 2.2 percent in 2014, 2.6 percent in 2015, and 2.7 percent in 2016 as the economy recovers. Appendix E provides the details of the consensus forecast for Ontario GDP.

3.2 **Provincial Population Forecast**

The Ontario population grew 1.0 percent in 2011, 1.1 percent in 2012, and 0.9 percent in 2013. Population growth in Ontario is forecast to grow at about the same pace as the nation in the forecast period. The economic forecast indicates that the Ontario population is expected to grow at about 1.0 percent per year between 2014 and 2016. Steady population growth contributes positively to the load forecast.

3.3 **Provincial Housing Forecast**

Helped by population growth and low interest rates, housing demand in Ontario continued moderate growth during the past three years. Housing starts statistics showed growth of 68,000 houses in 2011, 77,000 in 2012 and 61,000 in 2013. The consensus forecast calls for 59,000 housing starts in 2014, 60,000 in 2015, and 69,000 in 2016. Appendix E provides the details of the consensus forecast for Ontario housing starts.

3.4 **Commercial Floor Space Forecast**

Commercial construction activities slowed down during the last three years from 1.4 percent growth in 2011, to 1.3 percent in 2012 and 0.9 percent in 2013. The economic forecast shows commercial floor is going to continue moderate growth over the forecast horizon. The forecast calls for 0.9 percent growth in 2014 and 1.1 percent in 2015 and 1.0 percent in 2016. The forecast for commercial floor space additions is an important contributor to the commercial sector load forecast.
3.5 Industrial Production Forecast

Due to the slow world economic recovery and high Canadian dollar, the industrial recovery from the 2009 recession did not last long. The growth in industrial production declined from 4.4 percent in 2011 to 1.3 percent in 2012, and -2.4 percent in 2013. Industries that were hit hardest during the past three years were pulp and paper, textile, plastic and rubber, and electrical and computer products. The economic forecast calls for moderate growth of 0.6 percent in 2014, 1.9 percent in 2015 and 2.3 percent in 2016. The industrial production forecast is an important contributor to the industrial sector load forecast but it is also prone to economic cycles.

3.6 Conservation and Demand Management Forecast

In EB-2010-0002, the Board directed Hydro One to “work with the OPA in devising a robust, effective and accurate means of measuring the expected impacts of CDM programs promulgated by the OPA.” In EB-2012-0031, Hydro One worked with the stakeholders and the OPA to satisfy this directive and the report “Incorporating CDM Impacts in the Load Forecast” (EB-2012-0031 Exhibit A-15-2 Attachment 1) was approved.

In December of 2013, the Ministry of Energy released the updated Long-Term Energy Plan, Achieving Balance (“the 2013 LTEP”). The detailed breakdown of assumptions underpinning the 2013 LTEP was released by the OPA in February 2014. Hydro One has adopted the OPA’s province-wide conservation forecast and used a similar methodology to incorporate these CDM impacts into the load forecast. Hydro One adopted three CDM categories that are consistent with the OPA’s 2013 LTEP information: Energy Efficiency Programs, Codes and Standards, and demand reduction from Demand Response (DR) Resources. Details of the information provided by the OPA and the methodology used
by Hydro One to derive the CDM impacts for the 3 charge determinants are documented in Attachment 1 of this Exhibit.

Table 2 summarizes the CDM peak impacts assumed in Hydro One Transmission’s system load forecast for 2006 to 2016. These CDM peak impacts are consistent with the 2013 LTEP.

Table 2
Load Impact of CDM on Ontario Demand (MW)

<table>
<thead>
<tr>
<th>Year</th>
<th>Cumulative CDM Impact on Peak Demand *</th>
<th>Cumulative 12-month Average Peak Demand **</th>
</tr>
</thead>
<tbody>
<tr>
<td>2006</td>
<td>520</td>
<td>431</td>
</tr>
<tr>
<td>2007</td>
<td>893</td>
<td>711</td>
</tr>
<tr>
<td>2008</td>
<td>1,208</td>
<td>900</td>
</tr>
<tr>
<td>2009</td>
<td>1,215</td>
<td>825</td>
</tr>
<tr>
<td>2010</td>
<td>1,255</td>
<td>795</td>
</tr>
<tr>
<td>2011</td>
<td>1,539</td>
<td>990</td>
</tr>
<tr>
<td>2012</td>
<td>1,756</td>
<td>1,164</td>
</tr>
<tr>
<td>2013</td>
<td>2,619</td>
<td>1,543</td>
</tr>
<tr>
<td>2014</td>
<td>2,865</td>
<td>1,723</td>
</tr>
<tr>
<td>2015</td>
<td>3,014</td>
<td>1,872</td>
</tr>
<tr>
<td>2016</td>
<td>3,250</td>
<td>2,087</td>
</tr>
</tbody>
</table>

* The figures represent the load impact of CDM on summer peaks.
** The figures represent the load impact of CDM on monthly peaks, averaged over 12 months in the year.

3.7 By-Pass Forecast

Hydro One Transmission collects its transmission revenue through four types of Board-approved transmission charges (networks, line connection, transformation connection, and wholesale meter). When Hydro One Transmission’s customers get power from their own embedded generation or build their own transformation station or line connections to their distribution system, Hydro One Transmission charges cannot be applied. The following summarizes the by-pass forecast assumptions used in the test years:

Embedded Generation By-pass
A total of 471 MW of embedded generation (EG) was assumed to be in place in 2013. An additional 91 MW in 2014, 104 MW in 2015, and 102 MW in 2016 of new embedded generation is assumed in the load forecast, which reflects renewable energy projects initiated by the OPA.

Transformation and Line Connection By-pass
No transformation and line connection by-pass is assumed in the load forecast in this rate application.

4.0 LOAD FORECASTING METHODOLOGY

Hydro One Transmission’s system load forecast is developed using both econometric and end-use approaches. The forecast base year is corrected for abnormal weather conditions as explained in Section 4.1 and the forecast growth rates are applied to the normalized base year value. The load impacts of CDM and EG are added back to the historical values during the modeling process (see Figure 2 and Section 4.2).
The derivation of each of the Customer Forecast and the Customer Delivery Point Forecast is then addressed in Sections 4.3 and 4.4, respectively.

### 4.1 Weather Correction Analysis

Weather correction analysis is a statistical process that removes the abnormal or extreme weather effects from the load data to yield average conditions that reflect the more normal or expected weather that is used in the forecast. This is essential because the volatility of abnormal or extreme weather conditions can adversely impact the provision of a consistent and meaningful forecast for load growth. Hourly load data and hourly weather data of various weather stations across the province are used in the analysis.
4.1.1 Hydro One Networks’ Weather Correction Methodology

Hydro One Transmission’s weather correction methodology was originally developed by the forecasting and meteorology staff of the former Ontario Hydro. This weather correction method was used to forecast the total system load since 1988 and for forecasting local electric utility load since 1994. The weather correction methodology used by Hydro One Transmission is a proven technique that has performed well in the past years. The same methodology was reviewed and approved by the Board in previous Hydro One Networks’ Transmission rate cases (EB-2006-0501, EB-2008-0272, EB-2010-0002, and EB-2012-0031).

Normal weather data is based on the average weather conditions experienced over the last thirty-one (31) years. This methodology is consistent with the approach used by the IESO and the OPA. A weather-normal load forecast is a forecast of load assuming normal weather conditions with a weather-corrected base year.

Hydro One Transmission’s weather correction methodology uses four years of daily load and weather data to establish a sound statistical relationship between weather and load at the applicable transformer station or delivery point used to supply customer demand. Weather variables used in the analysis include temperature, wind speed, cloud cover and humidity. The estimated weather effects are then aggregated up to the required time interval. Past experience shows that weather correction should best be done on a daily basis, rather than weekly, monthly or annual basis as timing of extreme temperatures combined with wind speed and humidity can have a substantial impact on load that would otherwise not be captured by averages over a longer period of time. In particular, when abnormal weather conditions continue for several days, the cumulative impact is much greater than any single day’s impact.

The loads that are most impacted by changes in weather conditions are electric space heating and cooling in residential and commercial buildings. Across Ontario, the
penetration rate of such loads varies widely. Weather sensitivity of load supplied from one transformer station or delivery point may differ quite significantly from that of load supplied from another transformer station or delivery point, even in the same climate zone. The climate in Ontario varies considerably from the Niagara Peninsula to Thunder Bay, so it is important to use data from the appropriate weather stations that are in close proximity to the transformer station or the customer delivery point when correcting for weather effects. Weather data analyzed include temperature, wind speed, cloud cover and humidity. Data for five weather stations across Ontario are used in the analysis. They include Toronto, Windsor, Ottawa, North Bay and Thunder Bay. Each delivery point is linked to the closest weather station.

4.1.2 Weather Correction Practices in Other Jurisdictions

Hydro One Transmission completed a study on weather normalization practices by surveying over 50 utilities in North America in 2008. The study was submitted to the Board for review in the transmission rate case (EB-2008-0272). Major findings of the study are summarized below:

- Most utilities use long term weather data to calculate the weather normal conditions; about 75% of utilities are currently using 20 years or more for weather normalization.
- The most commonly used period for weather normalization is at least 30 years; no utilities use less than 10 years of weather data to do weather normalization.
- Weather normalization surveys undertaken by Edison Electric Institute, BC Hydro and ITRON show similar results as Hydro One Transmission’s survey.
- Most utilities update their weather data set and weather normalization analysis on an annual basis.
- Very few utilities have changed their weather normalization practices in recent years in response to global warming or other reasons.
The survey results were supportive of Hydro One Transmission’s weather-normalization methodology, which is based on the use of 31 years of weather data to define normal weather conditions.

The above study confirms that the weather normalization methodology used by Hydro One Transmission is appropriate. In light of the increased volatility on peak in recent years, the energy to peak relationships are reviewed and updated on an on-going basis, and has been done for this application.

Figures 3 and 4 below present the maximum and minimum daily temperature since 1953 as a measure of peak-generating weather conditions during summer and winter respectively.

Figure 3. Toronto Pearson International Airport: Maximum of Average Daily Temperature
4.2 Hydro One Transmission Forecasting Methodology

Hydro One Transmission uses econometric (top-down) and end-use (bottom-up) models to forecast the transmission system load. For the top-down approach, both monthly and annual econometric models are used. For the bottom-up approach, end-use models are used to analyse the transmission system load by sector (i.e. residential, commercial and industrial customers). Key information used in the analysis includes economic data, demographics, industrial production and commercial floor space forecast provided in the economic forecast. The purpose of using both the econometric and end-use forecast models is to arrive at a balanced forecast that represents a consistent set when looked at from macro (econometric) and micro (end-use) perspectives. The forecasting methodology used here was reviewed and approved by the Board in previous Hydro One Networks’ Transmission rate cases (EB-2006-0501, EB-2008-0272, EB-2010-0002, and EB-2012-0031).
4.2.1 Monthly Econometric Model

The monthly econometric model uses a multivariate time series approach to develop the monthly forecast for the total transmission system load. The model links monthly energy consumption to Ontario GDP and residential building permits, taking into account the August, 2003 blackout. The load impacts of CDM and embedded generation are added back to the historical data set during the modelling process. The transmission system load used in the model is weather-normal. Appendix A provides the detailed regression equations and definitions.

4.2.2 Annual Econometric Model

The annual econometric models cover five sectors of the economy: residential, commercial, industrial, agriculture, and transportation. Appendix B provides the detailed regression equations and definitions.

The residential sector is modelled as a two-equation system for saturation and usage of electric equipment. Explanatory variables used include energy prices, personal disposable income per household and weather conditions as measured by heating degree days. As in monthly and end-use models, the load impact of CDM and embedded generation is added back to historical figures.

The commercial sector links energy usage to electricity price, commercial GDP and weather conditions as measured by heating and cooling degree days.

The industrial model consists of an equation for total energy and a two-equation model to determine shares of electricity usage. Total energy is modelled as a function of energy price and industrial GDP. Energy shares are linked to relative energy prices. Dummy variables
are used to capture unusual changes in energy growth in the 70’s and early 80’s and to
measure the impact of technical change on energy shares.

The agricultural sector is modelled in relation to electricity price and income, while
accounting for cyclical and trend changes.

The transportation sector, which consists mainly of pipeline and road transport, is
modelled by an equation relating electricity usage to income, electricity price, and a
dummy variable to capture a change in load pattern since 1997.

4.2.3 End-Use Models

The end-use models cover the residential, commercial, industrial, agricultural and
transportation sectors. As in the monthly and annual econometric models previously
discussed, the load impact of CDM and embedded generation is added back to historical
figures. Appendix C provides details of the methodology used in the end-use analyses.

In the residential sector, the end-uses analysed include space heating, water heating, air
conditioning, and base load. The forecast of each end-use is based on the number of
households having that end-use and unit energy consumption of the equipment.

The commercial model analyses energy use by building type. Key drivers used in the
analysis are the commercial sector floor space and the intensity of end-use demand per unit
of floor space.

The industrial forecast is based on analysis for each major industrial segment, energy
intensity and expected economic growth.
The agricultural and transportation sector models are based on base year electricity consumption and the expected growth rates for each sector and segment.

4.3 Methodology for Customer Forecast

Both econometric and customer analyses based on survey results from the customers, when available, are used in the forecast. This is supplemented by the economic data provided in the economic forecast.

In February 2014, Hydro One Transmission conducted a customer load forecast survey with customers having more than 5 MW of load. The survey also covered the station service load requirements of generating stations when they are not producing electricity. In addition to questions relating to the total load of the customer, information at each of the delivery points was also collected. The customer survey results are used in preparing the customer forecast.

In addition to the information contained in the customer survey, a number of forecasting techniques are used to prepare the load forecast by customer. For large utility customers, each customer is modeled individually using the econometric approach. The drivers used in these models include provincial economic variables such as Ontario GDP, population, number of household, energy prices, as well as local demographic and economic variables such as population and related industrial and commercial loads. The impact on load of weather conditions is also taken into account. The best subset of the drivers is selected on the basis of regression criteria.

For industrial customers, several information sources are used to prepare the forecast. They include:

- historical load profile of the customer;
knowledge of the customer through industry monitoring;
• forecast provided by customer through the survey;
• company information through Hydro One Transmission account executives, industry
  and company forecasts from industry associations and government agencies; and
• production and industry forecasts provided in the economic forecast.

4.4 Methodology for Customer Delivery Point Forecast

This section discusses the forecasting methodology for the customer delivery point
forecast. Electricity Power Research Institute (EPRI)’s Hourly Electric Load Model
(HELM) is used to normalize the hourly load for each of the transmission customer
delivery points, removing abnormal weather effects and abnormal load patterns. Key
information used in analyzing the load shape for each delivery point includes hourly load
and weather data. The load growth for each delivery point is linked to the customer
forecast discussed above. The forecasts for all customer delivery points add up to the
regional and the total transmission system forecast.

The most updated customer totalization table is used to retrieve hourly peak electricity
demand data for each of the customer delivery points connected to the transmission
system. The totalization table reflects the latest records from Hydro One Transmission
and the IESO. For each customer delivery point, at least one full year of hourly data is
retrieved and checked for data quality. Hourly weather data is also retrieved to prepare
weather sensitivity analysis as discussed in Section 4.1.

In preparing the database for the load shape analysis, missing values are estimated by
load on a similar day and hour during the same month. For weather-sensitive load, local
weather conditions are also taken into account in estimating the missing values.
EPRI’s HELM is used to prepare the hourly weather response analysis by each delivery point. The model takes into account differences in load depending upon time of use (weekdays, weekends and holidays) and weather conditions. Load of industrial customers is assumed to be insensitive to weather and as such are forecast in relation to load on a similar day and hour during the historical period. The customer forecast is used to drive the customer delivery point forecast. The resulting customer delivery point forecast is therefore consistent with the customer load forecast and the total transmission forecast as discussed above. The charge determinant forecasts at the delivery point level add up to the total charge determinant forecasts presented in Table 4 in the next section. The customer delivery point forecast uses the latest customer totalization table that shows which customers pay Network, Line Connection and Transformation Connection service to determine the charge determinant forecast for each transmission service tariff. The basis for determining the transmission charges applicable to each customer delivery point is further discussed in Exhibit H1, Tab 3, Schedule 1.

5.0 LOAD FORECAST FOR 2015 AND 2016

Hydro One Transmission’s charge determinant forecast is derived from the Ontario peak demand forecast based on the econometric, end-use, and customer forecasts. Before deducting the load impact of CDM and embedded generation, the 12-month average charge determinant forecasts grow from 2013 in a manner consistent with the growth of the 12-month average peak for Ontario. Table 3 presents the forecast before and after deducting the load impacts attributed to embedded generation and CDM for the 2013-2016. The charge determinant forecast is based on the methodology approved by the OEB in its decisions for EB-2006-0501, EB-2008-0272, EB-2010-0002, and EB-2012-0031. Appendix D provides the historical actual and weather-corrected charge determinant data for 2002-2013.
Before deducting for the load impacts of embedded generation and CDM, Hydro One Transmission is forecast to deliver an average of 22,700 MW in 2014 (12-month average peak), rising to 23,133 MW in 2015, and 23,668 MW in 2016.

After deducting the load impacts of embedded generation and CDM, Hydro One Transmission is forecast to deliver an average of 20,415 MW in 2014 (12-month average peak), rising to 20,595 MW in 2015, and 20,814 MW in 2016.

The forecast is weather-normal and the actual load could be below or above the forecast depending on the weather conditions and/or a different economic growth pattern. Table 4 of this Exhibit presents the upper and lower bands of one standard deviation for the charge determinant forecast. Based on historical data, there is a two-in-three chance that the actual load in 2014, 2015, and 2016 will fall within the upper and lower bands. The bands are derived using Monte Carlo simulation technique relating variations in load to variations in Ontario GDP and weather.
### Table 3

**Load Forecast Before and After Embedded Generation and CDM**

*(12-Month Average Peak in MW)*

<table>
<thead>
<tr>
<th>Year</th>
<th>Ontario Demand (MW)</th>
<th>Network Connection (MW)</th>
<th>Line Connection (MW)</th>
<th>Transformation Connection (MW)</th>
</tr>
</thead>
<tbody>
<tr>
<td>2013</td>
<td>22,375</td>
<td>22,212</td>
<td>20,797</td>
<td>17,874</td>
</tr>
<tr>
<td>2014</td>
<td>22,700</td>
<td>22,535</td>
<td>21,099</td>
<td>18,135</td>
</tr>
<tr>
<td>2015</td>
<td>23,133</td>
<td>22,965</td>
<td>21,502</td>
<td>18,480</td>
</tr>
<tr>
<td>2016</td>
<td>23,668</td>
<td>23,496</td>
<td>21,999</td>
<td>18,908</td>
</tr>
</tbody>
</table>

**Load Impact of Embedded Generation**

<table>
<thead>
<tr>
<th>Year</th>
<th>Embedded Generation (MW)</th>
</tr>
</thead>
<tbody>
<tr>
<td>2013</td>
<td>471</td>
</tr>
<tr>
<td>2014</td>
<td>562</td>
</tr>
<tr>
<td>2015</td>
<td>666</td>
</tr>
<tr>
<td>2016</td>
<td>768</td>
</tr>
</tbody>
</table>

**Load Impact of CDM**

<table>
<thead>
<tr>
<th>Year</th>
<th>CDM (MW)</th>
</tr>
</thead>
<tbody>
<tr>
<td>2013</td>
<td>1,543</td>
</tr>
<tr>
<td>2014</td>
<td>1,723</td>
</tr>
<tr>
<td>2015</td>
<td>1,872</td>
</tr>
<tr>
<td>2016</td>
<td>2,087</td>
</tr>
</tbody>
</table>

**Load Forecast after Deducting Embedded Generation and CDM**

<table>
<thead>
<tr>
<th>Year</th>
<th>Load Forecast (MW)</th>
</tr>
</thead>
<tbody>
<tr>
<td>2013</td>
<td>20,360</td>
</tr>
<tr>
<td>2014</td>
<td>20,415</td>
</tr>
<tr>
<td>2015</td>
<td>20,595</td>
</tr>
<tr>
<td>2016</td>
<td>20,814</td>
</tr>
</tbody>
</table>

Note. All figures are weather-normal.
### Table 4

One Standard Deviation Uncertainty Bands for Hydro One Transmission’s Charge Determinants (Using Current Rates) (MW)

<table>
<thead>
<tr>
<th>Year</th>
<th>Lower Band</th>
<th>Forecast</th>
<th>Upper Band</th>
</tr>
</thead>
<tbody>
<tr>
<td><strong>Network Connection</strong></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>2013 (Actual)</td>
<td>20,220</td>
<td>20,220</td>
<td>20,220</td>
</tr>
<tr>
<td>2014</td>
<td>19,906</td>
<td>20,276</td>
<td>20,649</td>
</tr>
<tr>
<td>2015</td>
<td>19,966</td>
<td>20,457</td>
<td>20,949</td>
</tr>
<tr>
<td>2016</td>
<td>20,121</td>
<td>20,676</td>
<td>21,229</td>
</tr>
<tr>
<td><strong>Line Connection</strong></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>2013 (Actual)</td>
<td>19,322</td>
<td>19,322</td>
<td>19,322</td>
</tr>
<tr>
<td>2014</td>
<td>19,133</td>
<td>19,488</td>
<td>19,844</td>
</tr>
<tr>
<td>2015</td>
<td>19,278</td>
<td>19,752</td>
<td>20,228</td>
</tr>
<tr>
<td>2016</td>
<td>19,514</td>
<td>20,050</td>
<td>20,587</td>
</tr>
<tr>
<td><strong>Transformation Connection</strong></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>2013 (Actual)</td>
<td>16,606</td>
<td>16,606</td>
<td>16,606</td>
</tr>
<tr>
<td>2014</td>
<td>16,444</td>
<td>16,748</td>
<td>17,054</td>
</tr>
<tr>
<td>2015</td>
<td>16,568</td>
<td>16,975</td>
<td>17,383</td>
</tr>
<tr>
<td>2016</td>
<td>16,771</td>
<td>17,231</td>
<td>17,690</td>
</tr>
</tbody>
</table>

Note: All figures are weather-normal.

### 6.0 VARIABILITY OF HYDRO ONE’S LOAD FORECASTS

Hydro One Transmission has significant expertise in preparing Provincial electricity demand forecasts as well as hourly load shape analysis. As part of the load research work associated with EB-2005-0317, Hydro One prepared the load shape analysis for over 80 LDCs in Ontario for use in their distribution rate applications to the Board. The performance of Hydro One Transmission’s system load forecast since 1999 has been consistently accurate as shown in Table 5.
Table 5
Comparison of Average Monthly Transmission Peak Demand Forecast with Actual
(Variance of forecast as percentage of actual on weather corrected basis)

<table>
<thead>
<tr>
<th>Forecast made In Year</th>
<th>Forecast for current year</th>
<th>Forecast for 2\textsuperscript{nd} Year</th>
<th>Forecast for 3\textsuperscript{rd} Year</th>
</tr>
</thead>
<tbody>
<tr>
<td>1999</td>
<td>-0.92%</td>
<td>-2.22%</td>
<td>-2.30%</td>
</tr>
<tr>
<td>2000</td>
<td>0.18%</td>
<td>0.26%</td>
<td>0.22%</td>
</tr>
<tr>
<td>2001</td>
<td>-0.14%</td>
<td>-0.29%</td>
<td>0.41%</td>
</tr>
<tr>
<td>2002</td>
<td>0.15%</td>
<td>0.36%</td>
<td>-0.14%</td>
</tr>
<tr>
<td>2003</td>
<td>0.25%</td>
<td>0.09%</td>
<td>0.83%</td>
</tr>
<tr>
<td>2004</td>
<td>0.08%</td>
<td>0.59%</td>
<td>0.89%</td>
</tr>
<tr>
<td>2005</td>
<td>0.17%</td>
<td>0.36%</td>
<td>0.97%</td>
</tr>
<tr>
<td>2006</td>
<td>-0.69%</td>
<td>0.41%</td>
<td>0.15%</td>
</tr>
<tr>
<td>2007</td>
<td>0.93%</td>
<td>0.18%</td>
<td>0.70%</td>
</tr>
<tr>
<td>2008</td>
<td>-0.38%</td>
<td>0.24%</td>
<td>0.24%</td>
</tr>
<tr>
<td>2009</td>
<td>-0.23%</td>
<td>-0.88%</td>
<td>0.83%</td>
</tr>
<tr>
<td>2010</td>
<td>1.00%</td>
<td>0.32%</td>
<td>-0.28%</td>
</tr>
<tr>
<td>2011</td>
<td>-0.40%</td>
<td>-1.35%</td>
<td>-2.58%</td>
</tr>
<tr>
<td>2012</td>
<td>-0.05%</td>
<td>-0.20%</td>
<td>n.a.</td>
</tr>
<tr>
<td>2013</td>
<td>-0.22%</td>
<td>n.a.</td>
<td>n.a.</td>
</tr>
</tbody>
</table>

Mean                  | -0.02%                    | -0.15%                                 | -0.13%                                |
One standard deviation (+/-) | 1.60%                     | 2.43%                                  | 2.67%                                 |

Note. The forecasts are net of the load impact of CDM and embedded generation and are compared to the weather corrected actual.

Between 1999 and 2013, the average variance of the transmission peak demand forecast compared to the weather corrected actual peak is well within one standard deviation meaning there is a one-in-three chance that the actual will be outside the plus or minus range. The use of the one standard deviation as a measure of forecasting accuracy is an accepted standard in the utility industry.
Forecast accuracy for previous Board-approved forecasts of charge determinants are presented in Table 6. The figures reflect the percent deviation of forecast for each charge determinant over the forecast period compared to the historical actual on a weather corrected basis. The 2006-2008 forecasts were approved by the Board in EB-2006-0501. Similarly, the 2008-2010 forecasts were approved in EB-2008-0272, 2010-2012 in EB-2010-0002, and 2013-2014 in EB-2012-0031. Detailed comparison of forecasts for each forecast year separately is provided in Appendix F and Tables 6a to 6c.

### Table 6

**Historical Board Approved Forecasts vs. Historical Actual-Weather Corrected**

<table>
<thead>
<tr>
<th>Type of Connection</th>
<th>EB-2006-0501</th>
<th>EB-2008-0272</th>
<th>EB-2010-0002</th>
<th>EB-2012-0031</th>
<th>Average</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>Forecast</td>
<td>Forecast</td>
<td>Forecast</td>
<td>Forecast</td>
<td></td>
</tr>
<tr>
<td>Network</td>
<td>-0.49</td>
<td>-0.45</td>
<td>-0.42</td>
<td>-0.60</td>
<td>-0.49</td>
</tr>
<tr>
<td>Line</td>
<td>-0.71</td>
<td>0.79</td>
<td>0.68</td>
<td>0.38</td>
<td>0.29</td>
</tr>
<tr>
<td>Transformation</td>
<td>-1.02</td>
<td>0.16</td>
<td>0.52</td>
<td>0.68</td>
<td>0.09</td>
</tr>
<tr>
<td><strong>Average</strong></td>
<td>-0.74</td>
<td>0.17</td>
<td>0.26</td>
<td>0.15</td>
<td>-0.04</td>
</tr>
<tr>
<td><strong>One Standard Deviation (+/−)</strong></td>
<td>2.26</td>
<td>2.26</td>
<td>2.26</td>
<td>1.96</td>
<td></td>
</tr>
</tbody>
</table>

* A negative (positive) variance shows that the forecast was below (above) actual.
** Reflects expected deviation of forecast from actual-weather corrected based on historical variations.

As shown in Table 6, the deviations of previous Board-approved charge determinant forecasts from historical actuals on a weather-corrected basis are all within one standard deviation of errors, and the average deviation over the past four Board-approved forecasts (EB-2006-0501, EB-2008-0272, EB-2010-0002 and EB-2012-0031) is close to zero.
TRANSMISSION OUTLOOK

As per Section 2.4.2.2 of the Board’s Filing Requirements for Transmission Rates issued on January 2, 2014, Table 1 below provides a summary of Hydro One’s Transmission capital expenditures over the past five historical years, which includes the bridge year, and for five future years including the test years.

Details of all the Sustaining, Development, Operations and Common Corporate Cost capital investments required in the test years are provided in Exhibit D1 and details of all large projects greater than $3 million are provided in Exhibit D2, Tab 2, Schedule 3. The summary of capital expenditures in Table 1 for the years 2017 to 2019 shows spending at the program level. Additional details of spending for this period beyond the test years is not available.

- Sustaining capital expenditures increase significantly in the 2013 to 2015 period to deal with the continued growth in the number of assets that are beyond their expected service life and require replacement to maintain system performance at acceptable levels. The level of spending in the 2016 to 2019 period varies based on program priorities such as the number of stations requiring reinvestment.
- Development expenditures are generally declining over the ten year period as large projects like Bruce to Milton and other projects to accommodate renewable generation have been completed. As explained in Exhibit D1, Tab 3, Schedule 3, Section 3.9 there are four large transmission projects that may require significant capital expenditures in the 2015 – 2019 period. The expenditures are not included in this proposed application as the spending in the test years is too uncertain to forecast and the project schedules are driven by external parties including the Board and the OPA.
• Operations spending increases in the 2014 to 2017 period mainly due to the NMS Sustainment project, the new Back Up Control Centre facility and upgrades to computer and network systems.

• Common Corporate Costs increase in 2014 due to higher IT spending for the completion of the Cornerstone project and Facilities and Real Estate costs, and then expenditures decline over the 2015 to 2019 period.

Overall Capital expenditures remain flat in 2015 and decline over the 2016 to 2019 period. The four large Development projects referred to above include the East-West Tie Expansion, TransCanada’s Energy East Pipeline project, the Northwest Bulk Transmission Line project and the GTA Reactors project. While these projects could require significant capital expenditures in the test years, the in-services dates for these projects will be beyond the test years so there will be no impact on the rates requested in this application. Per Section 2.4.2.2, Hydro One’s treatment of contributed capital, which is particularly relevant for the Energy East Pipeline project, is shown for specific projects in Exhibit D2, Tab 2, Schedule 3. The treatment of Construction Work in Progress (CWIP) in the four historical years, including the bridge year and in the two test years is shown in Exhibit D2, Tab 3, Schedule 3. Information on the treatment of CWIP beyond the test years is not available.
### Table 1

**Transmission Capital Expenditures**

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**Development Capital**
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**Operations Capital**

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**Capital Common Corporate Costs and Other Costs**

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<td>Information Technology (including Cornerstone)</td>
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**Total Transmission Capital**

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<td>776.0</td>
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<td>899.4</td>
<td>866.3</td>
<td>847.8</td>
<td>838.8</td>
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COST EFFICIENCIES/PRODUCTIVITY

1.0 INTRODUCTION

Productivity at Hydro One remains an integral part of the Corporation’s strategy and business objectives. This exhibit outlines the historical (2011 – 2013), present (2014) and future (2015 – 2016) productivity initiative results within the Corporation. Productivity initiatives typically show results over a number of years and Hydro One continues to realize material cost reductions and avoidances, throughout the test years all of which are of direct benefit to Hydro One customers.

Productivity Definition

For the purpose of this analysis, the Hydro One definition of productivity is;

“The effectiveness of productive effort, is measured in terms of the rate of output per unit of input”

An example of Productivity can be demonstrated by improvements made in the Transmission Structure Replacement Program. The Transmission Structure Replacement Program has seen consistent unit cost reductions resulting from:

• strategic scheduling of work to decrease mobilization and demobilization occurrences to save time and travel costs;
the use of composite structures to decrease maintenance costs and extend the life cycle;

- benefits from right-of-way clearances that greatly reduce complications in installation; and

- increased proficiency in the assembly of composite structures.

In 2012 the transmission structure replacement unit price was $39,582. It is expected the unit price in 2016 will be $35,384. This is a cost reduction of $4198 per structure.

**OM&A Expenditures**

OM&A expenditures over the two test years, demonstrate more productivity; if not for these initiatives, Hydro One would be requiring more than 10% additional revenue per year. This is illustrated in Table 1.

**Table 1:**
Impact to Revenue Requirement Inclusive and Exclusive of Annual OM&A

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<th></th>
<th>2013 Actual</th>
<th>2014 Bridge</th>
<th>2015 Test</th>
<th>2016 Test</th>
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<td>452,095,281</td>
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<td>YoY growth</td>
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<td>15.5%</td>
<td>0.8%</td>
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<td>Add: Productivity Savings</td>
<td>37,466,766</td>
<td>41,855,121</td>
<td>45,784,676</td>
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<tr>
<td>Productivity Percentage</td>
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<td>9.6%</td>
<td>9.3%</td>
<td>10.1%</td>
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<tr>
<td>OM&amp;A without Productivity</td>
<td>425,913,244</td>
<td>490,464,329</td>
<td>497,879,957</td>
<td>506,587,375</td>
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<tr>
<td>YoY growth</td>
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<td>15.2%</td>
<td>1.5%</td>
<td>1.7%</td>
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2.0 PRODUCTIVITY EFFICIENCY INITIATIVES

The Corporation’s strategic objectives include a commitment to achieve productivity and cost-effectiveness improvements. Table 1 identifies the major categories of productivity initiatives currently underway along with the estimated cost savings achieved from 2011 to 2013, and forecasted savings for 2014 to 2016 for Hydro One Transmission. While all savings estimates are for gross cost savings, it should be noted that the implementation costs are taken into consideration as part of the business planning process discussed in Exhibit A, Tab 16, Schedule 1.

Using the actual savings numbers from historical years (2011 to 2013) and the forecast savings for the bridge (2014) and test years (2015 and 2016), Hydro One Transmission will realize $308.7 million in savings. For initiatives that are common to Transmission and Distribution, a common cost allocation was used consistent with the Black and Veatch studies provided in Exhibit C1, Tab 6, Schedule 1 and Exhibit C1, Tab 6, Schedule 3. $199.9 million has been forecast in savings for the bridge and test years for Transmission as shown in Figure 1 and Table 2.
Figure 1:
Transmission Productivity Savings

* Total productivity savings for forecast years.

Table 2:
Total Annual Savings - Transmission ($ Million)

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<td>70.5</td>
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2.0 PRODUCTIVITY INITIATIVE KEY SUCCESS STORIES

This section discusses the productivity categories and provides greater detail on how Hydro One is making improvements in an effort to provide greater value to the customer. Some key success stories have been provided to demonstrate the commitment Hydro One has made to reduce costs and improve productivity while maintaining or improving its output.

2.1 Back Office

Back Office productivity initiatives are related to the reduction in costs of the administrative and support functions that have been outsourced. The savings are shown in Figure 2.

Figure 2:

Back Office Savings (in $Millions)
Hydro One negotiated a multi-year outsourcing contract for back office work programs primarily focused on information technology, call service operations, supply management services, finance and accounting, and payroll administration. The contract which was originally setup in 2002 had an established annual price decline for the baseline services. The contract was subsequently renegotiated in 2009 with an end date at the start of 2015. This extended contract included improved service levels and a steeper annual price decline for the five years as a result of negotiated cost reductions and commitments to new business system (SAP) implementation. Hydro One expects to continue to outsource back office elements beyond 2015 through a new competitively bid contract that will result in further savings as discussed in Exhibit C1, Tab 3, Schedule 2.

2.2 Business Transformation

Business Transformation productivity initiatives are business unit led large IT projects that streamline processes and increase efficiencies. The savings are shown in Figure 3.

Figure 3:
Business Transformation Savings (in $Millions)
Examples of Business Transformation Savings initiatives include:

- **Business Process Consolidation** - The automation of the current, very manual process for annually compiling budget baselines and preparing financial information. This initiative will reduce time and effort in the data handling as well as in the intensive quality assurance checking currently required.

- **Asset Analytics Value Realization** - The Asset Analytics Project is also part of the overall information technology (“IT”) strategy to improve business practices. Asset Analytics is a powerful software package that allows thorough analysis of the huge volume of Hydro One data. The system shows prioritized lists of assets requiring maintenance and/or replacement. Use of this tool will ensure asset investments will be made in areas that have the highest priority based on our system information. This will ensure the assets with the greatest need for maintenance or replacement are completed first which will avoid costly failures in the field that result in much higher costs and customer inconvenience. For further details on the Asset Analytics tool, see Exhibit A, Tab 16, Schedule 3.

- **Engineering Design Tools** - Hydro One is employing new engineering design tools such as the 3D Standardized Model-Based Design Application and the E3 Engineering Design Program. These new tools are used to streamline the design process and auto-wiring design application by automating complex, repetitive design and drafting tasks, which will ultimately ensure consistent quality and efficiency of the work execution. This will allow Hydro One to produce designs with greater accuracy and consistency in less time, thus realizing a productivity improvement cost savings. Standard designs also benefit the commissioning phase of an asset’s life. Further details can be found in Exhibit A, Tab 16, Schedule 6.
2.3 Telephony

Telephony productivity initiatives enhance and rationalize services to reduce the monthly expenses for phone and data services. The savings from this category are shown in Figure 4.

**Figure 4:**
Telephony Savings (in $Millions)

![Telephony Savings Chart]

Standardization of cell phone contracts through the adoption of Government subsidized cell phone plans are directly reducing costs by lowering voice and data rate plans and eliminating the paper billing process. Enhancements to telephone, video and web conferencing are reducing travel costs as more and more employees utilize the technology to replace costly physical meetings when appropriate. Utilization of the Telecom Expense Management software will enable Hydro One to rationalize the number of voice and data line circuits as well as power system circuits (e.g. metering, provincial mobile radios, station phones, SCADA and satellite) across the province.

2.4 Business Systems
Business Systems productivity initiatives encompass savings realized from the incorporation of more efficient processes facilitated by the installation of more technically advanced computer systems. The savings from the Business Systems category are shown in Figure 5.

Figure 5:
Business Systems (in $Millions)

Hydro One has replaced its main business systems with SAP and will continue to gain efficiencies from these improved systems. Implementation started in 2007 and the platform was completed in 2010. The system modules that were implemented include Work Management, Supply Chain, Finance, Project Systems and Payroll, realizing value in areas such as Productivity, Cost Effectiveness, Process Efficiency, Better Decision Making, Compliance and Employee Engagement. Since then the Business Consolidation, Customer Information System and Asset Analytics system modules have been implemented. Examples of savings being realized include:
• **Strategic Sourcing** - Considerable savings have been realized by consolidating purchases for volume discounts, ensuring maximum value for equipment life cycle, improving security of supply through longer term agreements and fixed pricing, better planning with supplier as well as streamlining standards which simplifies procurement and lowers inventory levels. Other Supply Chain efficiency initiatives include consolidated warehouse operations and an investment recovery program. For further details of Supply Chain productivity initiatives see Exhibit C1, Tab 5, Schedule 1.

• **Rationalization of Legacy IT Systems** - There has been a reduction in IT application, database, licensing fees and support costs with the decommissioning of over 450 business software applications and system tools. The replacement of PeopleSoft, Congo’s and SAS applications with modern Enterprise Resource Planning and Business Integration solutions has resulted in an integrated enterprise suite that has further enabled more effective information access and productivity within the company.

2.5 **Staff Flexibility**

Staff Flexibility productivity savings are realized from the more efficient use of skilled and non-skilled labour and through the use of Purchase Service Agreements (PSAs) signed with the Unions to clear backlogs. The transmission portion of the savings realized from cost efficiencies in the Staff Flexibility Savings category is shown in Figure 6.
Hydro One continues to capitalize on staffing resource availability. Where safe and possible, lower skilled and/or contract resources are used to undertake less complex work leaving highly skilled resources to focus on complex work activities. Better use of highly skilled labour in a supervisory role has increased work accomplishment capability. This has resulted in better prioritization and more cost effective completion of the work programs. For further details of the corporate staffing strategy see Exhibit C1, Tab 4, Schedule 1. Another example of staff flexibility savings includes the outsourcing of non-core Facilities operations.
2.6 Process Improvement

Hydro One has identified opportunities for improvement in internal processes including more thorough and interactive advanced planning on complex projects and optimal designs that can be determined prior to project approval. Advanced scheduling reduces potential design changes or rework. The cost efficiency savings due to process improvements is shown in Figure 7.

Figure 7:
Process Improvement Savings (in $Millions)

Hydro One is also implementing improved work methods in the field. For example:

- Local Material Stocking - The stocking of frequently used materials at strategic locations will reduce labour costs associated with material delays due to shortages or manufacturing lead time of materials. Hydro One is also realizing savings from
more efficient restocking of materials left over from major projects. See Exhibit C1, Tab 5, Schedule 1 for additional details.

- **Work Prioritization, Planning and Bundling** - An improved investment prioritization process that assesses asset risk as well as station-centric work releases for sustainment work, will allow Hydro One to utilize resources more efficiently as detailed on Exhibit A, Tab 16, Schedule 6.

- **Earlier and Multi-Year Work Releases** - Earlier and multi-year work releases for Sustainment capital and Operations, Maintenance and Administration (OM&A) programs will allow service groups to plan and execute work more efficiently, including scheduling work changes and outages when site conditions are optimal, as detailed on Exhibit A, Tab 16, Schedule 6.

### 2.7 Miscellaneous Administration

Miscellaneous Administration productivity savings are being recognized with tighter controls and better communication of requirements. The savings from miscellaneous administration processes are shown in Figure 8.
Over the past 3 years there have been administration cost decreases between three to five percent across business units. The main areas where reductions have been implemented are in travel, meals and mileage. This was accomplished by implementing spend limits on meals, fixed mileage rates that decrease with increased mileage and reduced travel expenses by reducing number and improving scheduling of meetings.

### 2.8 Leveraging Technology in the Field

Leveraging Technology productivity savings involves making better use of modern technology and equipment in order to accomplish work faster and more efficiently. Savings realized in this category are illustrated in Figure 9.
Examples of savings realized from the use of technology include:

**Global Positioning System (GPS) / Telematics** - The use of GPS/Telematics in Hydro One vehicles has allowed for improved travel time through planned route optimization. This leads to increased fuel efficiency and a reduction in greenhouse gases. It also allows for increased fleet response time, and automated tracking of vehicle condition. Hydro One is also using energy efficient vehicles and retrofitting facilities with energy efficient equipment where possible.

**Smart meter Network Operating (SMNO)** - Recent transformation in the electricity utility industry has been centered on Smart Grid. For Hydro One, Smart Grid commenced with the provincial smart meter mandate. Hydro One recognized that implementing smart meters in a primarily rural geography would be challenging due to the then-existing
limitations in metering technology and the lack of metering communications options for data transfer. Hydro One undertook to influence the market to develop robust back office metering solutions with standards-based communications to enable the daily aggregation of over a million meters. This culminated in Hydro One leading Canadian utilities in acquiring dedicated spectrum for the use of the electrical sector. The improved telecommunications reach and connectivity for critical electricity operations enabled the use of mobile technologies to optimize field work execution. It allows information, systems and tools to be available to the workforce when they need them and allows reporting of the completion of work in real-time thus getting information to asset planners and to customers in a more timely and accurate manner.

Work Program Optimization (Transmission System Outage Grouping – TSOG) - The optimization of the preventative maintenance work program by bundling will result in reduced outages, increased productivity per outage and increase the customer communication and involvement. This is further discussed in Exhibit A, Tab 4, Schedule 1.

2.9 Centralized Operations

Centralized Operations involve consolidating and reorganization groups within Hydro One to create efficiencies in work processes that lead to a reduction in labour time. Figure 10 depicts the savings from this category.
Hydro One is focusing on ensuring as much field work gets done as possible by centralizing and reducing support functions. For example;

- replacing classroom training with E-Learning courses designed to be completed online at times that do not interfere with critical work activities; and
- Leveraging the provincial government contract through the Ministry of Transportation Ontario to capitalize on additional fuel rebates.

### 3.0 SUMMARY

Hydro One is developing a culture where productivity, efficiency and the customer are considered in every corporate process, practice and policy. With better tracking of cost efficiencies and productivity, accountabilities and expectations, Hydro One will continue to strive to achieve its missions and vision as a company:

“We will be an innovative and trusted company, delivering electricity safely, reliably and efficiently to create value for our customers.”
COST OF CAPITAL

1.0 INTRODUCTION

The purpose of this evidence is to summarize the method and cost of financing Hydro One Transmission’s capital requirements for the 2015 and 2016 test years.

2.0 CAPITAL STRUCTURE

Hydro One Transmission’s deemed capital structure for rate making purposes is 60% debt and 40% common equity. This capital structure was approved by the Board as part of its December 23, 2010 Decision on Hydro One’s Transmission Rate Application (EB-2010-0002). This is consistent with the Board’s report on the cost of capital: see the Report of the Board on the Cost of Capital for Ontario’s Regulated Utilities dated December 11, 2009 (EB-2009-0084). The 60% debt component is comprised of 4% deemed short term debt and 56% long term debt.

3.0 RETURN ON COMMON EQUITY

Hydro One Transmission’s evidence reflects a return of 9.71% for the test year 2015 and 9.96% for the test year 2016, per the Board’s formulaic approach in Appendix B of the Cost of Capital Report dated December 11, 2009. For 2015 and 2016 the return on equity calculation is based on the October 2013 Long Term Consensus Forecast.

Hydro One assumes that the return on equity for each test year will be updated in accordance with the Cost of Capital Report, upon the final decision in this case. Specifically, for 2015, the Board would determine the ROE for Hydro One Transmission based on the September 2014 Consensus Forecasts and Bank of Canada data which would be available in October 2014. Similarly, the 2016 ROE would be updated to
reflect the September 2015 Consensus Forecasts and Bank of Canada data available in October 2015.

4.0 DEEMED SHORT-TERM DEBT

The Board has determined that the deemed amount of short-term debt that should be factored into rate setting be fixed at 4% of rate base. The Board has indicated in Appendix D of the December 11, 2009 Cost of Capital Report that, once a year, in January, Board Staff will obtain real market quotes from major banks, for issuing spreads over Bankers’ Acceptance (BA) rates to calculate an average spread. The short term debt rate will be calculated as the average BA rates for the 3 months in advance of the effective date for the rates, plus the average spread obtained as described above. Variable rate debt which pays interest based on the BA rate, has been included as part of the deemed short term debt amount of 4% of rate base. The deemed short-term rate is 3.19% for 2015 and 4.45% for 2016 using the June 2013 Global Insight BA rate plus the average annual BA spread as per the OEB’s Cost of Capital Parameters, dated February 14, 2013, for Rates Effective May 1, 2013. Hydro One assumes that the deemed short term debt rate for each test year will be updated in accordance with the Cost of Capital Report, upon the final decision in this case. Specifically, for 2015, the Board would determine the deemed short term debt rate for Hydro One Distribution based on the September 2014 Bank of Canada data which would be available in October 2014 plus the average spread obtained by Board Staff in 2014. Similarly, for 2016, the Board would determine the deemed short term debt rate for Hydro One Distribution based on the September 2015 Bank of Canada data which would be available in October 2015 plus the average spread obtained by Board Staff in 2015.

5.0 LONG-TERM DEBT

The Board has determined that the deemed amount of long-term debt that should be factored into rate setting be fixed at 56% of rate base. The long term debt rate is
calculated to be 5.02% for 2015 and 5.08% for 2016. The long term debt rate is calculated as the weighted average rate on embedded debt, new debt and forecast debt planned to be issued in 2014, 2015 and 2016 as discussed in Exhibit B1, Tab 2, Schedule 1. Details of Hydro One Transmission’s long term debt rate calculation for the 2015 and 2016 test years are identified at Exhibit B2, Tab 1, Schedule 2, pages 9 to 12. A detailed discussion of Hydro One Transmission's debt and forecast interest rate is provided at Exhibit B1, Tab 2, Schedule 1.

Historical long-term debt cost information is filed at Exhibit B2, Tab 1, Schedule 2, pages 1 to 12.

As discussed in this exhibit, forecast interest rates will be updated consistent with the methodology used for the return on common equity and deemed short term interest rate. In addition Hydro One assumes that long term debt rate will be updated to reflect and take into account the actual issuances of debt since the time of original application consistent with the OEB Decision on Hydro One Transmission 2013 and 2014 rate application in EB-2012-0031.

As Hydro One Transmission has a market determined cost of debt, the weighted average long term debt rate is also applied to any notional debt that is required to match the actual amount of long term debt to the deemed amount of long term debt consistent with the Board’s Decision in EB-2012-0031.

6.0 COST OF CAPITAL SUMMARY

Hydro One Transmission’s 2015 rate base is $10,176.5 million which results in an after-tax required return of 6.82%. The 2016 rate base is $10,558.0 million, which results in an after-tax required return of 7.01%, as shown in Table 1, below:
## Table 1

### 2015 and 2016 Cost of Capital

<table>
<thead>
<tr>
<th>Amount of Deemed</th>
<th>2015</th>
<th></th>
<th></th>
<th>2016</th>
<th></th>
<th></th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>($M)</td>
<td>%</td>
<td>Rate (%)</td>
<td>($M)</td>
<td>%</td>
<td>Rate (%)</td>
</tr>
<tr>
<td>Long-term debt</td>
<td>5,698.8</td>
<td>56.0%</td>
<td>5.02%</td>
<td>5,912.5</td>
<td>56.0%</td>
<td>5.08%</td>
</tr>
<tr>
<td>Short-term debt</td>
<td>407.1</td>
<td>4.0%</td>
<td>3.19%</td>
<td>422.3</td>
<td>4.0%</td>
<td>4.45%</td>
</tr>
<tr>
<td>Common equity</td>
<td>4,070.6</td>
<td>40.0%</td>
<td>9.71%</td>
<td>4,223.2</td>
<td>40.0%</td>
<td>9.96%</td>
</tr>
<tr>
<td>Total</td>
<td>10,176.5</td>
<td>100.0%</td>
<td>6.82%</td>
<td>10,558.0</td>
<td>100.0%</td>
<td>7.01%</td>
</tr>
</tbody>
</table>

Historical, bridge and test year debt and equity summary schedules have been provided at Exhibit B2, Tab 1, Schedule 1.
COST OF THIRD PARTY LONG-TERM DEBT

1.0 HYDRO ONE TRANSMISSION LONG-TERM DEBT

The debt portfolio for Hydro One Transmission, as set out in Exhibit B2, Tab 1, Schedule 2, is based on debt issued by Hydro One Networks Inc. to Hydro One Inc., of which the Transmission business is mapped a portion. Hydro One Networks Inc. issues debt to Hydro One Inc., reflecting debt issues by Hydro One Inc. to third party public debt investors.

Third party public debt investors hold all of the long term debt issued by Hydro One Inc. Hydro One Inc.’s debt financing strategy takes into consideration the objectives of cost effectiveness, distributing debt maturities evenly over time, and ensuring the term of the debt portfolio is compatible with the long life of the Company’s assets.

Hydro One Inc. has a Medium Term Note ("MTN") Program that provides ready access to issue debt with a term greater than one year into the Canadian debt capital markets. The standard maturity terms in the area of five, ten and thirty years are preferred by investors and represent the main financing which Hydro One Inc. utilizes to execute its financing strategy and raise the required funds. The short form base shelf prospectus for the current $3.0 billion MTN Program is provided in Exhibit A, Tab 13, Schedule 2.

2.0 CREDIT RATINGS

As Hydro One Inc. issues medium term notes in the Canadian public debt markets, credit ratings are a requirement. The credit ratings of Hydro One Inc.’s debt obligations by Dominion Bond Rating Service, Moody’s Investors Service and Standard & Poor’s Rating Services are as follows:
Table 1
Credit Ratings for Hydro One Inc.

<table>
<thead>
<tr>
<th>Rating Agency</th>
<th>Short-term Debt</th>
<th>Debt</th>
</tr>
</thead>
<tbody>
<tr>
<td>Standard &amp; Poor’s Rating Services (S&amp;P)</td>
<td>A-1</td>
<td>A+</td>
</tr>
<tr>
<td>Dominion Bond Rating Service (DBRS)</td>
<td>R-1(middle)</td>
<td>A(high)</td>
</tr>
<tr>
<td>Moody’s Investors Service (Moody’s)</td>
<td>Prime-1</td>
<td>A1</td>
</tr>
</tbody>
</table>

The most recent rating agency reports are provided in Exhibit A, Tab 12, Schedule 1.

3.0 COST OF LONG-TERM DEBT

The long term debt rate is calculated as the weighted average rate on embedded debt, new debt and forecast debt planned to be issued in 2014, 2015 and 2016. The weighted average rate on long term debt rate is 5.02% for 2015 and 5.08% for 2016. Details of Hydro One Transmission’s long term debt rate calculation for the 2014 bridge year and 2015 and 2016 test years are identified at Exhibit B2, Tab 1, Schedule 2, pages 9 to 12.

The amount of each Hydro One Networks Inc. debt issue that is mapped to the Transmission business is based on its most recent forecast of borrowing requirements. Borrowing requirements are driven mainly by debt retirement, capital expenditures net of internally generated funds, and the maintenance of its capital structure. For example, in January of 2012, Hydro One Inc. issued $300 million of ten-year notes with a 3.20% coupon rate, of which $154 million was mapped to Hydro One Transmission, as shown on line 25 of Exhibit B2, Tab 1, Schedule 2, page 10.

The interest rates of debt issues mapped to the Transmission business, as shown in Exhibit B2, Tab 1, Schedule 2, are equal to the actual interest rates on debt issued by
Hydro One Networks Inc. to Hydro One Inc., and by Hydro One Inc. to third party public debt investors.

3.1 Embedded Debt

The Board has determined in its Cost of Capital Report that for embedded debt, the rate approved in prior Board decisions shall be maintained for the life of each active instrument, unless a new rate is negotiated, in which case it will be treated as new debt. Hydro One Transmission’s embedded long term debt, which was issued during the period from 2000 to 2013, is shown on lines 1 to 34 of Exhibit B2, Tab 1, Schedule 2, page 5 to 6. The rates on these embedded debt issues were approved by the Board as part of the Board’s 2014 Rate Order in EB-2012-0031, dated January 9, 2014.

3.2 New Debt

The Board has determined in its Cost of Capital Report that the rate for new debt that is held by a third party will be the prudently negotiated contract rate. This would include recognition of premiums and discounts.

3.3 Forecast Debt

Hydro One Transmission’s forecast borrowing requirements are $206 million for 2014, $478 million for 2015 and $592 million for 2016. For planning purposes it is assumed that debt issuance will be evenly distributed over the standard terms in the area of five, ten and thirty years, which are preferred by investors, while limiting total annual maturities for Hydro One Inc. to $750 million to avoid undue refinancing risk. Table 2 lists the fixed rate MTN's which Hydro One Networks Inc. plans to issue in 2014, and will be mapped to the Transmission business, as shown on lines 33 to 35 of Exhibit B2, Tab 1, Schedule 2, page 8.
Table 2
Forecast Debt Issues for remainder of 2014

<table>
<thead>
<tr>
<th>Principal Amount ($Millions)</th>
<th>Term (Years)</th>
<th>Coupon</th>
</tr>
</thead>
<tbody>
<tr>
<td>68.5</td>
<td>5</td>
<td>3.10%</td>
</tr>
<tr>
<td>68.5</td>
<td>10</td>
<td>4.09%</td>
</tr>
<tr>
<td>68.5</td>
<td>30</td>
<td>4.93%</td>
</tr>
</tbody>
</table>

Table 3 lists the fixed rate MTN's which Hydro One Networks Inc. plans to issue in 2015, and 2016 will be mapped to the Transmission business, as shown on lines 34 to 39 of Exhibit B2, Tab 1, Schedule 2, page 12.

Table 3
Forecast Debt Issues for 2015 and 2016

<table>
<thead>
<tr>
<th>Principal Amount ($Millions)</th>
<th>Term (Years)</th>
<th>Coupon</th>
<th>Principal Amount ($Millions)</th>
<th>Term (Years)</th>
<th>Coupon</th>
</tr>
</thead>
<tbody>
<tr>
<td>159.3</td>
<td>5</td>
<td>3.80%</td>
<td>197.5</td>
<td>5</td>
<td>4.30%</td>
</tr>
<tr>
<td>159.3</td>
<td>10</td>
<td>4.79%</td>
<td>197.5</td>
<td>10</td>
<td>5.29%</td>
</tr>
<tr>
<td>159.3</td>
<td>30</td>
<td>5.63%</td>
<td>197.5</td>
<td>30</td>
<td>6.13%</td>
</tr>
</tbody>
</table>

3.3 Interest Rates for 2014, 2015 and 2016 Forecast Debt Issues

Transmission business borrowing will be financed at market rates applicable to Hydro One Inc. Table 4 summarizes the derivation of the forecast Hydro One Inc. yield for each of the planned issuance terms for 2014, 2015 and 2016.
Table 4
Forecast Yield for 2014-2016 Issuance Terms

<table>
<thead>
<tr>
<th></th>
<th>2014</th>
<th></th>
<th></th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>5-year</td>
<td>10-year</td>
<td>30-year</td>
</tr>
<tr>
<td>Government of Canada</td>
<td>2.23%</td>
<td>2.90%</td>
<td>3.40%</td>
</tr>
<tr>
<td>Hydro One Spread</td>
<td>0.87%</td>
<td>1.19%</td>
<td>1.53%</td>
</tr>
<tr>
<td>Forecast Hydro One Yield</td>
<td>3.10%</td>
<td>4.09%</td>
<td>4.93%</td>
</tr>
</tbody>
</table>

<table>
<thead>
<tr>
<th></th>
<th>2015</th>
<th></th>
<th></th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>5-year</td>
<td>10-year</td>
<td>30-year</td>
</tr>
<tr>
<td>Government of Canada</td>
<td>2.93%</td>
<td>3.60%</td>
<td>4.10%</td>
</tr>
<tr>
<td>Hydro One Spread</td>
<td>0.87%</td>
<td>1.19%</td>
<td>1.53%</td>
</tr>
<tr>
<td>Forecast Hydro One Yield</td>
<td>3.80%</td>
<td>4.79%</td>
<td>5.63%</td>
</tr>
</tbody>
</table>

<table>
<thead>
<tr>
<th></th>
<th>2016</th>
<th></th>
<th></th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>5-year</td>
<td>10-year</td>
<td>30-year</td>
</tr>
<tr>
<td>Government of Canada</td>
<td>3.43%</td>
<td>4.10%</td>
<td>4.60%</td>
</tr>
<tr>
<td>Hydro One Spread</td>
<td>0.87%</td>
<td>1.19%</td>
<td>1.53%</td>
</tr>
<tr>
<td>Forecast Hydro One Yield</td>
<td>4.30%</td>
<td>5.29%</td>
<td>6.13%</td>
</tr>
</tbody>
</table>

Each rate is comprised of the forecast Canada bond yield plus the Hydro One Inc. credit spread applicable to that term. The ten-year Government of Canada bond yield forecast for 2014 is based on the average of the 3 month and 12 month forecast from the September 2013 Consensus Forecast. The ten-year Government of Canada bond yield forecast for 2015 and 2016 is based on the average of the October 2013 Long Term Consensus Forecast. The five- and 30-year Government of Canada bond yield forecasts are derived by adding the September, 2013 average spreads (five-year to ten-year for the five-year forecast and 30-year to ten-year for the 30-year forecast) to the ten-year Government of Canada bond yield forecast. Hydro One’s credit spreads over the Government of Canada bonds are based on the average of indicative new issue spreads for September, 2013 obtained from the Company's MTN dealer group for each planned issuance term.

Hydro One assumes that forecast debt issuance interest rates for each test year will be updated consistent with the ROE methodology, upon the final decision in this case. For
rates effective January 1, 2015, the forecast interest rate for Hydro One Transmission
debt issues will be based on the September 2014 Consensus Forecasts and the average of
indicative new issue spreads for September 2014 which will be obtained from the
Company's MTN dealer group for each planned issuance term. For rates effective
January 1, 2016, the forecast interest rate for Hydro One Transmission debt issues will be
based on the September 2015 Consensus Forecasts and the average of indicative new
issue spreads for September 2015 which will be obtained from the Company's MTN
dealer group for each planned issuance term. In addition Hydro One assumes that long
term debt rate will be updated to reflect and take into account the actual issuances of debt
since the time of original application consistent with the OEB’s Decision on Hydro One
Transmission’s 2013 and 2014 rate application in EB-2012-0031 and changes in the
interest rate forecast.

3.4 Treasury OM&A Costs

Treasury OM&A costs are incurred to:

- execute borrowing plans and issue commercial paper and long term debt;
- ensure compliance with securities regulations, bank and debt covenants;
- manage the company’s daily liquidity position, control cash and manage the
  company’s bank accounts;
- settle all transactions and manage the relationship with creditors; and
- communicate with debt investors, banks and credit rating agencies.

These costs are $1.6 million for both 2015 and for 2016 as shown on line 39, page 10 and
line 41, page 12 of Exhibit B2, Tab 1, Schedule 2.
3.5 Other Financing-Related Fees

Column (e) of Exhibit B2, Tab 1, Schedule 2 ("Premium, Discount and Expenses") represents the costs of issuing debt. These costs are specific to each debt issue and include commissions, legal fees, debt discounts or premiums on issues or re-openings of issues relative to par, and hedge gains or losses.

Other financing related fees, $2.9 million in 2015 and $3.0 million 2016, identified on line 40, page 10 and line 42, page 12 of Exhibit B2, Tab 1, Schedule 2, include the Transmission allocation of Hydro One Inc.’s standby credit facility, annual credit rating agency, banking, custodial and trustee fees.
SUMMARY OF OM&A EXPENDITURES

1.0 SUMMARY OF OM&A EXPENDITURES

The proposed OM&A expenditures result from a rigorous business planning and work prioritization process that reflects risk-based decision making to ensure that the most appropriate, cost effective solutions are put in place. This process is described in detail at Exhibit A, Tab 16.

The proposed OM&A programs represent the work required to meet public and employee safety objectives, maintain transmission reliability at targeted performance levels, and to comply with regulatory requirements (such as specified within the Transmission System Code), environmental requirements and Government direction.

The development of asset maintenance programs, as described in the following schedules of this Exhibit, is based on equipment specifications coupled with comprehensive asset condition information, as well as information on asset demographics, component performance and reliability, and equipment utilization.

Hydro One Transmission’s OM&A budget is grouped into different investment categories: Sustaining, Development, Operations, Customer Care, Common Corporate and Taxes Other than Income Taxes. Table 1 provides a summary of Hydro One Transmission’s OM&A expenditures for the historical, bridge and test years.
Table 1
Summary of Transmission OM&A Budget ($ Million)

<table>
<thead>
<tr>
<th>Description</th>
<th>Historic</th>
<th>Bridge</th>
<th>Test</th>
</tr>
</thead>
<tbody>
<tr>
<td>Sustaining</td>
<td>227.6</td>
<td>204.7</td>
<td>221.0</td>
</tr>
<tr>
<td>Development</td>
<td>12.6</td>
<td>8.5</td>
<td>8.6</td>
</tr>
<tr>
<td>Operations</td>
<td>57.3</td>
<td>54.8</td>
<td>56.7</td>
</tr>
<tr>
<td>Customer Care</td>
<td>5.2</td>
<td>4.4</td>
<td>5.3</td>
</tr>
<tr>
<td>Common Corporate and Other OM&amp;A</td>
<td>44.2</td>
<td>80.7</td>
<td>75.8</td>
</tr>
<tr>
<td>Property Taxes &amp; Rights Payments</td>
<td>67.5</td>
<td>62.1</td>
<td>21.2</td>
</tr>
<tr>
<td>TOTAL</td>
<td>414.5</td>
<td>415.2</td>
<td>388.4</td>
</tr>
</tbody>
</table>

Total OM&A expenditures for test year 2015 are forecast to increase by $3.5 million, or approximately 0.8% over the 2014 bridge year. Total OM&A expenditures for test year 2016 are forecast to increase by $5.4 million, or 1.2%, over 2015. The test year expenditures are required to address the increasing maintenance requirements of an aging and expanding transmission system.

2.0 SUSTAINING

The Sustaining OM&A budget represents investments required to maintain existing transmission lines and stations facilities so that they will continue to function as originally designed. The proposed investments are intended to ensure that the overall reliability of the system is maintained, that customer commitments are achieved, and that all legislative, regulatory, environmental and safety requirements are met. Details are provided at Exhibit C1, Tab 2, Schedule 2.
3.0 DEVELOPMENT

The Development OM&A budget funds research and development, as well as the development of new standards. The Development OM&A is described in detail at Exhibit C1, Tab 2, Schedule 3.

4.0 OPERATIONS

The Operations OM&A program represents the annual expenditures required for the Central Transmission Operations function, operated out of Hydro One's Ontario Grid Control Centre. The Transmission Operations function is concerned with the real time operations of the Hydro One Transmission system equipment, including the monitoring, control, detection and response to equipment operational issues. Details of the expenditures under this program are filed at Exhibit C1, Tab 2, Schedule 4.

5.0 CUSTOMER CARE OM&A

Hydro One Transmission’s Customer Service OM&A investments fund work activities required to develop, implement and monitor the Corporation’s plans to positively influence customer relationships and ensure affordability and overall value for the products and services offered to them. These work activities will enable Hydro One to foster a relationship based on transparency and trust. Details of the expenditures under this program are filed at Exhibit C1, Tab 2, Schedule 5.

6.0 COMMON CORPORATE COSTS AND OTHER OM&A

The Common Corporate Costs and other OM&A program includes: Common Corporate Functions and Services (CCFS), Asset Management, Information Technology, Cornerstone, Cost of Sales and Other OM&A expenses. CCFS includes Corporate
Management, Finance, Human Resources, Corporate Communications and Services, Legal, Regulatory Affairs, Corporate Security, Internal Audit and Real Estate. Common Asset Management services include System Investment, Business Performance, and Asset Strategies. IT and Cornerstone activities include providing and managing computer systems (for example, hardware and software) and IT infrastructure. Other OM&A programs include credits for overheads capitalized as capital projects are built and the cost of goods sold in support of external revenues. Details of the expenditures under this program are filed at Exhibit C1, Tab 3, Schedules 1 through 6.

7.0  TAXES OTHER THAN INCOME TAXES

This program consists of property and proxy taxes, and indemnity payments to the Province. Details of the expenditures under this program are filed at Exhibit C1, Tab 3, Schedule 7.

8.0  COMPARISON OF OM&A COSTS TO BOARD APPROVED

Table 2 compares 2013 actual costs to the 2013 OM&A expenditures approved by the Board in their Decision on Hydro One Transmission’s previous application in Proceeding EB-2012-0031.
Table 2

2013 Board Approved versus 2013 Actual OM&A Expenditures

<table>
<thead>
<tr>
<th>OM&amp;A Categories</th>
<th>2013 Board Approved ($ million)</th>
<th>2013 Actuals ($ million)</th>
<th>Variance ($ million)</th>
</tr>
</thead>
<tbody>
<tr>
<td>Sustaining</td>
<td>235.7</td>
<td>221.0</td>
<td>(14.8)</td>
</tr>
<tr>
<td>Development¹</td>
<td>13.7</td>
<td>8.6</td>
<td>(5.1)</td>
</tr>
<tr>
<td>Operations</td>
<td>57.7</td>
<td>56.7</td>
<td>(1.0)</td>
</tr>
<tr>
<td>Customer Care</td>
<td>4.9</td>
<td>5.3</td>
<td>0.4</td>
</tr>
<tr>
<td>Common Corporate &amp; Other Costs</td>
<td>61.9</td>
<td>75.8</td>
<td>13.9</td>
</tr>
<tr>
<td>Taxes other than Income Taxes</td>
<td>66.0</td>
<td>21.2</td>
<td>(44.8)</td>
</tr>
<tr>
<td>Total OM&amp;A</td>
<td><strong>440.3</strong></td>
<td><strong>388.4</strong></td>
<td><strong>(51.6)</strong></td>
</tr>
</tbody>
</table>

Hydro One Transmission’s actual 2013 OM&A costs were $51.6 million lower than the $440.3 million approved by the Board in Proceeding EB-2012-0031. The reduction in the Sustaining, Development, and Operations work program spend reflects Cornerstone savings (both are included in the Board Approved Shared Services and Other total in Table 2). The large reduction in the Taxes other than Income Taxes area is mainly because the company recognized a one-time Property tax rebate in 2013.

Table 3 compares 2014 projected costs to the 2014 OM&A expenditures approved by the Board in their Decision on Hydro One Transmission’s previous application in EB-2012-0031.

¹ Development costs are net of Licence Amendment to Upgrade TS’s to Facilitate Renewable Generation amounts
Table 3

2014 Board Approved versus 2014 Projected OM&A Expenditures

<table>
<thead>
<tr>
<th>OM&amp;A Categories</th>
<th>2014 Board Approved ($ million)</th>
<th>2014 Projected ($ million)</th>
<th>Variance ($ million)</th>
</tr>
</thead>
<tbody>
<tr>
<td>Sustaining</td>
<td>246.5</td>
<td>236.2</td>
<td>(10.3)</td>
</tr>
<tr>
<td>Development(^2)</td>
<td>14.7</td>
<td>12.9</td>
<td>(1.8)</td>
</tr>
<tr>
<td>Operations</td>
<td>58.0</td>
<td>57.4</td>
<td>(1.6)</td>
</tr>
<tr>
<td>Customer Care</td>
<td>4.7</td>
<td>5.8</td>
<td>1.1</td>
</tr>
<tr>
<td>Common Corporate &amp; Other Costs</td>
<td>59.0</td>
<td>70.6</td>
<td>11.6</td>
</tr>
<tr>
<td>Taxes other than Income Taxes</td>
<td>66.8</td>
<td>65.6</td>
<td>(1.2)</td>
</tr>
<tr>
<td><strong>Total</strong></td>
<td><strong>449.7</strong></td>
<td><strong>448.5</strong></td>
<td><strong>(1.2)</strong></td>
</tr>
</tbody>
</table>

Hydro One Transmission’s projected 2014 OM&A costs are $1.2 million less than the $449.7 million approved by the Board in Proceeding EB-2012-0031. The 2014 Board Approved amounts include the envelope OM&A adjustment as part of the settlement in EB-2012-0031.

The reduction in the Sustaining, Development, and Operations work program spend was driven by the need to stay within the overall Transmission business OM&A envelope approved in the Board’s last Decision, and also reflects Cornerstone savings. These variances are partially offset by an increase in Common Corporate and Other Costs primarily in the Real Estate and Facilities area.

\(^2\) Development costs are net of Licence Amendment to Upgrade TS’s to Facilitate Renewable Generation amounts
1.0 INTRODUCTION

Sustaining OM&A consists of expenditures required to maintain existing transmission system facilities so that they continue to function as originally designed. The expenditures covered under Sustaining OM&A are intended to maintain equipment performance at appropriate levels, thereby maintaining the overall reliability and service quality while satisfying all legislative, regulatory, environmental and safety requirements.

Hydro One Transmission manages its Sustaining OM&A program by dividing the program expenditures into three categories:

- **Stations**, which funds the work required to maintain existing assets located within transmission stations including existing protection, control, and telecommunication facilities;

- **Lines**, which funds the work required to maintain overhead transmission lines and underground cables, including vegetation management on transmission line rights-of-way;

- **Engineering and Environmental Support**, which funds the specialized and administrative support needed to assist with decision making processes in managing the transmission assets.

A summary of Hydro One Transmission’s Sustaining OM&A programs and proposed spending levels for the test years 2015 and 2016 are described herein.
2.0 SUSTAINING OM&A SUMMARY

The rigorous investment planning, prioritization and approval process described in Exhibit A, Tab 16, Schedules 1 to 5, has been completed for all Sustaining OM&A programs to ensure that assets are managed prudently while meeting customer, operational and regulatory needs.

The selection of planned Sustaining OM&A investments is guided by the asset risk assessment process described in Exhibit A, Tab 16, Schedule 7. This process takes into account the condition, age, performance, criticality and utilization of specific assets. An economic evaluation is also performed as part of the process. At times, the economic evaluation may determine that it is more cost-effective to replace an asset rather than to continue to repair or maintain it. These capital replacement activities are described in Exhibit D1, Tab 3, Schedule 2.

Sustaining transmission assets is essential to the long term viability and performance of these assets and this is reinforced by the Transmission System Code that requires Hydro One Transmission to “inspect, test and monitor its transmission facilities to ensure continued compliance with all applicable standards and instruments”. Over the long term, an adequately maintained transmission system that performs to a level of its original design is in the best interest of Hydro One Transmission and its customers. As outlined in Exhibit D1, Tab 2, Schedule 1, a greater portion of Hydro One’s transmission system is reaching an age where the deterioration in condition is taking place at an increasing rate. This will place added cost pressures on future maintenance programs to maintain equipment performance and reliability until such time that the assets can be replaced. In addition, the transmission system continues to expand and there is a need for increased maintenance expenditures when these new assets are placed into service. At the same time, Hydro One Transmission is continuously looking for improvement opportunities that improve the Hydro One transmission system, minimizing risk and adding value for
Hydro One’s customers. OM&A expenditures proposed in this exhibit will sustain the assets needs over the test years. It must be recognized that any reductions applied to the test years spending will have a compounding effect on cost pressures in the future.

The required funding for the Sustaining OM&A in the test years, along with the spending levels for the bridge and historic years are provided in Table 1 for each of the major sustaining categories.

<table>
<thead>
<tr>
<th>Description</th>
<th>Historic Years</th>
<th>Bridge Year</th>
<th>Test Years</th>
</tr>
</thead>
<tbody>
<tr>
<td>Stations</td>
<td>166.2</td>
<td>146.5</td>
<td>159.9</td>
</tr>
<tr>
<td>Lines</td>
<td>49.4</td>
<td>48.6</td>
<td>50.4</td>
</tr>
<tr>
<td>Engineering and Environmental Support</td>
<td>12.0</td>
<td>9.5</td>
<td>10.7</td>
</tr>
<tr>
<td>Total</td>
<td>227.6</td>
<td>204.7</td>
<td>221.0</td>
</tr>
</tbody>
</table>

The overall Sustaining OM&A requirements for the test year 2015 have increased 1% over projected spending in the bridge year 2014. The spending requirements for 2016 continue to increase by 1% over the 2015 requirements. The increase in overall spending in the test years relative to historic and bridge year expenditures is largely attributed to:

- Increased environmental remediation work to deal with legacy contamination in transmission stations; and
- Increased work in the area of cyber security following approval of the North American Electric Reliability Corporation (NERC) Critical Infrastructure Protection (CIP) Version 5 standards.

While some Sustaining programs are growing through the test years due to asset demographics and regulatory requirements (as mentioned above), a number of initiatives
are being undertaken to contain increases in maintenance costs associated with the aging system and increased regulatory requirements. These include:

- Optimized maintenance frequencies impacting overall costs and resource utilization, and additional moves to condition based maintenance;
- Increased bundling opportunities through alignment of maintenance activities and improved visibility of bundling opportunities. These provide efficiencies in the planning and execution of outages as well as with staff mobilization; and
- Increased capital replacement of assets mitigating the need for increases in corrective maintenance costs and equipment refurbishment activities through addressing worse performing assets and facilitating the integration of new equipment with lower lifecycle maintenance costs.

### 3.0 STATIONS

Transmission Station facilities are used for the delivery of power, voltage transformation, switching, and serve as connection points for both load customers and generators. Station facilities contain many of the following major components: power transformers, circuit breakers, disconnect switches, bus work, insulators, potheads, surge arrestors, capacitor banks, reactors, instrument devices, protection and control systems, station service systems, grounding systems, site infrastructure and buildings.

Stations Sustaining OM&A funding covers expenditures required to maintain the performance of the assets located within transmission stations. Hydro One Transmission manages its Stations Sustaining OM&A program by dividing the program into six categories:

1. **Land Assessment and Remediation**, a specific program that focuses on identification, mitigation and remediation of historical contamination located both inside and outside the station fence;
2. **Environmental Management**, an on-going program that focuses on the mitigation and remediation of contamination located both inside and outside the station fence and manages, tests for and disposes of PCB and other regulated waste that develops as part of Hydro One Transmission’s normal business practices;

3. **Power Equipment Maintenance**, which focuses on sustaining power equipment performance through planned and corrective maintenance work and equipment refurbishment;

4. **Ancillary Systems Maintenance**, which focuses on sustaining the performance of ancillary systems through planned and corrective maintenance work;

5. **Protection, Control, Monitoring, Metering and Telecommunications Maintenance**, which focuses on sustaining the power system protection, control, monitoring, metering and telecommunication facilities through planned and corrective maintenance work and providing Hydro One Transmission with the information, and communication necessary to operate the transmission system; and

6. **Site Infrastructure Maintenance**, which focuses on maintaining the infrastructure at stations through planned and corrective maintenance work.

Required funding for the test years 2015 and 2016, along with the spending levels for the bridge and historic years are provided in Table 2 for each of these categories.
<table>
<thead>
<tr>
<th>Description</th>
<th>Historic Years</th>
<th>Bridge Year</th>
<th>Test Years</th>
</tr>
</thead>
<tbody>
<tr>
<td>Land Assessment and Remediation</td>
<td>1.5</td>
<td>1.9</td>
<td>3.1</td>
</tr>
<tr>
<td>Environmental Management</td>
<td>15.2</td>
<td>11.3</td>
<td>11.9</td>
</tr>
<tr>
<td>Power Equipment Maintenance</td>
<td>68.1</td>
<td>55.7</td>
<td>60.2</td>
</tr>
<tr>
<td>Ancillary Systems Maintenance</td>
<td>11.2</td>
<td>10.1</td>
<td>10.1</td>
</tr>
<tr>
<td>Protection, Control, Monitoring, Metering and Telecommunications Maintenance</td>
<td>43.9</td>
<td>44.9</td>
<td>49.4</td>
</tr>
<tr>
<td>Site Infrastructure Maintenance</td>
<td>26.4</td>
<td>22.7</td>
<td>25.2</td>
</tr>
<tr>
<td><strong>Total</strong></td>
<td><strong>166.2</strong></td>
<td><strong>146.5</strong></td>
<td><strong>159.9</strong></td>
</tr>
</tbody>
</table>

The overall Stations Sustaining OM&A expenditures for the test year 2015 have increased 2% over projected spending in 2014. The spending requirements for 2016 continue to increase by approximately 2% over the 2015 requirements. Spending increases are in areas including:

- Cyber Security of protection, control, and telecommunications assets, which is required to meet NERC regulatory requirements, and
- Mitigation and remediation work which is required to address contamination resulting from past operations.

### 3.1 Land Assessment and Remediation

#### 3.1.1 Introduction

The Land Assessment and Remediation (“LAR”) program is primarily focused on the mitigation and remediation of historical discharge of contaminants from transmission station sites that may pose a risk to the public or Hydro One Transmission staff. On-site management controls are typically implemented to eliminate or mitigate on-site
contamination that could result in unacceptable risks to staff, the public and/or the environment should no action be taken.

As a responsible steward committed to protecting the environment for current and future generations, Hydro One Transmission manages its operations in an environmentally responsible manner. The LAR program meets Hydro One Transmission’s environmental policy objectives by assessing and mitigating on and off property historical contamination at transmission station sites. The LAR program also funds assessment and remediation work to address contamination at real estate facilities which include field service centres, administrative buildings and garage facilities.

3.1.2 Investment Plan

The LAR program utilizes a multi-phased approach involving successive levels of environmental site assessments, risk evaluation and prioritization, and remedial option evaluations leading to the selection of the preferred remedial or mitigating solution. The prioritization and selection process for environmental site assessment and remediation work is based on two factors: type and level of contamination that exceeds Ministry of the Environment (“MOE”) standards; and the potential for the contaminants to cause adverse effects on human health and/or the environment. The MOE supports Hydro One Transmission's risk-based approach and planned programs.

The LAR program consists of: Site Management, Site Assessment, and Remediation work. Site management is required once a site has been assessed or remediated, as there are often regulatory requirements imposed by the MOE to monitor groundwater quality in the area of the former contamination to ensure that groundwater is not impacted. The station-specific groundwater monitoring program may be required for a period of 3 to 5 years, and typically involves well installations, MOE registration, groundwater measurements and sample analysis, and eventual decommissioning of the monitoring
wells. Site management plans are developed to monitor and manage residual on-site contamination and to manage installed controls, such as barriers and long-term treatment systems.

Site assessment is planned at a number of transmission stations that have been identified as potential remediation sites. The assessment involves gathering information to identify actual or potential contamination and sources of contamination. This is done through a review of the site records, previous environmental reports and by analyzing soil and groundwater extracted from and around Hydro One Transmission properties. Soil and water samples are taken as surface grab samples or by drilling to obtain samples from various depths. The information is analysed, risks assessed and sites prioritized for remediation. Considering the 2011 update to the regulations that placed a higher standard for environmental management, it is expected that the outcome of the work planned in the test years will result in increased future expenditures to address those sites determined to be contaminated above thresholds.

Where contamination is identified, a remediation plan is developed and implemented to treat, remove or otherwise manage the contamination. The primary focus of the LAR program is to address off-site impacts and mitigate or manage on-site contamination. Where appropriate, co-ordination of LAR work with end of life refurbishment and capital upgrade projects are considered.
3.1.3 Summary of Expenditures

The planned expenditure for 2015 and 2016 is $3.1 million and $2.9 million respectively. Spending on this program fluctuates year to year depending on the number of sites selected for remediation and the extent of the remediation work required at each site to meet environmental obligations. When expenditures in this program are incurred, there is a corresponding credit to OM&A to demonstrate the fact that the cost is reflected in revenue requirement as an amortization expense and not as OM&A, as detailed in Exhibit C1, Tab 7, Schedule 1.

A reduction in this program may impact Hydro One Transmission’s ability to maintain compliance with MOE requirements, and will result in deferral of prudent remediation activities that could have financial and environmental impacts to Hydro One Transmission properties and neighbouring sites in future years.

3.2 Environmental Management

3.2.1 Introduction

Environmental Management focuses on mitigation and remediation of contamination located both inside and outside the station fence. This program enables Hydro One Transmission to satisfy obligations relating to environmental regulations and environmental policies pertaining to transmission station equipment.
3.2.2 Investment Plan

The Environmental Management program consists of four activities. Table 3 outlines the proposed funding for the test years 2015 and 2016, along with the spending levels for the bridge and historic years for each category.

<table>
<thead>
<tr>
<th>Description</th>
<th>Historic Years</th>
<th>Bridge Year</th>
<th>Test Years</th>
</tr>
</thead>
<tbody>
<tr>
<td>PCB Retirement and Waste Management</td>
<td>5.2</td>
<td>4.3</td>
<td>5.2</td>
</tr>
<tr>
<td>Transformer Oil Leak Reduction</td>
<td>2.2</td>
<td>2.4</td>
<td>3.2</td>
</tr>
<tr>
<td>Preventive and Corrective Maintenance</td>
<td>6.8</td>
<td>3.4</td>
<td>2.7</td>
</tr>
<tr>
<td>Environmental Compliance and Emergency Response Plan Updates</td>
<td>0.9</td>
<td>1.1</td>
<td>0.8</td>
</tr>
<tr>
<td><strong>Total</strong></td>
<td><strong>15.2</strong></td>
<td><strong>11.3</strong></td>
<td><strong>11.9</strong></td>
</tr>
</tbody>
</table>

PCB Retirement and Waste Management

In response to Environment Canada’s PCB Regulations enacted in 2009, Hydro One Transmission initiated the PCB retirement program to identify and phase-out its PCB inventory to comply with the regulation’s end-of-use requirements. In accordance with the regulations, oil-filled power equipment (transformers, breakers, instrument transformers, and associated capacitors, bushings, reclosers) located at Hydro One’s transmission stations that contain greater than 500 ppm PCB are to be retro-filled or replaced by December 31, 2014 (based on an extension granted to Hydro One by Environment Canada). Furthermore, the regulation also mandated that oil-filled power equipment that contain greater than 50 ppm PCB are to be retro-filled or replaced by December 31, 2025.
Hydro One Transmission and CEA-member utilities are lobbying for a regulatory amendment related to bushings and instrument transformers containing greater than 500 ppm PCB contamination due to outage and resource constraints. The proposed expenditures are based on anticipated regulatory relief from Environment Canada to extend the end-of-use date for these bushings and instrument transformers to 2025. Discussions are on-going with Environment Canada, yet Hydro One is confident the regulations will be amended in 2014.

In addition to the PCB contaminated oil, Hydro One Transmission’s daily activities also generate regulated waste, such as lead, cadmium, mercury, etc. that are required to be managed and disposed of in accordance with Provincial and Federal regulations.

The PCB retirement and waste management program funds the inspection, testing and retro-filling of equipment to reduce PCB contaminated oil; disposal and decommissioning of PCB contaminated equipment, as well as disposal of non-contaminated oil and other wastes.

Transformer Oil Leak Reduction

As transformers age, they are susceptible to leaks along seal gaskets and access covers, due to the effects of thermal cycling and gradual gasket deterioration. The main tank, access covers and fittings on most power transformers built prior to the mid-1980s utilize organic seal components as gaskets between flanges to retain oil; which begin to leak oil after performing well for the first 20 to 25 years.

Oil leaks are one of the most common deficiencies on transformers, and are a significant contributor to transformer forced outages. Multiple transformer failures have been attributed to aged gasket systems that can allow oil to leak out, and free water (in the form of snow and rain) to enter the transformer.
Transformer oil leaks are repaired on a temporary basis when first discovered under the demand program in order to expeditiously respond to the environmental risks. These repairs are usually stop-gap measures until a more permanent solution is implemented. Permanent repairs generally require outages and staff with a specific skill set to work on transformers.

Preventive and Corrective Maintenance

The preventive maintenance program is in place to ensure that spill containment systems are inspected and operate as designed; underground oil piping within transmission stations that is no longer in use is removed to eliminate risk of contaminating the surrounding environment, and non-functioning mechanical components (pumps, sensors, relays) used in oil/water separators that control effluent from the transformer spill containment pits are repaired or replaced.

The corrective maintenance program includes repairing spill containment systems, maintaining spill containment capacity for non-functioning spill containment systems by removing and disposing of the rainwater, containing and cleaning up insulating fluid spills as they occur and all other actions necessary to mitigate environmental risks posed by transmission equipment problems and failures.

Preventive and corrective maintenance allows Hydro One Transmission to meet its Environmental Policy objectives, maintain compliance with the MOE, minimize the risk to human health and the environment, and mitigate corporate exposure to legal and reputation risks.
Environmental Compliance and Emergency Response Plan Updates

The environmental compliance program encompasses activities necessary to allow Hydro One Transmission to remain in compliance with MOE Environmental Compliance Approvals (“ECAs”), formerly known as Certificate of Approvals, for various transmission stations throughout the province. Hydro One Transmission is required by the MOE to regularly test effluent as a requirement of site specific ECA documents.

Emergency Response Plans (“ERPs”) are documents that contain important station specific information that are kept at each transmission station. The ERPs are an effective tool for planning and responding to emergencies and contain important internal and external contact information, station maps and drawings as well as emergency response and evacuation procedures. The plans ensure that risk of harm to employees, contractors, the public, the environment and the physical assets of Hydro One Transmission is minimized. Funding under this program ensures that all ERPs contain up to date and accurate site-specific information.

3.2.2 Summary of Expenditures

The overall planned expenditure for environmental management in 2015 and 2016 is $14.9 million and $16.0 million respectively. This represents an average increase of 20% compared to the historic years, but is generally in-line with the 2014 bridge year expenditures of $15.3 million. This increase from historic years is required to:

- Complete additional transformer leak reductions to meet environmental obligations, as well as mitigating defects which could result in transformer failures impacting customers,
• Decommission additional underground oil handling systems which are no longer in use, and
• Complete additional refurbishment work on spill containment systems.

3.3 Power Equipment Maintenance

3.3.1 Introduction

The maintenance of Hydro One Transmission's power equipment is the most significant program within the Stations Sustaining OM&A category of expenditures. Hydro One’s transmission power equipment includes 722 transformers, 4,604 circuit breakers, as well as switches, insulators, bus work, instrument transformers, capacitor banks and reactors at the 286 transmission stations. Maintenance of this equipment is required to sustain in-service power equipment performance.

3.3.2 Investment Plan

The power equipment maintenance program is divided into six categories. Table 4 outlines the proposed funding for test years 2015 and 2016, along with the spending levels for the bridge and historic years for each category.
<table>
<thead>
<tr>
<th>Description</th>
<th>Historic Years</th>
<th>Bridge Year</th>
<th>Test Years</th>
</tr>
</thead>
<tbody>
<tr>
<td>Preventive Maintenance</td>
<td>18.3 19.3 20.0</td>
<td>19.5</td>
<td>20.0 20.4</td>
</tr>
<tr>
<td>Corrective Maintenance</td>
<td>26.0 22.2 24.7</td>
<td>21.6</td>
<td>22.1 22.7</td>
</tr>
<tr>
<td>500kV Autotransformer Refurbishments</td>
<td>8.8 2.2 2.1</td>
<td>2.2</td>
<td>2.2 1.0</td>
</tr>
<tr>
<td>115kV and 230kV Transformer Refurbishments</td>
<td>6.9 6.1 5.6</td>
<td>8.4</td>
<td>8.5 8.5</td>
</tr>
<tr>
<td>Breaker Refurbishments</td>
<td>3.3 1.6 4.1</td>
<td>2.8</td>
<td>3.0 2.1</td>
</tr>
<tr>
<td>Other Maintenance and Inspection Programs</td>
<td>4.9 4.4 3.6</td>
<td>4.7</td>
<td>4.9 5.0</td>
</tr>
<tr>
<td><strong>Total</strong></td>
<td>68.1 55.7 60.2</td>
<td><strong>59.2</strong></td>
<td><strong>60.7</strong> 59.7</td>
</tr>
</tbody>
</table>

Preventive Maintenance

Preventive maintenance is conducted to meet Hydro One Transmission’s obligations defined by the Transmission System Code to “inspect, test and monitor its transmission facilities to ensure continued compliance with all applicable standards and instruments”.

Hydro One Transmission's preventive maintenance program for power equipment is based on industry recognized Reliability Centered Maintenance (“RCM”) principles. The RCM principles utilized provide a structured methodology to determine inspection criteria based on known equipment failure modes, to enable equipment functionality to be met in a cost-effective manner. The total number of planned maintenance activities per year in power equipment maintenance is in the order of 9,000.

Hydro One Transmission’s preventive maintenance program places a priority on the completion of condition based monitoring such as visual inspections, oil analysis, function testing and equipment performance monitoring rather than the more intrusive time-based activities. The different power equipment types have varying maintenance
activities; examples of maintenance activities for transformers, breakers and switches include:

- Regular visual inspections to identify and record defects,
- Recording of pressures and temperatures to ensure that equipment is operating within appropriate specification; as well as identify oil leaks,
- Function testing of various equipment elements and alarms to ensure continued operation, reliability; as well as top up of oil as required,
- Selective intrusive maintenance to assess equipment condition, check contacts, test components, clean and lubricate, replace seals and complete minor repairs as required, and
- Diagnostic testing which includes: oil analysis for dissolved gas, moisture content, dielectric strength assessment and insulator testing.

The frequencies of these activities vary depending upon the make, model type and condition of the subject equipment. Program expenditure is based on the volume and type of maintenance work required to be completed during the calendar year.

While the demographics and condition of the fleet, as well as the expanding asset base, would typically be indicators of a need for significant increases in these programs, test year expenditures are generally in-line with those from historic and bridge years. This can be achieved through value being realized through a variety of tactics including:

- Shifting to more condition based maintenance (not carrying out costly intrusive maintenance activities until such time that diagnostic testing indicates a condition warranting this inspection),
- Increased Stations Sustaining Capital expenditures, resulting in greater avoided maintenance costs on aged assets that would otherwise require on-going maintenance to preserve equipment reliability,
• Installation of modern technologies with lower life cycle maintenance costs (such as replacing air blast circuit breakers with SF6 breakers which results in a 90% reduction in maintenance costs), and

• Improved ability to bundle activities making the most effective use of outage planning and mobilization of crews.

Corrective Maintenance

Corrective Maintenance work is required to repair equipment defects and return equipment condition and performance to an acceptable state. Corrective maintenance is a combination of planned and unplanned ‘demand’ work, including emergency response. Planned corrective maintenance addresses defects outside normal preventive maintenance cycles which can be scheduled and perhaps coordinated with other work to leverage efficiencies. Unplanned corrective maintenance results from all unscheduled, non-programmed maintenance necessitated by unforeseen problems and/or equipment failure. Emergency response may include preliminary investigation and minor or make safe repairs following equipment failure. This work is required to address the risk of harm and / or damage to any or all of employee safety, public safety, system reliability or the environment.

As expected, given the unplanned nature of this category of work, there is some variability on the number and severity of corrective maintenance issues addressed each year. However, with the on-going focus on Stations Sustaining Capital to address the worse performing assets, it is anticipated that corrective maintenance will remain in-line with recent historic levels.
500 kV Autotransformer Refurbishments

Refurbishment of the 500 kV autotransformer fleet is required to address the high failure rates of this critical class of equipment. Hydro One Transmission has experienced several 500 kV autotransformer failures on its system. The failure of a 500 kV autotransformer can jeopardize the reliability of the backbone 500 kV system and impact the stability of the electricity system. Interface limits may be affected and/or generation may be constrained. Due to the large amount of energy involved, failures have historically resulted in tank splits and oil spills, creating both safety and environmental hazards.

Investigations, that included third party design reviews, revealed a number of design limitations and highlighted that moisture levels in these units can reach unacceptably high levels leading to catastrophic failure. A remediation program was started in 2006 to address the primary deficiencies and has been successful at reducing the risk of failure until such time the transformers are replaced. As indicated in proceeding EB-2012-0031, further assessment has indicated that there continues to be autotransformers that require varying degrees of modifications to reduce their risk of failure.

115 kV and 230 kV Transformer Refurbishments

Refurbishment of the 115 kV and 230 kV transformer fleet is required to address transformer components, such as: gaskets, gauges, bushings, fans, pumps, etc., that typically require major refurbishment or replacement prior to the expected service life of the transformer. The refurbishments are extensive and include activities such as re-gasketting, replacement or refurbishment of components, painting, and oil processing. These refurbishments are cost effective, and allow the transformer to remain in-service through its expected service life while maintaining equipment and customer reliability.
During the refurbishment, Hydro One Transmission also takes the opportunity to outfit the transformers with modern accessories, leading to various benefits as part of the transformer’s life-cycle. For example, modern temperature monitors are installed and wired back to the Ontario Grid Control Centre (“OGCC”) to give the operators additional information to make real-time operating decisions with. In the case of transformer temperature, a measured reading is more accurate than a theoretically modelled measurement and may allow for additional transformer loading or alternatively, will ensure that equipment is operating within its ratings as to not unknowingly sacrifice equipment life.

In addition to refurbishments, a number of programs are being implemented to reduce the risk of equipment failure. These programs have been developed as a result of learning from failure investigations or from industry partners. Programs targeted at upgrading fall-arrest safety systems, proactive off-line dry-outs, installation of maintenance-free self-regenerating breathers, installation of under load tapchanger (ULTC) filtration systems, and the planned implementation of manufacturer recommended modifications to ULTCs are examples of such activities.

Breaker Refurbishments

Breaker refurbishments are required to address some specific models of circuit breakers (air blast, oil, GIS, and SF6) to allow them to reach their expected service life. Work planned in the test years focuses on mitigating specific reliability risks to customers or the bulk electricity system. A significant portion of these breaker refurbishment activities are as a result of past failures and the corrective action plans developed during failure investigations. For example, Hydro One Transmission continues to replace a component called the control selector switch on a cohort of breakers known to be at risk. Multiple breakers have been forced out of service due to the failure of this component, and a program has been established to replace the defective elements to reduce the likelihood of impacting customers. The majority of the expenditure in this category of work is specific
modifications and upgrades coming as a result of these similar investigations and is performed on air blast, oil, GIS, and SF6 circuit breakers.

Other Maintenance and Inspection Programs

Maintenance activities under this category include nuisance wildlife control, maintenance required for strategic spares and miscellaneous maintenance as outlined below.

Nuisance wildlife control programs are in place to combat the effects of both equipment interruptions and customer outages that can result when wildlife enter Hydro One’s transmission stations for various reasons such as shelter, food, breeding and hibernation. Animal related outages have averaged about 25 per year prior to preventive action being taken at targeted sites. The program involves installation of animal controls and barriers to limit the likelihood and consequence associated with animals climbing on electric equipment in a cost effective manner. Since the inception of this industry leading innovative approach, there has been a significant reduction in the number of animal contacts, with outages reduced by about 50% at the targeted sites.

Strategic spares maintenance programs are in place to maintain the inventory of circuit breakers and transformers that support the in-service fleet. The program includes the maintenance required to ensure that these components are available to enable timely response to system component failures and are maintained in a manner that would not to void manufacturer warranties.

Other miscellaneous maintenance programs for power equipment include: capacitor bank maintenance, insulator contamination monitoring and power washing, station string insulator testing program and station asset assessment activities. Although smaller, these activities are important to ensure equipment and customer reliability and manage equipment in a prudent and sustainable manner.
3.3.3 Summary of Expenditures

The overall planned expenditure for power equipment maintenance in 2015 and 2016 is $60.7 million and $59.7 million respectively. This is in line with recent historic spending. Some variations in program spending year over year can be observed, and are generally associated with implementation of specific investments rather than an on-going requirement.

A reduction in this program will result in reduced planned maintenance and refurbishment activities, which are in place to ensure station equipment is operating within specified parameters to ensure the reliability of the transmission system.

3.4 Ancillary Systems Maintenance

3.4.1 Introduction

Ancillary Systems are required at all of Hydro One’s transmission stations. These ancillary systems are comprised of station service systems, high pressure air systems, grounding systems, battery and battery charger systems, and oil processing facilities. These systems provide key services and operating support to all of the various station components.
3.4.2 Investment Plan

The ancillary systems maintenance program is divided into three categories. Table 5 outlines the proposed funding for test years 2015 and 2016, along with the spending levels for the bridge and historic years for each category.

<table>
<thead>
<tr>
<th>Description</th>
<th>Historic Years</th>
<th>Bridge Year</th>
<th>Test Years</th>
</tr>
</thead>
<tbody>
<tr>
<td>Preventive Maintenance</td>
<td>4.6</td>
<td>4.9</td>
<td>5.4</td>
</tr>
<tr>
<td>Corrective Maintenance</td>
<td>4.8</td>
<td>3.5</td>
<td>3.8</td>
</tr>
<tr>
<td>Other Maintenance Programs</td>
<td>1.8</td>
<td>1.6</td>
<td>0.9</td>
</tr>
<tr>
<td><strong>Total</strong></td>
<td><strong>11.2</strong></td>
<td><strong>10.1</strong></td>
<td><strong>10.1</strong></td>
</tr>
</tbody>
</table>

Preventive Maintenance

Similar to the Power Equipment preventive maintenance program, the preventive maintenance program for Ancillary Systems is founded on RCM principles and is established to allow equipment to reach its expected service life. The maintenance activities include periodic tests and inspections required to satisfy reliability, safety and regulatory requirements. Oversight bodies such as the Technical Standards and Safety Authority, IESO, NPCC, Ministry of Health’s *Occupational Health and Safety Act* and the MOE impose these requirements and in some cases mandate specific inspection and testing cycles. The total number of planned maintenance activities per year in ancillary maintenance is in the order of 5,500.

Corrective Maintenance

Similar to the Power Equipment corrective maintenance program, the corrective maintenance program for Ancillary Systems is required to repair equipment defects and
return equipment condition and performance to an acceptable state. Corrective maintenance is a combination of planned and unplanned ‘demand’ work, including emergency response. Corrective maintenance is required to address the risk of harm and / or damage to any or all of employee safety, public safety, system reliability or the environment.

Other Maintenance Programs

Other maintenance activities includes grounding studies, maintenance of Hydro One’s oil storage and processing operation at its Central Maintenance Facility, and upgrades to backup diesel generators.

The program also funds the payments for services at facilities shared with OPG or Bruce Power. Hydro One Transmission has a number of sites located within or adjacent to generating stations (Hydraulic, Thermal and Nuclear) where services are purchased directly from the plant in order to maintain switchyard operations. These services include AC/DC station service, water and snow removal. Agreements are in place between Hydro One Transmission and the generating entities with respect to what services are shared and appropriate compensation. Hydro One Transmission is billed on an annual basis for these services.

3.4.3 Summary of Expenditures

The planned expenditure for ancillary systems maintenance in 2015 and 2016 is $10.0 million and $10.0 million respectively. This is a slight decrease from historic spending. The primary factor influencing this positive downward trend is the retirement of air blast circuit breakers which eliminates the need for its ancillary high-pressure air systems which are maintenance intensive. Any further reduction in this program would not be prudent, as the ancillary systems maintenance program is substantially required to satisfy regulatory and/or safety obligations.
3.5 Protection, Control, Monitoring, Metering and Telecommunications Maintenance

3.5.1 Introduction

Protection, Control, Monitoring, Metering and Telecommunications assets are utilized to protect, control and operate the transmission system by sensing and isolating abnormal system conditions, providing real-time operational data and remote equipment control, and capturing detailed records for post-event analysis. The maintenance of these assets is required to sustain equipment performance and maintain compliance with applicable NERC standards.

3.5.2 Investment Plan

The protection, control, monitoring, metering and telecommunications maintenance program is divided into three categories. Table 6 outlines the proposed funding for the test years 2015 and 2016, along with the spending levels for the bridge and historic years for each category.

**Table 6**

Protection Control, Monitoring, Metering and Telecommunications OM&A ($ Millions)

<table>
<thead>
<tr>
<th>Description</th>
<th>Historic Years</th>
<th>Bridge Year</th>
<th>Test Years</th>
</tr>
</thead>
<tbody>
<tr>
<td>Protection, Control, Monitoring and Metering Equipment</td>
<td>20.8</td>
<td>19.3</td>
<td>20.4</td>
</tr>
<tr>
<td>Cyber Security</td>
<td>3.6</td>
<td>4.9</td>
<td>7.1</td>
</tr>
<tr>
<td>Telecommunications</td>
<td>19.4</td>
<td>20.7</td>
<td>21.9</td>
</tr>
<tr>
<td><strong>Total</strong></td>
<td>43.9</td>
<td>44.9</td>
<td>49.4</td>
</tr>
</tbody>
</table>
Protection, Control, Monitoring and Metering Equipment

Protection, Control, Monitoring and Metering Equipment maintenance covers the planned and corrective maintenance work required to sustain the performance of protection, control, monitoring and metering equipment.

Protective relays and their associated systems are critical in sensing abnormal system conditions and taking the appropriate actions in response to those conditions. These devices protect local supply, supply within Ontario and the potential impacts of problems on the Hydro One’s transmission system to the rest of the interconnected grid.

Wholesale revenue meters are used to measure energy flow between the IESO controlled power grid and metered market participants in accordance with Measurement Canada requirements for transaction settlements.

As such, a significant portion of the Protection, Control, Monitoring and Metering equipment maintenance programs are regulated and non-discretionary. The expenditures for maintenance of Protection, Control, Monitoring and Metering Equipment fall into three activities as outlined in Table 7.
## Table 7

### Protection, Control, Monitoring and Metering Equipment OM&A

($ Millions)

<table>
<thead>
<tr>
<th>Description</th>
<th>Historic Years 2011</th>
<th>Historic Years 2012</th>
<th>Historic Years 2013</th>
<th>Historic Years 2014</th>
<th>Bridge Year 2014</th>
<th>Test Years 2015</th>
<th>Test Years 2016</th>
</tr>
</thead>
<tbody>
<tr>
<td>Preventative Maintenance</td>
<td>6.1</td>
<td>5.0</td>
<td>5.3</td>
<td>5.3</td>
<td>4.9</td>
<td>6.1</td>
<td></td>
</tr>
<tr>
<td>Corrective Maintenance</td>
<td>7.2</td>
<td>7.3</td>
<td>7.5</td>
<td>6.1</td>
<td>6.2</td>
<td>6.3</td>
<td></td>
</tr>
<tr>
<td>Support Processes and Systems</td>
<td>7.5</td>
<td>7.0</td>
<td>7.6</td>
<td>8.6</td>
<td>8.7</td>
<td>8.9</td>
<td></td>
</tr>
<tr>
<td><strong>Total</strong></td>
<td><strong>20.8</strong></td>
<td><strong>19.3</strong></td>
<td><strong>20.4</strong></td>
<td><strong>20.0</strong></td>
<td><strong>19.8</strong></td>
<td><strong>21.2</strong></td>
<td></td>
</tr>
</tbody>
</table>

(1) Preventative Maintenance

Preventative Maintenance involves time based routine testing of protection systems and revenue meters. Protection systems spend most of their service life in a dormant state, yet must be relied upon to perform flawlessly during a fault or other abnormal system condition. Routine testing is the only means to maintain a high degree of certainty that the system will operate correctly when called upon. The testing frequency of protection systems that are designated as part of the Bulk Power System are mandated by NPCC guidelines; for the remaining portions of the system Hydro One Transmission follows internal policies that are in accordance with good utility practice.

Revenue Meters require periodic re-verification of their accuracy. These re-verifications are done at a frequency mandated by the *Electricity and Gas Inspection Act* and regulations overseen by Measurement Canada.

Based on the regulation guidelines for testing frequency, there is some variability on the number of protection system and meter tests performed each year.
(2) Corrective Maintenance

All protection, control, monitoring and metering assets experience some rate of failure or defects during their normal useful life. Failures can result in equipment damage as well as widespread power outages due to the criticality of protection, control, monitoring and metering assets within the system. In addition, this category of work includes addressing problems discovered from analysis of events and defects with certain makes and models of protections which have been identified to be problematic and jeopardize reliability of the electrical system.

Given the unplanned nature of this category of work, there is some variability on the number and severity of corrective maintenance issued addressed each year. However, with the on-going focus on Stations Sustaining Capital to address high risk assets, it is anticipated that corrective maintenance will trend below historic levels.

(3) Support Processes and Systems

Hydro One Transmission maintains a set of support processes and systems for the protection, control, monitoring and metering equipment. The support systems are in place to manage change control of the settings and configuration of protection and control systems, keep records of events, as well as manage the inventory and re-seal schedule for revenue meters. The support processes are in place for carrying out event analyses and follow-up actions, performing routine inspections, managing spare parts and tracking vendor advisories. Hydro One Transmission is incorporating new processes and systems required to meet new or more stringent reliability standards issued by NERC and NPCC, and are in the process of augmenting the condition assessment of protection systems resulting in an increase over historic spending.
Cyber Security

Cyber Security maintenance is required to sustain the systems and facilities in compliance with the NERC Critical Infrastructure Protection (CIP) Standards. Maintenance and system support for Cyber Security includes:

- Maintaining the various Cyber Security assets (e.g. Firewalls, Intrusion Detection Systems, Malware detection systems, Physical Security systems);
- Conducting required annual surveys of critical cyber assets and security perimeters; and
- Managing cyber security systems (e.g. maintaining personnel access lists, patch management, maintaining logs, updating firmware, periodic tests).

As outlined in proceeding EB-2012-0031, the energy sector is categorized as a critical infrastructure by the Canadian and US Federal governments. Acknowledging the importance of protecting the reliability of the interconnected grid, NERC developed an initial set of CIP standards to ensure regular testing and updating of the security systems and procedures for changes that occur in staffing as well as in the transmission assets that require security.

On November 22, 2013 Version 5 of the NERC CIP standards were approved by the Federal Energy Regulatory Commission (“FERC”), extending the applicability of cyber security requirements to additional assets within the Hydro One’s transmission system. With the adoption of Version 5, the number of sites for evaluation and inclusion into the NERC CIP cyber security compliance program will increase. Hydro One Transmission will be required to revise change management procedures and increase system management to incorporate these additional requirements.
Telecommunications

Telecommunication systems provide high reliability and high-speed communications required for the protection, monitoring and control of Hydro One’s transmission system. Hydro One Transmission’s telecommunication system consists of digital fiber-optic networks, power line carrier (“PLC”) systems, owned or leased metallic cables, digital microwave, and the associated auxiliary telecommunication equipment for each. The expenditures for telecommunication systems fall into three activities as outlined in Table 8.

<table>
<thead>
<tr>
<th>Description</th>
<th>Historic Years</th>
<th>Bridge Year</th>
<th>Test Years</th>
</tr>
</thead>
<tbody>
<tr>
<td>Preventative and Corrective</td>
<td>4.5 4.6 5.5</td>
<td>5.4 5.5 5.6</td>
<td></td>
</tr>
<tr>
<td>Maintenance</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Leased Telecommunication Circuits</td>
<td>8.6 8.9 9.5</td>
<td>9.7 9.8 10.0</td>
<td></td>
</tr>
<tr>
<td>Hydro One Telecom Contract</td>
<td>6.2 7.3 6.9</td>
<td>7.1 7.3 7.5</td>
<td></td>
</tr>
<tr>
<td>Total</td>
<td>19.4 20.7 21.9</td>
<td>22.1 22.6 23.1</td>
<td></td>
</tr>
</tbody>
</table>

(1) Preventative and Corrective Maintenance

Preventative and corrective maintenance is required to sustain power system telecommunication assets. Hydro One Transmission’s telecommunication assets include the terminal equipment for PLC systems, synchronous optical networking equipment, multiplexors, neutralizing transformers, tone equipment, radios and DC power supply for these devices, as well as the microwave radio towers. The maintenance program for these telecommunication assets includes the re-verification of equipment that supports protection systems directly, inspections, repairs and emergency work as well as replenishing spare parts inventories.
(2) Leased Telecommunication Circuits

Hydro One Transmission leases telecommunication circuits in order to support the telecommunication requirements for protection and control of the power system. This program covers the monthly fees associated with leasing of the telecommunication circuits as well as for the provincial mobile radio system. This program is also subject to tariffs for telecommunication services as approved and regulated by the Canadian Radio-television Telecommunications Commission (“CRTC”). With the increasing deployment of new protection, control and monitoring equipment, the number of leased telecommunications circuits and circuit capacity required to support the power system is also increasing.

(3) Hydro One Telecom Contract

Hydro One Networks receives monitoring and alarm response for power system telecommunication circuits, outage management, vendor management, and system analysis services under contract from Hydro One Telecom (“HOT”). This program covers the payment to HOT for these contracted services, as well as the services related to updating the computer systems used in the management of the telecommunications circuits provided by HOT.

3.5.3 Summary of Expenditures

The overall planned expenditure for protection, control, monitoring, metering and telecommunications maintenance in 2015 and 2016 is $51.7 million and $53.7 million respectively. This represents an increase of 3% in 2015 over the bridge year 2014 and an increase of 4% in 2016 over the test year 2015. The main factors contributing to this increase are:

- Cyber Security with the increased change and system management work required due to the expanded applicability of Version 5 of the NERC CIP cyber security requirements to Hydro One Transmission assets, and
• Telecommunication Systems with the increased new and upgraded leased
telecommunications services required to support protection, control, monitoring and
metering equipment.

A reduction in this program may compromise Hydro One Transmission’s ability to
comply with reliability and cyber security regulations and result in an increase in
equipment failures causing one or more of the following: equipment outages, equipment
damage, load interruption and widespread interruption to the interconnected electrical
system.

3.6 Site Infrastructure Maintenance

3.6.1 Introduction

Hydro One Transmission’s site facilities and infrastructure systems are comprised of yard
drainage, fire protection and detection, structural footings, station buildings, cranes,
elevators, heating ventilation and air-conditioning (“HVAC”) systems, access roads,
water supplies, sewage management, and fences at transmission stations. These systems
provide infrastructure and support services to all other station components, prevent
unauthorized access, and make the station site functional for equipment and staff.

3.6.2 Investment Plan

The Site Infrastructure Maintenance program is focused on the planned and corrective
maintenance at transmission stations to ensure that these site facilities and infrastructure
systems remain in a safe condition and in compliance with regulations.

The program is extensively driven by assessment of data collected, demand work, as well
as regulatory requirements (such as building and fire codes, the Occupational Health and
Safety Act and the Ministry of Environment requirements, as well as community by-laws) and corporate standards. The program is divided into three categories. Table 9 outlines the proposed funding for test years 2015 and 2016, along with the spending levels for the bridge and historic years.

<table>
<thead>
<tr>
<th>Description</th>
<th>Historic Years</th>
<th>Bridge Year</th>
<th>Test Years</th>
</tr>
</thead>
<tbody>
<tr>
<td>Facilities and Infrastructure Maintenance</td>
<td>22.0</td>
<td>18.5</td>
<td>20.3</td>
</tr>
<tr>
<td>Grounds Maintenance</td>
<td>4.0</td>
<td>3.4</td>
<td>3.4</td>
</tr>
<tr>
<td>Site Perimeter Maintenance</td>
<td>0.4</td>
<td>0.7</td>
<td>1.4</td>
</tr>
<tr>
<td><strong>Total</strong></td>
<td><strong>26.4</strong></td>
<td><strong>22.7</strong></td>
<td><strong>25.2</strong></td>
</tr>
</tbody>
</table>

Facilities and Infrastructure Maintenance

This program is focused on the preventative and corrective maintenance of the facilities and infrastructure at the transmission stations. Data and information on the condition of station sites and buildings is collected through regular inspections, as well as information gathered during maintenance work and trouble call response. Contracted inspections and asset surveys are also conducted.

The preventive maintenance program for site facilities and infrastructure addresses a wide variety of activities such as: building maintenance and facility improvements; HVAC maintenance; inspections; janitorial services; water system maintenance and testing; roads, bridges and railway maintenance; station civil geotechnical inspections and maintenance; and asset assessments.

The corrective maintenance program addresses demand work including trouble calls and identified defects related to station infrastructure facilities.
Grounds Maintenance

Grounds maintenance involves the application of herbicides to control weeds and vegetation inside Hydro One’s transmission stations. Weed and vegetation control is required to keep step and touch voltages at safe levels for workers and others that enter the station. In addition, grounds maintenance includes snow removal to allow access to and within a station, grass cutting, clean-up and general maintenance that may be required for site drainage and grading.

Site Perimeter Maintenance

The site perimeter maintenance program includes preventive and corrective maintenance at station perimeters, (e.g., fences and gates) to prevent unauthorized access, perimeter measures to keep animals out of stations and reduce likelihood of power interruptions due to animal contact. The activities under this program complement broader corporate security initiatives targeted at safeguarding transmission assets to ensure public and employee safety and maintain equipment and system reliability.

3.6.3 Summary of Expenditures

The planned expenditure for site in 2015 and 2016 is $28.5 million and $29.3 million respectively. This represents an increase of less than 3% in 2015 over the bridge year 2014 and a similar increase in 2016 over the test year 2015. However, this represents an average increase of approximately 17% compared to the historic years. The increase from the historic years is a result of on-going work to address deficiencies with Hydro One’s building infrastructure that pose a risk to reliability if not remedied (i.e. leaking roofs, basements, etc.) as well as additional work to maintain station perimeter fences to keep unauthorized individuals and animals out of stations.
A reduction in this program will result in increased number building infrastructure or station perimeter defects going unresolved, which can lead to events impacting the customer or system reliability.

4.0 LINES

Transmission lines are used to transmit electric power, via integrated network and radial circuits, to either transmission-connected industrial or commercial customers, or to local distribution companies, including Hydro One Distribution, who in turn distribute the power to end-use customers. Hydro One’s transmission lines primarily operate at voltages of 500 kV, 230 kV, and 115 kV, with minor lengths operating at 345 kV and 69 kV. Hydro One’s transmission system consists of approximately 30,000 circuit km of overhead transmission lines located on about 21,000 km of rights-of-way, and 290 circuit km of underground transmission lines.

Overhead transmission line components include structures (primarily steel or wood) and corresponding foundations, conductors, shieldwire, insulators, lightning arrestors, hardware, switches, and grounding systems. Underground transmission line components include cables, terminations, oil pressure systems and grounding systems. The underground transmission lines are generally located in large urban centres.

Lines Sustaining OM&A funding covers expenditures required to maintain existing overhead and underground transmission lines assets. Hydro One Transmission manages its Lines Sustaining OM&A program by dividing the program into three categories:

1. **Vegetation Management**, which ensures that clearances to energized equipment are maintained and includes brush control, line clearing, condition patrol, demand maintenance and ground maintenance.
2. **Overhead Lines Maintenance**, which focuses on inspections and testing of overhead lines components to identify defects as well as emergency response and minor component replacement programs.

3. **Underground Cable Maintenance**, which focuses on inspections, analysis, tests, surveys and diagnostics of cables, vaults, jackets and potheads as well as condition and route patrols, and corrective maintenance.

Required funding for the test years 2015 and 2016, along with spending levels for the bridge and historic years are provided in Table 10 for each category.

**Table 10**

<table>
<thead>
<tr>
<th>Description</th>
<th>Historic Years</th>
<th>Bridge Year</th>
<th>Test Years</th>
</tr>
</thead>
<tbody>
<tr>
<td>Vegetation Management</td>
<td>26.6</td>
<td>27.1</td>
<td>31.1</td>
</tr>
<tr>
<td>Overhead Lines Maintenance</td>
<td>16.1</td>
<td>17.9</td>
<td>15.7</td>
</tr>
<tr>
<td>Underground Cable Maintenance</td>
<td>6.6</td>
<td>3.6</td>
<td>3.6</td>
</tr>
<tr>
<td><strong>Total</strong></td>
<td><strong>49.4</strong></td>
<td><strong>48.6</strong></td>
<td><strong>50.4</strong></td>
</tr>
</tbody>
</table>

The overall Lines Sustaining OM&A expenditures for the test years 2015 and 2016 are in line with the 2014 requirement. However, this represents an average increase of 20% compared to the historic years. Increases from historic years are to account for additional vegetation management inspections required by the NERC standard and additional line clearing and brush control to meet target clearing cycles. There is also a requirement to carry out increased levels of conductor and shieldwire testing and to replace defective u-bolts and conductor dampers.
4.1 Vegetation Management

4.1.1 Introduction

Hydro One Transmission has approximately 30,000 circuit km of overhead transmission lines located on about 21,000 km of rights-of-way. These lands contain varying types of vegetation, from forests to grass lands, some of which can grow into the proximity of transmission lines and threaten system reliability. To ensure a sustainable level of reliability, a vegetation management program is required to ensure that clearances between vegetation and energized equipment are maintained. The program controls vegetation growth in a manner that considers environmental, ecological and social impacts, while responding to reliability and landowners concerns.

4.1.2 Investment Plan

The vegetation management program is divided into six categories. Table 11 outlines the proposed funding for the test years 2015 and 2016; along with the spending levels for the bridge and historic years for each category.
Table 11
Vegetation Management OM&A
($ Millions)

<table>
<thead>
<tr>
<th>Description</th>
<th>Historic Years</th>
<th>Bridge Year</th>
<th>Test Years</th>
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</thead>
<tbody>
<tr>
<td>Brush Control</td>
<td>17.0</td>
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<td>19.8</td>
</tr>
<tr>
<td>Line Clearing</td>
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<td>5.3</td>
<td>5.2</td>
</tr>
<tr>
<td>Property Owner Contact</td>
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<td>1.3</td>
<td>1.2</td>
</tr>
<tr>
<td>Condition Patrols</td>
<td>1.3</td>
<td>1.4</td>
<td>1.6</td>
</tr>
<tr>
<td>Demand Maintenance</td>
<td>1.0</td>
<td>1.4</td>
<td>0.9</td>
</tr>
<tr>
<td>Grounds Maintenance</td>
<td>1.9</td>
<td>2.2</td>
<td>2.3</td>
</tr>
<tr>
<td><strong>Total</strong></td>
<td><strong>26.6</strong></td>
<td><strong>27.1</strong></td>
<td><strong>31.1</strong></td>
</tr>
</tbody>
</table>

**Brush Control**

Brush control refers to managing the growth of vegetation on the rights-of-way to ensure the vegetation does not grow to a height that would cause an outage to the transmission line. The brush control also maintains access along the rights-of-way for inspection, maintenance activities, and emergency response. A number of different methods are used to manage rights-of-way vegetation, including selective herbicide application, species management, and mechanical brushing.

**Line Clearing**

Line clearing refers to the activity of assessing and removing “Danger Trees” that grow at the side of the right-of-way or on the right-of-way as well as trimming of any trees that may pose a threat to the line. Danger trees are trees of questionable soundness and health, which could fall and contact line conductors, causing an outage. In some cases, removed trees are replaced with compatible vegetation to address local and environmental concerns. Line clearing is carried out as a separate activity from brush control, as it requires a higher level of skill to identify and remove trees that may jeopardize the security of a transmission line.
The activities of brush control and line clearing must comply with the requirements of the NERC Vegetation Management Standard (FAC-003-2) which were established to prevent blackout reoccurrences.

Brush control and line clearing are generally performed on a cyclical basis as rights-of-way are maintained on approximately, 6 and 8 year cycles depending on the region and its associated growth cycle (i.e. climate, species composition, etc.) These cycle lengths have been evaluated over time and are considered to be appropriate for the Hydro One transmission system, as they provide a cost-effective and sustainable level of reliability and are generally consistent with past accomplishment.

Property Owner Contact

Property Owner Contact is undertaken to acquire approval for access onto private property, obtain input concerning any restrictions and environmental concerns, and to communicate maintenance plans to property owners. During this activity, job planning and project layouts are completed, a detailed work package is prepared, and approvals are obtained from stakeholders such as property owners, municipalities, and the Ministry of Natural Resources where applicable. This work is done in conjunction with the line clearing and brush control programs, thus any increase in these programs or their complexity with respect to number of property owners, will have a direct impact on the volume of property owner contacts.
Condition Patrols

Condition patrols are conducted along rights-of-way to identify, assess and document potential risks to the security of a line, as well as to obtain information concerning the condition of the vegetation on rights-of-way. Patrols are carried out typically mid-cycle by experienced staff to assess the condition of the rights-of-way and schedule the removal of vegetation that may pose a threat before the next clearing cycle. A mid-cycle condition patrol is considered optimal as it strikes a balance between having to forecast too much future growth in order to schedule the next set of maintenance activities and the risk of leaving excessive growth on the system too long.

During the patrol, data is captured on vegetation growth rates, quantities of danger trees, species of brush and trees, and clearance conditions. Analysis of condition patrol data provides an indication of growth rates, clearances, and other vegetation conditions that will need to be addressed. Vegetation that poses a threat prior to the next scheduled line clearing or brush control treatment is addressed to ensure the reliability of the electrical system. Similarly, if a right-of-way is found to be in good condition despite not having been maintained for a lengthy period of time, then the line clearing and brush control schedule may be lengthened.

In addition to the condition patrols, Hydro One Transmission will be required to inspect applicable lines annually as outlined in the recent revision to the NERC Vegetation Management Standard (FAC-003-2); which became enforceable in 2014.

Demand Maintenance

Demand maintenance work is required to address vegetation management issues that cannot wait until the next scheduled line clearing or brush control maintenance. Issues addressed through demand maintenance arise as a result of problems identified by the public, storm damage, urban development, tree caused outages and problems identified during annual and condition patrols.
Grounds Maintenance

Grounds maintenance includes activities on transmission rights-of-ways such as grass cutting in urban areas, security patrols, maintenance of access barriers and fences, snow removal, and garbage removal. Maintenance is undertaken in consideration of regulatory requirements, local by-laws, and customer requirements. For example, grass cutting must be carried out during the growing season to comply with local by-laws with respect to weed control.

4.1.3 Summary of Expenditures

The overall planned expenditure for vegetation management in 2015 and 2016 is $32.8 million and $33.2 million respectively. This represents an average increase of 20% compared to the historic years, but is generally in-line with the 2014 bridge year expenditures of $32.2 million. The increase from the historic years is a result of the additional inspections required by the NERC Vegetation Management Standard as well as the requirement to perform additional line clearing and brush control to meet target clearing cycles.

A reduction in this program would result in an increased risk of trees and brush encroaching on the minimum clearance distances potentially resulting in outages and regulatory intervention with fines, as well as a decline in customer and system reliability.
4.2 Overhead Lines Maintenance

4.2.1 Introduction

The overhead lines maintenance program is required to maintain the reliability of transmission lines, address safety issues, meet regulatory requirements, and ensure the financial long term viability of the overhead lines system. The program includes activities such as overhead lines inspections to identify defects, emergency response, and the gathering of information that will enable funding to be allocated on a priority basis to maximize the life of the lines assets and maintain performance. The program also provides for repair or replacement of defective equipment and components.

4.2.2 Investment Plan

The Overhead Lines Maintenance program is divided into three activities. Table 12 outlines the proposed funding for the test years 2015 and 2016; along with the spending levels for the bridge and historic years for each category.

<table>
<thead>
<tr>
<th>Description</th>
<th>Historic Years</th>
<th>Bridge Year</th>
<th>Test Years</th>
</tr>
</thead>
<tbody>
<tr>
<td>Preventive Maintenance and Asset Assessment</td>
<td>9.0</td>
<td>9.1</td>
<td>7.9</td>
</tr>
<tr>
<td>Demand Maintenance</td>
<td>2.9</td>
<td>3.2</td>
<td>3.2</td>
</tr>
<tr>
<td>Planned Corrective Maintenance and Projects</td>
<td>4.2</td>
<td>5.6</td>
<td>4.6</td>
</tr>
<tr>
<td><strong>Total</strong></td>
<td><strong>16.1</strong></td>
<td><strong>17.9</strong></td>
<td><strong>15.7</strong></td>
</tr>
</tbody>
</table>
Preventive Maintenance and Asset Assessment

Preventive maintenance and asset assessment encompasses a number of activities that are undertaken to keep lines assets in working order and to identify conditions that may impact their operation and reliability, as well as acquiring condition information needed to identify components in need of replacement or refurbishment.

The preventive maintenance activities include foot, helicopter and thermovision patrols; insulator washing; switch maintenance; and the assessment of various transmission line components that include poles, steel towers, insulators, conductors, shieldwires, anchors, and guys. The patrols identify any public safety issues and defects that may jeopardize customer and system reliability. Annual patrols are undertaken by helicopter but in areas where flight restrictions exist, lines are patrolled on foot. The thermovision patrols are carried out with the purpose of identifying “hot spots” (e.g. loose connections) that put line components at risk of failure and that are not visible to the naked eye. Predicting imminent failures has tremendous reliability benefits and as a result, thermovision patrols are conducted on an average 3-year cycle. More critical lines such as those on the 500 kV system, inter-ties (i.e. inter-provincial or international lines), and those servicing critical generating plants have thermovision patrols conducted on an annual basis.

Asset assessment includes a number of activities that have been designed to provide the information needed to manage the transmission lines system and to identify defects that jeopardize public and worker safety and the reliability of the system. Specific activities include:

- Steel tower assessments to examine tower components above ground and at the ground line. Assessments are carried out on those lines that show signs of noticeable corrosion and that have structures in swamps, standing water or are located in known corrosive areas.
• Shieldwire and conductor testing to target conductors that have been in service for more than 50 years and shieldwires in service for more than 30 years. Once tested, those conductors and shieldwires determined to be at end of life, and pose a risk to the reliability of the system as well as a hazard to the public and employees, are scheduled for replacement under the appropriate capital programs.

• Insulator testing is conducted on specific line sections where annual assessments of reliability performance or patrol observations suggest insulator conditions may be deteriorating.

• Periodic field survey of electrical clearances of transmission lines to ensure that clearances are adequate for current operating conditions, or in response to proposed increases in operating conditions.

• Wood pole line assessments that involve detailed helicopter inspections of the condition of cross-arms and pole tops, and individual pole testing to evaluate the soundness of the wood near the ground line. The lines selected for detailed helicopter inspections are identified based on accessibility, pole ages, and reliability information.

Wherever possible, assessment activities are scheduled in a complementary fashion such that cyclical and non-cyclical needs are addressed as efficiently as possible. For example, a line section that requires pole and cross-arm assessments will be scheduled for a detailed helicopter patrol and pole testing such that both assessments are met and the need for the separate cyclical helicopter patrol is avoided.

**Demand Maintenance**

Demand maintenance is needed to respond to emerging problems and to restore power should it become necessary. Lightning storms, ice build-up on lines and high winds can result in the failure of transmission line components, which requires immediate response and repair. This program also addresses problems identified during line patrols that need
a short term response to prevent a potential outage or to address a serious safety issue.  
This program is reactive in nature and varies due to weather, equipment deterioration and  
equipment failures.

**Planned Corrective Maintenance and Projects**

The planned corrective maintenance and projects program includes minor corrective  
work, larger scale projects, as well as technical support to resolve reliability problems  
with transmission line assets. The planned corrective maintenance activities and projects  
are developed using the data collected through the patrols and asset assessment activities,  
as well as information on equipment reliability performance, and findings of expert  
analysis.

Planned corrective maintenance addresses ground wire replacements, clearance  
corrections, and planned defect corrections such as: loose guy wires, broken strands of  
conductor, damaged insulator strings, dislodged tower members, and broken ground wire.

The larger scale projects address wide spread design, manufacturing, or condition  
deficiencies; or safety and reliability concerns. Maintenance of this type is targeted to  
specific locations that have been identified as high risk. Some of the activities include:

- Replacement of worn u-bolts that support the insulator strings and conductors,
- Replacement of dampers that limit vibration of conductor,
- Addition of tower anchor bolt security to deter vandalism,
- Installation of anti-climbing barriers to prevent public access to towers, and
- Replacement of conductor to address damage on several lines as a result of vibrations  
  stemming from aged defective conductor “torsional” damping devices.
4.2.3 **Summary of Expenditures**

The overall planned expenditure for the overhead lines program in 2015 and 2016 is $20.2 million and $20.7 million respectively. This represents an average decrease of 7% compared with the 2014 bridge year but a marked increase over historic years. The increase from the historic years is to address worn and defective u-bolts and dampers identified in the system; as well as to carry out additional conductor and shieldwire sampling and testing on the aging conductor population.

A reduction in this program will result in defects remaining on the system for extended periods of time and thereby increasing the likelihood of failures resulting in increased reliability risks and public safety issues.

4.3 **Underground Cable Maintenance**

4.3.1 **Introduction**

Hydro One Transmission’s high voltage underground (“HVUG”) cable system consists of 115 kV and 230 kV cables. Underground cables are located in the urban centres of Toronto, Hamilton and Ottawa, with short sections in London, Sarnia, Picton, Windsor and Thunder Bay.

This program reduces the risk of cable equipment failure which can seriously impact service and reliability to a large number of urban areas. The activities within this program ensure that corrective action is taken when component failure is imminent or when defects are discovered during routine inspections, Hydro One Transmission provides timely response to external requests for a cable locate, and the integrity of the cable is maintained by performing cable diagnostics which provide an indication of the state of
the cable components since most of the underground facilities are not visible or easily accessible.

4.3.2 Investment Plan

The Underground Cable Maintenance program is divided into three activities. Table 13 outlines the proposed funding levels for the test years 2015 and 2016; along with the spending levels for the bridge and historic years for each category.

<table>
<thead>
<tr>
<th>Description</th>
<th>Historic Years</th>
<th>Bridge Year</th>
<th>Test Years</th>
</tr>
</thead>
<tbody>
<tr>
<td>Cable Locates</td>
<td>0.8</td>
<td>1.4</td>
<td>1.2</td>
</tr>
<tr>
<td>Preventative Maintenance</td>
<td>0.7</td>
<td>0.4</td>
<td>0.9</td>
</tr>
<tr>
<td>Corrective Maintenance</td>
<td>5.1</td>
<td>1.8</td>
<td>1.6</td>
</tr>
<tr>
<td><strong>Total</strong></td>
<td><strong>6.6</strong></td>
<td><strong>3.6</strong></td>
<td><strong>3.6</strong></td>
</tr>
</tbody>
</table>

Cable Locates

This program responds to external requests for locating Hydro One Transmission’s underground cable facilities. Responding to these requests is in everyone’s best interest as anyone excavating near a cable may cause damage to these costly assets and harm themselves or members of the public. Hydro One Transmission uses the services of “Ontario One Call” to field requests for cable locates and then completes the field identification as required.

This program is driven by external demand and the costs are not recovered by end use charges, which is consistent with the practice of other utilities. The “no fee” policy is in place to encourage contractors to make use of the service and avoid costly and hazardous
situations. The forecast for the future volume of cable locates is based on the analysis of the historical number of requests.

Preventive Maintenance

Preventative Maintenance activities are aimed at determining cable condition and ensuring system reliability. Underground cables are made of a number of components and subsystems, the condition of which can deteriorate during the cables’ service life.

Underground cable condition information is determined through a number of activities as listed below.

- Condition patrols focused on underground cables and their auxiliary systems such as the oil pumping plants and cathodic rectifiers.
- Cable pipe polarization spot checks to monitor the corrosion protection that is installed on the cable pipes.
- Cable pipe corrosion surveys on the protective steel pipes that protect many of Hydro One’s Transmission cables.
- Oil testing and analysis to determine if there is any accumulation of dissolved gases in the insulating oil, which may be a sign of deteriorating condition.
- Route patrols at ground level to look for any unknown excavations near the cables or any evidence of oil leaks that would indicate a breach in the piping system.
- Jacket tests on cables in the system that are not protected by a steel pipe. These include oil filled cables protected by a metallic sheath and an outer polyethylene jacket.
- Infrared tests on cable components called potheads, which mark the transition of a conductor from overhead to underground, to determine if the materials that make up the pothead are exceeding thermal limits.
- Vault inspections on cable systems having splice locations that are enclosed in a concrete vault.
• Cable diagnostic activities to assess condition and maintain reliability of the cable systems. Tests include oil leak detection, sheath current measurements and laboratory insulation assessment.

The large majority of preventative maintenance activities are cyclical in nature (e.g. route patrols are conducted twice per month). However, condition data and reliability performance may drive the need to adjust the frequency of maintenance activities for specific cables that may be a source of concern.

Corrective Maintenance

Corrective maintenance work includes repairs of defects discovered through preventative maintenance activities, and may involve repairing oil leaks, coating of cable terminations, repairing of cable sheath and pipe coating, and topping up oil levels. These repairs are essential to keep the cables and their associated components in a reliable state of operation.

The activities included under corrective maintenance are primarily reactive and demand in nature, but also include planned corrective activities. Planned corrective work is done where problems arise and there is adequate time to correct defects without significantly jeopardizing reliability and safety. Planned corrective work includes removal and replacement of oil that has unacceptable concentrations of harmful gases, sheath repairs that have been damaged through corrosion, and adjustment and repairs to monitoring equipment.
4.3.3 Summary of Expenditures

The overall planned expenditure for the underground cable program in 2015 and 2016 is $4.8 million and $4.9 million respectively. This represents an average increase of 5% compared to the historic years, but is generally in-line with the 2014 bridge year expenditures of $4.7 million. This increase is required to complete a backlog of more time consuming and complex activities, such as cable jacket tests and polarization surveys on the cable sheaths and pipes which are cycle driven, outage dependent and are critical in order to maintain the expected service life of these aging assets. The corrective costs which are demand driven in the test years 2015 and 2016 are in line with the average costs during the historic years.

A reduction in this program will limit the ability to detect and repair defects, which will shorten the life expectancy of these critical assets, and will cause premature deterioration leading to oil leaks, insulation damage and loss of supply to critical customers in the major urban centres of Ontario. It will also increase environmental risks associated with an increase in oil leaks from these aging cables.

5.0 ENGINEERING AND ENVIRONMENTAL SUPPORT

5.1 Introduction

The engineering and environmental support program is in place to support activities, including management of records and drawings, CAD drawing support, data base management and provision of specific technical information (e.g. preliminary costing of potential investments for selecting the most cost-effective alternative). In addition, this program funds technical support including specialized studies, outage assessments conducted by the IESO, event investigation and incidents response and external
consulting services that provide technical expertise not available within Hydro One Transmission.

5.2 Investment Plan

This program is primarily driven by demand and the level work required support the transmission capital work programs. As the capital work program increases, the level of support required is impacted as these projects will require drawings, and in-turn increased drawing maintenance. The technical support and specialized studies are completed on an ad-hoc basis to aid in the decision making process for capital investments.

Table 14 outlines the proposed funding levels for the test years 2015 and 2016; along with the spending levels for the bridge and historic years.

Table 14
Engineering and Environmental Support OM&A
($ Millions)

<table>
<thead>
<tr>
<th>Description</th>
<th>Historic Years</th>
<th>Bridge Year</th>
<th>Test Years</th>
</tr>
</thead>
<tbody>
<tr>
<td>Engineering and Environmental Support</td>
<td>12.0</td>
<td>9.5</td>
<td>10.7</td>
</tr>
<tr>
<td><strong>Total</strong></td>
<td><strong>12.0</strong></td>
<td><strong>9.5</strong></td>
<td><strong>10.7</strong></td>
</tr>
</tbody>
</table>

This program is reviewed annually to assess the level of engineering and environmental support needs to recognize any incremental requirements related to the magnitude and scope of the planned transmission work programs.
5.3 Summary of Expenditures

The planned expenditure for the engineering and environmental support program in 2015 and 2016 is $11.9 million and $10.8 million respectively. This represents an average increase of 6% over the historic years, but is in-line with the 2014 bridge year expenditures of $11.9 million. This increase is required to complete risk assessments and engineering studies of arc flash hazards within Hydro One’s transmission stations. These studies are required to ensure safety of employees through identification of potentially unmitigated arc flash hazards and establishment of appropriate barriers and controls. These studies are consistent with the content of the CSA Z462 standard for Workplace Electrical Safety. A reduction in this program will result in deferral of these studies to identify and manage safety risks.
SUMMARY OF COMMON CORPORATE COSTS OM&A

Hydro One Common Corporate Costs OM&A is comprised of Common Corporate Functions and Services (“CCFS”), Asset Management Services, Information Technology (“IT”), Cornerstone, Cost of Sales to external parties and Other OM&A.

CCFS includes Corporate Management, Finance, Human Resources, Corporate Communications, Legal, Regulatory Affairs, Corporate Security, Internal Audit and Real Estate. Common Asset Management services include System Investment and Asset Stewardship and Strategies. IT and Cornerstone activities include providing and managing computer systems and installing enterprise IT systems. Other OM&A includes the capitalized overhead credit, the environmental provision credit, indirect depreciation and other costs.

Hydro One utilizes a centralized shared services model to deliver its common services to the Transmission and Distribution businesses within Hydro One Networks Inc., and to the legal entities Hydro One Inc., Hydro One Telecom Inc., Hydro One Networks Brampton Inc., and Hydro One Remote Communities Inc. Many organizations have adopted a common corporate cost model as an effective method of delivering common services to multiple subsidiaries and/or multiple business units. Hydro One adopted this model when it was established in 1999. The additional cost to establish the common functions in each of its subsidiaries would be cost prohibitive.

Table 1 summarizes the Transmission portion of the Common Corporate Cost and Other OM&A Costs over the Historic, Bridge and Test years.
Table 1

Allocated Transmission Corporate common costs and Other OM&A Costs

($ Millions)

<table>
<thead>
<tr>
<th>Description</th>
<th>Historic</th>
<th>Bridge</th>
<th>Test</th>
</tr>
</thead>
<tbody>
<tr>
<td>Common Corporate Functions and Services</td>
<td>74.0</td>
<td>80.5</td>
<td>87.7</td>
</tr>
<tr>
<td>Asset Management</td>
<td>25.0</td>
<td>32.3</td>
<td>31.8</td>
</tr>
<tr>
<td>Information Technology</td>
<td>57.6</td>
<td>60.7</td>
<td>61.1</td>
</tr>
<tr>
<td>Cost of Sales</td>
<td>12.8</td>
<td>11.4</td>
<td>13.9</td>
</tr>
<tr>
<td>Other OM&amp;A</td>
<td>(125.1)</td>
<td>(104.2)</td>
<td>(118.6)</td>
</tr>
<tr>
<td>Total</td>
<td>44.2</td>
<td>80.7</td>
<td>75.8</td>
</tr>
</tbody>
</table>

In the 2009-2014 period, Hydro One applied a cost allocation methodology developed by Black and Veatch Corporation (B&V) which utilizes a breakdown of activities and drivers. In 2013, the Company commissioned B&V to update the methodology to allocate common costs among the business entities using the common services, as discussed in Exhibit C1, Tab 6, Schedule 1. The approach utilizes a further breakdown of activities and drivers and is used in this proposed application.

The increase in OM&A spending in the test years 2015 through 2016 as compared to the historical years is primarily related to the trends described below.

- CCFS costs increase over the test years due to increased HR support for expanded field work programs and succession planning, long-term relationship building with First Nations and Métis communities and funding for the corporate records management project. See Exhibit C1, Tab 3, Schedule 3 for details.
• The work undertaken by Asset Management is expected to increase. Asset Management costs should benefit from productivity initiatives underway that are expected to impact the resourcing and demographic management strategy for the organization. See Exhibit C1, Tab 3, Schedule 4 for details.

• Other OM&A consists of credits associated with capitalized overheads, environmental provisions, indirect depreciation and Other Costs. These credits are explained in Exhibit C1, Tab 3, Schedule 3, Section 3.
COMMON CORPORATE FUNCTIONS AND SERVICES AND OTHER OM&A

1.0 OVERVIEW

Hydro One Networks has identified certain functions that provide common services to all business units. It was determined that these functions could be shared effectively by all business units, avoiding costly and unnecessary duplication. These costs are referred to as Common Corporate Functions and Services (“CCFS”). Included in this exhibit is a discussion of CCFS costs and activities as well as Other OM&A which is comprised of credits associated with Capitalized Overhead, Environmental Provisions, Indirect Depreciation and Other Costs.

2.0 COMMON CORPORATE FUNCTIONS AND SERVICES

Table 1 presents, for comparison purposes, the total CCFS costs over the Historic, Bridge and Test years as well as the 2015 and 2016 Hydro One Transmission allocation amounts.
Table 1

<table>
<thead>
<tr>
<th>Description</th>
<th>Historic Years</th>
<th>Bridge Year</th>
<th>Test Years</th>
<th>TX Allocation</th>
</tr>
</thead>
<tbody>
<tr>
<td>Corporate Management</td>
<td>5.1</td>
<td>5.0</td>
<td>4.9</td>
<td>5.3</td>
</tr>
<tr>
<td>Finance</td>
<td>31.9</td>
<td>35.2</td>
<td>41.9</td>
<td>45.0</td>
</tr>
<tr>
<td>Human Resources</td>
<td>11.0</td>
<td>9.9</td>
<td>11.1</td>
<td>13.1</td>
</tr>
<tr>
<td>Corporate Communications &amp; Services</td>
<td>8.7</td>
<td>11.3</td>
<td>15.0</td>
<td>13.9</td>
</tr>
<tr>
<td>General Counsel and Secretariat</td>
<td>7.4</td>
<td>8.8</td>
<td>9.6</td>
<td>10.1</td>
</tr>
<tr>
<td>Regulatory Affairs</td>
<td>20.1</td>
<td>20.6</td>
<td>20.6</td>
<td>24.1</td>
</tr>
<tr>
<td>Security Management</td>
<td>3.0</td>
<td>3.1</td>
<td>3.4</td>
<td>4.8</td>
</tr>
<tr>
<td>Internal Audit</td>
<td>3.1</td>
<td>3.5</td>
<td>3.4</td>
<td>3.6</td>
</tr>
<tr>
<td>Real Estate &amp; Facilities</td>
<td>51.6</td>
<td>54.6</td>
<td>54.1</td>
<td>60.2</td>
</tr>
<tr>
<td>Total CCF&amp;S Costs</td>
<td>141.9</td>
<td>152.0</td>
<td>164.0</td>
<td>180.1</td>
</tr>
</tbody>
</table>

Total CCFS costs increase by $13.1 million from 2013 to 2015 primarily due to the following factors: higher Real Estate costs for additional work space as a result of the growth in the company’s work program, increased Finance costs as a result of additional work functions being transferred to the Corporate Controller group previously in other groups and higher Corporate Security and Human Resource expenses. These increases are partially offset by decreased costs related to Outsourcing Contract Management.
From 2015 to 2016, total CCFS costs decrease by $1.0 million primarily due to a decrease in Finance and Human Resource costs.

Details on costs and work in each CCFS function are provided in the following sections.

2.1 Corporate Management

The following Table 2 provides a summary of Corporate Management costs:

<table>
<thead>
<tr>
<th>Description</th>
<th>Historic 2011</th>
<th>Bridge 2012</th>
<th>Test 2013</th>
<th>TX Allocation</th>
</tr>
</thead>
<tbody>
<tr>
<td>Total Cost</td>
<td>5.1</td>
<td>5.0</td>
<td>4.9</td>
<td>5.3</td>
</tr>
<tr>
<td></td>
<td>5.4</td>
<td>5.4</td>
<td>2.8</td>
<td>2.8</td>
</tr>
</tbody>
</table>

Corporate Management represents those functions responsible for providing overall strategic direction to the corporation, including the Board of Directors, Chief Executive Officer ("CEO"), Treasurer’s Office, Chief Financial Officer ("CFO") and General Counsel and Corporate Secretariat.

The General Counsel and Corporate Secretariat function provides advice and support to the Board of Directors and Corporate Officers. It provides advice and training, reports on Code of Conduct, reports on activities related to the Freedom of Information and Protection of Privacy Act (Ontario) as well as the Personal Information Protection & Electronic Documents Act (Canada).

The CFO is responsible for overseeing the finance function and for reporting information to Hydro One Inc.’s subsidiaries, regulators, investors and the shareholder. This includes reviewing and approving financial and investment decisions, business and strategic plans.
and ensuring the integrity of, and compliance with, internal controls over regulatory, financial and accounting activities.

The allocation of the costs associated with the activities of Corporate Management are governed by service level agreements between Hydro One Inc., Hydro One Networks and their affiliates as outlined in Exhibit A, Tab 9, Schedule 3. This exhibit also describes the activities performed by Hydro One Inc., Hydro One Networks and the amounts allocated to the various subsidiaries.

### 2.2 Finance

Table 3 provides a summary of finance costs.

<table>
<thead>
<tr>
<th>Description</th>
<th>Historic</th>
<th>Bridge</th>
<th>Test</th>
<th>TX Allocation</th>
</tr>
</thead>
<tbody>
<tr>
<td><strong>Total Cost</strong></td>
<td>31.9</td>
<td>35.2</td>
<td>41.9</td>
<td>45.0</td>
</tr>
</tbody>
</table>

### 2.2.1 Overview

Finance provides strategic advice and services related to planning, processing, recording, reporting and monitoring all financial transactions taking place within the organization. Clients include parties which are both internal and external to the organization, depending on the service provided. Services are provided through the following specialist functions:

- Corporate Controller;
- Corporate Tax; and
- Treasury.
2.2.2 Corporate Controller

The Corporate Controller provides leadership and direction regarding all business planning, performance management, financial reporting, accounting and internal control policies and procedures to ensure statutory and regulatory compliance and consistency with generally accepted accounting principles.

This function oversees the development of actual and forecast financial information and manages reporting processes for appropriate audiences or stakeholders. This function is also responsible for managing and providing direction to the company on internal control matters, employing measures such as “organization authority registers” and financial policies and procedures. It also provides leadership on compliance with Ontario securities laws, including Bill 198, and the Multi-Jurisdictional Disclosure System (“MJDS”) rules for a foreign-issuer registered with the U.S. Securities Exchange Commission (“SEC”).

The Corporate Controller function is responsible for establishing and leading the annual business planning and budgeting processes and for presenting the plan to the Board of Directors and the Provincial Government. This function is also responsible for developing and leading strategies and plans that support corporate goals related to the transmission and distribution businesses. This involves conducting special studies in areas like corporate performance, including reliability performance, benchmarking, work program performance, productivity, and cost savings management. Lastly, the Corporate Controller function performs services such as business case review, business valuation, transaction support, and develops and maintains financial models and provides analytical support for a variety of financial planning and reporting processes.

Many routine financial services are outsourced to a third party supplier, such as accounts payable, accounts receivable, fixed asset accounting, general accounting, planning budgeting and reporting support, pension support, human resources pay services and a
number of administrative procedures. The costs of these services comprise a major
portion of the Corporate Controller costs.

The total cost of Corporate Controller activities in 2015 is $37.9 million and, in 2016,
$37.0 million. The portion allocated to Hydro One Transmission is $21.6 million in 2015

Corporate Controller costs increased by $7.9 million in 2013 and a further $1.5 million in
2014, mainly due to the addition of certain functions to the Corporate Controller
organization made after company filed its transmission rate application EB-2012-0031.
In 2013, additional functions were added to the Corporate Controller organization: the
performance reporting functions previously included in the Business Performance
category within Asset Management, and the Time Reporting Centre and Corporate
Charge Card Compliance functions previously included in work program costs. In 2014,
Work Management and Project Accounting Specialists were moved to the Corporate
Controller’s organization. These transfers were made to better align the finance function
within the Corporate Controller organization. Beginning in 2016, costs are expected to
decrease due to process streamlining, productivity improvements and a decline in
outsourcing fees.

2.2.3 Corporate Tax

Corporate Tax manages the tax affairs (compliance, audits and planning), for each
taxable entity within the Hydro One group of companies. This includes corporate income
taxes, harmonized sales tax (previously, goods and services tax and provincial sales tax),
debt retirement charge, payroll and non-resident withholding tax, and the employer health
tax. Corporate Tax ensures that internal and external tax compliance requirements are
met. Moreover, Corporate Tax provides tax consulting services to other departments
with respect to mergers and acquisitions activities, payroll tax, taxable benefits,
agreements, financing, and all transactions and information about tax costs for regulatory purposes.

The costs associated with Corporate Tax activities are $2.4 million in 2015 and 2016, with $1.2 million being charged to Transmission annually.

2.2.4 **Treasury and Risk**

Total annual treasury costs are $6.5 million in 2015 and $6.6 million in 2016. Of these amounts, $2.7 million is incurred annually to:

- execute borrowing plans and issue commercial paper and long-term debt;
- ensure compliance with securities regulations, banks and debt covenants;
- manage the company’s daily liquidity position, control cash and manage the company’s bank accounts;
- settle all transactions and manage the relationship with creditors;
- communicate with debt investors, banks and credit rating agencies;
- develop business risk management policies, frameworks and processes;
- introduce and promote new techniques for assisting management to identify and evaluate risks within operations;
- prepare corporate risk assessments; and
- maintain a framework of key business risks.

A portion of the Treasury budget is recovered through the cost of long-term debt, as stated in Exhibit B1, Tab 2, Schedule 1.

The remaining $3.7 million for 2015 and $3.8 million for 2016 include costs relating to risk assessment, the negotiation and purchase of insurance policies, and claims management and settlement. These costs cover premiums paid for corporate shared
services insurance coverage, including third party liability, fiduciary liability, and directors and officers insurance. They also include the cost of self-insurance for liability exposures that are either not covered by insurance policies or fall below the specified deductibles. The cost of other insurance coverage is paid for and reported by the lines of business to whom the coverage is applicable.

Hydro One Transmission accounts for $2.5 million of the Treasury budget for 2015 and $2.5 million of the budget for 2016.

Table 4 shows the premiums for all of Hydro One Inc.’s insurance policies and the cost of self-insurance for the 2011 to 2016 period. Self-insurance costs for the 2015 and 2016 period take into consideration the company’s risks exposures, the long-term historical claims experience, the deductible on the liability policies and the costs of insuring the self-insured exposures. The main driver for self-insurance costs are claims by third parties which can fluctuate from year to year.

<table>
<thead>
<tr>
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<th></th>
<th></th>
<th></th>
<th></th>
<th></th>
</tr>
</thead>
<tbody>
<tr>
<td>Premiums paid for Corporate Functions and Services Insurance Policies *</td>
<td>1.2</td>
<td>1.3</td>
<td>1.4</td>
<td>1.7</td>
<td>1.8</td>
<td>1.8</td>
</tr>
<tr>
<td>Self-insurance Cost</td>
<td>0.8</td>
<td>3.2</td>
<td>1.2</td>
<td>2.0</td>
<td>2.0</td>
<td>2.0</td>
</tr>
<tr>
<td><strong>Total</strong></td>
<td><strong>2.0</strong></td>
<td><strong>4.5</strong></td>
<td><strong>2.6</strong></td>
<td><strong>3.7</strong></td>
<td><strong>3.7</strong></td>
<td><strong>3.8</strong></td>
</tr>
</tbody>
</table>

*The cost of other insurance coverage is captured and reported by the lines of business where the coverage is applicable.
2.3 Human Resources – “People & Culture”

Table 5 provides a summary of Human Resources costs:

<table>
<thead>
<tr>
<th></th>
<th></th>
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<th></th>
<th></th>
<th></th>
<th></th>
<th></th>
<th></th>
</tr>
</thead>
<tbody>
<tr>
<td>Total Cost</td>
<td>11.0</td>
<td>9.9</td>
<td>11.1</td>
<td>13.1</td>
<td>13.0</td>
<td>12.2</td>
<td>6.9</td>
<td>6.5</td>
</tr>
</tbody>
</table>

Early in 2013, the Human Resources function was renamed “People and Culture” (“P&C”) to highlight, in part, the importance of employees and the cultural transformation that Hydro One Networks is undertaking.

The P&C function exists to ensure that Hydro One Networks has the policies, systems and programs to attract, manage, engage and retain a high performing workforce to execute the corporate strategy. P&C provides consulting, leadership development and recruiting, diversity and resourcing programs, compensation and benefits services, and labour relations services.

One of the greatest challenges facing Hydro One Networks is in an area where P&C will be expected to play a significant role – the dramatic demographic transition that will be occurring in the company’s workforce over the next few years. In December 31, 2013, approximately 1,000 active staff members (serving both transmission and distribution businesses) were eligible for undiscounted retirement. The number of employees eligible to retire continues to grow, and the uptake in retirement is growing. Based on employee data today, over 1,500 employees will be eligible to retire by 2016. Retirement-eligible employees opting to retire increased by 16% between the period 2011 and 2012, and retirement rates for 2013 continued to show an increase in employees electing to retire.
2.3.1 Human Resource (HR) Operations

Hydro One Networks’ HR Operations provide advice and guidance to managers, supervisors, and employees on a myriad of issues related to HR policies and procedures, collective agreement administration, staffing and other large initiatives that impact staff. In addition to general HR consulting, HR Operations also performs a number of ‘specialist’ support/service activities. The Pension and Benefits Section within HR Operations administers the Hydro One pension plan for approximately 7,100 pensioners. In addition, this Section also administers the benefits programs for all employee groups.

2.3.2 Talent Management

This P&C function recommends and administers policy in areas related to external hiring and leadership development. In addition, it manages all of Hydro One Networks’ management/leadership development activities, including the assessment of high-potential succession candidates and miscellaneous specialized one-off hiring initiatives, as required.

2.3.3 Recruitment Solutions & Diversity

This function manages Hydro One Networks’ principal\(^1\) cyclical hiring and on-boarding processes - the New Graduate, the Co-Op Student, Internship and Developmental Student Programs, and the Summer Student Hiring Program. Additionally, this function is accountable for managing Hydro One’s Two-year New Grad Training and Development Program and implementing the company’s Diversity Plan, which includes Aboriginal recruitment and the Women in Leadership Program.

\(^1\) Trades staff are hired through the Power Workers’ Union Hiring Hall processes.
2.3.4 Compensation & Benefits

This function manages compensation, benefits, reporting and master data for all Hydro One Networks’ employees and pensioners by ensuring the accurate application, record-keeping and security of all such information. The Compensation and Benefits Group also provides regular, strategic reporting to senior management on HR and pay data on topics such as retirement demographics, headcount, overtime reports, data for OEB submissions, etc., as well as participating in industry wide compensation, benefit and pension surveys. The same group also manages the Short Term Incentive for management’s compensation.

2.3.5 Labour Relations

Labour Relations provides advice, guidance and training to managers regarding collective agreements and labour legislation and manages the grievance and arbitration process. The company is a party to twenty-four collective agreements and a number of mid-term agreements and letters of understanding. Labour Relations is responsible for negotiating and administering all such agreements and letters of understanding. In addition, the company must comply with legislation, such as the Ontario Labour Relations Act, the Employment Standards Act (Ontario), the Human Rights Code (Ontario), etc., all of which require interpretation to advise managers.

2.3.6 HR Productivity Initiatives

Continuous improvement is a core value at Hydro One Networks. Within the P&C function, there have been a number of initiatives to enhance productivity:

- The Human Resources/Payroll Transformation Project commenced in late 2013. This project will build further on the SAP platform and the SuccessFactors processes and
technology to automate a number of talent management processes including, performance management, succession and career development, compensation management, recruitment management, and to update the company’s current learning management system.

- The automation of Hydro One Networks’ performance management process will improve the quality of the information available to managers regarding their staff, provide transparency and consistency in creating goals and assessing performance, provide the ability to calibrate performance, improve the ease of accessing this information, and provide reporting and trending information that currently does not exist because the process is manual.

- The Pension Administration Team is outsourcing additional transactional tasks that are currently completed by the pension analysts. This will allow the team to focus on more strategic pension issues and improve service and communication to plan members. The goal is to reduce costs to the pension plan, increase pension awareness and mitigate risk on the transactional items.

- HR Operations and Labour Relation have been merged under P&C, which creates an opportunity to leverage relationships throughout the organization to drive the desired cultural transformation and leverage natural synergies between these two groups.

- The creation of new reports will improve reporting, making information more accessible for managers as required. This will reduce the number of ad hoc requests, which will reduce the transactional work required by the P&C Reporting Group, permit them to focus on more strategic and analytical work, and improve their ability to respond to urgent requests (such as requests from the OEB or the Hydro One Board of Directors).
A pensioner website is being developed that will provide external access to required information for pensioners. This will reduce the basic transactional work stemming from calls from pensioners. This will also reduce the cost of mailing printed materials to pensioners.

P&C re-branded its existing internal website and launched a new “People Matters” internal website, with emphasis being placed on better and more up-to-date information, new tools and better search capabilities. Making this information available on the internal website will reduce basic transactional work for P&C staff and will provide more detailed and consistent information for the company’s staff members, generally.

P&C will automate some master data transactions, using SAP technology, which will permit managers to complete HR transactions online, capturing data once at its source.

The vacancy management process has moved from a paper-based format to an electronic format. Files that were once stored in paper hardcopy are now stored electronically, allowing for quick and easy management of the information.

A new recruitment consultant was selected in 2013. The new consultant will assume many of the administrative duties currently done by P&C’s internal recruitment consultants. This will allow the internal recruitment consultants to focus on more strategic or relationship-building activities instead of simply processing paperwork. The goal is to improve customer service and decrease the administrative aspect of the job.
2.4 Corporate Communications

Table 6 provides a summary of Corporate Communications costs.

<table>
<thead>
<tr>
<th>Description</th>
<th>Historic</th>
<th>Bridge</th>
<th>Test</th>
<th>TX Allocation</th>
</tr>
</thead>
<tbody>
<tr>
<td>Total Cost</td>
<td>8.7</td>
<td>11.3</td>
<td>15.0</td>
<td>5.9</td>
</tr>
</tbody>
</table>

This function is performed by Corporate Communications, First Nations and Métis Relations and Outsourcing Services. The increase in costs over the historical years through the bridge year is reflective of the activities in the First Nations and Métis Relations, Corporate Communications and Outsourcing Services programs. First Nations and Métis Relations programs sustain long-term relationship building and negotiations with First Nations and Métis communities and are impacted by the growth of Hydro One core SDO work programs. Corporate Communications programs are targeting improvements in customer communications regarding power outages while increasing customer education and engagement efforts and research to support improved customer communication. The current outsourcing contract with Inergi LP expires in 2015. The re-tendering process currently underway which results in additional costs for the Outsourcing Services group. More details on the re-tendering process are available in Exhibit C1, Tab 3, Schedule 2.

2.4.1 Corporate Communications

Corporate Relations is comprised of Corporate Affairs, External Relations and the Executive Office. Corporate Relations is responsible for ensuring that Hydro One Networks builds the strategic relationships required to advance corporate objectives and
present a single, positive brand internally and externally. Corporate Affairs is responsible for corporate reputation, executive support, customer and employee communications, media relations, community investment, web communications and corporate brand identity. External Relations is accountable for supporting the company’s relationships with the government and its key stakeholders. External Relations also leads the Public Affairs Group which supports Hydro One Networks’ public consultation obligations and community relations programs. The Executive Office supports the executive team. It advances key strategic initiatives and interfacing with lines of business to assist in the implementation of these initiatives, coordinating the development of processes to ensure alignment within Hydro One Networks and a unified focus on key priorities.

In 2013, Corporate Relations costs increased primarily due to Corporate Affairs incurring one-time expenses, such as costs to support the Mobile Customer Discovery Centre and an increased number of customer surveys in support of this Proposed Custom Application. The Executive Office also absorbed the costs of two rotational staff in 2013. For the 2015-2016 forecast, these additional costs have not been included.

2.4.2 First Nations and Métis Relations

Another important role that falls within the Corporate Relations function is First Nations and Métis Relations. First Nations and Métis Relations programs foster and maintain long-term relationship building and conduct engagement with First Nations and Métis communities that may be impacted by Hydro One Networks core SDO work programs.

Hydro One Networks owns and maintains assets on reserve lands and within the traditional territories of First Nations & Métis Peoples. Hydro One Networks recognizes that First Nations and Métis peoples and their lands are unique in Canada, with distinct legal, historical and cultural significance. Building relationships with First Nations and
Métis communities based upon trust, confidence, and accountability is vital to achieving our corporate objectives. The First Nations and Métis Relations group encompasses the following functions:

- Sustains long-term capability in the areas of First Nations and Métis relationship building, engagement and the successful development and implementation of initiatives to achieve Hydro One Networks’ goals and objectives;
- Develops and maintains key relationships with government officials as well as representatives of key businesses including but not limited to other energy companies;
- Supports procurement opportunities for qualified First Nations & Métis businesses;
- Provides engagement services on projects and/or initiatives that potentially affect the First Nations & Métis peoples and communities;
- Provides leadership and advice within the company in the building of knowledge and awareness of First Nations and Métis historic and contemporary issues; and
- Develops, in conjunction with the Human Resources and Labour Relations departments, initiatives to enhance the level of aboriginal employment at Hydro One Network.

First Nations and Métis Relations costs are $3.1 million annually between 2015-2016. The portion allocated to Hydro One Transmission is $1.9 million annually for 2015 and 2016.

The increase in costs in the 2014 bridge year and 2015-2016 test years is required to sustain long-term relationship building and engagement processes with First Nations and Métis as a result of the growth of the Hydro One Networks core SDO work programs.
2.4.3  **Outsourcing Services**

The mandate of the Outsourcing Services Group is to govern and manage the contractual relationship with the company’s outsourcing partner (currently, Inergi LP) in a manner that fosters collaboration and optimizes value and minimizes risk by ensuring that contracted services are delivered. The Outsourcing Services Group is responsible for managing the design, development, and implementation of new service delivery agreements with Hydro One Networks’ suppliers.

The current outsourcing agreement with Inergi LP expires in 2015. Higher costs for the Outsourcing Services Group in the 2012 to 2014 period are primarily driven by: (a) fees for external support in preparing and issuing a request for proposals ("RFP") to replace the current outsourcing agreement, and (b) fees for a benchmarking study commissioned in 2013 to determine whether the costs under the current contract are market-comparable.

The Outsourcing Services Group’s annual costs are $2.9 million in test years 2015 and 2016. The portion allocated to Hydro One Transmission is $1.7 million in 2015 and $1.7 million for 2016.
2.5 General Counsel and Secretariat

Table 7 provides a summary of the costs of the General Counsel and Secretariat function:

<table>
<thead>
<tr>
<th>Description</th>
<th>Historic</th>
<th>Bridge</th>
<th>Test</th>
<th>TX Allocation</th>
</tr>
</thead>
<tbody>
<tr>
<td>Total Cost</td>
<td>7.4</td>
<td>8.8</td>
<td>9.6</td>
<td>10.1</td>
</tr>
<tr>
<td></td>
<td>10.2</td>
<td>10.2</td>
<td>5.4</td>
<td>5.4</td>
</tr>
</tbody>
</table>

2.5.1 Overview

The offices of the General Counsel and Corporate Secretary ("GC&CS") provide legal advice and direction to Hydro One Networks and its affiliates, as well as overall guidance in the areas of corporate structure, governance, business ethics and the business code of conduct. The GC&CS consists of two main functions: Law and the Corporate Secretariat. The Corporate Secretariat reports to the General Counsel.

The GC&CS functions in Hydro One Networks are set out below:

- Providing legal services to all business units including the company’s major borrowing and financing initiatives, regulatory activities, transmission and distribution businesses (contracts, other commercial matters), employment, including pension and benefits, health, safety and environment, litigation, all Board of Directors-related activities, and arranging for the provision of legal services to the company. The volume of these services is driven by capital and OM&A activities, as well as increasing regulatory and legislative oversight functions;
- Overseeing the Law and Corporate Secretariat functions; and
- Ensuring compliance with legal and regulatory requirements.
Hydro One Networks does most of its legal work in-house, except when the in-house expertise is not available (for example, tax, labour) or when the workload exceeds the capacity of the internal legal group.

The increase in costs for GC&CS is driven mainly by increased work requirements related to the GEA, securities law matters including registration in the United States with the Securities and Exchange Commission (SEC), corporate finance matters and pension-related matters. Examples of the additional workload include procurement-related work due to large work programs, preparation of legal agreements associated with distributed generation, real estate-related legal work to obtain land and land rights for new development projects, and preparation of renewed securities-related documents for filing in Ontario and with the SEC.

2.5.2 Law

Law provides legal advice to all business units of the company, acting as an internal law firm. It advises on most aspects of law affecting Hydro One Networks, and relies on its experience and knowledge of the company’s business in providing economic and timely advice. This function maintains core knowledge of the law and the company’s business.

2.5.3 Corporate Secretariat

The Corporate Secretariat provides support to the Office of the Chair, the Board of Directors and its Committees, including the administrative aspects of the Board of Directors and its meetings. It provides advice and analysis with regard to a variety of board-related matters, including corporate governance best practices and emerging trends and issues. It provides advice and direction with regard to the business Code of Conduct, ensuring appropriate actions to resolve known or suspected violations.
2.6 Regulatory Affairs

Table 8 provides a summary of Regulatory Affairs costs:

<table>
<thead>
<tr>
<th>Description</th>
<th>Historic</th>
<th>Bridge</th>
<th>Test</th>
<th>TX Allocation</th>
</tr>
</thead>
<tbody>
<tr>
<td>Regulatory Affairs</td>
<td>9.1</td>
<td>7.4</td>
<td>7.6</td>
<td>8.3</td>
</tr>
<tr>
<td>OEB/NEB Costs</td>
<td>11.0</td>
<td>13.2</td>
<td>13.1</td>
<td>15.8</td>
</tr>
<tr>
<td>Total Cost</td>
<td>20.1</td>
<td>20.6</td>
<td>20.6</td>
<td>24.1</td>
</tr>
</tbody>
</table>

2.6.1 Overview

Regulatory Affairs consists of the Compliance, Applications and Regulatory Administration functions. The costs include Hydro One Networks’ share of the Ontario Energy Board (“OEB”) costs, including the OEB quarterly assessment costs, OEB proceeding-specific costs and OEB-ordered intervener cost awards.

2.6.2 Regulatory Affairs Activities

Regulatory Affairs is responsible for managing the company's relationships with the regulatory bodies with which it interacts, including the Ontario Energy Board, the IESO, the OPA, and the National Energy Board. Through this function, it is responsible for developing strategy and coordinating the company's submissions to these bodies as well participation in regulatory initiatives.

Regulatory Affairs is involved in the coordination, preparation and processing of applications, as well as providing support to witnesses and business support staff. Such proceeding-specific services are provided for a wide range of applications, including
distribution and transmission rates, transmission leaves-to-construct, merger/ acquisition/
amalgamation/ divestiture applications and area and system supply planning. In addition
to proceeding-specific work, Regulatory Affairs is responsible for a variety of ongoing
reporting and other activities. The function prepares quarterly and annual reports
required under OEB Reporting and Record-keeping Requirements. Work includes
meeting, reporting on, and responding to regulatory compliance issues. Pricing and cost
allocation analysis and support are also provided within Regulatory Affairs for rate
applications. This includes the development of rate structures and rates for the regulated
transmission and distribution tariffs applicable to Hydro One Networks and provides
support in submitting and defending rate proposals. The function also assists with the
implementation of approved transmission and distribution rates.

Load Forecasting and Load Data Management Units are included within the Regulatory
Affairs group. Load forecasts are developed to enable system planning and financial
planning which underlie Hydro One Networks’ financial forecasts. The load forecast
function provides load forecast data including the capture of conservation and demand
management impacts. Load forecast staff support the company’s business units and the
OPA with forecasting analysis and evaluation covering time of use, bypass and
embedded generation. The Load Data Management Unit provides analytical support for
conservation and demand management projects and provides load research analysis.

Regulatory costs in 2014 through 2016 are being driven by an aggressive regulatory
program. This includes a distribution rate application for 2015-2019 and a proposed
transmission rate application for 2015-2016. Furthermore, the OEB is continuing a busy
and challenging program of reviews and initiatives, most of which involve the company.
At the present time, the OEB is conducting several generic proceedings on issues such as:
• Code amendments to the Transmission and Distribution System Codes;
• Consultation to Review the Framework Governing the Participation of Intervenors in Board Proceedings;
• Initiative to Develop Electricity Distribution System Reliability Standards;
• Regional Planning for Electricity Infrastructure; and
• Numerous other matters that arise from time to time.

2.6.3 **Ontario Energy Board Costs**

Under the *Ontario Energy Board Act, 1998*, the OEB is required to recover all of its annual operating costs. Almost all of its costs are recovered from gas and electricity distributors and electricity transmitters. A small fraction of OEB costs are recovered from the IESO, the OPA, Ontario Power Generation and from licensing fees and penalties. OEB costs that are subject to recovery include its staff costs, office space costs, administration costs and overheads. These costs are allocated to one of six categories – electricity distribution, electricity transmission, gas distribution, IESO, OPA and Ontario Power Generation. Hydro One Networks' allocation arises from OEB costs related to electricity distribution and transmission.

2.7 **Security Management**

Table 9 provides a summary of Security Management program costs.

<table>
<thead>
<tr>
<th>Description</th>
<th>Historic Bridge</th>
<th>Test TX Allocation</th>
</tr>
</thead>
<tbody>
<tr>
<td>Total Cost</td>
<td>3.0</td>
<td>3.1</td>
</tr>
</tbody>
</table>
The Security Management function (formerly referred to as Corporate Security Services) exists to enable Hydro One Networks’ success primarily in the protection of assets (assets include people, property and information), development and maintenance of Business Continuity and Emergency Preparedness & Response Plans and to assist in the reliable delivery of electricity. Security Management adds value by providing advice, coordination, guidance, investigative, technical and intelligence gathering expertise and services to company staff that support and optimize the reliable delivery of electricity, the protection of Hydro One Networks’ assets, and the resumption of business in the event of an all hazards (natural, technological or human-caused) incident. Effective asset protection and recovery can be the primary differentiating factor between success and failure for a critical infrastructure organization such as Hydro One Networks. This is achieved by effective corporate security policies, directives, guidelines and services, which can significantly enhance employee and business productivity and safety.

The increase in costs is a result of an increased focus on a variety of mitigating strategies to reduce the impact of metal theft (primarily copper) that threaten the reliability of the transmission and distribution systems and the safety and security of staff, first responders and the general public.

Incidents of copper theft have dropped, in part, due to adding security protection systems at heavily targeted transmission sites. However, more organized criminal incidents have occurred in relation to metal thefts recently, primarily targeting stations that have not benefited from increased capital expenditures for protection systems. Although the total number of incidents has dropped, the average loss per incident is increasing due to the sophistication and organization of these crime groups. These crimes take longer to investigate, and prevention methods and strategies are often very complex and costly.

Total Security Management costs are $4.8 million in 2015 and $4.6 million in 2016. The amounts allocated to Hydro One Transmission are $2.2 million for 2015 and $2.1 million for 2016.
2.8 Internal Audit

Table 10 provides a summary of Internal Audit costs.

<table>
<thead>
<tr>
<th>Description</th>
<th>Historic</th>
<th>Bridge</th>
<th>Test</th>
<th>TX Allocation</th>
</tr>
</thead>
<tbody>
<tr>
<td>Total Cost</td>
<td>3.1</td>
<td>3.5</td>
<td>3.4</td>
<td>3.6</td>
</tr>
</tbody>
</table>

Internal Audit reports to the CEO and the Audit and Finance Committee of the Board of Directors. It provides independent and objective assurance and consulting services designed to add value to and improve Hydro One Networks’ operations. The mandate for Internal Audit is to provide independent assurance to the CEO and the Board of Directors that internal controls are adequate in areas of high-risk and to follow-up and report on management actions to address findings from past audits.

The department helps the company accomplish its objectives by bringing a systematic and disciplined approach to evaluating and improving the effectiveness of risk management, internal control and governance processes. The total costs for this function are $3.6 million annually for 2015 and 2016. The portion allocated to Hydro One Transmission is $2.4 million annually for 2015 and 2016.
2.9 Real Estate and Facilities

Table 11 provides a summary of Real Estate and Facilities costs.

Table 11

<table>
<thead>
<tr>
<th>Description</th>
<th>Historic</th>
<th>Bridge</th>
<th>Test</th>
<th>TX Allocation</th>
</tr>
</thead>
<tbody>
<tr>
<td>Real Estate</td>
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<td>8.8</td>
<td>9.3</td>
<td>9.7</td>
</tr>
<tr>
<td>Facilities</td>
<td>42.3</td>
<td>45.8</td>
<td>44.8</td>
<td>50.5</td>
</tr>
<tr>
<td>Total Cost</td>
<td>51.6</td>
<td>54.6</td>
<td>54.1</td>
<td>60.2</td>
</tr>
</tbody>
</table>

2.9.1 Overview

The total cost for the Facilities and Real Estate function in 2015 is $61.4 million, with $36.6 million allocated to Hydro One Transmission. The 2016 cost is $61.3 million, with $36.6 million of that allocated to Hydro One Transmission.

The 2015-2016 funding is required for the expanded facilities work program that responds to current and future anticipated Hydro One Networks’ work space accommodation needs. This includes new facilities in the field. The facilities work program accounts for approximately 84% of total funding in test years 2015 and 2016.

The increase in funding requirements is mainly driven by new facilities and building additions being put in-service. New facilities will be replacing existing facilities at the end of their useful lives, and new facilities are also needed to meet increased accommodation needs driven by Hydro One Networks’ work program and operating requirements (which include housing specialized work equipment). The increase in funding requirements in bridge year 2014 and test years 2015 and 2016 is attributable to
planned office improvements, which are expected to result in additional swing space and office moves costs. The funding requirements in the bridge and test years also reflect corporate health and safety initiatives and expected increases in fixed operating costs.

2.9.2 Real Estate Services (“RES”)

Real Estate Services manages Hydro One Networks’ land rights portfolio across the Province. This involves maintaining rights across over 200,000 acres of owned corridor, easement and “statutory right” properties and acquiring any new rights needed to ensure the safe and reliable operation of the transmission and distribution system. In addition, Real Estate Services oversees the management of Hydro One Networks’ rights associated with distribution and transmission lands, stations and other property.

Real Estate Services’ key work activities include:

• managing the acquisition of new real estate rights, which supports the company’s distribution and transmission development and reinforcement project initiatives across the Province including those designed to accommodate renewable power sources on the grid;
• managing the Provincial secondary land use program on behalf of Ministry of Infrastructure/ Infrastructure Ontario (leasing transmission corridor lands to external parties);
• managing easement, other rights agreements on public/private sector, railway and other lands;
• managing First Nations land use permit settlements on reserve lands;
• managing about 500,000 unregistered, low-voltage, real estate rights agreements;
• providing specialized real estate service activities including managing property tax payments to municipalities, appealing property tax assessments, and providing employee relocation services; and
• maintaining Geographic Information System (GIS) – property record database.

More specific support is provided on a selected project basis. This includes provision of land ownership information, damage claim settlement, road access and other rights acquisitions.

Specialized real estate services are provided as necessary. This includes assessment appeals, payment of property taxes on lands/buildings, and employee relocation services as appropriate.

2.9.3 Facilities

The Facilities work program includes all aspects of company work space requirements which comprise not only company-owned facilities, but management of the portfolio of leased facilities and oversight of the construction of new facilities. The Facilities function manages all of the building and site facilities across the company. This includes leasing costs and contract management for head office. In addition, it includes costs for administrative facilities, service centres, and other work locations (for example, the London Call Centre). The Facilities organization is responsible to ensure program delivery in terms of service levels, planned capital improvements and providing for Hydro One Networks’ accommodation needs.

The Facilities program focuses on providing employee workspace at sites across the province including head office, administrative and service centres, the OGCC, and other work locations (for example, the London Call Centre).

Providing adequate workspace, storage and garage facilities for employees and trades is critical to the effective undertaking of organizational work programs. Equally important is ensuring that new or existing employee workspaces are consistently maintained to a
standard that meets current work requirements and complies with all corporate, legislative and other related health, safety and environmental standards. This program includes:

- providing accommodation strategies and acquiring new employee / trades workspace in line with operational requirements;
- managing 46 contract lease agreements for workspace rented from other parties, including renewals and contractual obligations undertaken regarding payment of rent, operating expenses and taxes;
- co-ordinating activities related to the ongoing management, operation, maintenance and inspection of 91 Administrative/Service Centres and Ontario Grid Control Centre; and
- providing support services for head office space, such as provision of office supplies and equipment, coordination of office moves, records management and tenant services.

The facilities costs are largely driven by space needs (including workspace and housing space for material and work equipment) which is affected by company work programs and factors such as changing business and operating requirements and fixed cost contractual obligations. Also, the current regulatory environment (including health and safety requirements) ultimately impacts operating costs. Accommodation needs are influenced by the development and growth of the company’s work programs and initiatives.

The majority of the Facilities work program costs are fixed. The Facilities work program is driven by fixed-cost contractual obligations, which arise primarily through relationships with external landlords. For example, rent, operating and tax costs are specified in formal lease agreements and opportunities to significantly amend these set
costs typically do not materialize until the agreement expires. Other fixed costs are represented by negotiated contracts with internal and external service providers for base level facility maintenance (administrative/service centre building maintenance, janitorial and snow removal, minor repairs, building component inspections) and similar activities. These contracts focus on maintaining facilities in a condition that meets current employee work requirements and corporate/legislative requirements. Fixed facility cost components (for example, utilities, property taxes, operational costs) are expected to continue to rise. 2015-2016 test year funding also takes into consideration changing factors in the operating environment.

3.0 OTHER OM&A

Other OM&A expenses are comprised of credits associated with Capitalized Overhead, Environmental Provisions, Indirect Depreciation and Other Costs as listed in Table 12.

Table 12

<table>
<thead>
<tr>
<th>Description</th>
<th>Test</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>2015</td>
</tr>
<tr>
<td>Capitalized Overhead</td>
<td>(122.2)</td>
</tr>
<tr>
<td>Environmental Provision</td>
<td>(6.3)</td>
</tr>
<tr>
<td>Indirect Depreciation</td>
<td>(6.4)</td>
</tr>
<tr>
<td>Other</td>
<td>0.9</td>
</tr>
<tr>
<td>Total</td>
<td>(134.0)</td>
</tr>
</tbody>
</table>
3.1 Capitalized Overhead Credit

Table 13
Transmission Corporate Overhead Credit ($ Millions)

<table>
<thead>
<tr>
<th>Description</th>
<th>Test</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>2015</td>
</tr>
<tr>
<td>Transmission</td>
<td>(122.2)</td>
</tr>
</tbody>
</table>

Capitalized overheads represent that portion of allocated shared corporate and/or business unit functions and services that support capital work. These costs are included in shared services and in the lines of businesses. OM&A expenses are thus reduced by the capitalized amounts. Capitalized OM&A costs are charged to capital work based on a capital overhead rate derived from the allocation and capitalization studies performed by Black & Veatch.

3.2 Environmental Provision

Table 14
Transmission Environmental Provision ($ Millions)

<table>
<thead>
<tr>
<th>Description</th>
<th>Test</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>2015</td>
</tr>
<tr>
<td>Transmission</td>
<td>(6.3)</td>
</tr>
</tbody>
</table>

In 2001, Hydro One Networks first recognized a liability on its balance sheet for the present value of the future estimated environmental expenditures needed to manage the risks associated with two legacy environmental issues inherited from Ontario Hydro. These risks pertained to polychlorinated biphenyls (PCBs) and two chemically contaminated lands. Future expenditures are required to inspect, test and remediate the contamination. Environmental work is initially recognized in the sustaining OM&A work program. The amount is then removed from OM&A as the costs are charged to the balance sheet provision. As well, the offsetting environmental regulatory asset is
amortized based on the pattern of expenditure. The resultant impact on revenue requirement of this environmental work is nil, since the amortization expense is grouped with 'Depreciation and Amortization' on the operating statement.

3.3 Indirect Depreciation

<table>
<thead>
<tr>
<th>Description</th>
<th>Test</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>2015</td>
</tr>
<tr>
<td>Indirect Depreciation</td>
<td>(6.4)</td>
</tr>
</tbody>
</table>

Transportation and Work Equipment ("TWE") charges in the OM&A work programs include depreciation expense associated with the asset being used. For accounting classification purposes, it is necessary to remove this depreciation amount from OM&A work programs and appropriately charge it as a depreciation expense. The credit increases in the test years due to the expanded use of T&WE in the larger SDO work program.

3.4 Other

<table>
<thead>
<tr>
<th>Description</th>
<th>Test</th>
</tr>
</thead>
<tbody>
<tr>
<td>Other Costs</td>
<td>2015</td>
</tr>
<tr>
<td></td>
<td>0.9</td>
</tr>
</tbody>
</table>

These costs represent material unexpected or non-recurring expenses. For example, they include items such as adjustments to provisions, vacation reserves, Gregorian or fiscal adjustments and inventory adjustments.
COMMON CORPORATE COSTS, COST ALLOCATION

METHODOLOGY

Allocation of Common Corporate Costs to Hydro One’s Distribution and Transmission businesses and to each Hydro One affiliate is based on clearly articulated shared functions and services and an established cost allocation approach based on cost causality principles.

The Common Corporate Costs OM&A programs include the provision of Corporate Common Functions and Services (“CCF&S”), Customer Service, Asset Management, Information Technology, and Operating Programs to support the Hydro One Networks’ Distribution and Transmission businesses.

CCF&S include Corporate Management, Finance, Human Resources, Corporate Communications & Services, General Counsel & Secretariat, Regulatory Affairs, Corporate Security, Internal Audit and Real Estate & Facilities.

A description of the CCF&S has been provided at Exhibit C1, Tab 3, Schedule 3.

Since 2004, in connection with each cost of service application, Hydro One has commissioned a study by Black and Veatch (B&V) to recommend a best practice methodology to allocate common corporate costs among the business entities using the common services. The adopted methodology represents the industry’s best practices, identifying appropriate cost drivers to reflect cost causality and benefits received. The 2014 report on this study is provided as Attachment 1 to this exhibit.

As part of the 2014 study, the cost drivers used to allocate the common corporate costs in EB-2012-0031 were updated to incorporate current information. Updating the driver
inputs resulted in a shift in allocated costs from Transmission to Distribution ($4.0 million or 1.0% of the total common corporate costs).

A time study was conducted within Hydro One’s Planning & Operating and Customer Service groups. The time study for these groups spanned a four week period ending May 31, 2013 and represented approximately $115 million of labour costs. Incorporating the time study’s results caused a shift in allocated costs from Distribution to Transmission ($4.2 million or 1.0% of the total common corporate costs).

Updating the time allocations of the functions and activities of all other groups that did not participate in the time study resulted in a shift from Distribution ($2.9 million or 0.7%) and Brampton ($0.2 million or 0.1%) to Transmission ($2.9 million or 0.7%) and Hydro One’s shareholder ($0.2 million or 0.1%). (Percentages are based on total common corporate costs.)

Hydro One accepted the results of the 2014 B&V study as providing a reasonable and equitable approach to the assignment of common corporate costs among the business entities using the common services. This methodology was based on the R. J. Rudden Associates (Rudden) Study that the Board accepted in the Distribution rate decision RP-2005-0020/EB-2005-0378.

The following Tables 1 to 2 provide the annual allocation of 2015-2016 CCF&S costs, respectively to all business units.
### Table 1
**Allocation of 2015 CCF&S Costs ($ Millions)**

<table>
<thead>
<tr>
<th>Description</th>
<th>Total</th>
<th>Transmission</th>
<th>Distribution</th>
<th>Hydro One Telecom</th>
<th>Hydro One Brampton</th>
<th>Hydro One Remotes</th>
<th>Hydro One Inc.</th>
</tr>
</thead>
<tbody>
<tr>
<td>Corporate Management</td>
<td>5.4</td>
<td>2.8</td>
<td>2.4</td>
<td>0.1</td>
<td>0.1</td>
<td>0.0</td>
<td>0.1</td>
</tr>
<tr>
<td>Finance</td>
<td>44.6</td>
<td>25.3</td>
<td>18.0</td>
<td>0.8</td>
<td>0.2</td>
<td>0.3</td>
<td>0.0</td>
</tr>
<tr>
<td>Human Resources</td>
<td>13.0</td>
<td>6.9</td>
<td>5.7</td>
<td>0.2</td>
<td>0.0</td>
<td>0.1</td>
<td>0.0</td>
</tr>
<tr>
<td>Corporate Communications &amp; Services</td>
<td>12.6</td>
<td>5.9</td>
<td>6.6</td>
<td>0.0</td>
<td>0.0</td>
<td>0.1</td>
<td>0.0</td>
</tr>
<tr>
<td>General Counsel &amp; Secretariat</td>
<td>10.2</td>
<td>5.4</td>
<td>4.1</td>
<td>0.1</td>
<td>0.2</td>
<td>0.3</td>
<td>0.1</td>
</tr>
<tr>
<td>Regulatory Affairs</td>
<td>21.5</td>
<td>9.3</td>
<td>12.0</td>
<td>0.0</td>
<td>0.0</td>
<td>0.1</td>
<td>0.2</td>
</tr>
<tr>
<td>Corporate Security</td>
<td>4.8</td>
<td>2.2</td>
<td>2.5</td>
<td>0.0</td>
<td>0.0</td>
<td>0.0</td>
<td>0.0</td>
</tr>
<tr>
<td>Internal Audit</td>
<td>3.6</td>
<td>2.4</td>
<td>1.1</td>
<td>0.1</td>
<td>0.0</td>
<td>0.0</td>
<td>0.0</td>
</tr>
<tr>
<td>Real Estate &amp; Facilities</td>
<td>61.4</td>
<td>36.6</td>
<td>24.7</td>
<td>0.0</td>
<td>0.0</td>
<td>0.0</td>
<td>0.0</td>
</tr>
<tr>
<td><strong>Total CCF&amp;S Costs</strong></td>
<td><strong>177.1</strong></td>
<td><strong>96.8</strong></td>
<td><strong>77.2</strong></td>
<td><strong>1.3</strong></td>
<td><strong>0.5</strong></td>
<td><strong>0.9</strong></td>
<td><strong>0.4</strong></td>
</tr>
</tbody>
</table>

### Table 2
**Allocation of 2016 CCF&S Costs ($ Millions)**

<table>
<thead>
<tr>
<th>Description</th>
<th>Total</th>
<th>Transmission</th>
<th>Distribution</th>
<th>Hydro One Telecom</th>
<th>Hydro One Brampton</th>
<th>Hydro One Remotes</th>
<th>Hydro One Inc.</th>
</tr>
</thead>
<tbody>
<tr>
<td>Corporate Management</td>
<td>5.4</td>
<td>2.8</td>
<td>2.4</td>
<td>0.1</td>
<td>0.1</td>
<td>0.0</td>
<td>0.1</td>
</tr>
<tr>
<td>Finance</td>
<td>43.8</td>
<td>24.9</td>
<td>17.6</td>
<td>0.7</td>
<td>0.2</td>
<td>0.3</td>
<td>0.0</td>
</tr>
<tr>
<td>Human Resources</td>
<td>12.2</td>
<td>6.5</td>
<td>5.4</td>
<td>0.2</td>
<td>0.0</td>
<td>0.1</td>
<td>0.0</td>
</tr>
<tr>
<td>Corporate Communications &amp; Services</td>
<td>12.6</td>
<td>5.9</td>
<td>6.6</td>
<td>0.0</td>
<td>0.0</td>
<td>0.1</td>
<td>0.0</td>
</tr>
<tr>
<td>General Counsel &amp; Secretariat</td>
<td>10.2</td>
<td>5.4</td>
<td>4.1</td>
<td>0.1</td>
<td>0.2</td>
<td>0.3</td>
<td>0.1</td>
</tr>
<tr>
<td>Regulatory Affairs</td>
<td>22.4</td>
<td>9.8</td>
<td>12.4</td>
<td>0.0</td>
<td>0.0</td>
<td>0.1</td>
<td>0.2</td>
</tr>
<tr>
<td>Corporate Security</td>
<td>4.6</td>
<td>2.1</td>
<td>2.4</td>
<td>0.0</td>
<td>0.0</td>
<td>0.0</td>
<td>0.0</td>
</tr>
<tr>
<td>Internal Audit</td>
<td>3.6</td>
<td>2.4</td>
<td>1.1</td>
<td>0.1</td>
<td>0.0</td>
<td>0.0</td>
<td>0.0</td>
</tr>
<tr>
<td>Real Estate &amp; Facilities</td>
<td>61.3</td>
<td>36.6</td>
<td>24.7</td>
<td>0.0</td>
<td>0.0</td>
<td>0.0</td>
<td>0.0</td>
</tr>
<tr>
<td><strong>Total CCF&amp;S Costs</strong></td>
<td><strong>176.1</strong></td>
<td><strong>96.4</strong></td>
<td><strong>76.7</strong></td>
<td><strong>1.2</strong></td>
<td><strong>0.5</strong></td>
<td><strong>0.9</strong></td>
<td><strong>0.4</strong></td>
</tr>
</tbody>
</table>
OVERHEAD CAPITALIZATION RATE

This evidence describes the methodology used to allocate Common Corporate Costs (which includes Corporate Functions and Services, Asset Management and Operators) to capital projects.

Hydro One capitalizes costs that are directly attributable to capital projects and also capitalizes overheads supporting capital projects. The overhead capitalization rate is a calculated percentage representing the amount of overhead costs that are required to support capital projects in a given year.

In its April 9, 2010 Decision on Hydro One's 2010 and 2011 distribution rates (EB-2009-0096), the Board accepted the methodology, recommendations and the allocation of costs from a study by Black & Veatch (B&V) (formerly RJ Rudden Associates). This study was commissioned to derive an overhead capitalization rate for Hydro One Distribution's common corporate costs. The accepted methodology was also used the previous distribution rate application EB-2007-0681 and the most recent transmission rate application EB-2012-0031.

Hydro One commissioned B&V to review and update its capital overhead methodology. The 2015-2016 overhead capitalization rates have been calculated consistent with the previously accepted B&V study methodology. The consistency in the use of this approach for the 2015-2016 test years has been reviewed by B&V in 2014, and is provided as Attachment 1 to this Exhibit.

Hydro One Networks in 2007 began reviewing the overhead capitalization rate on a quarterly basis to determine if the rate needed to be changed to reflect in-year changes in capital spending and associated support costs. At year-end, capitalized overheads are
trued-up to reflect actual results. This results in a better alignment of overhead costs with the capital projects that they support and removes the need for an e-factor adjustment.

Hydro One proposes that the resulting overhead capitalization rate as calculated in the B&V study in 2013, continues to be a reasonable method of distributing common corporate costs to capital projects. Hydro One’s submissions in this Proposed Application reflect the overhead capitalization rate as developed.

Table 1 summarizes the overhead capitalization rates as reviewed by B&V.

<table>
<thead>
<tr>
<th>Overhead Cost Category</th>
<th>Test Years</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>2015</td>
</tr>
<tr>
<td>Capitalized Administrative &amp; General Costs</td>
<td>11%</td>
</tr>
<tr>
<td>Capitalized Operating Costs</td>
<td>3%</td>
</tr>
<tr>
<td>Total</td>
<td>14%</td>
</tr>
</tbody>
</table>

Table 2

<table>
<thead>
<tr>
<th>Overhead Cost Category</th>
<th>Test Years</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>2015</td>
</tr>
<tr>
<td>Capitalized Administrative &amp; General Costs</td>
<td>92.8</td>
</tr>
<tr>
<td>Capitalized Operating Costs</td>
<td>29.5</td>
</tr>
<tr>
<td>Total</td>
<td>122.2</td>
</tr>
</tbody>
</table>

In its EB-2011-0268 decision, the Board granted Hydro One Transmission approval to adopt United States Generally Accepted Accounting Principles (US GAAP) in place of

In its EB-2011-0268 decision, the Board also directed Hydro One Transmission to conduct a critical review of its then current and proposed capitalization practices. The Board stated that the review should not be a benchmarking study, but should include information, for comparison purposes, on what US transmitters typically capitalize and capitalization methodologies employed by other transmitters. (See page 13 of the decision.) A summary of the results of this review (which covered both transmission and distribution entities) was filed as part of Hydro One Transmission’s last transmission rate application (EB-2012-0031). The methodologies used to allocate Common Corporate Costs and Other O&M costs to the transmission overhead capitalization rate was determined to be appropriate by the intervenors and Board Staff who participated in the Settlement Conference, and was accepted by the Board in its Decision.

As documented in the review report, Hydro One critically reviewed its cost capitalization policy with a particular focus on the capitalization of overhead and indirect costs. In its review, Hydro One found that its treatment of overhead capitalized is generally consistent with other major US and Canadian industry participants. Hydro One’s overhead capitalization rate, when expressed as a percentage of gross operating costs, is within the observed range and essentially consistent with the median found in Hydro One’s industry research of other Canadian and US utilities. Hydro One also concluded that its overhead and indirect cost capitalization methodology, as reviewed by Black and Veatch and previously approved by the Board, is consistent with (a) legacy Canadian and existing US GAAP and (b) regulatory principles, including the key goals of achieving intergenerational equity and avoiding cross subsidization.
COMMON ASSET ALLOCATION

1.0 INTRODUCTION

This evidence will discuss the nature of Common Fixed Assets ("Shared Assets") and the method by which the costs of these assets are assigned to the Distribution and Transmission business units.

Similar to the corporate common costs discussed in Exhibit C1, Tab 6, Schedule 1, Hydro One has been able to maximize efficiencies through the centralization of the maintenance, management and purchase of shared assets at the corporate level. These assets include shared land and buildings, telecommunication equipment, computer equipment, applications software, tools and transportation and work equipment ("T&WE").

2.0 SHARED ASSETS AND FACILITIES COSTS

Most fixed assets are directly assigned to the appropriate business unit. The remaining assets (4% of total assets) are considered shared assets, and are allocated to Transmission and Distribution as described later in this exhibit. Table 1 summarizes the total gross fixed assets and identifies the proportion of allocated shared assets.
Table 1
Summary of Gross Fixed Assets
as at December 31, 2012 ($ Million)

<table>
<thead>
<tr>
<th></th>
<th>Transmission</th>
<th>Distribution</th>
<th>Total</th>
</tr>
</thead>
<tbody>
<tr>
<td>Total Fixed Assets</td>
<td>13,540.7</td>
<td>8,363.0</td>
<td>21,903.7</td>
</tr>
<tr>
<td>Shared Assets (in Total)</td>
<td>511.7</td>
<td>698.7</td>
<td>1,210.4</td>
</tr>
<tr>
<td>Shared Asset %</td>
<td>42.3%</td>
<td>57.7%</td>
<td>100%</td>
</tr>
</tbody>
</table>

Shared assets are sub-divided into two categories. Major Fixed Assets consist of land, buildings, applications software, and telecommunications equipment. Minor Fixed Assets include office furniture, computer equipment, tools and T&WE. Table 2 shows the proportion of major and minor shared fixed assets, accumulated depreciation and net book value as of December 31, 2012.

Table 2
Details of Shared Net Fixed Assets
as at December 31, 2012 ($ Million)

<table>
<thead>
<tr>
<th>Asset</th>
<th>Gross Asset Value</th>
<th>Accumulated Depreciation</th>
<th>Net Book Value</th>
</tr>
</thead>
<tbody>
<tr>
<td>Shared Major Assets</td>
<td>539.2</td>
<td>292.2</td>
<td>247.0</td>
</tr>
<tr>
<td>Shared Minor Assets</td>
<td>671.2</td>
<td>386.2</td>
<td>285.0</td>
</tr>
<tr>
<td>Total Shared Assets</td>
<td>1,210.4</td>
<td>678.4</td>
<td>532.0</td>
</tr>
</tbody>
</table>

3.0 ALLOCATION OF SHARED ASSETS IN SERVICE

Due to the nature of Hydro One's business, shared assets are not directly attributable to either the Transmission or Distribution business units. In addition, from year to year, the use of these shared assets may change, based upon changes in the underlying
transmission and distribution work programs. Consequently, the methodology by which shared assets are allocated to the Transmission and Distribution business units is subject to periodic review. The intent of such a review is to ensure that the assignment of assets is reflective of their use and that the costs are apportioned appropriately amongst the business units.

In 2008, Hydro One commissioned a study by Black & Veatch (B&V) (Formerly R.J. Rudden Associates) to determine a methodology to allocate the assets which are not directly attributable to Transmission or Distribution. The methodology developed represents industry best practices, identifying appropriate cost drivers to reflect cost causality and benefits received. The B&V study resulted in the allocation of shared assets based on the relative usage by Transmission and Distribution or by cost drivers, similar to those used for the common corporate functions and services.

Hydro One has accepted the approach of the B&V study as a reasonable representation of the use of shared assets amongst the business units. This methodology was utilized and subsequently endorsed by the Board in the previous Distribution rate Decision RP-2005-0020/EB-2005-0378/EB-2007-0681 and in the subsequent Transmission rate Decision EB-2006-0501/EB2008-0272/EB-2010-0002/EB-2012-0031, and was also used in Hydro One’s latest application for Distribution Rates for 2015 to 2019 (EB-2013-0416).

The appropriate use of the common asset allocation methodology for the 2015 to 2016 test years has been reviewed and confirmed by B&V in 2014, and is provided as Attachment 1 to this Exhibit.

Due to the significance of Cornerstone as a Shared Asset, Hydro One has developed transfer price charge rates to allocate a portion of the revenue requirement related to certain Shared Assets to the Telecom and Remotes businesses. The methodology and
impact of the transfer price charges are described in more detail in Attachment 1 to this Exhibit.

Hydro One has used the approved B&V Asset Allocation methodology in this proposed application and Table 3 below shows the Hydro One Common Asset allocation as at December 31, 2012.

Table 3
Hydro One Common Asset Allocation
as at December 31, 2012 ($ Million)

<table>
<thead>
<tr>
<th>Total Gross Value</th>
<th>All Hydro One Transmission &amp; Distribution Assets</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>$21,903.7 million</td>
</tr>
<tr>
<td>Transmission (Total)</td>
<td>$13,540.7</td>
</tr>
<tr>
<td>Distribution (Total)</td>
<td>$8,363.0</td>
</tr>
<tr>
<td>Transmission (Direct)</td>
<td>$13,029.0</td>
</tr>
<tr>
<td>Distribution (Direct)</td>
<td>$7,664.3</td>
</tr>
<tr>
<td>Transmission (Common)</td>
<td>$511.7</td>
</tr>
<tr>
<td>Distribution (Common)</td>
<td>$698.7</td>
</tr>
</tbody>
</table>
DEPRECIATION AND AMORTIZATION EXPENSES

1.0 INTRODUCTION

The purpose of this evidence is to summarize the method and amount of Hydro One Transmission’s depreciation and amortization expense for the 2015 and 2016 test years.

The depreciation and amortization expense for Hydro One’s submission for 2007 and 2008 Electricity Transmission revenue requirements (EB-2006-0501) was supported by an independent study conducted by Foster Associates Inc. (Foster), completed in June, 2006. In EB-2008-0272, Hydro One submitted a 2008 Technical Update conducted by Foster completed in August 2008 that supported the 2009 and 2010 depreciation and amortization expense. No Depreciation Study or Technical Update was carried out for 2011 or 2012 rates and depreciation rates were not changed from those previously approved. The Board accepted the costs flowing from the previous Depreciation Study and Technical Updates for the purpose of supporting Transmission rates in those years. Foster Associates has completed a new Depreciation Study for Hydro One Transmission in support of its 2015 and 2016 proposed application. The new study can be found at Exhibit C1, Tab 7, Schedule 1, Attachment 1.

The depreciation and amortization expense for 2015 is $394.2 million and for 2016 is $404.0 million.

2.0 DEPRECIATION EXPENSE

In accordance with the Board’s Decision (EB-2006-0501), Hydro One Transmission used the Foster methodology, updated to reflect the results from the new Depreciation Study
completed in 2014, for determining the depreciation rates proposed to be used in the
calculation of depreciation expenses for 2015 and 2016.

The depreciation expense for 2015 is $387.7 million and for 2016 is $397.9 million.

Detailed depreciation schedules are filed at Exhibit C2, Tab 4, Schedule 1.

Table 1
Transmission Depreciation Expense

<table>
<thead>
<tr>
<th>Description</th>
<th>Historic</th>
<th>Bridge</th>
<th>Test</th>
</tr>
</thead>
<tbody>
<tr>
<td>Depreciation On Fixed Assets</td>
<td>282.3</td>
<td>301.4</td>
<td>304.3</td>
</tr>
<tr>
<td>Less Capitalized Depreciation</td>
<td>(9.6)</td>
<td>(9.3)</td>
<td>(9.7)</td>
</tr>
<tr>
<td>Asset Removal Costs</td>
<td>19.7</td>
<td>22.1</td>
<td>25.4</td>
</tr>
<tr>
<td>Losses/(Gains) On Asset Disposition</td>
<td>(0.1)</td>
<td>(0.1)</td>
<td>0.2</td>
</tr>
<tr>
<td>Total</td>
<td>292.3</td>
<td>314.1</td>
<td>320.3</td>
</tr>
</tbody>
</table>

3.0 AMORTIZATION EXPENSE

Amortization expense addresses the recovery of amounts that the Board has required
Hydro One Transmission to defer to a future date. The Board has, in past decisions,
approved the deferred balance and prescribed the method and time period over which the
balance in each regulatory deferral or variance account may be disposed.
Amortization schedules for test, bridge and historical years are filed at Exhibit C2, Tab 4, Schedule 1. Table 2, below, reproduces this summary.

### Table 2

**Transmission Amortization Expense (S Million)**

<table>
<thead>
<tr>
<th></th>
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<th></th>
<th></th>
<th></th>
<th></th>
</tr>
</thead>
<tbody>
<tr>
<td>Environmental Assets and Other</td>
<td></td>
<td>8.9</td>
<td>5.9</td>
<td>6.1</td>
<td></td>
<td>11.2</td>
<td>6.5</td>
<td></td>
<td>6.1</td>
</tr>
</tbody>
</table>

3.1 **Environmental Assets and Other**

Hydro One Transmission provides for estimated future expenditures required to remediate past environmental contamination and to comply with current environmental legislation. Since these future expenditures are expected to be recovered in future rates, Hydro One Transmission has recognized the net present value of these estimated future expenditures as a regulatory asset on its Balance Sheet. This regulatory asset balance is amortized on a basis consistent with the pattern of current expenditures expected to be incurred up to the year 2018. Hydro One Distribution received concurrence from the Board for this accounting treatment as part of the RP-2000-0023 Decision. Hydro One Transmission’s treatment of these costs in its Application for 2007-2008 Transmission Rates (EB-2006-0501) was consistent with that Decision and was accepted by the Board. The treatment of these costs in this Submission is consistent with both of these prior proceedings.
PAYMENTS IN LIEU OF CORPORATE INCOME TAXES

1.0 INTRODUCTION

Under the Electricity Act, 1998, Hydro One Networks Inc. ("Networks") is required to make payments in lieu of corporate income taxes ("PILs") relating to taxable income earned by its transmission business. The Board has directed that the taxes payable method should also be used for regulatory purposes, according to its 2006 EDR Handbook, Section 7.1 “OEB 2006 Regulatory Taxes Expense Methodology”.

Under the taxes payable method, no provision is made for future income taxes that result from timing differences between the tax basis of assets and liabilities and their carrying amounts for accounting purposes. Accordingly, the taxes payable method will result in the PILs income tax payable being different from the amount that would have been recorded, had the combined Canadian Federal and Ontario statutory income tax rate been applied to the regulatory net income before tax. When unrecorded future income taxes become payable, it is expected that they will be included in the rates approved by the Board and recovered from customers at that time.

PILS installments are remitted by Networks to the OEFC at the end of each month. Any balance owing at the end of the year is required to be paid by the end of February of the following year.

In the absence of an Electricity Transmission Handbook, the 2015 and 2016 Hydro One transmission regulatory tax calculations have been prepared consistent with the approach found in the 2006 EDR Handbook and the 2006 EDR Tax Model, as this approach reflects the tax payable relating to taxable income earned by the transmission business.
2.0 INCOME TAX RATE (FEDERAL AND ONTARIO)

A combined income tax rate of 26.5% has been used for the test years 2015 and 2016, comprised of a Federal rate of 15% and an Ontario rate of 11.5% as a result of the Ontario budget bill enacted on June 20, 2012. Any variance between actual taxes payable and forecast taxes, as a result of rate changes for income tax or capital cost allowance will be captured in a deferral account for tax rate changes, described further in Exhibit F1, Tab 1, Schedules 1 and 2.

3.0 RECONCILIATION BETWEEN REGULATORY NET INCOME BEFORE TAX AND TAXABLE INCOME

Reconciliation between the regulatory net income before tax ("NIBT") and taxable income for the test years 2015 and 2016 is provided in Exhibit C2, Tab 5, Schedule 1, Attachments 1 & 2. This schedule contains the income tax component of the PILs computation. It also shows how the taxable income is computed by making adjustments to the regulatory NIBT for items such as depreciation and capital cost allowance (CCA).

Reconciliation between the accounting NIBT and taxable income for the historical years 2009 and 2010 is also provided in Exhibit C2, Tab 5, Schedule 1, Attachments 3 & 4. In order to make it easier to follow these reconciliations, Hydro One Transmission has placed these adjustments into the following five categories:

1) Recurring items that must be added (deducted) because they have been included in the OM&A expenses in arriving at the revenue requirement, or for which appropriate tax adjustments are made (for example, depreciation versus CCA);
2) Deferral accounts not included in the revenue requirement;
3) Reversal of accounting adjustments not included in the revenue requirement;
4) Recurring items not in the revenue requirement; and
5) Items whose impact is immaterial in total, and as such, have not been included in the Company’s business plan (applicable to test years only).

4.0 OVERVIEW OF PROCESS TO ARRIVE AT TAXABLE INCOME

The starting point for the computation of Hydro One Transmission's taxable income is the NIBT as shown on the utility's income statement for the year. The NIBT is prepared using U.S. Generally Accepted Accounting Principles, but taxable income is computed using the relevant tax legislation, interpretations and assessing practices. Therefore, many adjustments are typically made to the NIBT to arrive at taxable income. Essentially, the NIBT is increased by amounts that are not deductible for tax purposes. This includes items such as depreciation, contingent liabilities, accounting losses, accounting provisions such as other post employment benefits ("OPEB") and revenue that has been received but not recognized for accounting purposes (for example, transmission export revenue). On the other hand, the NIBT is reduced by amounts that are deductible for tax purposes but have not been deducted in computing NIBT. This includes items such as CCA, the deductible portion of capitalized overhead, accounting gains and OPEB payments. Such reductions also include expenses incurred for which a deferral account has been set up on the balance sheet, rather than shown as a deduction through the income statement.

Consequently, it is imperative that the NIBT be adjusted for amounts that have been included (or deducted) for accounting purposes that are not income (or deductible) for tax return purposes.
5.0 TAX TREATMENT OF DEFERRAL ACCOUNTS (REGULATORY ASSETS AND LIABILITIES)

Deferral accounts are typically recognized by utilities' balance sheets for foregone revenue or for expenses that have been incurred, for which recovery will be sought from ratepayers through future rates. Disposition of the deferral accounts is determined by the Board.

For example, as shown in Table 1, assuming that a 25% tax rate and a $100 expense is incurred, the utility will be allowed to deduct the $100 in computing taxable income for the year in which the expense has been incurred. If the Board subsequently approves recovery of this expense over a 2-year period through a rate rider, the income will be included in computing taxable income for the year in which it is billed to ratepayers. The net result is that the utility has recovered the $100 cost although the income or expense has been taxed or deducted in different years.

<table>
<thead>
<tr>
<th>Table 1</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
</tr>
<tr>
<td>---</td>
</tr>
<tr>
<td>Income (deduction)</td>
</tr>
<tr>
<td>Tax Refund (payable)</td>
</tr>
<tr>
<td>Cash Inflow (outflow)</td>
</tr>
</tbody>
</table>

Therefore, deferral accounts have not been included in computing tax payable for purposes of the revenue requirement since the tax benefit has or will be obtained through the tax system. It should be noted that this conclusion is consistent with the "2006 EDR Handbook Report of the Board" issued May 11, 2005 (page 61) that stated as follows:

"A PILS or tax provision is not needed for the recovery of deferred regulatory asset costs, because the distributors have deducted, or will
deduct, these costs in calculating taxable income in their returns. The Handbook will reflect this treatment."

6.0 CONTINGENT LIABILITIES/ACCOUNTING RESERVES

Where an accounting provision is recognized for certain contingent costs that the utility may have to incur in the future (such as obsolescence provisions, lawsuits, staff reductions), the provision will reduce the NIBT of the utility. In each subsequent year, the balance for the contingent liability/accounting reserve is reviewed by the utility for reasonableness based upon the information available at that time. The balance may be adjusted upward or downward, with NIBT either decreasing or increasing, respectively.

However, for tax purposes, a contingent liability or accounting reserve is not deductible. Rather, the amount will only be deductible (or capitalized) in computing taxable income for the taxation year in which the obligation has actually been settled. Therefore, to the extent that the current year NIBT has been increased (or decreased) by the contingent liability or accounting reserve provision, the NIBT must be adjusted to reverse the increase (or decrease) in computing taxable income.

It is not necessary to adjust the 2015 and 2016 NIBT for contingent liabilities in computing taxable income since no changes were forecasted in the contingent liability balances for 20135 and 20146. Therefore, such amounts are not included in the tax computation for purposes of the revenue requirement.
The combined (Federal and Ontario) enacted income tax rates are as follows:

<table>
<thead>
<tr>
<th></th>
<th>Historic</th>
<th>Bridge</th>
<th>Test</th>
</tr>
</thead>
<tbody>
<tr>
<td><strong>Federal Tax Rate (%)</strong></td>
<td>16.50</td>
<td>15.00</td>
<td>15.00</td>
</tr>
<tr>
<td></td>
<td>15.00</td>
<td>15.00</td>
<td>15.00</td>
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<tr>
<td></td>
<td>15.00</td>
<td>15.00</td>
<td>15.00</td>
</tr>
<tr>
<td></td>
<td>15.00</td>
<td>15.00</td>
<td>15.00</td>
</tr>
<tr>
<td><strong>Provincial Rate (%)</strong></td>
<td>11.75</td>
<td>11.50</td>
<td>11.50</td>
</tr>
<tr>
<td></td>
<td>11.50</td>
<td>11.50</td>
<td>11.50</td>
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<tr>
<td></td>
<td>11.50</td>
<td>11.50</td>
<td>11.50</td>
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<tr>
<td></td>
<td>11.50</td>
<td>11.50</td>
<td>11.50</td>
</tr>
<tr>
<td><strong>Total Statutory Tax Rate (%)</strong></td>
<td><strong>28.25</strong></td>
<td><strong>26.50</strong></td>
<td><strong>26.50</strong></td>
</tr>
<tr>
<td></td>
<td>26.50</td>
<td>26.50</td>
<td>26.50</td>
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<tr>
<td></td>
<td>26.50</td>
<td>26.50</td>
<td>26.50</td>
</tr>
<tr>
<td></td>
<td>26.50</td>
<td>26.50</td>
<td>26.50</td>
</tr>
<tr>
<td><strong>Capital Tax Rate (%)&lt;sup&gt;(1)&lt;/sup&gt;</strong></td>
<td>nil</td>
<td>nil</td>
<td>nil</td>
</tr>
<tr>
<td></td>
<td>nil</td>
<td>nil</td>
<td>nil</td>
</tr>
<tr>
<td></td>
<td>nil</td>
<td>nil</td>
<td>nil</td>
</tr>
<tr>
<td></td>
<td>nil</td>
<td>nil</td>
<td>nil</td>
</tr>
</tbody>
</table>

<sup>(1)</sup> As of July 1, 2010, the Ontario capital tax is eliminated.
1.0 INTRODUCTION

This Exhibit provides the forecast of Hydro One Transmission’s rate base for the 2015 and 2016 test years and provides a detailed description of each of the rate base components. The composition of Hydro One Transmission’s assets is described in Exhibit A, Tab 5, Schedule 1.

The rate base underlying the test year revenue requirement includes a forecast of net utility plant, calculated on a mid-year average basis, plus a working capital allowance. Net utility plant is gross plant in-service minus accumulated depreciation. Working capital includes an allowance for cash working capital and materials and supplies inventory.

2.0 UTILITY RATE BASE

Hydro One Transmission’s utility rate base for the transmission system for the test years is filed in Exhibit D2, Tab 1, Schedule 1. The calculation of average balances to derive net utility plant for the historical, bridge and test years is filed in Exhibit D2, Tab 3, Schedule 1 and Exhibit D2, Tab 3, Schedule 2.

Hydro One Transmission’s forecast rate base for the 2015 test year is $10,176.5 million and for the 2016 test year is $10,558.0 million. Table 1 provides a summary of the calculation of the Transmission rate base for the 2015 and 2016 test years.
Table 1.

Transmission Rate Base ($ Millions)\(^1\)

<table>
<thead>
<tr>
<th>Description</th>
<th>2015</th>
<th>2016</th>
</tr>
</thead>
<tbody>
<tr>
<td>Gross Plant</td>
<td>15,665.6</td>
<td>16,353.0</td>
</tr>
<tr>
<td>Less: Accumulated Depreciation</td>
<td>(5,515.7)</td>
<td>(5,819.3)</td>
</tr>
<tr>
<td><strong>Net plant in service</strong></td>
<td><strong>10,149.9</strong></td>
<td><strong>10,533.7</strong></td>
</tr>
<tr>
<td>Working Capital</td>
<td>26.6</td>
<td>24.2</td>
</tr>
<tr>
<td><strong>Total Rate Base</strong></td>
<td><strong>10,176.5</strong></td>
<td><strong>10,558.0</strong></td>
</tr>
</tbody>
</table>

2.1 Derivation of Net Utility Plant

The mid-year gross plant balance reflects the in-service additions resulting from the capital expenditure program forecast for the test years. These programs are described in detail in the Company’s written evidence at Exhibits D1, Tab 3 and in the supporting schedules filed at Exhibit D2, Tab 2, Schedules 1 and 2. The justifications for individual capital projects in excess of $3 million are filed in Exhibit D2, Tab 2, Schedule 3.

The 2015 Net Plant in-service of $10,149.9 million is $240.2 million or 2.4% higher than 2014 Board-approved Net Plant of $9,909.7 million approved in EB-2012-0031. The 2016 Net Plant in-service of $10,533.7 million is $383.9 million or 3.8% higher than 2015 Test Year. These increases reflect the Company’s infrastructure investments to address asset replacement and refurbishment needs of our aging system, and to expand the system for the purposes of load growth, accommodating a modified generation mix,

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\(^1\) Gross plant and accumulated depreciation values are calculated using a mid-year approach. Capital contributions have been netted out. Contributed capital refers to amounts contributed by third parties to specific capital projects, such as, for example, Joint Use Assets.
and expanding access to interconnected electricity markets as described throughout Exhibit D1.

A continuity schedule for gross fixed assets for the test, bridge and historical years is shown in Exhibit D2, Tab 3, Schedule 1. In-service additions in that exhibit reflect the placing in-service of some of Hydro One Transmission’s capital programs, shown in Exhibit D1, Tab 1, Schedule 2 and described in detail in Exhibit D1, Tab 3.

A continuity schedule for accumulated depreciation for the test, bridge and historical years is shown in Exhibit D2, Tab 3, Schedule 2. The accumulated depreciation balance for the test years incorporates the accepted Foster Associates’ Inc. methodology. The depreciation expense is further discussed in Exhibit C1, Tab 7, Schedule 1.

2.2 Cash Working Capital

In 2012, Hydro One Transmission retained Navigant Consulting Inc. to undertake a lead-lag study. The provision for working capital in 2015 and 2016 incorporates the results of this new study.

The cash working capital requirement for the transmission system is based on the following factors:

- the forecast of revenues,
- the forecast of OM&A, taxes and other cash expenditures and the net lead lag days determined.

Applying the lead lag study methodology results in a net cash working capital requirement of $12.9 million for the 2015 test year and $10.3 million for the 2016 test year. The calculation of cash working capital is discussed in further detail in Exhibit D1, Tab 1, Schedule 3.
2.3 Materials and Supplies Inventory

The other component of working capital is materials and supplies inventory. The average annual materials and supplies inventory balances are $13.7 million for 2015 and $14.0 million for 2016. Materials and supplies inventory is discussed in further detail in Exhibit D1, Tab 5, Schedule 1.

3.0 COMPARISON OF RATE BASE TO BOARD APPROVED

Table 3 compares 2013 costs to the 2013 Rate Base approved by the Board in their Decision on Hydro One Transmission’s previous application in EB-2012-0031.

<table>
<thead>
<tr>
<th>Rate Base Component</th>
<th>2013 Actual</th>
<th>2013 Board Approved</th>
<th>Variance</th>
</tr>
</thead>
<tbody>
<tr>
<td>Gross Plant</td>
<td>14,148.8</td>
<td>14,309.0</td>
<td>(160.2)</td>
</tr>
<tr>
<td>Accumulated Depreciation</td>
<td>(4,964.3)</td>
<td>(4,981.0)</td>
<td>16.7</td>
</tr>
<tr>
<td>Net Utility Plant</td>
<td>9,184.6</td>
<td>9,328.0</td>
<td>(143.5)</td>
</tr>
<tr>
<td>Cash Working Capital¹</td>
<td>11.7</td>
<td>11.7</td>
<td>0.0</td>
</tr>
<tr>
<td>Materials &amp; Supplies Inventory</td>
<td>13.3</td>
<td>13.7</td>
<td>(0.4)</td>
</tr>
<tr>
<td><strong>Total Rate Base</strong></td>
<td><strong>9,209.3</strong></td>
<td><strong>9,353.4</strong></td>
<td><strong>(143.9)</strong></td>
</tr>
</tbody>
</table>

Notes:
1. Hydro One Transmission does not calculate actual cash working capital, thus the 2013 approved amount was used for illustrative purposes.

Total rate base was $143.9 million below the Board approved amount; a variance of 1.5%.

Table 4 compares 2014 forecast costs to the 2014 Rate Base approved by the Board in their Decision on Hydro One Transmission’s previous application EB-2012-0031.
### Table 4

<table>
<thead>
<tr>
<th>Rate Base Component</th>
<th>2014 Bridge Year (Forecast)</th>
<th>2014 Board Approved</th>
<th>Variance</th>
</tr>
</thead>
<tbody>
<tr>
<td>Gross Plant</td>
<td>14,871.4</td>
<td>15,177.1</td>
<td>(305.8)</td>
</tr>
<tr>
<td>Accumulated Depreciation</td>
<td>(5225.2)</td>
<td>(5,267.4)</td>
<td>42.2</td>
</tr>
<tr>
<td><strong>Net Utility Plant</strong></td>
<td><strong>9,646.2</strong></td>
<td><strong>9,909.7</strong></td>
<td><strong>(263.6)</strong></td>
</tr>
<tr>
<td>Cash Working Capital</td>
<td>11.1</td>
<td>11.1</td>
<td>0.0</td>
</tr>
<tr>
<td>Materials &amp; Supplies Inventory</td>
<td>13.4</td>
<td>12.9</td>
<td>0.5</td>
</tr>
<tr>
<td><strong>Total Rate Base</strong></td>
<td><strong>9,670.7</strong></td>
<td><strong>9,933.8</strong></td>
<td><strong>(263.0)</strong></td>
</tr>
</tbody>
</table>

1. Hydro One Transmission does not calculate actual cash working capital, thus the 2014 approved amount was used for illustrative purposes.

Total rate base was $263.0 million below the Board approved amount, a variance of 2.6%.
IN-SERVICE CAPITAL ADDITIONS

In-service additions represent increases to rate base as a result of capital work being declared in-service and ready for use by Hydro One Transmission’s customers. However, the absolute amount of in-service additions and capital expenditures in any given year will typically be different. This difference arises from the multi-year nature of many capital projects and from the fact that some projects can come into service in stages.

<table>
<thead>
<tr>
<th></th>
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<th></th>
<th></th>
<th></th>
<th></th>
<th></th>
</tr>
</thead>
<tbody>
<tr>
<td>Sustaining</td>
<td>403.8</td>
<td>443.3</td>
<td>588.4</td>
<td>701.1</td>
<td>572.2</td>
<td>480.9</td>
<td></td>
</tr>
<tr>
<td>Development</td>
<td>231.7</td>
<td>261.8</td>
<td>177.3</td>
<td>205.8</td>
<td>134.7</td>
<td>119.4</td>
<td></td>
</tr>
<tr>
<td>Operations</td>
<td>5.9</td>
<td>15.1</td>
<td>19.0</td>
<td>48.0</td>
<td>50.4</td>
<td>10.0</td>
<td></td>
</tr>
<tr>
<td>Common &amp; Other</td>
<td>62.4</td>
<td>64.0</td>
<td>78.7</td>
<td>68.0</td>
<td>64.1</td>
<td>63.1</td>
<td></td>
</tr>
<tr>
<td><strong>Total</strong></td>
<td><strong>703.8</strong></td>
<td><strong>784.2</strong></td>
<td><strong>863.3</strong></td>
<td><strong>1023.1</strong></td>
<td><strong>821.3</strong></td>
<td><strong>673.3</strong></td>
<td></td>
</tr>
</tbody>
</table>

Hydro One Transmission is expecting to achieve this level of in-service capital additions by utilizing a mix of internal and external resources, including outsourcing. Please refer to our Work Execution Strategy in Exhibit A, Tab 16, Schedule 6 for how Hydro One Transmission intends to accomplish the work program.

Primary factors behind the 2013 in-service additions being $80 million lower than the OEB approved level of $784 million include:
- Sustainment in-service additions were lower than the approved amount by approximately $40 million due primarily to delays in the relocation of assets at
Abitibi Canyon SS to Pinard TS and replacement of the Merivale Gas Insulated Switchgear (GIS) largely resulting from outage coordination issues.

- Development in-service additions were lower than the approved amount by roughly $30 million due primarily to delays in the Hearn TS and Hawthorne TS projects due to complications in obtaining outages.

- Operations in-service additions were lower than the approved amount by about $10 million primarily as a result of the cancellation of the Wide Area Network (WAN) project due to the lower demand for telecom network capacity.

The 2014 in-service additions are anticipated to be lower than the OEB approved level of $1,023 million by about $160 million primarily due to the following factors:

- Development in-service additions are forecast to be about $60 million lower primarily due to delays in the Midtown Transmission Reinforcement project which suffered from flooding of an access shaft.

- Sustainment in-service additions are forecast to be roughly $100 million lower primarily due to:
  - The Riverside Junction by Strachan TS underground cable replacement project, which is expected to be completed for less than the previously approved amount partly due to lower material costs through procurement savings (approximately $35 million);
  - The replacement of the Bruce Special Protection Scheme being delayed due to functional requirement changes following a revised scope of work with the IESO (approximately $30 million); and
The execution of the Bruce A TS air blast breaker replacement project being delayed due to inclusion of additional work required at the site to address short circuit issues and additional end of life assets in an integrated manner to aide in outage coordination with the generators (approximately $35 million).

- Operations in-service additions are forecast to be lower by about $10 million due to the cancellation of the WAN project.

**In Service Additions in 2015 and 2016**

In-service capital additions will decrease in 2015 as compared to the 2014 projected amount and decrease more significantly in 2016 as compared to 2015. The significant decrease from 2015 to 2016 is mainly due to lower additions in Sustaining and Operations. The decrease in Sustaining reflects the completion of some major projects and the continuation of several large projects in the test years that will come into service in 2017 and beyond. The decrease in Operations is due to the large Network Management System (NMS) and other system upgrade projects coming in service in 2015.

For 2015 and 2016, Hydro One is continuing the shift towards completing more Sustaining capital work in an integrated manner in part to reduce the current problem of projects being delayed due to outage planning constraints. Going forward in the test years and beyond, Hydro One expects the in-service forecasts to be achievable with a greater focus on this integrated approach to planning and executing work to increase the probability of achieving required outages. In addition, a greater portion of the projects going in-service in 2015 and 2016 already have work in progress.
Capital Expenditures for 2015 and 2016 are described at the program and major project level in Exhibit D1, Tab 3 and Tab 4. All projects with spending greater than $3M in one of test years are described in more detail in Exhibit D2, Tab 2, Schedule 3.

A summary of the major in service additions in the Sustaining, Development and Operating areas is provided in Table 2:

Table 2

<table>
<thead>
<tr>
<th>($M)</th>
<th>2015</th>
<th>2016</th>
</tr>
</thead>
<tbody>
<tr>
<td>Sustaining</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Integrated DESN Replacements</td>
<td>113.9</td>
<td>60.7</td>
</tr>
<tr>
<td>EOL Station Reconfigurations</td>
<td>35.0</td>
<td>-</td>
</tr>
<tr>
<td>Power Transformer Replacements</td>
<td>38.1</td>
<td>53.5</td>
</tr>
<tr>
<td>BSPS Replacement</td>
<td>28.3</td>
<td>-</td>
</tr>
<tr>
<td>Integrated Station P&amp;C Replacements</td>
<td>28.0</td>
<td>29.9</td>
</tr>
<tr>
<td>Transmission Line Reinvestments</td>
<td>37.2</td>
<td>29.6</td>
</tr>
<tr>
<td>Wood Pole Replacements</td>
<td>24.5</td>
<td>26.6</td>
</tr>
</tbody>
</table>

Development

<table>
<thead>
<tr>
<th>($M)</th>
<th>2015</th>
<th>2016</th>
</tr>
</thead>
<tbody>
<tr>
<td>Midtown Transmission Reinforcement</td>
<td>61.6</td>
<td>-</td>
</tr>
<tr>
<td>Hawthorne TS Uprate Short Circuit</td>
<td>10.7</td>
<td>-</td>
</tr>
<tr>
<td>Guelph Area Transmission Reinforcement</td>
<td>-</td>
<td>94.3</td>
</tr>
<tr>
<td>Manby TS Uprate 115kV Switchyard</td>
<td>-</td>
<td>16.2</td>
</tr>
<tr>
<td>Operating</td>
<td>35.2</td>
<td>-</td>
</tr>
<tr>
<td>-------------------</td>
<td>------</td>
<td>---</td>
</tr>
</tbody>
</table>

In the Common Corporate Costs area, there are in-service additions in 2015 and 2016 for IT systems, transport & work equipment and head office and field facility improvements.
TRANSMISSION ASSETS INVESTMENT OVERVIEW

1.0 INTRODUCTION

This exhibit provides a summary of the overriding requirements of the sustaining programs and the reliability statistics that are critical to understanding how performance of various assets impact the power system and customers. It also provides a longer term asset-centric view of the key transmission assets and their primary risk factors such as: demographic, performance, and condition information. These three dimensions together provide information to support the test-year Sustaining OM&A and Capital expenditures submitted in Exhibit C1, Tab 2, Schedule 2 and Exhibit D1, Tab 3, Schedule 2 respectively.

2.0 SUSTAINING OVERVIEW

Sustaining transmission assets is essential to the long term viability and performance of the transmission system. This is reinforced by the Transmission System Code that requires Hydro One Transmission to “inspect, test and monitor its transmission facilities to ensure continued compliance with all applicable standards and instruments”. Over the long term, an adequately maintained transmission system that performs to a level of its original design is in the best interest of Hydro One and its customers.

Hydro One Transmission’s assets are reaching the end of their expected service life at a rate that exceeds the historic rate of replacement. This will result in cost pressures on both capital and maintenance programs to maintain the historic level of risk. In addition, the transmission system is in a continuing period of expansion that will present a need for increased maintenance expenditures as the asset base increases. The programs proposed to sustain the assets address current asset needs, and consider the trends of demographics, condition and reliability and the associated risk. It must be recognized that any
reductions applied to the test years spending will have a compounding effect on system risks and cost pressures now and in the future.

The proposed test year Sustaining investment plan is directionally focused on maintaining equipment reliability and overall system reliability, through continued Sustaining Capital expenditures, while containing the test year Sustaining OM&A expenditures increases to less than inflation.

Sustaining programs strive to continuously innovate through adopting new technologies and approaches. Value will be derived by using innovative analytic tools and technologies. Efficient data collection and manipulation improves the effectiveness and consistency in investment plans. Value is also achieved through optimizing life cycle costs and targeting the right balance of capital and OM&A expenditures. In determining the appropriate maintenance strategies consideration is given to various approaches such as condition-based maintenance and time-based maintenance. Benchmarking against other utilities helps ensure that activities are in line with industry standards and practices.

Continued growth in the fleet replacement rates for key assets is imperative to manage the long-term reliability and lifecycle cost of the transmission fleet to the benefit of the ratepayer. Reducing Sustaining Capital funding will require increased Sustaining OM&A funding to maintain assets that are at end of life and should be replaced.

3.0 RELIABILITY OVERVIEW

Throughout the Sustaining exhibits, references are made to asset reliability and to system reliability. It is important to understand the difference between these two dimensions, as they are related, but need to be analysed separately to have a clear picture of trends and developing risk.
As a consequence of the redundancy often found in the transmission system, it’s not unusual for an equipment defect or failure to have only a momentary impact on the power system, or in some cases no noticeable impact to end-use customers at all. For example, Hydro One Transmission typically has redundant transformers at load delivery stations, so that power can continue to be supplied to downstream customers during routine maintenance or in the event of a failure. In the event of a power system fault, depending on fault location and how the protections operate to clear the faulted zone, there may be no delivery interruption at all, or a very short interruption (fractions of a second to a few seconds), or the delivery points could be lost for an extended period of time (minutes to hours). These delivery point interruptions are tracked at the corporate level and benchmarked with peers.

Hydro One Transmission analyses equipment condition and defects as a leading indicator to major equipment performance (i.e. transformers, breakers, protections, circuits). As trends in major equipment performance begin to shift, there will be a lagging effect on broader system reliability. In managing the power system, specifically Sustaining investments, it is imperative to understand the leading-lagging spectrum of equipment condition, to major equipment performance, to system or delivery performance. By the time delivery impact begins to degrade, there would be significant underlying performance issues with major equipment that would take significant time and money to rebound from. Figure 1 represents the increasing impact to Customers as equipment defects evolve to major equipment outages that can impact delivery performance.
Throughout the Sustaining exhibits, references are made to the impact of a particular asset to system reliability. This is most often expressed in terms of the frequency and duration of power interruptions. Figures 2 through 5 demonstrate the relative contribution between various assets to the system-wide delivery measures. Note that Lines assets that impact delivery performance are typically assessed against the entire system (radial single-point supplies and reinforced multi-circuit supplies), whereas Stations assets are expressed in terms of the multi-circuit delivery performance.

Figures 2 show the 10-year history of the contribution of equipment failure to the frequency of delivery points interruptions for both delivery points; whereas Figure 3 focuses only on the frequency of the delivery point interruptions for only the reinforced or multi-circuit supplied delivery points.

There is an increasing trend of the number of equipment failures causing interruptions to customers, although there is some variability year over year. With the failure of Station equipment having a much more significant impact than Lines equipment. Sustaining capital and maintenance programs are largely focused on managing these reliability risks.
Figures 4 show the 10-year history of the contribution of equipment failure to the duration of delivery points interruptions for all delivery points; whereas Figure 5 focuses only on the duration of delivery point interruptions for the reinforced or multi-circuit
supplied delivery points.

There is a gradual worsening trend of the duration of interruptions across the entire system, with large variability year over year demonstrating that failures from equipment typically at the end of life can have major impacts on customer reliability measures.

Figure 4: Equipment Failures Contributing to Duration of Interruptions; All Delivery Points (Single & Multi-circuit Supplied)
4.0 TRANSMISSION ASSET RISK ANALYSIS

The information presented below entails the asset risk analysis summaries for key transmission assets, based on the asset risk assessment process introduced in Exhibit A, Tab 16, Schedule 7. These summaries provide an overview of the strategy used to manage the asset, the forecasts of fleet demographics based on planned replacement rates, the condition and performance of the fleet, and the combined capital and OM&A cost impacts and relevant trends.

Various risk factors are considered for major transmission assets. Table 1 provides a summarized view of the primary asset risk factors for the key transmission assets impacting the majority of Sustaining Capital and OM&A expenditures as outlined in Exhibits D1, Tab 3, Schedule 2 and Exhibit C1, Tab 2, Schedule 2 respectively.

Figure 5: Equipment Failures Contributing to Duration of Interruptions; Reinforced Delivery Points (Multi-Circuit Supplied Only)
<table>
<thead>
<tr>
<th>STATIONS</th>
<th></th>
<th></th>
<th>Overall Asset Risk</th>
<th></th>
<th></th>
</tr>
</thead>
<tbody>
<tr>
<td>Number of Assets</td>
<td>Assets Beyond Expected Service Life [% of Fleet]</td>
<td>Demographics</td>
<td>Performance</td>
<td>Condition</td>
<td>Historic Renewal Rate 2011-2013 [% of Fleet]</td>
</tr>
<tr>
<td>STATIONS</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Transformers</td>
<td>722 units</td>
<td>24%</td>
<td>High</td>
<td>Fair</td>
<td>Fair</td>
</tr>
<tr>
<td>Circuit Breakers</td>
<td>4,604 units</td>
<td>8%</td>
<td>Low</td>
<td>High</td>
<td>High</td>
</tr>
<tr>
<td>Protection Systems</td>
<td>12,135 systems</td>
<td>17%</td>
<td>Fair</td>
<td>Fair</td>
<td>High</td>
</tr>
<tr>
<td>LINES</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Overhead Conductor and Hardware</td>
<td>30,000 kms</td>
<td>19%</td>
<td>High</td>
<td>Fair</td>
<td>Fair</td>
</tr>
<tr>
<td>Wood Pole Structures</td>
<td>42,000 units</td>
<td>26%</td>
<td>Fair</td>
<td>Low</td>
<td>High</td>
</tr>
<tr>
<td>Steel Structures</td>
<td>50,000 units</td>
<td>21%</td>
<td>High</td>
<td>Low</td>
<td>Fair</td>
</tr>
<tr>
<td>Underground Cables</td>
<td>290 kms</td>
<td>16%</td>
<td>High</td>
<td>Fair</td>
<td>High</td>
</tr>
</tbody>
</table>
4.1 Transmission Station Assets

4.1.1 Transformers

Asset Overview

Hydro One Transmission has 722 large transmission class transformers in service, as outlined in Table 2.

Table 2: Transformer by Type

<table>
<thead>
<tr>
<th>Transformer Type</th>
<th>Number of Transformers</th>
</tr>
</thead>
<tbody>
<tr>
<td>Autotransformer – 500 kV</td>
<td>45</td>
</tr>
<tr>
<td>– 230 kV</td>
<td>89</td>
</tr>
<tr>
<td>Phase Shifter / Regulator / Reactor</td>
<td>5</td>
</tr>
<tr>
<td>Step Down Transformer – 230 kV</td>
<td>243</td>
</tr>
<tr>
<td>– 115 kV</td>
<td>340</td>
</tr>
</tbody>
</table>

The most common power transformer is the step-down transformer, which converts a transmission level voltage (230 kV or 115 kV) to a lower distribution voltage of less than 50 kV for customer supply. Another type is the autotransformer (as depicted in Figure 6) which connects to high voltage transmission systems such as 500/230 kV and 230/115 kV. Other transformers included in this group are phase shifting transformers, shunt reactors, and regulating transformers.

Figure 6: 500/230 kV Autotransformer
Currently 24% of the transformer population is beyond its expected service life. Continuing at the historic rate of replacement, the number of transformers beyond their expected service life would increase to 35% by year 2024.

The condition of the transformer fleet, determined through industry standard diagnostic testing, is such that 8% present high or very high condition risks that need to be mitigated.

The forced outage frequency of transformers is relatively stable. However, transformers failures can have a significant impact to local and system reliability and continue to be one of the leading causes of delivery point interruptions. Transformers failures also have a negative impact on the environment in the event of oil spills.

Given the demographics of the transformer population, the condition trend and the risks associated with transformer failures, an increased rate of replacement over historic years is required to maintain an acceptable level of risk. Regulatory requirements related to oil leaks, noise levels and PCB contaminated oil in equipment also contribute to the need to replace some of the transformer fleet.

**Asset Strategy**

Hydro One Transmission’s strategy for transformers is to manage the aging transformer fleet in a manner that preserves reliability while minimizing rate impacts. Hydro One Transmission continues to shift towards more condition based maintenance in order to maintain OM&A expenditures. Hydro One Transmission also proposes a replacement rate of approximately 3.6% per year to manage risks associated with operating an aged transformer population. This will result in continuation of the strategy to reduce the portion of the fleet operating with high risks associated with end of life issues.
Asset Assessment Details

Demographics

Hydro One Transmission uses a normal expected service life (‘‘ESL’’) of between 40 years and 60 years depending on the type of transformer. Table 3 outlines Hydro One Transmission’s ESL for various types of transformers. This is generally beyond the CEA-average transformer life expectancy of 40 years.

<table>
<thead>
<tr>
<th>Transformer Type</th>
<th>Expected Service Life</th>
</tr>
</thead>
<tbody>
<tr>
<td>Autotransformer – 500 kV</td>
<td>40 years</td>
</tr>
<tr>
<td>– 230 kV</td>
<td>50 years</td>
</tr>
<tr>
<td>Phase Shifter / Regulator / Reactor</td>
<td>40 years</td>
</tr>
<tr>
<td>Stepdown Transformer – 230 kV two-winding</td>
<td>50 years</td>
</tr>
<tr>
<td>– 115 kV or 230 kV three-winding</td>
<td>40 years</td>
</tr>
<tr>
<td>– 115 kV two-winding</td>
<td>60 years</td>
</tr>
</tbody>
</table>

The average age of the transformer fleet is currently 35 years of age and 24% of the in-service transformers are currently beyond their expected service life. The demographics of the transformer population is outlined in Figure 7.

![Figure 7: Demographics of the Transformer Fleet](image)
The potential risks to system and customer reliability as a result of this long-term demographic pressure needs to be managed through continued capital replacement programs. As can be seen in Figure 8, continuing at the historic rate of replacement would result in the percentage of transformers beyond their expected service life to increase to 35% by 2024. However at the proposed replacement rate of 26 transformers a year, the percentage of transformers beyond their expected service life will improve from 24% to 19% over the next 10 years.

![Figure 8: Projection of Transformers Beyond Expected Service Life](image)

**Figure 8: Projection of Transformers Beyond Expected Service Life**

**Performance**

The forced outage frequency of transformers is relatively stable, as outlined in Figure 9. However, transformers failures can have a significant impact to local and system reliability. Transformer forced outages are one of the leading causes to customer delivery point interruptions, and represent 26% of the equipment-caused events impacting delivery point interruptions with multiple supplies over the past 10 years. To mitigate this risk the transformer replacements in the test years are focused on replacing transformers that are at the highest risk of causing delivery point interruptions and impacting the bulk electricity system.
Condition
Transformer condition is a leading predictive indicator of equipment reliability. Condition is primarily based on transformer oil testing (dissolved gas analysis, furan, standard oil testing), power factor testing, and general findings from the preventive and corrective maintenance programs. The internal components degrade as a function of time, heat from transformer loading, exposure to oxygen, moisture contamination, and damaging acids in the insulating oil as a result of insulation aging. Degradation is irreversible and transformer replacement is the only economically viable solution.

Based on results gathered, currently 8% of Hydro One Transmission’s transformer population has condition that puts it in high or very high risk, as outlined in Figure 10.
The transformers which tend to be in the worst condition are also those which are approaching or beyond their expected service life. Transformer condition is generally correlated to asset age, as well as how it has been operated and maintained throughout its service life. Sustaining capital and maintenance programs are targeted at transformers in degraded condition typically with high or very high risk of failure.

To date, the sustaining replacements have addressed many of the transformers with the highest probability of failure along with a number of maintenance activities have focused on remedial actions to mitigate the most significant risks. However to maintain the condition of the fleet, given the demographics and utilization, a continued replacement program beyond historic accomplishment rates is required to maintain or gradually improve the overall fleet condition.

**Other Influencing Factors**

Other factors driving the increase in transformer replacements are summarized below.
• Oil Leaks - Provincial regulations require that oil leaks are mitigated either through temporary measures such as absorbent materials and drip trays, through typically expensive refurbishment to re-gasket transformers, or replacement. Replacement is often the best technical and economical solution for aged transformers.

• Environmental Compliance Approval (“ECA”) Commitments - (formerly CofA). Often ECA approvals come with a condition of bringing other aspects of the transmission station up to modern standards within a specified period of time, typically 3 years. Transformers are usually the influencing factor in ECA commitments for both spill containment and noise limits.

• Polychlorinated Biphenyl (“PCB”) Contamination – Approximately 25% of bushings older than 1985 are forecast to contain oil with a PCB concentration of greater than 50 ppm. Environment Canada has a regulated end-of-use date of 2025 for oil volumes greater than 50 ppm. Replacements of this equipment will be required to maintain environmental compliance.

Cost Trends and Impacts

<table>
<thead>
<tr>
<th>Transformer Portfolio</th>
<th>Historic</th>
<th>Bridge</th>
<th>Test</th>
</tr>
</thead>
<tbody>
<tr>
<td># of Replacements*</td>
<td>16</td>
<td>12</td>
<td>15</td>
</tr>
<tr>
<td>% of Fleet</td>
<td>2.2%</td>
<td>1.7%</td>
<td>2.1%</td>
</tr>
<tr>
<td>Capital ($M)</td>
<td>81.1</td>
<td>100.5</td>
<td>120.7</td>
</tr>
<tr>
<td>OM&amp;A ($M)</td>
<td>30.2</td>
<td>23.2</td>
<td>21.8</td>
</tr>
</tbody>
</table>

*Note that transformer replacements above are conducted under both the categories of Power Transformers and Station Re-Investment as outlined in Exhibit D1, Tab 3, Schedule 2.

The capital replacement rate in the test years is consistent with the bridge year forecast, which is an increase over historic level. Continued renewal of the fleet at this rate should be sufficient to maintain an acceptable level of risk through the test years. There is some
variability in capital expenditures year over year, which is mostly a function of the type and size of transformers being planned for replacement.

OM&A expenditures are generally consistent year over year with some minor variation as accomplishment of targeted programs is completed.

Transformers are a major element in ensuring a reliable bulk electricity system. Transformer failures are directly impactive to load customers, either through loss of load or significant risk exposure of single supply until such time the transformer can be replaced. Maintaining the fleet in an adequate condition will help preserve reliability in line with good utility practice and regulatory obligations.

4.1.2 Circuit Breakers

Asset Overview

Hydro One Transmission has 4,604 circuit breakers in service, as outlined in Table 4. High voltage (“HV”) breakers are installed in 500 kV, 230 kV or 115 kV positions, and medium voltage (“MV”) breakers are installed at 44 kV, 27.6 kV, 13.8 kV or 12.5 kV positions.

<table>
<thead>
<tr>
<th>Circuit Breaker Type</th>
<th>Number of Circuit Breakers</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>HV</td>
</tr>
<tr>
<td>Oil</td>
<td>479</td>
</tr>
<tr>
<td>SF6</td>
<td>642</td>
</tr>
<tr>
<td>Air Blast</td>
<td>182</td>
</tr>
<tr>
<td>GIS</td>
<td>91</td>
</tr>
<tr>
<td>Metalclad</td>
<td>0</td>
</tr>
<tr>
<td>Vacuum</td>
<td>0</td>
</tr>
</tbody>
</table>
A circuit breaker is a mechanical switching device that is capable of making, carrying and interrupting electrical current under normal and abnormal circuit conditions. Abnormal conditions occur during a short circuit such as a lightning strike or conductor contact to ground. During these conditions, very high electrical currents are generated that greatly exceed the normal operating levels. A circuit breaker is used to break the electrical circuit and interrupt the current to minimize the effect of the high currents on the rest of the system. Figures 11A through 11E illustrate the five primary types of circuit breakers used in Hydro One’s transmission system.

Figure 11A: Oil Circuit Breaker

Figure 11B: SF6 Circuit Breaker

Figure 11C: Metalclad Circuit Breakers

Figure 11D: Air Blast Circuit Breakers
Currently 8% of the circuit breaker population is beyond its expected service life. Continuing at the historic rate of replacement, the number of circuit breakers beyond their expected service life would increase to 13% by year 2024.

The condition of the circuit breaker fleet, determined through industry standard maintenance practices, is such that 16% present high or very high condition risks that need to be mitigated.

The forced outage frequency of circuit breakers is relatively stable. However, circuit breaker failures can have a significant impact to local and system reliability and continue to be one of the leading causes of delivery point interruptions. Circuit breaker failures also have a negative impact on the environment in the event of SF6 release.

Given the demographics of the circuit breaker population, the condition trend and the risks associated with circuit breaker failures, increased rate of replacement over historic years is required to maintain an acceptable level of risk. Regulatory requirements related to oil leaks and PCB contamination in equipment also contribute to the need to replace some of the circuit breaker fleet.
Asset Strategy

Hydro One Transmission’s strategy for circuit breakers is to manage the aging circuit breaker fleet in a manner that maintains system reliability while minimizing rate impacts. A targeted approach will focus on replacement of worst performing and/or obsolete breaker types. Hydro One Transmission is also shifting towards increasing the number of circuit breaker replacements completed in an integrated manner. At select stations, entire low voltage switchyards will be replaced with a pre-fabricated solutions consisting of metalclad or GIS, which will help manage the demographic pressures cost effectively and have several intangible benefits in areas of constructability and maintainability as well as reliability.

Asset Assessment Details

Demographics

Hydro One Transmission uses a normal expected service life (“ESL”) of 40 years all circuit breakers with the exception of oil circuit breakers, where an ESL of 55 years is used.

The average age of the circuit breaker fleet is currently 27 years of age and 8 % of the in-service circuit breakers are currently beyond their expected service life. The demographics of the population is outlined in Figure 12.
Historic replacements have been generally sufficient to maintain a relatively small portion of the overall circuit breakers in operation beyond their ESL. Within the overall population, there are certain circuit breaker types which are operating at or beyond their ESLs.

- Approximately half of the air-blast breakers are beyond their ESL. These breakers are typically installed at system critical network stations;
- A large portion of the aged inventory is oil circuit breakers. The current replacement is focused on only the worst performing and/or technically obsolete models but an increased replacement rate will be required in the future;
- A significant portion of the metalclad breakers are operating well beyond their expected life. Legacy designs come with inherent safety risks that require mitigation.

Continued renewal of the fleet will be required to manage risks to system and customer reliability as a result of the long-term demographic pressures, as well as the more acute issues associated with air blast and metalclad circuit breakers.

As can be seen in Figure 13, continuing at the historic rate of replacement would result in the percentage of breakers beyond their expected service life to increase to 13% by 2024.
However at the proposed replacement rate, the percentage of breakers beyond their expected service life will have a more gradually increase from 8% to 10% over the next 10 years.

![Figure 13: Projection of Circuit Breakers Beyond Expected Service Life](image)

**Performance**

As displayed in Figure 14, Hydro One Transmission’s circuit breaker reliability for the entire circuit breaker population has been generally stable over the past five years.
In 2013 there was a marked degradation in performance at the fleet population level which is primarily attributed to a much higher number of forced outages on air blast circuit breakers than previous years. This trend is notable in Figure 15, where the performance data for the different breaker interrupting mediums technologies is depicted.
Condition

Circuit breaker condition is a leading predictive indicator of equipment reliability. Condition is primarily based on feedback from preventive maintenance and corrective maintenance programs through diagnostic testing such as breaker timing, breaker oil analysis, history of deficiencies, etc. The components generally degrade as a function of time and usage. In some cases the degradation is reversible through replacement of wear components during maintenance but in many cases replacement is the only technical or economically viable solution.

Based on the results gathered, currently 16% of Hydro One Transmission’s circuit breaker population has condition that puts it in high or very high risk, as outlined in Figure 16.

![Figure 16: Circuit Breaker Fleet Condition Assessment](image)

Other Influencing Factors

Other factors affecting circuit breakers that drive replacements requirements are summarized below.
• Safety - As the circuit breaker design has evolved over the past 50+ years, so has the safety standards and the requirement for safer work methods to protect utility workers. Early generation metalclad switchgear is most notable for having significant arc flash and electrical burn hazards in the event of equipment failure. These risks become more significant as the equipment ages.

• Technical Obsolescence - Many breakers are no longer supported by vendors and aftermarket parts are not available and/or cost effective. This is a significant factor for air blast circuit breakers, some first generation SF6 circuit breakers, and certain types of metalclad and oil circuit breakers.

• Equipment Operations - Breakers that have exceeded their expected service life in terms of number of operations are considered for replacement. Due to their frequent operation, this is most typical of capacitor and reactor breaker positions.

• Environmental Impact – Minimizing SF6 emissions and their resultant impact as a greenhouse gas to the environment is considered in the replacement or refurbishment plans for SF6 breakers.

Cost Trends and Impacts

<table>
<thead>
<tr>
<th>Circuit Breaker Portfolio</th>
<th>Historic</th>
<th>Bridge</th>
<th>Test</th>
</tr>
</thead>
<tbody>
<tr>
<td># of Replacements*</td>
<td>100</td>
<td>55</td>
<td>57</td>
</tr>
<tr>
<td>% of Fleet</td>
<td>2.2</td>
<td>1.2</td>
<td>1.2</td>
</tr>
<tr>
<td>Capital ($M)</td>
<td>55.8</td>
<td>39.7</td>
<td>54.5</td>
</tr>
<tr>
<td>OM&amp;A ($M)</td>
<td>19.3</td>
<td>18.5</td>
<td>20.7</td>
</tr>
</tbody>
</table>

* Note that circuit breaker replacements in the test years are a combination of both the categories Circuit Breakers and Station Re-Investment as outlined in Exhibit D1, Tab 3, Schedule 2.
The capital replacement rate in the test years is an increase over historic and bridge levels. Continued renewal of the fleet at an increased rate is required to maintain an acceptable level of risk through the test years. There is some variability in capital expenditures year over year, which is mostly a function of the type and size of circuit breakers being planned for replacement.

OM&A expenditures are generally consistent year over year with some minor variation as accomplishment of targeted programs is completed.

Circuit breakers are a major element in ensuring a reliable bulk electricity system. Breaker failures are directly impactive to load customers, either through loss of load or significant risk exposure of single supply until such time the station configuration can be returned to normal. Maintaining the fleet in an adequate condition will help preserve reliability in-line with good utility practice and regulatory obligations.

4.1.3 Protections

Asset Overview

Hydro One Transmission has over 12,135 protection systems in service. Protective relays and their associated systems are critical elements of the transmission system. They are connected throughout the transmission network to detect abnormal system conditions caused by natural events, physical accidents, or equipment failure. Upon detecting an abnormal condition, the systems immediately operate the necessary station equipment, such as circuit breakers and switches, to isolate faulted equipment, such as transmission lines, transformers, generators, or buswork, from sources of energy and the rest of the network. Failure to promptly isolate abnormal conditions can cause widespread outages, damage to equipment and injury to workers and the public.
Hydro One Transmission protection system fleet is comprised of three technological vintages; electromechanical, solid state, and microprocessor, as outlined in Table 5.

<table>
<thead>
<tr>
<th>Protection System Technology</th>
<th>Number of Protection Systems</th>
</tr>
</thead>
<tbody>
<tr>
<td>Electromechanical</td>
<td>4,775</td>
</tr>
<tr>
<td>Solid State</td>
<td>2,600</td>
</tr>
<tr>
<td>Microprocessor</td>
<td>4,760</td>
</tr>
</tbody>
</table>

By population, electromechanical and microprocessor protections are the most prevalent in Hydro One Transmission’s fleet. Electromechanical relaying utilizes the principles of electromagnetic induction to convert electrical energy to mechanical movement to detect faults. In contrast, solid state systems rely on transistors using integrated circuit technology to detect fault conditions and microprocessor based systems provide advanced monitoring and fault detection capabilities. Figures 17A through 17C illustrate the three technology types of protection systems used in Hydro One’s transmission system.
Figure 17C: Microprocessor Based Protection Scheme

- Currently 17% of the protection system population is beyond its expected service life. Continuing at the historic rate of replacement, the number of protection systems beyond their expected service life would increase to approximately 25% by year 2025.

- The condition of the protection system fleet is such that 26% present high or very high condition risks that need to be mitigated. There are specific concerns with Programmable Auxiliary Logic Controller (“PALC”) relays, a solid state system, that have experienced an increase in defects over the last 10 years. An increase in the replacement rate is required to arrest this trend.

- Protection systems are composed of up to 100 individual components. With the vast number of protections, and complexity of replacement, there is significant risk if a common mode of failure for common manufacturer types/designs is experienced. Protection systems cannot be out of service for longer than several days without
incurring significant penalties in market inefficiency, disrupting planned outages, or
impacting provincial or interconnected system reliability.

Given the demographics of the protection system population, the condition trend and
risks associated with protection failures, an increased rate of replacement over historic
years is required to maintain an acceptable level of risk. Protections are in the midst of a
major technological change as old electromechanical and solid state relays are no longer
available. A change in technology adds complexity to replacement activities; however the
new microprocessor systems offer features not previously available in the older systems,
including self-monitoring and alarming which allows for less frequent maintenance and
remote data gathering to increase efficiency and ease of event analysis.

Asset Strategy

Hydro One Transmission’s strategy for protection systems is to manage the aging
protection systems fleet in a manner that maintains reliability while minimizing rate
impact. Hydro One Transmission continues to contain OM&A expenditures through the
replacement of electromechanical and solid state relays with microprocessor based
systems which require less frequent maintenance while providing enhanced monitoring to
ensure reliability. Hydro One Transmission proposes a replacement rate of approximately
3.7% per year in order to proactively replace protection systems before failure. This will
be achieved by greater deployment of modular PCT installations at load stations where
large numbers of protections are in need of replacement, continuing focused replacements
of system critical protections, targeted replacement of failure prone relays such as PALC
based systems, and bundling work opportunities with major refurbishment or re-
investment projects.
Asset Assessment Details

Demographics
Hydro One Transmission uses technology-specific expected service lives (“ESL”) for protection systems. Table 6 outlines Hydro One Transmission’s ESL for the various technologies: electromechanical, solid state and microprocessor. The variation of ESL by technological vintage is based on generally accepted industry practice and internal experience.

<table>
<thead>
<tr>
<th>Protection Technology</th>
<th>Expected Service Life</th>
</tr>
</thead>
<tbody>
<tr>
<td>Electromechanical</td>
<td>45 years</td>
</tr>
<tr>
<td>Solid State</td>
<td>25 years</td>
</tr>
<tr>
<td>Microprocessor</td>
<td>20 years</td>
</tr>
</tbody>
</table>

The average age of the protection system fleet is currently 23 years of age and 17% of the in-service protection systems are currently beyond their expected service life. Assessing the demographics of the individual technology types: 12% of electromechanical systems are operating beyond expected service life, 60% of solid state systems are operating beyond expected service life, and the first generation microprocessor systems have started to reach their ESL with 0.1% of these systems operating beyond expected service life. Furthermore, up to 8% of the current microprocessor system fleet will reach its expected service life within the next 5 years. The demographics of the protection system population is outlined in Figure 18.
Figure 18: Demographics of Protection Systems Fleet

The potential risks to system and customer reliability as a result of this long-term demographic pressure needs to be managed through increasing capital replacement programs. As can be seen in Figure 19, continuing at the historic rate of replacement would result in the percentage of protection systems beyond their expected service life increasing to 25% by 2025. However at the proposed replacement rate of 450 protection systems a year will allow the percentage of protection systems beyond expected service life to remain relatively constant over the next 10 years.
Figure 19: Projection of Protection Systems Beyond Expected Service Life

Performance

The forced outage frequency of equipment caused by protection systems has been a relatively declining trend for lines equipment and a relatively stable trend for station equipment over the past 10 years, as outlined in Figure 20. Protection systems play a critical role in ensuring the safe and reliable operation of the transmission system. The systems must be both dependable (operating when required) and secure (not operating on faults in adjacent protection zones) to ensure the reliability of supply. Protection systems cannot be out of service for longer than several days without incurring significant penalties in market inefficiency, disrupting planned outages, or impacting provincial or interconnected system reliability. To mitigate this risk the protection system replacements in the test years are focused on replacing protection systems that are at the highest risk of causing delivery point interruptions and impacting to the bulk electricity system.
Figure 20: Station and Lines Equipment Direct Forced Outage Frequency Caused by Protection Equipment

PALC relays, one type of solid state protection system, have shown an increase in recorded defects and trouble calls over the last 10 years. Performance data shown in Figure 21 demonstrates an overall increasing trend in defects affecting PALC relays, with the moving 4 year average increasing 63% over the last 6 years. Targeted investment to replace PALC relays is required to arrest the increasing trend and maintain reliability.
Condition

Protection system condition is an important indicator of equipment reliability. Condition is primarily based on age and general findings from the preventive and corrective maintenance programs. The internal components degrade as a function of time, which can alter the performance of the relay. This is primarily a concern with electromechanical systems, however component aging or defects and thermal cycling can also affect solid state and microprocessor based protection systems. However, as microprocessor based protections are a relatively new technology, detailed condition metrics and indicators are not as well established.

Based on results gathered, currently 26% of Hydro One Transmission’s protection system population has a condition that puts it in high or very high risk, as outlined in Figure 22.
The protection systems which tend to be in the worst condition are also those operating beyond their expected service life or are identified as high risk such as PALC relays. Maintenance programs and re-verification intervals take into account the limitations and risks associated with each technological vintage to ensure continued and reliable operation. Electromechanical systems, as a result, require more frequent re-verification in contrast to microprocessor based systems to ensure reliable operation.

The sustaining capital replacement programs are targeted at replacing protection systems critical to system and customer reliability and with a high or very high risk of failure. However to maintain the condition of the fleet, given the demographics, a continued replacement program beyond historic replacement rates is required to maintain or gradually improve the overall fleet condition.

Figure 22: Protection Systems Fleet Condition Assessment
Other Influencing Factors

Other factors driving the increase in protection system replacements are summarized below.

- Safety – Operating protection systems beyond their expected service life increases the risk of systems failing to operate and potentially exposing workers and the public to the harm associated with uncontrolled flow of energy. Proactive replacements are required to mitigate this risk.

- Technical Obsolescence – Many protection systems are no longer available, limiting the availability of spares and support; which can adversely impact outage planning and overall system reliability. This is a significant factor for electromechanical and solid state systems.

- Innovation – New microprocessor based protection systems have advanced monitoring and diagnostic capabilities which can provide insight into station equipment performance and early detection of problems, potentially avoiding equipment damage. Modern microprocessor protection systems can be deployed with pre-tested configuration settings to facilitate fast and efficient system protection changes to accommodate dynamic changes to the configuration of the transmission system. Extended maintenance intervals for microprocessor based systems help contain OM&A expenditures and reduce life cycle costs.
Cost Trends and Impacts

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<thead>
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</thead>
<tbody>
<tr>
<td># of Replacements*</td>
<td>389</td>
<td>350</td>
<td>340</td>
<td>350</td>
<td>365</td>
<td>450</td>
</tr>
<tr>
<td>% of Fleet</td>
<td>3.5%</td>
<td>2.9%</td>
<td>2.8%</td>
<td>2.9%</td>
<td>3.0%</td>
<td>3.7%</td>
</tr>
<tr>
<td>Capital ($M)</td>
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<td>53.5</td>
<td>53.8</td>
<td>56.3</td>
<td>57.9</td>
<td>70.5</td>
</tr>
<tr>
<td>OM&amp;A ($M)</td>
<td>11.3</td>
<td>9.7</td>
<td>9.7</td>
<td>10.6</td>
<td>10.3</td>
<td>11.7</td>
</tr>
</tbody>
</table>

*Note that protection replacements above are conducted under both the categories of Protection and Station Re-Investment as outlined in Exhibit D1, Tab 3, Schedule 2.

**Note: Excludes capital expenditures for protection replacements included under Station Re-Investment.

The capital replacement rate in the test years is increasing over the bridge and historic levels. Continued renewal of the fleet at an increased rate is required to maintain an acceptable level of risk over the test years and prevent an increase of protections operating beyond their expected service. This will be achieved by greater deployment of modular, prefabricated PCT buildings at load stations where a significant numbers of protections are in need of replacement; focused replacements of system critical protections; targeted replacements of failure prone relays such as PALC based systems; and bundling work opportunities with major refurbishment or re-investment projects.

OM&A expenditures are generally consistent year over year with minor variations attributed to time-based scheduling of preventative maintenance. Replacement of electromechanical and solid state protections with modern microprocessor based protection systems is expected to lower future maintenance costs as the new technology allows for extended maintenance intervals.

Protections are a critical component in ensuring a safe and reliable bulk electricity system, and maintaining a reliable supply to customers. Maintaining the fleet in an adequate condition will help preserve reliability in line with good utility practice and regulatory obligations.
4.2 Transmission Line Assets

4.2.1 Transmission Overhead Conductor and Hardware

Asset Overview

Hydro One’s transmission system consists of approximately 30,000 circuit km of overhead transmission lines. Transmission lines are used to transmit electric power, via integrated network and radial circuits, to either transmission-connected industrial or commercial customers, or local distribution companies, including Hydro One Distribution, who in turn distribute the power to end-use customers. Hydro One’s transmission lines primarily operate at voltages of 500 kV, 230 kV, and 115 kV, with minor lengths operating at 345 kV and 69 kV.

The bulk of Hydro One Transmission’s overhead lines are constructed using aluminum conductors reinforced with a steel core ("ACSR"), as depicted in Figure 23. ACSR is the most prominent type of conductor used on transmission systems. The conductors are supported by steel structures, porcelain insulators and connecting hardware. The lines are protected from lightning strikes by shieldwire mounted above the conductors.

Figure 23: ACSR Conductor
Currently 19% of conductor population is beyond their expected service life. The conductor kilometers beyond its expected service life will almost double over the next 10 years.

The condition of the conductors is such that 8% present fair or high condition risks that need to be mitigated.

The number and duration of forced outages for conductors has shown slight improvement of the last 10 years. However conductor failures can have very negative consequences both in terms of reliability and safety.

Given the current demographics of the conductor population, condition trend and the risks associated with conductor failures, an increased rate of conductor sampling, testing and replacements over historic years is required to maintain current levels of performance and risk.

**Asset Strategy**

Hydro One Transmission’s strategy for conductors is to manage the aging conductor population in a manner that preserves reliability while minimizing rate impacts. Hydro One Transmission intends on continuing with a replacement rate of approximately 0.3% per year to manage risks associated with operating an aged conductor population. Hydro One Transmission considers condition assessment results, performance data, asset demographics and the consequence of failure to system and customer reliability when making replacement decisions related to conductors. When a conductor is deemed to have reached its end of service life all major components within that line section including the structures, shieldwire, u-bolts and insulators are assessed and refurbished to meet future system requirements. This work bundling of conductor replacement with refurbishment of other transmission line components at the same time is a cost effective approach that is taken in replacing all conductors.
Asset Assessment Details

Demographics
Hydro One Transmission uses an expected service life (“ESL”) of approximately 70 years for conductors; although this can vary based on several factors, environmental conditions being the primary factor. The average age of transmission conductor fleet is currently 52 years of age and 19% of the conductors are currently beyond their expected service life. The demographics of the conductor population is outlined in Figure 24.

![Figure 24: Demographics of Conductor Fleet](image)

Although there have been recent increases in replacement rates to deal with immediate risks; as Figure 25 demonstrates by 2024 the number of conductors beyond their expected service life will nearly double. Hence a significant increase in future replacements will be required to maintain acceptable fleet demographics. If untended this would significantly increase the risk associated with system and customer reliability, as well as impacting exposure to public safety risks on populated areas, road crossings, public use of transmission corridors, etc.
Performance

Conductor failure can have very negative consequences both in terms of reliability and safety. The number of forced outages due to conductor failures has shown slight improvement over the past 10 years, as outlined in Figure 26.
The forced outage duration due to conductor failure, displayed in Figure 27, demonstrates that conductor outage duration has been relatively stable over the last 10 years.

*Note: The extreme outage duration in 2009 was due to an emergency conductor replacement on B10H/B20H circuits.

**Figure 27: Forced Outage Duration due to Conductor and related Hardware Failures**

It is expected that the outage frequency and duration performance will deteriorate given the demographics and condition of the fleet over the next 10 to 20 years if programs are not increased.

**Condition**

Hydro One Transmission has implemented a condition assessment program to assess condition of conductors after they reach 50 years of age. The corrosivity of the surrounding environment will have a significant impact on the condition of the conductor.

The results from these tests and previous studies carried out on life expectancy of conductors indicate that currently 8% of Hydro One Transmission’s conductor population has condition that puts it in fair or high risk, as outlined in Figure 28.
Figure 28: Conductor Fleet Condition Assessment

Hydro One Transmission continues to assess the merits of utilizing the use of a remote controlled conductor assessment device that can be used on energized lines and crawls along the conductor to non-destructively assess conductor condition.

Other Influencing Factors

- Aeolian Vibration - Geographical location, line orientation and more importantly conductor tension contribute to level of vibration each circuit experiences, which directly influences the useful lifespan of a conductor. Hydro One Transmission has experienced premature conductor failures due to a combination of conductor condition and conductor fatigue due to vibration.

- Safety – Given that transmission lines operate in the public domain, additional consideration must be given to the consequence of failure and potential impact on safety of the public. Factors as right-of-way use and proximity to road crossings are factors when assessing risk.
Cost Trends and Impacts

<table>
<thead>
<tr>
<th>Conductor Portfolio</th>
<th>Historic</th>
<th>Bridge</th>
<th>Test</th>
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<tbody>
<tr>
<td>Kms of Circuit Replacements</td>
<td>37</td>
<td>22</td>
<td>75</td>
</tr>
<tr>
<td>% of Fleet</td>
<td>0.1%</td>
<td>0.1%</td>
<td>0.3%</td>
</tr>
<tr>
<td>Capital ($M)</td>
<td>10.2</td>
<td>8.6</td>
<td>17.8</td>
</tr>
<tr>
<td>OM&amp;A ($M)</td>
<td>10.6</td>
<td>10.6</td>
<td>9.4</td>
</tr>
</tbody>
</table>

The capital replacement rate has increased in recent years from a historic level of 0.1% to an average 0.3% of the fleet per year. Continued renewal of the fleet at this rate should be sufficient to continue to maintain the current level of risk through the test years. The circuits being addressed in the bridge and test years have all been identified as in poor condition through the testing and assessment process. The proposed OM&A expenditures level has increased slightly due to the need for more condition assessments to manage the risk of an aging fleet.

4.2.2 Transmission Wood Pole Structures

Asset Overview

Hydro One Transmission has approximately 42,000 wood pole structures. Wood has been a popular material for use in building transmission lines because of its cost effectiveness and reliability over the life of the asset. The majority of the wood pole structure population is located in Northern Ontario, typically in remote locations with difficult access. These wood pole structures are utilized on 230 kV and 115 kV circuits depending on the geographic location and security requirements of the line. The majority of transmission wood pole circuits support radial feed circuits, and as a result wood pole or cross-arm failure can often result in a direct customer outage.
The two basic transmission wood pole design types in use by Hydro One Transmission are “H Frame” design and “Single Pole” design. The H-Frame design consists of two poles and a cross-arm; whereas the “Single Pole” design uses a single pole with steel or wood cross-arms to suspend the conductors.

At the 230 kV circuit level a larger wood pole structure was traditionally used which utilized smaller wood poles as cross-arms to support the insulators and conductors. This structure type is known as the Gulfport type and approximately 5,800 of these were installed on the transmission system beginning in the mid 1960’s. However, the small poles used as cross-arms were subsequently found to be defective and suffer from internal rot. Replacement programs over the past 10 years have been focused on eliminating these from the system.

Figures 29A through 29C illustrate these three different wood pole design types used in Hydro One’s transmission system.

Figure 29A: Wood Pole H–Frame Structure  Figure 29B: Wishbone Structure
• Currently 26% of the wood pole population is beyond its expected service life.

• The condition of the wood pole fleet, determined through industry standard maintenance practices, is such that 16% present fair or high condition risks that need to be mitigated.

• The number and duration of forced outages for wood poles has shown slight improvement over the last 10 years. However wood poles failures can have very negative consequence to reliability due to the majority of transmission wood pole circuits supporting radial feed circuits.

Given the current demographics of the wood pole population, condition trend and the risks associated with wood pole failures, the continuation of a rate of replacement of 2% is required to maintain current levels of performance and risk.
Asset Strategy

Hydro One Transmission’s strategy for wood poles is to manage the aging wood pole population in a manner that preserves reliability while minimizing rate impacts. Hydro One Transmission intends on continuing with a replacement rate of approximately 2% per year to manage risks associated with operating an aged wood pole population and the defective 230 kV Gulfport type structures. Hydro One Transmission considers results of wood pole inspections and tests done in accordance with CSA guidelines, performance data, asset demographics and the consequence of failure to system and customer reliability when making replacement decisions related to wood poles. This will result in a continuation of the strategy to proactively replace wood poles to reduce wood pole failures that impact customer reliability, and minimize emergency response activities that have a higher risk of negatively impacting environmentally sensitive areas.

Asset Assessment Details

Demographics

Based on Hydro One Transmission’s experience, the normal expected service life (“ESL”) used for wood poles is about 50 years. Wood poles and cross-arms are normally treated with preservatives in order to prevent premature decay and extend their expected service life. The average age of the wood pole fleet is currently 32 years and 26% of the wood poles are currently beyond their expected service life. The demographics of the wood pole population is outlined in Figure 30.
Figure 30: Demographics of the Wood Pole Fleet

Hydro One Transmission is proposing to maintain the current historic replacement rate of approximately 2% over the test years. As can be seen in Figure 31, at this rate of replacement the number of wood poles beyond their expected service life will improve from the present 26% to 18% by 2024.

Figure 31: Projection of Wood Poles Beyond Expected Service Life
Performance

The majority of transmission wood pole structures are located in Northern Ontario and many of these structures support radial circuits. As a result, a wood pole or cross-arm can often result in a direct customer outage. Many of these northern wood pole circuits feed major industrial customers and without an adequate supply of power, these customers are often forced to shut down until power is restored.

The number of forced outages due to wood pole structure failures has shown slight improvement over the past 10 years, as outlined in Figure 32, based on the current rate of replacement to address end of life wood poles and the defective Gulfport structures on the system.

![Figure 32: Forced Outages Due to Wood Pole Failures](image)

The forced outage duration due to wood pole failures, displayed in Figure 33, demonstrates that wood pole outage duration has been stable over the last 10 years, except for the extreme spike in 2010. This type of year is not unexpected given many of these circuits are radial supplies and in remote locations, with difficult access.
At the current rate of replacement, this level of reliability is expected to remain consistent over the next 10 years hence maintaining current level of customer interruption performance.

**Condition**

Wood structures deteriorate over time; the rate of deterioration depends on location, weather, type of wood, treatment, insects and wildlife. As a result, uniform deterioration does not occur and the condition of wood structures varies, even in the same location. Wood pole structures are comprised of either a single pole or multiple wood poles with a wood cross-arm which is bolted to the poles to support the insulator strings and conductors. Due to the nature of the design, the wood cross-arm tends to be the weak link and is typically the primary cause of failure.

Wood pole assessments are undertaken to inspect the condition of cross-arms and pole tops, and to evaluate the soundness of the wood near the ground line. Based on the current condition assessment, 16% of Hydro One Transmission’s wood pole population
has condition that puts it in fair or high risk, as outlined in Figure 34. The assessment is continuously reviewed and adjusted as new conditions are reported or factors are considered. Approximately 10% of the wood pole population needs to be assessed to determine their current condition risk.

Figure 34: Wood Pole Fleet Condition Assessment

The number of poles reaching the end of life identified each year through condition assessments is in-line with the current replacement rate, and hence the number of wood poles in fair and high risk condition is expected to remain stable. As a result, reliability and safety risks will be in-line with past performance.

Cost Trends and Impacts

<table>
<thead>
<tr>
<th>Wood Pole Portfolio</th>
<th>Historic</th>
<th>Bridge</th>
<th>Test</th>
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<tbody>
<tr>
<td># of Replacements</td>
<td>862</td>
<td>763</td>
<td>830</td>
</tr>
<tr>
<td>% of Fleet</td>
<td>2.1%</td>
<td>1.8%</td>
<td>2.0%</td>
</tr>
<tr>
<td>Capital ($M)</td>
<td>30.1</td>
<td>27.2</td>
<td>32.7</td>
</tr>
<tr>
<td>OM&amp;A ($M)</td>
<td>2.9</td>
<td>4.4</td>
<td>3.1</td>
</tr>
</tbody>
</table>
The capital replacement rate in the test years remains consistent with the bridge year and historic levels. Continued renewal of the fleet at this rate has been very effective at keeping pace with the number of structures that reach their expected service life. Once the remaining defective Gulfport structures are eliminated from the transmission system within 4 years, the number of annual replacements is expected to be reduced.

OM&A expenditures are generally consistent year over year with some minor variation as accomplishment of targeted programs is completed.

Hydro One Transmission has also now begun to use composite poles to replace approximately 25% of its wood pole population that have reached their expected service life. This will allow for evaluation of this emerging technology product to determine if life cycle costs of these assets can be reduced. Any benefits realized would be on the longer term horizon.

4.2.3 Transmission Steel Structures

Asset Overview

Hydro One Transmission has approximately 50,000 steel structures, as depicted in Figure 35A, on the transmission system to support the transmission lines across the province. These structures have various designs, sizes and configurations and support transmission circuits from 115 kV to 500 kV.

Steel structures are manufactured with a hot dipped galvanized zinc coating to protect the steel from corrosion. Based on Hydro One Transmission and industry experience, the expected service life of zinc coating can be anywhere from 30 to 60 years, and is the primary life-limiting factor for steel structures. Once a structure has lost its galvanizing and has begun to corrode, as depicted in Figure 35B, the bare steel underneath is exposed
to the environment. If corrosion is allowed to continue, the steel structure will begin to lose mechanical strength. Recoating the structure with zinc-based paint, as depicted in Figure 35C, will provide on-going protection to the underlying steel.

Figure 35A: Steel Tower Structure

Figure 35B: Steel Tower with Corrosion

Figure 35C: Steel Tower Recoated

- Currently 21% of the steel structure population is beyond its expected service life. Continuing at the historic rate of replacement, the number of steel structures beyond their expected service life would increase to 24% by year 2024.
The condition of the steel structure fleet, determined through industry standard maintenance practices, is such that 3% present fair or high condition risks that need to be mitigated.

The number of forced outages for steel structures has shown slight deterioration over the last 10 years; although the duration of forced outages for steel structures has remained stable.

Given the current demographics of the steel structure population, condition trend and the risks associated with steel structure failures, an increase in the fleet renewal is required to maintain current levels of performance and risk.

**Asset Strategy**

Hydro One Transmission’s strategy for steel structures is to manage the aging fleet of steel structures through a combination of planned replacements, component refurbishments and tower coating in order to maintain reliability of the system while minimizing rate impacts.

Effective tower coating can maintain a steel tower structure indefinitely by re-application of the coating approximately every 20 to 25 years depending on the installed environment of the structure. However, tower replacement is a requirement once the structure has degraded to a point where recoating cannot stop the corrosion process. Hydro One Transmission strives to recoat before this point is reached; as the life cycle costs of regular coating programs are estimated to be less than half of a replacement strategy.
Asset Assessment Details

Demographics

Hydro One Transmission uses a normal expected service life (“ESL”) of between 80 to 100 years for steel structures if the structures are not re-coated. The average age of the steel structure fleet is currently 56 years of age and 21% are currently beyond their ESL; for which 4% of these are beyond 100 years. The demographics of the steel structure population is outlined in Figure 36.

![Figure 36: Demographics of Steel Structure Fleet](image)

As can be seen in Figure 37, continuing at the historic fleet renewal rate would result in the percentage of steel structures beyond their expected service life increasing to 24% by 2024. However under the proposed plan, the percentage of steel structures beyond their expected service life will decrease from 21% to 18% over the next 10 years.
Performance

Forced outages for steel structures represents the number of times an outage is caused due to a steel structure failure such as failed, broken or bent tower member. It excludes forced outages caused by external interferences (animal contact, weather, etc.). Although single circuit tower outages typically do not result in delivery point interruptions, a multiple circuit tower failure can result in customer outages.

The number of forced outages due to steel structure failures has shown slight increase over the past 10 years, as outlined in Figure 38. With the current condition of the steel structures and the demographics of the fleet, it is expected that an increase in the capital programs will be required to prevent future increases in forced outages due to steel structures.
The forced outage duration due to steel structure failures, displayed in Figure 39, demonstrates a stable outage duration trend over the last 10 years, except for the extreme spikes in 2004 and 2005. These type of spikes are not unexpected given the very remote locations of some of the circuits, with difficult access. This can place considerable strain on the system as it may result in loss of supply to large customers including local distribution companies and generation connections.
Condition

The condition of the steel structures is determined through inspections, patrols and detailed corrosion assessment. Towers are visually inspected in accordance with NACE (“Nation Association of Corrosion Engineers”) guidelines on the degree of corrosion. Detailed corrosion assessment includes climbing towers and measuring the remaining thickness of protective coating, loss of metal if any and assessment of bolts and fittings.

Based on the current assessment of condition, 3% of Hydro One Transmission steel structures have condition in the fair or high risk category, as outlined in Figure 40, and meet the current refurbishment/coating criteria. This assessment is continuously reviewed and adjusted as new conditions are reported or factors are considered. An additional 14% of steel structures need to be assessed in order to determine their condition.

![Figure 40: Steel Structure Fleet Condition Assessment](image)

In order to maintain the condition of the fleet, the rate of refurbishment/coating will need to be increased. Towers in fair and high condition will require coating within the next 5
years. Should they exceed this optimum time to coat, the structures will eventually require either partial or full replacement.

Other Influencing Factors

- Innovation - Hydro One Transmission is continuing to investigate using alternative recoating products in order to reduce the amount of steel surface preparation and increase the drying process. This should reduce outage time and therefore permit a higher number of towers to be coated within the limited outage windows. Hydro One Transmission also continues to explore new steel tower coatings that are longer lasting than those that are currently commercially available.

Cost Trends and Impacts

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<td># of Refurbishments</td>
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<td>226</td>
<td>218</td>
<td>350</td>
<td>350</td>
<td>400</td>
</tr>
<tr>
<td># of Replacements</td>
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<td>0</td>
<td>17</td>
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<td>4</td>
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</tr>
<tr>
<td>% of Fleet</td>
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<td>0.5%</td>
<td>0.7%</td>
<td>0.7%</td>
<td>0.8%</td>
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<td>Capital ($M)</td>
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<td>13.3</td>
<td>11.1</td>
<td>10.7</td>
<td>16.0</td>
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<tr>
<td>OM&amp;A ($M)</td>
<td>4.7</td>
<td>4.8</td>
<td>3.1</td>
<td>4.4</td>
<td>4.1</td>
<td>4.2</td>
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</table>

The capital investment in the test years is an increase over historic levels. The strategy to manage the aging fleet of steel towers is a combination of planned replacements, component refurbishment and tower coating. The number of towers that have been refurbished, coated or replaced over the past 10 years has been very low. The result of recent condition inspections has pointed to rapid deterioration of steel structures in highly corrosive areas, which demonstrates a need to increase the fleet renewal. Hydro One Transmission plans to undertake an aggressive tower coating program to sustain these assets. Tower coating has been identified as the preferred alternative as it has a life cycle
cost of roughly half that of tower replacement and is less impactive to the system as
circuit outages required for coating are minimal.

OM&A expenditures are relatively stable with assessment activities performed frequently
to assess zinc coating thickness and member condition.

4.2.4 Transmission Underground Cables

Asset Overview

Hydro One’s transmission system consists of approximately 290 km of underground
cables that supply city centres in Toronto, Ottawa and Hamilton with short sections in
London, Sarnia, Picton, Windsor and Thunder Bay. Transmission underground cables are
typically extensions to, or links between, portions of the overhead transmission system
operating at 230 kV and 115 kV. Underground cables are mainly used in urban areas
where it is either impossible, or extremely difficult to build overhead transmission lines
due to legal, environmental and safety reasons.

Depending on the cable design the three phase conductors may be contained together
within a steel pipe or each phase conductor self-contained in its own sheath and installed
separately underground. Transmission underground cables are systems, similar to
transmission lines, made up of numerous components all of which need to integrate and
function properly in order to deliver power with the reliability that is demanded.

There are three different types of high voltage underground cables in use on the
transmission system: Low-Pressure Oil-Filled (“LPOF”) cables, High-Pressure Oil-Filled
Pipe-Type (“HPOF”) cables, and Extruded Cross Linked Polyethylene (“XLPE”) cables.
Figures 41A through 41C illustrate the three types of underground cables used in Hydro One’s transmission system.

Figure 41A: LPOF Cable

Figure 41B: HPOF Cable

Figure 41C: XLPE Cable
• Currently 16% of the underground cable population is beyond its expected service life. Continuing at the historic rate of replacement, the number of underground cables beyond their expected service life would increase to 30% by 2024.

• The condition of the underground cable fleet, determined through industry standard maintenance practices, is such that 14% present fair or high condition risks that need to be mitigated.

• The number of forced outages for underground cables has shown slight improvement over the last 10 years. However, the duration of forced outages for underground cables has been increasing. Due to the nature and construction of these assets, failures can result in significant reliability and environmental impacts.

Given the current aging demographics of the underground cable population, condition trend along with the nature of the problems recently experienced, and the risks associated with underground cables failures, are all indicative of the need to increase the historic level of replacement in order to preserve the current levels of performance and risk.

Asset Strategy

Hydro One Transmission’s strategy for underground cables is to manage the aging underground cables that supply city centres in Toronto, Ottawa and Hamilton in a matter that preserves reliability while minimizing rate impacts. Hydro One Transmission has employed and will continue with its rigorous maintenance program (involving inspections, analysis, and diagnostic testing of cables, vaults, jackets and potheads) that extends the life of these assets. Hydro One Transmission plans to continue forward with an average replacement rate consistent with the bridge year in order to manage the reliability and environmental risks associated with operating an aged underground cable population.
Asset Assessment Details

Demographics

Hydro One Transmission uses a normal expected service life ("ESL") of 50 years for underground transmission cables, which is based primarily on the original design expectations. However, due to the very rigorous maintenance program employed by Hydro One Transmission a number of cables beyond this age are still in satisfactory operating condition. The average age of the underground cable fleet is currently about 37 years and about 16% of cables are beyond their expected service life. The demographics of the underground cable population is outlined in Figure 42.

![Figure 42: Demographics of Underground Cables Fleet](image)

The potential risks to reliability and safety as a result of the aging demographics and deteriorating cable condition needs to be managed through a continued rigorous maintenance program to detect developing defects, as well as through capital replacement programs. As can be seen in Figure 43, continuing at the historic rate of replacement would result in the percentage of underground cables beyond their expected service life increasing to 30% by
2024. However at the proposed replacement rate, the percentage of underground cables beyond their expected service life will increase from 16% to 20% by 2024.

![Figure 43: Projection of Underground Cables Beyond Expected Service Life](image)

**Performance**

The underground transmission cables were first designed and installed with built-in redundancy and capacity so that failures would not immediately result in outages to customers. Many of these cables are still in service and are starting to experience the effects of aging and the increased loading due to the expansion in the downtown areas. There has been minimal impact in customer reliability due to underground cable failures over the last 10 years; however as the asset ages there is increased risk of failure with the underground system.

The number of forced outages due to a failure on part of the underground cable system has shown a slight improvement over the past 10 years, as outlined in Figure 44. There have been a number of major component replacement projects during the past 10 years...
including joint, termination, oil pressure system and bonding upgrades which have contributed to this reduction in the forced outages.

![Bar Chart: Forced Outages due to Underground Cable Failures](image)

**Figure 44: Forced Outages due to Underground Cable Failures**

The forced outage duration of each occurrence was increasing significantly during the period from 2008 to 2011 but has been minimal during the last two years, as depicted in Figure 45. This recent decrease is mainly contributable to the replacement of two high risk end of life cable circuits H2JK and K6J. However, the increase in outage duration is representative of problems becoming more serious.
The forced outages depicted in Figure 44 and 45 are failures that were significant enough to require the circuit to be forced out of service. There are many other cases where equipment defects and cable leaks have occurred but were not severe enough to force the circuit from service but instead were addressed under a planned outage. Considering the deteriorating condition and demographics of the fleet, the continuation of a rate of replacement consistent with the bridge year is required to maintain the current forced outage frequency.

**Condition**

Hydro One Transmission assesses its underground cable fleet condition based on a variety of factors. This assessment is continuously reviewed and adjusted as new conditions are reported or factors are considered. Not all sections of a buried cable are accessible for maintenance inspections and diagnostics, but the inspections are generally representative of the entire cable system.
Based on the current assessment of the underground cable fleet condition, 14% of Hydro One Transmission’s underground cable population has condition that puts it in the fair or high risk, as outlined in Figure 46.

![Figure 46: Underground Cable Fleet Condition Assessment](image)

Underground cables located in major cities where loading has increased significantly since the original installation, impact the aging process and condition trend of these cables, as well as the likelihood of cable failures. In order to maintain the condition of the fleet, given the demographics and utilization, continued renewal of the fleet is required.

**Other Influencing Factors**

Other factors driving the increase in underground cable replacements are summarized below.

- Technical Obsolescence – There are some types of underground cables technology that are no longer available and supported by manufacturers. This is a significant factor for low pressure oil filled cables that rely on gravity feed oil reservoirs that are no longer available.

- Environmental Impacts – The failure of an underground cable can result in the leakage of oil into the surrounding area. In 2003, a downtown Toronto cable circuit
(H3L) failed which resulted in 5,500 litres of oil spilling into the Don River. The failure was located and repaired, which took over a month to complete. When the circuit was returned to service, it failed again after only 2 months at another location, indicating the need to replace.

- Equipment Loading – Cables are located in major cities where loading has increased significantly since original installation impacting the aging process as well as the number of cable failures.

- Criticality – Underground cables are used to supply the load of major cities, thus a failure of the cable can result in significant impact to customers. In 2010, a downtown Toronto cable circuit (H2JK) failed, since the other supply circuit (K6J) was on a planned outage at the time, the failure of the cable caused all of the five delivery points at Strachan TS to go out of service. The longer term major risk was if the condition of these two circuits deteriorated to a level that was impractical to repair, then both circuits would have to be removed from service resulting in considerable strain and risk to the system for a prolonged period of time.

**Cost Trends and Impacts**

<table>
<thead>
<tr>
<th>Underground Cable Portfolio</th>
<th>Historic</th>
<th>Bridge</th>
<th>Test</th>
</tr>
</thead>
<tbody>
<tr>
<td>Kms of Circuit Replacements</td>
<td>0</td>
<td>0</td>
<td>5.0</td>
</tr>
<tr>
<td>% of Fleet</td>
<td>0%</td>
<td>0%</td>
<td>1.7%</td>
</tr>
<tr>
<td>Capital ($M)</td>
<td>0.6</td>
<td>2.6</td>
<td>32.8</td>
</tr>
<tr>
<td>OM&amp;A ($M)</td>
<td>6.6</td>
<td>3.6</td>
<td>4.3</td>
</tr>
</tbody>
</table>

Hydro One is now entering into a period where the underground cable circuits are approaching their end of expected life and in order to effectively manage the underground cables continued renewal of the fleet must be maintained. There is some
variability in capital expenditures year over year, which is mostly a function of the timing and magnitude of individual projects. The replacement of older oil filled cable systems with new XLPE cable systems, which have lower maintenance costs, will result in lower lifecycle costs.

OM&A expenditures are relatively stable year over year in order to carry out assessment activities to provide insight into cable condition.

Many factors drive cable replacement; the key factors include condition, performance, obsolescence, age, circuit criticality, and environmental impacts. Failure of underground cables can take significant time to repair or replace. This can place considerable strain on the system as it may restrict outages required for maintenance or repair of other equipment. Overloading other cables and related elements can place the system at risk of failure, loss of supply and blackout to the customer.
SUMMARY OF CAPITAL EXPENDITURES

1.0 SUMMARY OF CAPITAL BUDGET

The proposed capital expenditures result from a rigorous business planning and work prioritization process that reflects risk-based decision-making to ensure that the appropriate, cost-effective solutions are put into place to meet Hydro One Transmission objectives. These processes are described in detail in Exhibit A, Tab 16, Schedules 1 to 7.

The capital expenditures proposed in this filing represent investments that will ultimately become in-service capital assets supporting the Hydro One Transmission business. Specifically, these expenditures include:

a) design and development of specific assets providing future economic benefits;
b) purchase, construction and commissioning of specific assets providing future economic benefits;
c) additions to specific assets; and
d) betterments that result in improvement of capacity, efficiency, useful life span, or economy of specific assets.

The proposed capital programs address Hydro One Transmission’s integrated set of asset replacement and expansion needs to meet its objectives of: public and employee safety; maintenance of transmission reliability at targeted performance levels; meeting system growth requirements; compliance with regulatory requirements (such as specified within the Transmission System Code); environmental requirements; and Government direction. The development of these capital programs is based on comprehensive asset condition information, system loading versus capacity information and various studies.
Hydro One Transmission's capital budget is grouped into four different investment categories: Sustaining, Development, Operations, and Common Corporate Costs Capital. Table 1 provides a summary of Hydro One Transmission’s capital expenditures for the historical, bridge and test years.

<table>
<thead>
<tr>
<th></th>
<th></th>
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<th></th>
<th></th>
<th></th>
<th></th>
<th></th>
<th></th>
</tr>
</thead>
<tbody>
<tr>
<td>Sustaining</td>
<td>333.2</td>
<td>389.3</td>
<td>480.0</td>
<td>579.3</td>
<td>581.9</td>
<td>548.6</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Development</td>
<td>415.9</td>
<td>329.4</td>
<td>171.7</td>
<td>195.6</td>
<td>209.7</td>
<td>211.8</td>
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<td></td>
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<tr>
<td>Operations</td>
<td>8.8</td>
<td>15.2</td>
<td>17.7</td>
<td>38.5</td>
<td>38.4</td>
<td>37.4</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Common Corporate Costs Capital</td>
<td>52.3</td>
<td>42.1</td>
<td>49.1</td>
<td>85.8</td>
<td>69.4</td>
<td>68.5</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>TOTAL</td>
<td><strong>810.2</strong></td>
<td><strong>776.0</strong></td>
<td><strong>718.5</strong></td>
<td><strong>899.2</strong></td>
<td><strong>899.4</strong></td>
<td><strong>866.3</strong></td>
<td></td>
<td></td>
<td></td>
</tr>
</tbody>
</table>

*AFUDC for the period 2009 to 2011

The Transmission Capital requirements continue to grow over the 2014 to 2015 period to address asset replacement and refurbishment needs of Hydro One’s aging system, and to expand the system for the purposes of load growth, accommodating a modified generation mix, and expanding access to interconnected electricity markets. Overall spending requirements decline in 2016.

The increase in Sustaining expenditures is primarily due to the continued growth in the number of assets that are beyond their expected service life and have been identified as either at end of life, obsolete with no spare parts available, or requiring replacement in order to satisfy changes in the regulations that govern the transmission business. The increase in Development expenditures is primarily driven by large projects such as Clarington TS and Guelph Area Transmission Reinforcement. Operations spending increases mainly due to the NMS sustainment program, the WAN Outreach program and the Fault Locating program. Common Costs increases are primarily in the Facilities and Real Estate area for increased spending on building improvements in older field facilities.
and for head office improvements, and higher IT spending in the bridge year for the completion of the Cornerstone project.

Investment Summary Documents in support of capital projects with cash flows in excess of $3.0 million in either 2015 or 2016 are filed at Exhibit D2, Tab 2, Schedule 3.

2.0 SUSTAINING

The Sustaining capital program includes the costs for investments required to replace or refurbish components to ensure that existing transmission system facilities function as originally designed. Hydro One Transmission manages its sustaining program within two program categories, namely stations and lines. Details of the expenditures under this program are provided at Exhibit D1, Tab 3, Schedule 2.

3.0 DEVELOPMENT

The Development capital program consists of the investments required to upgrade or enhance transmission system capabilities to address load growth, generation connection requirements and transmission congestion, and to ensure that the system is designed and operated in a safe, secure and reliable manner. Details of the expenditures under this program are provided at Exhibit D1, Tab 3, Schedule 3.

4.0 OPERATIONS

The Operations capital program represents investments in infrastructure required to sustain the Central Transmission Operations function, which is operated from Hydro One's Ontario Grid Control Centre. Details of the expenditures under this program are filed at Exhibit D1, Tab 3, Schedule 4.
SUSTAINING CAPITAL

1.0  INTRODUCTION

Sustaining Capital consists of expenditures required to refurbish or replace transmission system components which are at end of life for technical or economic reasons to ensure the system will continue to function as originally designed. The expenditures covered under Sustaining Capital are intended to sustain existing transmission system facilities performance at required levels, thereby maintaining the overall reliability of the system while satisfying all legislative, regulatory, environmental and safety requirements.

Hydro One Transmission manages its Sustaining Capital program by dividing the expenditures into the following two categories:

- **Stations**, which funds the work required to refurbish or replace existing assets located within transmission stations, including existing protection, control, and telecommunication assets, and

- **Lines**, which funds the work required to refurbish or replace existing assets associated with overhead and underground transmission lines.

Sustaining Capital programs are driven by the asset needs and focus on managing the risks associated with the fleet of aging transmission assets. A summary of Hydro One Transmission’s Sustaining Capital programs and proposed spending levels for the test years 2015 and 2016 are described herein.
2.0 SUSTAINING CAPITAL SUMMARY

The rigorous investment planning, prioritization and approval process described in Exhibit A, Tab 16, Schedules 1 to 5, has been completed for all Sustaining Capital programs to ensure that assets are managed prudently while meeting customer, operational and regulatory needs.

The selection of planned Sustaining Capital investments is guided by the asset risk assessment process described in Exhibit A, Tab 16, Schedule 7. This process takes into account the condition, age, performance, criticality and utilization of specific assets. A summary of the asset risk assessment for key transmission assets is provided in Exhibit D1, Tab 2, Schedule 1.

Over the long term, an adequately maintained transmission system that performs to the level of its original design is in the best interest of Hydro One Transmission and its customers. As outlined in Exhibit D1, Tab 2, Schedule 1 a significant portion of Hydro One’s transmission system is at an age where factors such as degraded condition and demographic pressures are contributing to operational risks. These risks must be managed in a cost-effective manner for the benefit of customers. Capital expenditures proposed in this exhibit address the needs identified in the test years as a result of the aging asset base. It must be recognized that any reductions applied to the test years spending will have a compounding effect on cost pressures in the future, and the ability to complete the required work, both in capital replacements and corrective maintenance as well as impact reliability and potentially safety.

The required funding for Sustaining Capital in the test years, along with the spending levels for the bridge and historic years is provided in Table 1 for each of the major sustaining categories.
Table 1
Sustaining Capital
($ Millions)

<table>
<thead>
<tr>
<th>Description</th>
<th>Historic Years</th>
<th>Bridge Year</th>
<th>Test Years</th>
</tr>
</thead>
<tbody>
<tr>
<td>Stations</td>
<td>262.7</td>
<td>322.5</td>
<td>355.3</td>
</tr>
<tr>
<td>Lines</td>
<td>70.6</td>
<td>66.8</td>
<td>124.8</td>
</tr>
<tr>
<td>Total</td>
<td>333.2</td>
<td>389.3</td>
<td>480.0</td>
</tr>
</tbody>
</table>

The overall Sustaining Capital requirements for the test year 2015 have increased by less than 1% over projected spending in the bridge year 2014. The Sustaining Capital requirements for 2016 are approximately 6% less than the 2015 requirements. The proposed expenditures in 2015 and 2016 are felt to adequately maintain reliability to customers and the bulk electricity system, and manage the population of aging assets over this time period. Expenditures are focused on assets that are beyond their expected service life, have been identified as in degraded condition, are obsolete with no spare parts available, and/or require replacement in order to satisfy changes in the regulations that govern Hydro One Transmission’s business.

As outlined in Exhibit D1, Tab 2, Schedule 1, asset demographics continue to create a challenge in managing the transmission system. The design of the Hydro One transmission system and effectiveness of Hydro One Transmission’s maintenance programs have minimized the impact of aging assets on customers. However, equipment performance and condition trends reveal the necessity for continued investment to maintain the historic levels of risk.

One notable difference in the test year spending is the on-going focus on integrated projects in both the Stations and Lines asset categories. With many asset types beyond their expected service life and showing signs of the need for replacement, larger scale Station or Line refurbishment projects are an effective option to deal with the specific
assets and in many cases make modifications that would not otherwise be practical. This may include upgrading load delivery stations to existing standards to eliminate safety risks, modifying the configuration at transmission stations, or removing oil filled cable systems. The air blast breaker replacement projects are one example with significant benefits. These breakers are typically installed at critical system stations, and once replaced, the equipment reliability is expected to improve by a factor of five and the replacement breakers will result in a 90% savings in maintenance costs.

Reduction in the Sustaining Capital funding would have impacts in a number of areas:

- A marked reduction in equipment and customer reliability at transmission stations as a result of increased transformer failures, inoperable breakers and switches, and potential misoperation of protection systems;
- Risk of non-compliance with Ministry of Environment regulations concerning adequate drainage and oil spills, and lack of progress against PCB phase out plans mandated by Environment Canada;
- Potential for wide spread power disruptions should the critical protection and control systems start to fail due to late response to aging infrastructure. A similar situation applies to several classes of breakers that are aging and do not have support for spare parts;
- Risk of non-compliance with NPCC and NERC regulations that require secure facilities for connection to the north east power grid. Protection and control systems are critical in this regard and if reliability cannot be maintained, Hydro One Transmission risks citations and fines; and
- An increase in power outages to lines facilities due to failure of structures, insulators and other components that make up the lines system. These facilities are located in the public domain and as such need to be kept in a state of good repair to adequately manage public safety and to maintain customer and system reliability.
3.0 STATIONS

Transmission Station facilities are used for the delivery of power, voltage transformation, switching, and serve as connection points for both load customers and generators. Station facilities contain many of the following major components: power transformers, circuit breakers, disconnect switches, bus work, insulators, potheads, power cables, surge arrestors, capacitor banks, reactors, instrument devices, protection and control systems, station service systems, grounding systems, site infrastructure and buildings.

Stations Sustaining Capital funding covers expenditures required to sustain existing assets located within transmission stations including protection, control and telecommunications facilities. Hydro One Transmission manages its Stations Sustaining Capital program by dividing the program into eight categories:

1. Circuit Breakers, which funds the capital investments to refurbish or replace circuit breakers;

2. Station Re-investment, which funds the capital investments to refurbish or replace several station components or systems in an integrated manner;

3. Power Transformers, which funds the capital investments to refurbish or replace power transformers;

4. Other Power Equipment, which funds the capital investments to refurbish or replace power equipment, other than power transformers and circuit breakers. This includes disconnect switches, capacitor banks, reactors, surge arrestors, low voltage cables and potheads, instrument devices and insulators. These components provide over-voltage protection, electrical insulation, metering and protection capability, electrical isolation, and voltage control;
5. **Ancillary Systems**, which funds the capital investments to refurbish or replace ancillary systems (such as station service systems, grounding systems, high pressure air (‘‘HPA’’) systems etc.);

6. **Station Environment**, which funds the capital investments for the installation, replacement and refurbishment of transformer spill containment systems;

7. **Protection, Control, Monitoring and Telecommunications**, which funds the capital investments to refurbish or replace protection, control, monitoring and telecommunications equipment;

8. **Site Facilities and Infrastructure**, which funds capital investments to refurbish and replace station infrastructure (such as station buildings, heating ventilation and air conditioning (‘‘HVAC’’) systems, water supplies, sewage, fences, fire protection, drainage, structural footings, etc.).

Required funding for the test years 2015 and 2016, along with the spending levels for the bridge and historic years are provided in Table 2 for each of these categories.
Table 2
Stations Sustaining Capital
($ Millions)

<table>
<thead>
<tr>
<th>Description</th>
<th>Historic Years</th>
<th>Bridge Year</th>
<th>Test Years</th>
</tr>
</thead>
<tbody>
<tr>
<td>Circuit Breakers</td>
<td>29.2</td>
<td>11.2</td>
<td>23.4</td>
</tr>
<tr>
<td>Station Re-investment</td>
<td>36.4</td>
<td>62.1</td>
<td>89.0</td>
</tr>
<tr>
<td>Power Transformers</td>
<td>81.1</td>
<td>78.4</td>
<td>87.0</td>
</tr>
<tr>
<td>Other Power Equipment</td>
<td>16.2</td>
<td>28.3</td>
<td>26.5</td>
</tr>
<tr>
<td>Ancillary Systems</td>
<td>13.4</td>
<td>16.4</td>
<td>15.5</td>
</tr>
<tr>
<td>Station Environment</td>
<td>7.0</td>
<td>7.6</td>
<td>6.6</td>
</tr>
<tr>
<td>Protection, Control, Monitoring, and Telecommunications</td>
<td>61.6</td>
<td>95.0</td>
<td>84.4</td>
</tr>
<tr>
<td>Site Facilities and Infrastructure</td>
<td>17.8</td>
<td>23.4</td>
<td>22.9</td>
</tr>
<tr>
<td>Total</td>
<td>262.7</td>
<td>322.5</td>
<td>355.3</td>
</tr>
</tbody>
</table>

The overall Stations Sustaining Capital expenditures for the test year 2015 are approximately 2% less than the projected spending in 2014. The spending requirements for 2016 are also about 4% less the 2015 requirements. Though there is a declining trend, the planned expenditures for the test years represents on average a 40% increase compared to the historic years. These expenditures reflect the continuation of existing asset replacement rates to maintain reliability and risks levels on an on-going basis. Some variability can be observed year over year associated with the timing of specific projects. The primary driver for capital expenditures being higher when compared to historic years is due to the on-going focus within Station Re-investment on replacing air blast circuit breakers at critical system stations and executing integrated station rebuilds at load delivery stations.
3.1 Circuit Breakers

3.1.1 Introduction

Circuit breakers provide protection to the system under fault conditions, and provide a switching function under normal operating conditions. Hydro One Transmission has approximately 4,604 circuit breakers on the transmission system. Programs are developed to manage the risks associated with premature physical deterioration, decrease in reliability performance, and an aging asset base. Hydro One Transmission has over 120 unique circuit breakers types from approximately 30 different manufacturers currently operating on the system. The two main classification/interrupting type of circuit breakers that are addressed within this circuit breaker replacement program are Oil and Sulfur Hexafluoride (“SF6”) circuit breakers. There are also some circuit breakers on the system that utilize vacuum interruption technology, and a small number of targeted replacements are planned within the test years. Generally this program does not include the replacement of air blast circuit breakers (“ABCB”), metalclad or gas insulated switchgear (“GIS”), as replacements of this type typically involve a broader scope than just a “one for one” replacement. This being the case, ABCB, metalclad and GIS are typically replaced on a project basis under the Station Re-investment, as discussed in Section 3.2 of this exhibit.

3.1.2 Investment Plan

In order to effectively manage the circuit breaker replacement programs, specific maintenance tests have been developed to obtain the data required to determine the condition and the likelihood of failure of circuit breakers. These tests, along with the operating history and application, individual breaker and breaker family performance, asset criticality and demographic data provide the basic information required to conduct asset assessments and determine asset replacement needs.
Table 3 outlines the proposed funding for test years 2015 and 2016, along with the spending levels for the bridge and historic years for the circuit breaker replacement programs.

### Table 3
Circuit Breakers
($ Millions)

<table>
<thead>
<tr>
<th>Description</th>
<th>Historic Years</th>
<th>Bridge Year</th>
<th>Test Years</th>
</tr>
</thead>
<tbody>
<tr>
<td>Oil Circuit Breaker Replacements</td>
<td>8.9</td>
<td>6.5</td>
<td>9.3</td>
</tr>
<tr>
<td>SF6 Circuit Breaker Replacements</td>
<td>15.4</td>
<td>11.2</td>
<td>10.8</td>
</tr>
<tr>
<td>Other Circuit Breaker Programs</td>
<td>4.9</td>
<td>(6.5)</td>
<td>3.4</td>
</tr>
<tr>
<td>Total</td>
<td>29.2</td>
<td>11.2</td>
<td>23.4</td>
</tr>
</tbody>
</table>

**Oil Circuit Breaker Replacements**

Hydro One Transmission owns and manages 1,818 oil circuit breakers. These breakers are no longer manufactured and replacement parts are becoming increasingly expensive and harder to source. In many cases the breakers cannot be economically repaired and if not replaced will impact on Hydro One Transmission’s ability to supply reliable power. Many of these circuit breakers are at or approaching their expected service life. As the asset ages, the condition will further deteriorate, creating untenable conditions in keeping this class of equipment in service with reliable performance. This replacement program focuses primarily on technically obsolete and poor performing breakers.

Additional details for this program are provided in the Investment Summary Document S01 in Exhibit D2, Tab 2, Schedule 3.
SF6 Circuit Breaker Replacements

Hydro One Transmission manages 1,579 SF6 circuit breakers, the first of which were installed in the late 1960s. The newer SF6 circuit breaker designs remain as one of the utility standards for circuit breaker installations and are used to replace other circuit breaker types that have become obsolete. This replacement program focuses primarily on breakers in capacitor and reactor switching positions, which are subjected to the most severe application. These breakers have exceeded the number of design operations, are demonstrating poor performance, and require on-going costly corrective maintenance if not replaced. Another significant area of the replacement program is focused on the early generation SF6 breakers with poor design characteristics, high leak rates and that are now technically obsolete.

Additional details for this program are provided in the Investment Summary Document S02 in Exhibit D2, Tab 2, Schedule 3.

Other Circuit Breaker Programs

Hydro One Transmission also manages 41 vacuum breakers installed in 44 kV, 27.6 kV, and 13.8 kV positions. There is a targeted replacement program focused on breakers with design deficiencies, poor performance or breaker designs that are no longer supported by the manufacturer and where spare parts are not available, thus mitigating the risk of extended outage duration impacting customer reliability, should one of these breakers fail. Other investments under the other program category focus on the purchase of operating spare circuit breakers and the demand costs to replace failed units.

3.1.3 Summary of Expenditures

The planned expenditure for 2015 and 2016 is $13.5 million and $24.5 million respectively. The 2015 expenditures are significantly less than the bridge year, whereas the 2016 expenditure is generally in line with the previous years spending in this
program. This reduction in 2015 corresponds to an increase in 2015 spending in the Integrated DESN Investment category within the Station Re-investment program. The circuit breakers identified in need of replacement that would have otherwise been completed within the oil circuit breaker and SF6 circuit breaker replacement programs are being completed as part of integrated station-level refurbishments. Integration of the replacement of multiple end of life components into a single project allows additional efficiencies to be realized during the design, construction, and commissioning stages of the work.

A reduction in this program will delay the replacement of aged and degraded equipment that is technically obsolete, resulting in increased risk exposure to reliability at both system stations and customer load delivery stations.

### 3.2 Station Re-investment

#### 3.2.1 Introduction

Older stations typically contain a number of components that reach end of life at about the same time. Efficiency gains are achieved in many cases by replacing all such components within the station as part of the same project. This practice also contributes to greater customer satisfaction due to fewer planned outages, and reduced risk of unplanned outages that can occur when one or more system elements are removed from service. Station re-investment work complements other individual component replacement programs within Stations Sustaining Capital. Hydro One Transmission continues towards executing a greater portion of the planned work in this integrated fashion.
In order to effectively manage a reliable transmission system, all critical components within a transmission station are assessed against required functionality, condition, performance, safety and environmental impacts. The required work is then combined in the most economical manner.

Hydro One Transmission manages its Station Re-investment program by grouping projects into similar types of work. Table 4 outlines the proposed funding for test years 2015 and 2016, along with the spending levels for the bridge and historic years for each grouping.

### Table 4
Station Re-Investment
($ Millions)

<table>
<thead>
<tr>
<th>Description</th>
<th>Historic Years</th>
<th>Bridge Year</th>
<th>Test Years</th>
</tr>
</thead>
<tbody>
<tr>
<td>Metalclad Switchgear Replacements</td>
<td>6.0</td>
<td>(4.2)</td>
<td>(0.4)</td>
</tr>
<tr>
<td>Air Blast Circuit Breaker Replacements</td>
<td>16.4</td>
<td>22.4</td>
<td>17.9</td>
</tr>
<tr>
<td>End of Life Station Reconfigurations</td>
<td>7.6</td>
<td>27.0</td>
<td>39.7</td>
</tr>
<tr>
<td>Integrated DESN Replacements</td>
<td>0.1</td>
<td>1.0</td>
<td>30.4</td>
</tr>
<tr>
<td>Integrated Station Component Replacements</td>
<td>0</td>
<td>0</td>
<td>0.6</td>
</tr>
<tr>
<td>Other Historical Projects</td>
<td>6.3</td>
<td>16.0</td>
<td>0.8</td>
</tr>
<tr>
<td><strong>Total</strong></td>
<td><strong>36.4</strong></td>
<td><strong>62.1</strong></td>
<td><strong>89.0</strong></td>
</tr>
</tbody>
</table>

Metalclad Switchgear Replacements Projects

Hydro One Transmission has a number of metalclad switchgear lineups, typically at indoor stations in urban areas. Replacement programs are established to replace switchgear beyond its expected service life. Several installations are from the 1950s and have safety concerns, are technically obsolete, and are important to maintaining customer
reliability in Toronto, Hamilton, and Ottawa. In the case of Toronto, a multiyear program is underway to replace aged infrastructure in coordination with Toronto Hydro Electric System Limited (“THESL”). Prioritization has been done in coordination with THESL, allowing both utilities to leverage resources and construction outages. A portion of this work is recoverable from THESL. In 2012 and 2013, there were capital contributions from Toronto Hydro in the amount of $5.5 million and $0.6 million respectively for betterments made in coordination with replacement of the metalclad switchgear at Strachan TS, Glengrove TS and Carlaw TS.

Additional details for these projects are provided in the Investment Summary Document S03 in Exhibit D2, Tab 2, Schedule 3.

Air Blast Circuit Breaker Replacement Projects

Air blast circuit breakers are the poorest performing breakers in the Hydro One transmission system. Typically ABCBs were originally installed at critical transmission station during the 1970’s build of the transmission system. ABCBs have the highest operating cost of any breaker technology, due to their high pressure air systems with sensitive components that need frequent maintenance. These circuit breakers are no longer produced and many models lack support for parts and technical expertise.

The transmission stations identified for ABCB replacements are outlined in Table 5. These breakers planned for replacement have been problematic and are in need of replacement due to performance, obsolescence, and system criticality. The work will entail replacement of the existing ABCB’s with modern SF6 circuit breakers, as well as include the removal of the high pressure air systems and adjoining equipment determined to be at end of life.
Table 5
Air Blast Circuit Breaker Replacement Projects
($ Millions)

<table>
<thead>
<tr>
<th>Ref#</th>
<th>Description</th>
<th>Test Years</th>
<th>Total Cost</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td></td>
<td>2015</td>
<td>2016</td>
</tr>
<tr>
<td>S04</td>
<td>Richview TS</td>
<td>23.5</td>
<td>22.1</td>
</tr>
<tr>
<td>S05</td>
<td>Beck #2 TS</td>
<td>15.4</td>
<td>9.9</td>
</tr>
<tr>
<td>S06</td>
<td>Bruce A TS</td>
<td>22.1</td>
<td>26.4</td>
</tr>
<tr>
<td>S07</td>
<td>Burlington TS</td>
<td>11.3</td>
<td>0.0</td>
</tr>
<tr>
<td></td>
<td>Other Projects &lt;$3M</td>
<td>1.4</td>
<td>1.0</td>
</tr>
<tr>
<td></td>
<td><strong>Total</strong></td>
<td><strong>73.7</strong></td>
<td><strong>59.4</strong></td>
</tr>
</tbody>
</table>

Additional details for these projects are provided in the Investment Summary Documents S04 to S07 in Exhibit D2, Tab 2, Schedule 3.

**End of Life Station Reconfiguration Projects**
Consistent with the integrated strategy of Station Re-investments, end of life station reconfiguration projects address many assets and components that are in need of replacement at a single station. These projects stem from typical end of life replacement needs, but the solutions employed also have a significant element of station reconfiguration. Synergies in design, construction and procurement can be best realized by executing an integrated project of this nature when all major station infrastructure is in need of replacement within the same general timeframe.

The transmission stations identified for end of life station reconfiguration are outlined in Table 6. The work will entail replacement of end of life assets as well as a substantial reconfiguration to the station’s topology to meet existing requirements.
Table 6
End of Life Station Reconfiguration Projects
($Millions)

<table>
<thead>
<tr>
<th>Ref#</th>
<th>Description</th>
<th>Test Years</th>
<th>Total Cost</th>
</tr>
</thead>
<tbody>
<tr>
<td>S08</td>
<td>Gage TS</td>
<td>26.9</td>
<td>72.4</td>
</tr>
<tr>
<td>S09</td>
<td>Timmins TS</td>
<td>5.2</td>
<td>10.7</td>
</tr>
<tr>
<td>S10</td>
<td>Hanmer TS</td>
<td>8.0</td>
<td>16.0</td>
</tr>
<tr>
<td></td>
<td><strong>Total</strong></td>
<td><strong>40.0</strong></td>
<td><strong>26.9</strong></td>
</tr>
</tbody>
</table>

Additional details for these projects are provided in the Investment Summary Documents S08 to S10 in Exhibit D2, Tab 2, Schedule 3.

Integrated DESN Replacement Projects

Projects within this grouping are targeted at replacing multiple assets within DESN (dual element spot network) stations, which facilitate power transformation from the bulk supply stations to load customers, typically at 44 kV, 27.6 kV, and 13.8 kV. The underlying force for the investment is typically multiple transformers that are in need of replacement, at which point opportunities are sought after to replace assets such as spill containment, protection and control systems, circuit breakers, disconnect switches and surge arresters at the same time in an integrated manner. Combining multiple elements into a single work package allows additional efficiencies to be realized during the design, construction, and commissioning stages of the work. The DESN stations identified for integrated replacements are outlined in Table 7.

Table 7
Integrated DESN Replacement Projects
($Millions)

<table>
<thead>
<tr>
<th>Ref#</th>
<th>Description</th>
<th>Test Years</th>
<th>Total Cost</th>
</tr>
</thead>
<tbody>
<tr>
<td>S11</td>
<td>Dunnville TS</td>
<td>4.6</td>
<td>18.3</td>
</tr>
<tr>
<td>S12</td>
<td>National Research Council TS</td>
<td>15.5</td>
<td>22.1</td>
</tr>
<tr>
<td>S13</td>
<td>Espanola TS</td>
<td>0.9</td>
<td>18.8</td>
</tr>
<tr>
<td>S14</td>
<td>Strathroy TS</td>
<td>0.0</td>
<td>19.5</td>
</tr>
<tr>
<td>Ref#</td>
<td>Description</td>
<td>Test Years</td>
<td>Total Cost</td>
</tr>
<tr>
<td>------</td>
<td>-----------------</td>
<td>-------------</td>
<td>------------</td>
</tr>
<tr>
<td></td>
<td></td>
<td>2015</td>
<td>2016</td>
</tr>
<tr>
<td>S15</td>
<td>Elgin TS</td>
<td>18.8</td>
<td>11.3</td>
</tr>
<tr>
<td>S16</td>
<td>Gerrard TS</td>
<td>18.8</td>
<td>0.0</td>
</tr>
<tr>
<td>S17</td>
<td>Chenaux TS</td>
<td>14.0</td>
<td>5.9</td>
</tr>
<tr>
<td>S18</td>
<td>Overbrook TS</td>
<td>11.3</td>
<td>0.0</td>
</tr>
<tr>
<td>S19</td>
<td>Ear Falls TS</td>
<td>5.4</td>
<td>0.0</td>
</tr>
<tr>
<td>S20</td>
<td>Wiltshire TS</td>
<td>5.1</td>
<td>5.2</td>
</tr>
<tr>
<td>S21</td>
<td>Bridgman TS</td>
<td>4.5</td>
<td>0.0</td>
</tr>
<tr>
<td>S22</td>
<td>Dundas TS</td>
<td>3.4</td>
<td>0.0</td>
</tr>
<tr>
<td>S23</td>
<td>Goderich TS</td>
<td>0.9</td>
<td>6.6</td>
</tr>
<tr>
<td>S24</td>
<td>Leaside TS</td>
<td>1.9</td>
<td>9.7</td>
</tr>
<tr>
<td>Other Projects &lt;$3M</td>
<td>1.9</td>
<td>2.9</td>
<td></td>
</tr>
<tr>
<td>Total</td>
<td></td>
<td>107.1</td>
<td>64.2</td>
</tr>
</tbody>
</table>

Additional details for these projects are provided in the Investment Summary Documents S11 to S24 in Exhibit D2, Tab 2, Schedule 3.

**Integrated Station Component Replacement Projects**

Projects within this grouping are to address multiple end of life components at a station which require replacement, but where the scope of work does not warrant a major rebuild of the station as would be the case in the Integrated DESN Replacement category. This category of expenditure was started in 2013 on a pilot basis for nine transmission stations with work spanning over 2013 to 2016. The intention of the pilot was to work through a modified approach to planning and executing component replacement work to leverage efficiencies through better integration. Learnings from this pilot approach will be applied in future rate applications, as Hydro One Transmission continues towards executing a greater portion of planned work in an integrated fashion.

Additional details for these projects are provided in the Investment Summary Document S25 in Exhibit D2, Tab 2, Schedule 3.
3.2.3 Summary of Expenditures

The planned expenditure for 2015 and 2016 is $241.0 million and $159.7 million respectively. Expenditures in Station Re-investment are highly dependent on the type and magnitude of specific projects carried out each year, as such there can be significant year over year variations. However the test year expenditures represent a significant increase over the historic spending, and are primarily a function of increased expenditures on air blast circuit breaker replacements and integrated DESN replacement projects. Although the expenditures within this category are higher than historic and bridge years, reductions in other categories of Stations Sustaining Capital have been implemented. This represents a general shift in planning approach to complete more sustaining capital investments using integrated approaches, as opposed to focusing primarily on component level replacements.

A reduction in this program will result in delays to address degrading performance of air blast circuit breakers at critical network stations, and the integrated rebuild of stations delivering load to customers. Negative impacts to both system reliability and customer reliability would be a result.

3.3 Power Transformers

3.3.1 Introduction

In total, Hydro One Transmission has 722 large transmission class transformers in service. The most common power transformer is the step-down transformer, which converts a transmission level voltage (230 kV or 115 kV) to a lower distribution voltage of less than 50 kV for customer supply. Another type is the autotransformer which connects to high voltage transmission systems such as 500/230 kV and 230/115 kV. Other transformers included in this group are phase shifting transformers, shunt reactors,
regulating transformers. Grounding transformers and station service transformers are not included in this figure.

3.3.2 Investment Plan

Power Transformers are critical for the operation of the power system. In order to effectively manage the power transformer population, data is obtained from numerous sources which include inspections, diagnostic testing, planned maintenance activities, equipment performance reports, and feedback from real time operating systems that provide equipment loading.

The power transformer program addresses transformer replacements and purchases, as well as other transformer related activities. Table 8 outlines the proposed funding for test years 2015 and 2016, along with the spending levels for the bridge and historic years for each category.

<table>
<thead>
<tr>
<th>Description</th>
<th>Historic Years</th>
<th>Bridge Year</th>
<th>Test Years</th>
</tr>
</thead>
<tbody>
<tr>
<td>Power Transformer Replacements</td>
<td>56.3</td>
<td>71.8</td>
<td>74.4</td>
</tr>
<tr>
<td>Operating Spare Transformer Purchases</td>
<td>18.9</td>
<td>4.2</td>
<td>10.1</td>
</tr>
<tr>
<td>Other Transformer Programs</td>
<td>5.8</td>
<td>2.4</td>
<td>2.5</td>
</tr>
<tr>
<td><strong>Total</strong></td>
<td><strong>81.1</strong></td>
<td><strong>78.4</strong></td>
<td><strong>87.0</strong></td>
</tr>
</tbody>
</table>
Power Transformer Replacements
This program is in place to replace transformers that have reached end of life under
planned conditions, as well as replacements under demand conditions following failures
of in-service transformers. Specific maintenance tests have been developed to obtain the
data required to determine condition and the likelihood of failure. The results from these
tests, in combination with data on the operating history, individual transformer and
transformer family performance, equipment criticality and demographic data provide the
information required to determine if a unit is in need of replacement. The replacement
of end of life power transformers are required to mitigate impacts to reliability, environment, customer, and safety.

Additional details for this program are provided in the Investment Summary Document S26 in Exhibit D2, Tab 2, Schedule 3.

Operating Spare Transformer Purchases
This program is in place to purchase operating spare transformers in line with Hydro One Transmission’s probabilistic approach to determine the number of spare transformer requirements. The analysis considers performance trends and supply chain considerations of Hydro One Transmission’s various power transformer types, and groups them into optimized spare cohorts to adequately cover the in-service population. The transmission operating spare complement modeled requirement is intended to replenish inventory that is expected to be drawn down for future failures.

Additional details for this program are provided in the Investment Summary Document S27 in Exhibit D2, Tab 2, Schedule 3.
Other Transformer Programs

- Replacement of station service transformers that have reached end of life. Station service transformers step down primary voltages, i.e., 230 kV, 115 kV, 44 kV, 27.6 kV or 13.8 kV to secondary voltages of 600V or 120V AC to supply station auxiliary equipment such as battery chargers, transformer cooling and tap changers, and station heaters.

- Installation of online monitoring and diagnostic equipment to provide real-time condition data that impacts both the day-to-day operation of the transformers and the longer term sustaining capital replacements.

3.3.3 Summary of Expenditures

The planned expenditure for 2015 and 2016 is $30.6 million and $75.3 million respectively. The 2015 expenditures are significantly less than previous years, whereas the 2016 expenditures are generally in line with historic spending in this program. This reduction in 2015 corresponds to an increase in 2015 spending in the Integrated DESN Investment category within the Station Re-investment program. Similar to the circuit breaker replacement program, the transformers identified in need of replacement that would have otherwise been completed within the power transformer replacement program are being completed as part of integrated station-level refurbishments. As demonstrated in Exhibit D1, Tab 2, Schedule 1, the total number of transformer replacements across the combination of all program categories is remaining generally consistent in the test years relative to bridge year.

A reduction in this program will delay the replacement of aged and degraded equipment as well as will result in maintaining a less than optimal spare inventory, resulting in increased risk exposure to reliability at both system stations and customer load delivery stations.
3.4 Other Power Equipment

3.4.1 Introduction

In addition to circuit breakers and power transformers, there are other components and system elements that are integral parts of transmission stations. These include disconnect switches, capacitor banks, reactors, surge arrestors, low voltage cables and potheads, instrument transformers and insulators. These components provide over-voltage protection, electrical insulation, metering and protection capability, electrical isolation, and voltage control.

3.4.2 Investment Plan

In order to effectively manage these other power equipment populations, data is obtained from numerous sources which include inspections, diagnostic testing, planned maintenance activities, along with operating history, historic load profile, individual equipment and family of equipment performance, asset criticality and demographic data.

Table 9 outlines the proposed funding for test years 2015 and 2016, along with the spending levels for the bridge and historic years for the investments that are included in Other Power Equipment category.
Table 9
Other Power Equipment
($ Millions)

<table>
<thead>
<tr>
<th>Description</th>
<th>Historic Years</th>
<th>Bridge Year</th>
<th>Test Years</th>
</tr>
</thead>
<tbody>
<tr>
<td>Disconnect Switch Replacements</td>
<td>2.8</td>
<td>8.9</td>
<td>6.8</td>
</tr>
<tr>
<td>Capacitor Bank Replacements</td>
<td>3.7</td>
<td>4.8</td>
<td>4.1</td>
</tr>
<tr>
<td>Instrument Transformer Replacements</td>
<td>3.3</td>
<td>4.7</td>
<td>8.9</td>
</tr>
<tr>
<td>Insulator Replacements</td>
<td>4.7</td>
<td>3.9</td>
<td>3.5</td>
</tr>
<tr>
<td>Other Power Equipment Programs</td>
<td>1.8</td>
<td>6.0</td>
<td>3.2</td>
</tr>
<tr>
<td><strong>Total</strong></td>
<td><strong>16.2</strong></td>
<td><strong>28.3</strong></td>
<td><strong>26.5</strong></td>
</tr>
</tbody>
</table>

Disconnect Switch Replacements

Disconnect switches are used to provide an open connection in an electrical circuit. They can be manually or electrically driven and can be three phase or single phase. There are over 14,000 of these switches of various types and sizes and voltage levels within the transmission system. The replacement program is focused primarily on replacing disconnect switches in degraded condition. The condition of disconnect switches is obtained primarily from visual inspections of the current carrying parts, insulators, and mechanism and linkages as well as operational tests. The program also addresses problematic switches with a known safety issue, which has resulted in some switches failing and falling closed which is a considerable risk for the power system and staff relying on switches as guaranteed isolating point for work protection.

Additional details for this program are provided in the Investment Summary Document S28 in Exhibit D2, Tab 2, Schedule 3.
Capacitor Bank Replacements

Capacitor banks play a vital role in voltage regulation and power factor correction. There are over 360 capacitor banks positioned throughout the transmission system. The replacement program is focused on replacement of aged capacitor banks in degraded condition that are required to provide voltage support to maintain local reliability. Replacement information is mainly obtained through visual inspections during preventive maintenance and defects identified during corrective maintenance programs; which are generally correlated with asset age demographics.

Additional details for this program are provided in the Investment Summary Document S29 in Exhibit D2, Tab 2, Schedule 3.

Instrument Transformer Replacements

Instrument transformers play a vital role in the operation of the power system. Current and voltage transformers are instrument transformers whose role is to provide the measurements to drive protective relays to operate properly. They also provide the necessary measurements and metering information for system operators. The replacement program is focused on replacement of aged instrument transformers in degraded condition which pose a risk to system and customer reliability should they fail. Some replacements are required as part of Hydro One Transmission’s PCB removals program to meet regulatory deadlines set by Environment Canada. Replacement information is obtained from visual inspections of the instrument transformers including bushings, corrosion, and oil levels, as well as resistance tests, power factor and capacitance measurements, and dissolved gas in oil and oil moisture tests.

Additional details for this program are provided in the Investment Summary Document S30 in Exhibit D2, Tab 2, Schedule 3.
Insulator Replacements

Insulators are used in transmission stations for termination of conductors at structures and to support buses or equipment (e.g. disconnect switches, circuit breakers, instrument transformers, etc.). Station insulators are subject to both electrical and mechanical stresses at the installation point. There are over 220,000 insulators throughout Hydro One’s transmission stations. Insulators are visually inspected to determine their condition and those that meet end of life criteria are replaced. Insulator replacements are performed under both planned and demand conditions and address a variety of insulator types across the numerous different pieces of equipment. Insulator failures cause equipment outages (potentially load interruptions), pose a safety risk to personnel, and can result in damage to other equipment that is exposed to the fault.

Additional details for this program are provided in the Investment Summary Document S31 in Exhibit D2, Tab 2, Schedule 3.

Other Power Equipment Programs

• Replacement of low voltage cable and pothead that have reached end of life. There are over 1,500 cable potheads within the transmission system. Cable potheads can leak over time, reducing their dielectric strength resulting in failures.

• Replacement of surge arrestors that have reached end of life. There are over 1,800 sets of surge arrestors within the transmission system. Surge arrestors are used to protect transformers from the effects of lightning strikes and therefore reduce equipment outages.
3.4.3 Summary of Expenditures

The planned expenditure for 2015 and 2016 is $23.7 million and $25.9 million respectively. The average of the test-year expenditures is in line with the average historic and bridge year spending.

A reduction in this program will result in on-going operational risks associated with operating aged and degraded components and system elements that are integral parts of transmission stations, with likely impact to system and/or customer reliability.

3.5 Ancillary Systems

3.5.1 Introduction

Ancillary Systems are required at all of Hydro One’s transmission stations. These ancillary systems are comprised of station service systems, HPA systems, grounding systems, and battery and battery charger systems. These systems provide key services and operating support to all of the various station components (breakers, power transformers, protections, controls, and monitoring and infrastructure systems).

3.5.2 Investment Plan

Asset condition information is obtained for the various ancillary systems in order to effectively manage the replacement program. This information, plus asset demographic data and an understanding of the consequence to the system due to the failure, provides the basic information requirements to conduct equipment assessments and determine those assets in need of replacement.
Table 10 outlines the proposed funding for test years 2015 and 2016, along with the spending levels for the bridge and historic years for the investments that are included in Ancillary Systems category.

<table>
<thead>
<tr>
<th>Description</th>
<th>Historic Years</th>
<th>Bridge Year</th>
<th>Test Years</th>
</tr>
</thead>
<tbody>
<tr>
<td>Station Service Replacements</td>
<td>9.1</td>
<td>9.7</td>
<td>10.0</td>
</tr>
<tr>
<td>Station Battery and Charger Replacements</td>
<td>1.4</td>
<td>2.6</td>
<td>1.8</td>
</tr>
<tr>
<td>Station Grounding Replacements</td>
<td>2.6</td>
<td>3.8</td>
<td>3.6</td>
</tr>
<tr>
<td>Other Ancillary System Programs</td>
<td>0.3</td>
<td>0.3</td>
<td>0.1</td>
</tr>
<tr>
<td><strong>Total</strong></td>
<td><strong>13.4</strong></td>
<td><strong>16.4</strong></td>
<td><strong>15.5</strong></td>
</tr>
</tbody>
</table>

Station Service Replacements

Station service systems comprise all equipment necessary to distribute AC or DC power to station facilities from the battery and battery charger systems. The AC station service supplies power for transformer cooling, tap changer control, switchgear heating, battery chargers, HVAC, etc., all of which are essential to the provision of reliable power by the transmission stations and to connected loads. The DC station service supplies power for protection, control and communication systems, which protect and provide remote control of station equipment. In the event of a power supply failure, the station service system is designed to enable the transfer of loads over to the second station service supply. The replacement program is focused primarily on replacement of aged and degraded equipment which is required to perform adequately under normal and emergency conditions. Through installation of equipment built to modern standards mitigation of arc-flash safety risks associated with legacy installations is also achieved. Additional details for this program are provided in the Investment Summary Document S32 in Exhibit D2, Tab 2, Schedule 3.
Station Battery and Charger Replacements

All of Hydro One’s transmission stations contain at least one battery and battery charger system. Battery and battery charger systems designated as ‘Station’ supply all protection and control and other station ancillary DC services, while ‘Telecom’ designated systems supply the communication system DC requirements at selected stations.

Replacement information is obtained through visual inspections of the battery cells plate condition, connections, and seals, as well as functional testing such as: electrolyte level and specific gravity tests, impedance tests, voltage tests, equalize charge tests, battery load test, and battery discharge duration, charger volt and amp readings, and DC float and output test.

The replacement program is focused primarily on station battery and battery charger systems which can no longer be relied upon to perform their required back-up functionality, including sites which are NPCC regulated. The replacement program for telecom battery and battery charger systems are managed as part of the auxiliary telecommunication system as outlined in Section 3.7 of this exhibit.

Station Grounding System Replacements

Grounding systems are designed to ensure safety of personnel and equipment in and around transmission stations. Grounding systems provide a means of ensuring a common potential between metal structures and equipment accessible to personnel so that hazardous step, touch, mesh and transferred voltages do not occur. In addition, effective grounding systems limit the damage to equipment during faults or surges and they ensure proper operation of protective devices such as relays and surge arresters.

Replacement information for grounding systems is obtained from visual inspection, present and projected fault levels, history of faults, system configuration and technical details obtained through testing programs.
The replacement program is focused primarily on replacements and upgrades of grounding systems which are known to be in degraded condition and cannot be relied upon to adequately perform their critical safety function at stations where no other major refurbishments are planned.

Other Ancillary System Replacements

- Refurbishment of HPA system to address deficient HPA system components to maintain reliability of the ABCBs at critical network stations.
- Implementation of new AC station service system metering requirements mandated by the IESO.

3.5.3 Summary of Expenditures

The planned expenditure for 2015 and 2016 is $19.0 million and $19.4 million respectively. Overall the test year expenditures are approximately 25% higher than the average historic years spending. The increase in spending is required to continue to replace technically obsolete station service systems, as well as implement AC station service metering requirements mandated by the IESO.

A reduction in this program will result in on-going operational risks associated with operating aged and degraded components and system elements that are integral parts of transmission stations, with likely impact to system and/or customer reliability. Some of the programs are also intended to mitigate risks associated with regulatory compliance (i.e. battery and battery charger replacements for NPCC compliance), and safety (i.e. upgrade of grounding systems and replacement of station service systems), and reductions would limit Hydro One Transmission’s ability to manage these obligations.
3.6 Station Environment

3.6.1 Introduction

The stations environment program is driven by environmental requirements to install, replace and/or refurbish transformer spill containment systems. Spill containment systems are barriers designed to capture and control transformer oil spills, thus minimizing risk to the environment.

3.6.2 Investment Plan

Hydro One Transmission demonstrates effective environmental stewardship and corporate risk mitigation by proactively managing its transformer spill containment system infrastructure through replacements, refurbishments or installation of new systems. Table 11 outlines the proposed funding for test years 2015 and 2016, along with the spending levels for the bridge and historic years for spill containment systems.

Table 11
Stations Environment
($ Millions)

<table>
<thead>
<tr>
<th>Description</th>
<th>Historic Years</th>
<th>Bridge Year</th>
<th>Test Years</th>
</tr>
</thead>
<tbody>
<tr>
<td>Spill Containment</td>
<td>7.0</td>
<td>7.6</td>
<td>6.6</td>
</tr>
</tbody>
</table>

Hydro One Transmission has approximately 75% of the transformer fleet equipped with spill containment systems. Of the spill containment systems installed there are 156 systems that are regulated by the Ministry of the Environment (“MOE”) issued Environmental Compliance Approval (“ECA”), formerly known as Certificate of Approval, which mandates operational and maintenance requirements. The stations environment program will primarily be focused on addressing the older spill containment systems.
systems (i.e. pit liner systems installed in the 1970s) that have either significantly reduced functionality or are nearing end of life and do not meet Hydro One Transmission’s current standards. Additionally there is an on-going requirement, set forth by the MOE, to install additional systems at stations to ensure the entire station is up to modern ECA standards any time that modifications are made to existing stations. Hydro One is typically granted a 3-year window by the MOE in which to make site-wide upgrades. These site-wide commitments account for roughly half of the program in the test years.

The prioritization and selection of a new installation and replacement or refurbishment of an existing spill containment system is based on asset condition information, site environmental and geotechnical data, drainage effluent quality, transformer leak records, and station-specific spill risk analysis.

Additional details for this program are provided in the Investment Summary Document S33 in Exhibit D2, Tab 2, Schedule 3.

3.6.3 Summary of Expenditures

The planned expenditure for 2015 and 2016 is $11.3 million and $10.8 million respectively. This represents a significant increase over the historic and bridge spending. This increase is a result of an accelerated program required to mitigate environmental risks associated with aged and degraded containment systems as well as installation of new containment systems as required by the MOE.
A reduction in this program will increase the environmental risk exposure and constrain Hydro One Transmission’s ability to meet regulatory obligations established by the MOE.

3.7 Protection, Control, Monitoring and Telecommunications

3.7.1 Introduction

In order to protect, control and regulate the operation of the transmission system, there are four key systems: protective systems, control system, monitoring system and telecommunication systems.

Protection systems are devices connected throughout the transmission network for the purpose of sensing abnormal system conditions (e.g. as a result of natural events, physical accidents, equipment failure). Upon sensing an abnormal condition, protection systems immediately operate the appropriate circuit breakers to isolate the affected equipment (e.g. transmission line, transformer, generator, buswork) from sources of energy and the rest of the transmission system.

Control systems are used to perform control, monitoring, and alarming functions for each station remotely from the Ontario Grid Control Centre (“OGCC”), the back-up control centre, or locally at the station. Control systems also provide real time data to the IESO’s energy management system in accordance with the Market Rules.

Monitoring systems provide detailed, high speed records of normal and abnormal events that occur in stations or on transmission lines. These systems are required to meet NPCC and IESO requirements, and are used to analyze the performance of protective relays and schemes and to ensure due diligence. The information obtained from monitoring systems
Telecommunication systems provide high reliability and high-speed communication required for the protection, monitoring, and control of Hydro One’s transmission system. These systems enable station-to-station communication, which helps minimize outage impact and equipment damage due to faults, and the remote monitoring and control of equipment throughout the system. Hydro One Transmission’s telecommunication system consists of digital fiber-optic networks, Power Line Carrier (“PLC”) systems, owned or leased metallic cables, digital microwave, and auxiliary telecommunication equipment associated with the primary systems.

3.7.2 Investment Plan

In order to effectively manage these systems investments are grouped into three categories according to the function of the asset or the compliance requirement. Table 12 outlines the proposed funding for the test years 2015 and 2016, along with the spending levels for the bridge and historic years for each category.

<table>
<thead>
<tr>
<th>Description</th>
<th>Historic Years</th>
<th>Bridge Year</th>
<th>Test Years</th>
</tr>
</thead>
<tbody>
<tr>
<td>Protection, Control and Monitoring</td>
<td>44.4</td>
<td>72.3</td>
<td>65.4</td>
</tr>
<tr>
<td>Auxiliary Telecommunication</td>
<td>14.7</td>
<td>16.7</td>
<td>14.1</td>
</tr>
<tr>
<td>Cyber Security</td>
<td>2.4</td>
<td>6.0</td>
<td>4.8</td>
</tr>
<tr>
<td>Total</td>
<td>61.6</td>
<td>95.0</td>
<td>84.4</td>
</tr>
</tbody>
</table>
Protection, Control and Monitoring

Protection, Control and Monitoring assets exist in very large numbers. This class of assets include: protective relays and their auxiliaries, remote terminal units ("RTU"), sequence of event recorders ("SER"), digital fault recorders, special protection schemes, local control systems and revenue metering systems; There are over 12,000 protection and control systems, each system consisting of up to 100 components. These systems cannot be out of service for longer than several days without incurring significant cost due to market inefficiency, disruption of planned outages, or impacting reliability. It is critical to ensure that end of life assets have well-defined replacement criteria and are replaced before the onset of failures or rapidly increasing maintenance. Should a large population of assets essential to the operation of the transmission system begin failing simultaneously, the results could be potentially disastrous. In order to avoid major disruption to the transmission system, it is essential to plan and execute the replacement programs for these assets in a proactive manner so that they are replaced before failure.

Replacement information is mainly obtained through actual defects and failure rates; inspection and testing results including calibration drift; obsolescence including lack of manufacturer support; demographic data; and/or NERC and NPCC reliability standards. The replacement program is focused primarily on the proactive replacement of systems approaching the end of their expected service life based on analysis of the demographics of population cohorts relative to the expected physical failure and end of life distributions for each; as well as addresses demand corrective to unplanned priority replacement of end of life protection and control equipment causing significant customer or system impact. Specific replacement programs are outlined in Table 13. Additional details for these programs are provided in the Investment Summary Documents S34 to S36 in Exhibit D2, Tab 2, Schedule 3.
### Table 13
Protection, Control and Monitoring
($ Millions)

<table>
<thead>
<tr>
<th>Ref#</th>
<th>Description</th>
<th>Test Years</th>
<th>Total Cost</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td></td>
<td>2015</td>
<td>2016</td>
</tr>
<tr>
<td>S34</td>
<td>Integrated Station P&amp;C Replacements</td>
<td>28.7</td>
<td>31.4</td>
</tr>
<tr>
<td>S35</td>
<td>Protection Replacements</td>
<td>18.4</td>
<td>21.6</td>
</tr>
<tr>
<td>S36</td>
<td>RTU and SER Replacements</td>
<td>4.3</td>
<td>8.2</td>
</tr>
<tr>
<td></td>
<td>Other Protection, Control and Monitoring Programs</td>
<td>5.3</td>
<td>6.9</td>
</tr>
<tr>
<td></td>
<td><strong>Total</strong></td>
<td><strong>56.8</strong></td>
<td><strong>68.1</strong></td>
</tr>
</tbody>
</table>

Other protection, control and monitoring programs include:

- Modification or upgrade to under frequency load shedding protection equipment in response to NPCC Directory 12 requirements to allow for load shedding at specified frequency thresholds. Full compliance is expected to be completed by 2017 in accordance with the implementation plan submitted to NPCC by the IESO.

- Upgrade of monitoring equipment to ensure compliance with NERC Reliability Standards, NPCC Regional Standards and IESO Market Rules with respect to disturbance monitoring.

### Auxiliary Telecommunication

Telecommunication systems provide high reliability and high-speed communication required for the protection, control, and monitoring of Hydro One’s transmission system. Hydro One Transmission’s telecommunication system consists of digital fiber-optic networks, power line carrier systems, owned or leased metallic cables, digital microwave, and the associated auxiliary telecommunication equipment for each. Auxiliary telecommunication equipment includes such equipment as: DC remote trip systems, tone channels, fiber optic cable and telecom battery and battery charger systems.
The replacement program is primarily focused on replacing end of life auxiliary telecommunications equipment that supports protection and control equipment throughout the transmission system. Efficiencies in this program are realized through coordination with the replacement of protection and control equipment. Replacements are prioritized based on asset performance and the sustainment of protection and control system in compliance with NPCC and NERC reliability standards. Specific replacement programs are outlined in Table 14. Additional details for these programs are provided in the Investment Summary Documents S37 to S39 in Exhibit D2, Tab 2, Schedule 3.

### Table 14

**Auxiliary Telecommunication**

($ Millions)

<table>
<thead>
<tr>
<th>Ref#</th>
<th>Description</th>
<th>Test Years</th>
<th>Total Cost</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td></td>
<td>2015</td>
<td>2016</td>
</tr>
<tr>
<td>S37</td>
<td>DC Signaling (Remote Trip) Replacements</td>
<td>6.7</td>
<td>4.6</td>
</tr>
<tr>
<td>S38</td>
<td>Protection Tone Channel Replacements</td>
<td>4.2</td>
<td>4.2</td>
</tr>
<tr>
<td>S39</td>
<td>PLC Device Replacements</td>
<td>4.6</td>
<td>4.7</td>
</tr>
<tr>
<td></td>
<td>Other Auxiliary Telecommunication Programs</td>
<td>6.3</td>
<td>6.4</td>
</tr>
<tr>
<td></td>
<td><strong>Total</strong></td>
<td><strong>21.8</strong></td>
<td><strong>20.0</strong></td>
</tr>
</tbody>
</table>

Other auxiliary telecommunication programs include:

- Replacement of end of life battery and battery charger systems that power telecommunications equipment to ensure reliable operation during local or widespread outages.
- Replacement of end of life neutralizing transformers used to protect personnel, metallic communication circuits and telecommunications equipment from high voltages that can occur on telecommunications equipment in a transmission station.
- Enhancements of computer hardware and the operations support systems used by the Integrated Telecommunication Management Centre (“ITMC”) for the monitoring and management of the power system telecommunications system.
Cyber Security

The cyber security program entails the implementation of systems and facilities required to achieve and sustain compliance with the NERC Critical Infrastructure Protection ("CIP") standards and address other cyber security vulnerabilities of equal or greater risk.

As outlined in proceeding EB-2012-0031, the energy sector is categorized as a critical infrastructure. This initiated the development of a set of ten NERC Critical Infrastructure Protection standards (CIP-002 to CIP-011), also referred to as the “Cyber Security” standards; to protect the reliability of the interconnected grid. In addition, NPCC Directory 4 instituted specific requirements for ensuring cyber security of grid protection systems. Hydro One Transmission must maintain compliance with the requirements of these standards. In addition, Hydro One Transmission follows good utility and IT Security practice to ensure that all cyber vulnerabilities are identified and secured.

On November 22, 2013 Version 5 of the NERC CIP standards were approved by the Federal Energy Regulatory Commission ("FERC"), extending the applicability of cyber security requirements to additional assets within Hydro One’s transmission system. With the adoption of Version 5, the number of sites for evaluation and inclusion into the NERC CIP cyber security compliance program will increase. The new revision of this standard is expected to come into effect on April 1, 2016. Thus this cyber security program primarily focuses on ensuring compliance with the requirements of the new standards.

Other cyber security initiatives in 2015 and 2016 are required to address cyber vulnerabilities as they are uncovered and to implement improved security on the devices used by field staff to access and maintain Critical Cyber Assets. Additional details for this program are provided in the Investment Summary Documents S40 to S41 in Exhibit D2, Tab 2, Schedule 3.
3.7.3 Summary of Expenditures

The planned expenditure for 2015 and 2016 is $92.2 million and $95.6 million respectively. This represents a decrease of about 20% over the bridge year 2014. This decrease is a result of the consolidation of the RTU and SER replacements into the Station Re-investment program to realize additional efficiencies during design, construction and commissioning. Investments in cyber security in 2014 are higher than historic to ensure compliance with the recently approved Version 5 of the NERC CIP Cyber Security standards and will ramp down over the test years once implemented in alignment with the mandated NPCC plan.

A reduction in this program will see a significant increase in the risk to the operation of the power system as reductions will limit the rate at which end of life protection, control, monitoring and telecommunications assets can be replaced, increasing the risk and frequency of failure. Failure of protection systems to immediately detect and isolate abnormal system conditions can cause widespread outages in local supply and the interconnected grid as well as equipment damage and injury to workers and the public. The failure of control and monitoring equipment can result in the complete loss of remote operating control of a station by system operators, requiring the dispatch of field personnel to locally control the station. Reductions will also jeopardize compliance with NERC cyber security requirements.

3.8 Site Facilities and Infrastructure

3.8.1 Introduction

Hydro One Transmission’s site facilities and infrastructure systems are comprised of yard drainage, fire protection and detection, structural footings, station buildings, cranes, elevators, HVAC systems, access roads, water supplies, sewage management, and fences
at transmission stations. These systems provide infrastructure and support services to all other station components, prevent unauthorized access, and make the station site functional for equipment and staff.

3.8.2 Investment Plan

The site facilities and infrastructure program is grouped into three categories to effectively manage the needs of these assets. Table 15 outlines the proposed funding for the test years 2015 and 2016, along with spending levels for the bridge and historic years for each category.

Table 15
Transmission Site Facilities and Infrastructure
($ Millions)

<table>
<thead>
<tr>
<th>Description</th>
<th>Historic Years</th>
<th></th>
<th>Bridge Year</th>
<th>Test Years</th>
</tr>
</thead>
<tbody>
<tr>
<td>Station Building Infrastructure</td>
<td>6.0</td>
<td>4.5</td>
<td>4.3</td>
<td>8.5</td>
</tr>
<tr>
<td>Station Civil Infrastructure</td>
<td>12.1</td>
<td>15.0</td>
<td>10.2</td>
<td>9.6</td>
</tr>
<tr>
<td>Station Perimeter Fences</td>
<td>(0.4)</td>
<td>3.8</td>
<td>8.4</td>
<td>1.9</td>
</tr>
<tr>
<td><strong>Total</strong></td>
<td><strong>17.8</strong></td>
<td><strong>23.4</strong></td>
<td><strong>22.9</strong></td>
<td><strong>20.0</strong></td>
</tr>
</tbody>
</table>

Station Building Infrastructure

This program targets the refurbishment or replacement of building components within transmission stations typically designed to house Hydro One staff, and in some cases electrical assets (i.e. protection, control, and telecom components). Types of work included are: replacement of the building roof, replacement of HVAC systems, upgrades to the water supply systems, or other refurbishments or enhancements to the station building.

Additional details for this program are provided in the Investment Summary Document S42 in Exhibit D2, Tab 2, Schedule 3.
Station Civil Infrastructure

This program targets the refurbishment or replacement of components and systems within the transmission stations that are designed to support or protect power system equipment. Types of work included are: refurbishment of support structures (concrete footings or steel/wood structures within the station), replacement of fire protection system/deluge systems, refurbishment of deteriorated cable trays that house control and power cables, replacement of drainage systems yard gravel, and repair to access roads in the station.

Additional details for this program are provided in the Investment Summary Document S43 in Exhibit D2, Tab 2, Schedule 3.

Station Perimeter Fences

The station perimeter fences program focuses on effectively deterring and delaying unauthorized individuals and animals from gaining access to transmission facility property. There has been a significant increase in criminal activity aimed at transmission stations. These incidents include copper theft, trespassing and major breaches of the perimeter fence.

The focus of this program is to enhance perimeter fences first before considering other areas within a station. Continued improvement of Hydro One Transmission’s perimeter fences is imperative to ensure public and employee safety, and also reduce and combat instances of theft from Hydro One transmission stations. In addition, perimeter fences also help to keep wildlife out of stations, thereby mitigating the risk of animal contacts which are a significant contributor to delivery point interruptions.
3.8.3 Summary of Expenditures

The planned expenditure for 2015 and 2016 is $18.1 million and $18.5 million respectively. While the test year expenditures for the overall Transmission Site Facilities and Infrastructure program represent a decrease from bridge year and average historic spending, there are year over year variations within each program category to address the needs of the specific infrastructure assets to maintain system and customer reliability; as well as combat instances of theft from Hydro One transmission stations that impact public and employee safety.

4.0 LINES

Transmission lines are used to transmit electric power, via integrated network and radial circuits, to either transmission-connected industrial or commercial customers, or local distribution companies, including Hydro One Distribution, who in turn distribute the power to end-use customers. Hydro One’s transmission lines primarily operate at voltages of 500 kV, 230 kV, and 115 kV, with minor lengths operating at 345 kV and 69 kV. Hydro One’s transmission system consists of approximately 30,000 circuit km of overhead transmission lines located on about 21,000 km of rights-of-way and 290 circuit km of underground transmission lines.

Overhead transmission line components include structures (primarily steel or wood) and corresponding foundations, conductors, shieldwire, insulators, lightning arrestors, hardware, switches, and grounding systems. Underground transmission line components include cables, terminations, oil pressure systems and grounding systems. The underground transmission lines are generally located in large urban centres.
Lines Sustaining Capital funding covers expenditures required to replace or refurbish overhead and underground transmission lines or specific components that have reached the end of their service life. Hydro One Transmission manages its Lines Sustaining Capital programs by dividing the program into three categories:

1. **Overhead Lines Refurbishment and Component Replacement**, which funds the capital investments to refurbish or replace line components as well as funds tower refurbishment and coating and capital corrective work associated with clearance corrections and rights-of-way facilities;

2. **Transmission Line Re-investment**, which funds the capital investments to refurbish complete line sections on a project basis; as well as funds secondary land use projects, where Hydro One Transmission is required to relocate its facilities to accommodate new roads or other infrastructure changes;

3. **Underground Cables Refurbishment and Replacement**, which funds the capital investments to refurbish or replace cable sections and components.

Required funding for the test years, along with the spending levels for the bridge and historic years are provided in Table 16 for each of these categories.
The overall Lines Sustaining Capital spending requirement for the 2015 test year is approximately 10% higher than the planned expenditures in the 2014 bridge year; whereas the spending requirement for 2016 is generally in line with the 2014 bridge year. These spending variations can be expected depending on the size and complexity of the underground or overhead line refurbishment projects undertaken at any point in time. However the proposed spending for the test years represents an increase of 30% compared to the average spending over the historic and bridge years. These expenditures reflect the need for an increase in the line refurbishment and underground cable replacements to address the number of these assets that are approaching end of life. A significant increase is also required in the refurbishment of steel towers in order to extend the life of these assets.

### 4.1 Overhead Lines Refurbishment and Component Replacement

#### 4.1.1 Introduction

Hydro One’s transmission system consists of approximately 30,000 circuit km of overhead transmission lines. In many cases, it is more cost-effective to replace one or
more of the transmission line components that have reached their end of life rather than to rebuild the entire line. Transmission line components include: wood poles, insulators, shieldwire, switches, and steel structures. This program focuses on the replacement of individual overhead line components, as well as addresses electrical clearance corrections, right-of-way upgrades and emergency replacements.

It should be noted that in terms of component replacement, the focus of this program is on overhead line components other than conductors. When a conductor reaches the end of its life, the project takes on a much larger scope than individual component replacement with an emphasis to replace all components nearing end of life. Such conductor replacement projects are addressed under the Transmission Line Re-Investment Program, which is discussed in Section 4.2 of this exhibit.

4.1.2 Investment Plan

The overhead line refurbishment and component replacement program is grouped into categories to effectively manage the needs of the overhead line assets. Hydro One Transmission considers asset condition and performance, along with safety and regulatory compliance requirements when carrying out assessments on line components to determine which components are deemed to be at end of life and require refurbishment or replacement.

Table 17 outlines the proposed funding for the test years 2015 and 2016, along with spending levels for the bridge and historic years for each category.
Table 17
Overhead Lines Refurbishment and Component Replacement
($ Millions)

<table>
<thead>
<tr>
<th>Description</th>
<th>Historic Years</th>
<th>Bridge Year</th>
<th>Test Years</th>
</tr>
</thead>
<tbody>
<tr>
<td>Wood Pole Replacements</td>
<td>29.1</td>
<td>26.9</td>
<td>32.7</td>
</tr>
<tr>
<td>Steel Structure Coating</td>
<td>1.6</td>
<td>5.7</td>
<td>5.1</td>
</tr>
<tr>
<td>Steel Structure Replacements</td>
<td>0.1</td>
<td>0.5</td>
<td>8.3</td>
</tr>
<tr>
<td>Steel Structure Foundation Refurbishments</td>
<td>1.8</td>
<td>3.3</td>
<td>4.5</td>
</tr>
<tr>
<td>Shieldwire Replacements</td>
<td>3.0</td>
<td>4.4</td>
<td>2.9</td>
</tr>
<tr>
<td>Insulator Replacements</td>
<td>2.6</td>
<td>3.3</td>
<td>6.9</td>
</tr>
<tr>
<td>Transmission Lines Emergency Restoration</td>
<td>12.9</td>
<td>8.0</td>
<td>8.2</td>
</tr>
<tr>
<td>Other Line Component Replacements</td>
<td>0.0</td>
<td>3.4</td>
<td>5.6</td>
</tr>
<tr>
<td><strong>Total</strong></td>
<td><strong>52.4</strong></td>
<td><strong>55.5</strong></td>
<td><strong>74.2</strong></td>
</tr>
</tbody>
</table>

Wood Pole Replacements

Hydro One Transmission utilizes both wood poles and steel structures to support overhead transmission lines. Hydro One’s transmission system contains approximately 42,000 wood pole structures. The replacement program is focused primarily on replacing wood poles that are at end of life. Wood poles are determined to be at end of life based on the results of wood pole tests and inspections, at which point they are scheduled for replacement. In addition to end of life replacements, Hydro One Transmission continues to address the defective 230 kV Gulfport type structures which are exhibiting pole deterioration on the inside.

Additional details for this program are provided in the Investment Summary Document S44 in Exhibit D2, Tab 2, Schedule 3.
Steel Structure Coating

Hydro One’s transmission system includes about 50,000 steel structures. Steel structures are manufactured with a zinc-based galvanized coating that protects the underlying steel against corrosion. The coating will generally last from 30 to 60 years, with the more corrosive environments depleting the galvanizing at a quicker rate. Assessment of the steel structure condition is carried out on an annual basis as part of the maintenance program, with a focus on transmission line sections that are greater than 30 years and are located in highly corrosive areas or in locations where known problems exist. The assessments determine the amount of galvanizing that remains on the structure, or in the case where the coating is depleted, the amount of metal loss that has occurred. This program focuses on coating steel tower structures that the assessment has deemed in need of corrosion protection due to loss of galvanized coating.

Additional details for this program are provided in the Investment Summary Document S45 in Exhibit D2, Tab 2, Schedule 3.

Steel Structure Replacements

Once the galvanized coating on a steel structure has been depleted, the bare steel becomes exposed to the environment and begins to corrode at a much faster rate. If the tower is not re-coated and corrosion is allowed to continue, components of the steel structures will begin to lose strength and eventually fall below Hydro One Transmission’s design standards. Once a structure is identified as being in poor condition through visual inspection and measurement of the zinc coating, a detailed corrosion assessment is conducted to determine whether it is possible to replace a portion of the steel structure and coat the remaining structure to protect it from corrosion or whether it is more economical to replace the entire structure. This program addresses the replacement of steel structures where the corrosion assessment has deemed the structure to be at end of life.
Additional details for this program are provided in the Investment Summary Document S46 in Exhibit D2, Tab 2, Schedule 3.

Steel Structure Foundation Refurbishments

The foundations of the transmission structures are integral to the strength of the steel structure. One of the earlier vintages of steel structures is the lattice steel structures which are constructed with a grillage (buried steel) foundation. These particular structure foundations are prone to deterioration of the protective zinc coating and/or corrosion at or below the groundline depending on the ground conditions. About 60% of lattice type steel towers on the Hydro One transmission system have grillage footings. The transmission lines foundation refurbishment program is focused on assessing the condition of the foundations and anchors and repairing or replacing foundations and anchors that have been deemed not to satisfy the original installed design requirements. The assessment of foundation uses a pre-specified rating system and the decision to coat, repair or replace depends on the severity of corrosion or metal loss found.

Additional details for this program are provided in the Investment Summary Document S47 in Exhibit D2, Tab 2, Schedule 3.

Shieldwire Replacements

The shieldwire in Hydro One’s transmission system is primarily made up of galvanized steel wire that is positioned above the conductors to protect a circuit against lightning related outages and to provide continuity of the grounding system. When the zinc galvanizing has depleted, the underlying steel begins to corrode, resulting in pitting and loss of metal and eventual failure if not replaced in time. Hydro One Transmission maintains an on-going shieldwire testing program where a sample of wire is removed from a line section and tested in a laboratory to determine the condition of the wire and the need for replacement. This program focuses on the replacement of shieldwire that
testing has deemed to not meet the required design requirement and is at risk of failing and dropping to the ground.

Additional details for this program are provided in the Investment Summary Document S48 in Exhibit D2, Tab 2, Schedule 3.

**Insulator Replacements**

Insulators are used in Hydro One Transmission’s overhead lines to suspend energized conductor from supporting structures typically made of wood and steel. Insulator failures result in outages and at times allow energized conductor to fall to the ground creating safety hazards. Transmission line insulators’ expected service life varies, depending on the type, design, manufacturer and their installed environment. Due to this large variation in the life expectancy some insulators require replacement well before the circuit reaches end of life. This program addresses the replacement of insulators that have reached end of life as well known insulator design or manufacturing issues for different insulator types.

Additional details for this program are provided in the Investment Summary Document S49 in Exhibit D2, Tab 2, Schedule 3.

**Transmission Lines Emergency Restoration**

A number of transmission line components fail each year due to adverse weather, component deterioration, vandalism, or through accidents caused by public activity. This demand driven program is needed to restore power following transmission line failures and to replace or repair those line components where there is an imminent danger of failure as identified through line patrols or asset assessment. The types of emergency work covered under this program includes the replacement of failed or defective transmission line components such as wood structures, cross-arms, towers, insulators, conductor, shieldwire and hardware.
Additional details for this program are provided in the Investment Summary Document S50 in Exhibit D2, Tab 2, Schedule 3.

Other Component Replacements

Other component replacements include replacement of switches, rights-of-way access components and aviation lights that have reached end of life. Replacements of these components are essential to maintain system reliability and to address public and employee safety risks. Transmission line clearance corrections are also part of this program and are required to reinstate electrical ratings for the circuit. This may involve raising a structure or installing an inter-space structure to increase clearances.

4.1.3 Summary of Expenditures

The planned expenditure for 2015 and 2016 is $67.4 million and $74.5 million respectively. This is in line with expenditures in the 2014 bridge year but represents about a 15% increase over historic spending. This increase over historic spending is required to address an increase need for steel structure and foundation coating as well as steel structure replacement due to corrosion and a reduction of structural integrity.

A reduction in this program will lead to an increase of line component failures which can result in safety hazards to the public and could leave customers without power for lengthy periods of time, until repairs can be made. Furthermore, reductions to steel structure and foundation coating programs will result in increased costs in the future for costly steel structure replacements once structures exceed optimum time to coat and repair.
4.2 Transmission Lines Re-Investment

4.2.1 Introduction

Transmission line conductors are one of the most critical elements of a transmission line, both from an operational and safety perspective. When the conductor condition deteriorates to a critical level, failures are likely to occur in multiple locations anywhere on a line section. The overhead lines re-investment program addresses the need to re-build sections of transmission line based primarily on conductors reaching end of life, but will strategically also replace the other line components at or nearing end of life at the same time.

4.2.2 Investment Plan

Specific transmission line sections are selected for replacement from the assessment of condition based on the conductor testing results and the criticality of the line. Conductors are assessed by removing samples from a line section, and then testing the conductor strength, corrosion and serviceability characteristics (e.g. ductility and damage due to metal fatigue). Hydro One Transmission also considers asset demographics and performance as well as the ability to minimize safety and reliability risks.

Once selected, the entire transmission line section is then refurbished to meet present and future system requirements. The transmission lines identified for replacement are outlined in Table 18.
Table 18
Transmission Line Refurbishment Projects
($ Millions)

<table>
<thead>
<tr>
<th>Ref #</th>
<th>Description</th>
<th>Test Years</th>
<th>Total Cost</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td></td>
<td>2015</td>
<td>2016</td>
</tr>
<tr>
<td>S51</td>
<td>C25H Line Refurbishment</td>
<td>27.1</td>
<td>0.0</td>
</tr>
<tr>
<td>S52</td>
<td>H24C Line Refurbishment</td>
<td>4.9</td>
<td>12.0</td>
</tr>
<tr>
<td>S53</td>
<td>D10S/D9HS Line Refurbishment</td>
<td>4.8</td>
<td>0.0</td>
</tr>
<tr>
<td>S54</td>
<td>Q11S/Q12S Line Refurbishment</td>
<td>0.0</td>
<td>17.1</td>
</tr>
<tr>
<td></td>
<td>Other Line Refurbishment Projects &lt; $3M</td>
<td>0.0</td>
<td>0.2</td>
</tr>
<tr>
<td></td>
<td>Total</td>
<td>36.8</td>
<td>29.3</td>
</tr>
</tbody>
</table>

In addition to the line refurbishment projects, the Line Re-investment program also funds the relocation, removal, or reinforcement of transmission assets in order to facilitate third-party projects such as roadwork, transit systems, and other major infrastructure or development work that may encroach upon or impact Hydro One Transmission assets and rights-of-ways. The projects planned for the test years are outlined in Table 19. The size and complexity of these projects vary from year to year, and are fully recoverable.

Table 19
Secondary Land Use and Recoverable Projects
($ Millions)

<table>
<thead>
<tr>
<th>Ref #</th>
<th>Description</th>
<th>Test Years</th>
<th>Total Cost</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td></td>
<td>2015</td>
<td>2016</td>
</tr>
<tr>
<td>S55</td>
<td>Keith TS Hwy 401 Expansion (Recoverable)</td>
<td>19.6</td>
<td>17.2</td>
</tr>
<tr>
<td>S55</td>
<td>Waterloo LRT (Recoverable)</td>
<td>17.1</td>
<td>0.0</td>
</tr>
<tr>
<td>S55</td>
<td>Mavers Aggregate Pit (Recoverable)</td>
<td>4.8</td>
<td>8.4</td>
</tr>
<tr>
<td>S55</td>
<td>Thunder Bay Hwy 11/17 Widening (Recoverable)</td>
<td>3.3</td>
<td>0.0</td>
</tr>
<tr>
<td></td>
<td>Other Recoverable Projects &lt; $3M</td>
<td>2.9</td>
<td>2.9</td>
</tr>
<tr>
<td></td>
<td>Total Cost</td>
<td>47.7</td>
<td>28.5</td>
</tr>
<tr>
<td></td>
<td>Contribution</td>
<td>47.7</td>
<td>28.5</td>
</tr>
<tr>
<td></td>
<td>Net Capital Cost</td>
<td>0.0</td>
<td>0.0</td>
</tr>
</tbody>
</table>

Additional details for these projects are provided in the Investment Summary Documents S51 to S55 in Exhibit D2, Tab 2, Schedule 3.
4.2.3. **Summary of Expenditures**

The planned expenditure for 2015 and 2016 is $36.8 million and $29.3 million, respectively. The average spending in the test years is in line with the bridge year 2014, though year over year costs vary depending on the number and size of the line projects that require re-conductoring and refurbishment. However, the test year expenditures represent a significant increase over the historic spending. This increase is required to address the increasing number of conductors that are being identified as reaching end of life through the conductor sample and testing program.

A reduction in this program will result in an increase in line failures, which could leave customers without power for lengthy periods of time until repairs are made or create safety hazards for the public.

4.3 **Underground Cables Refurbishment and Replacement**

4.3.1 **Introduction**

Hydro One’s transmission system consists of approximately 290 circuit km of underground 115 kV and 230 kV transmission cables. The high voltage underground (“HVUG”) cable systems are comprised of a number of sub-systems and components that need to function properly in an integrated manner to be able to deliver a reliable supply of electricity. The primary components and sub-systems are:

- Underground cable, that is made up of an inner core conductor of either copper or aluminum, insulation that is made of liquid impregnated paper or cross-linked polyethylene, and a protective sheath or steel pipe with a protective cover or coating;
- Cathodic protection systems, that protect the steel pipe against corrosion;
- Liquid pressurization systems, that include pumping plants to ensure oil or gas pressure is maintained at acceptable levels;
• Bonding and grounding systems, that address safety risks and control induction on the
cable sheath; and

• Insulated cable terminations that connect a cable to an overhead line or connect a
cable to a transformer station.

Hydro One Transmission’s underground cable systems supply urban centres in Toronto,
Ottawa and Hamilton, with short sections in London, Sarnia, Picton, Windsor and
Thunder Bay. These underground cable systems are essential for electrical supply and as
such require a very high degree of reliability. This program addresses the replacement or
refurbishment of components and line sections of the HVUG cable system in order to
maintain this reliability and mitigate safety concerns.

4.3.2 Investment Plan

Specific HVUG cable systems are selected for refurbishment or replacement once
deemed at end of life. The decision to deem an underground cable and or cable
components at end of life is driven predominantly by cable performance, condition, and
component obsolescence. Of particular importance is condition data that is gathered from
cable diagnostics and maintenance activities such as condition patrols, cable pipe
corrosion surveys, oil tests, jacket tests, infrared scans and intrusive examination of
insulation systems when afforded the opportunity. Based on assessment findings, entire
cables or their subsystems are scheduled for replacement or refurbishment. Priority is
given to assemblies and/or cables that are critical to the operation of the transmission
system.
Planned capital investments in primary cable components and sub-systems vary from year to year depending on system needs. Table 20 outlines the planned projects for the test years. Additional details for these projects are provided in the Investment Summary Documents S56 and S57 in Exhibit D2, Tab 2, Schedule 3.

### Table 20
Underground Cable Projects
($ Millions)

<table>
<thead>
<tr>
<th>Ref #</th>
<th>Description</th>
<th>Test Years</th>
<th>Total Cost</th>
</tr>
</thead>
<tbody>
<tr>
<td>S56</td>
<td>H2JK / K6J Cable Replacement</td>
<td>12.1</td>
<td>62.0</td>
</tr>
<tr>
<td>S57</td>
<td>H7L / H11L Cable Replacement</td>
<td>14.3</td>
<td>28.8</td>
</tr>
<tr>
<td></td>
<td>Other Underground Cable Projects &lt; $3M</td>
<td>1.8</td>
<td>15.1</td>
</tr>
<tr>
<td></td>
<td><strong>Total</strong></td>
<td><strong>28.1</strong></td>
<td><strong>15.1</strong></td>
</tr>
</tbody>
</table>

Other underground cable projects include:
- Emergency repairs to the HVUG cable systems.
- Replacement of ring gaps associated with the cable bonding and grounding on the terminal ends of underground cables circuits. Studies have shown that due to rising fault currents at some stations the current devices are no longer adequate during system fault situations and could fail explosively.
- Replacement of sump pumps that control water levels in cable tunnels that accommodate underground cable circuits.
- Upgrades to the cathodic protection isolation devices on the underground pipe type cables which are critical to mitigate the risk of corrosion to the steel carrier pipes that contain the insulated conductors.

### 4.3.3 Summary of Expenditures

The planned expenditure for 2015 and 2016 is $28.1 million and $15.1 million respectively. The average spending in the test years is in line with the bridge year 2014,
though year over year costs vary depending on the number and size of the underground
cable replacement projects. However the test year expenditures represent a significant
increase over the historic spending. This increase over historic years is required to replace
a number of underground cable circuits that are in poor condition and are impacting the
environment due to leakage of oil.

A reduction in this program will jeopardize the electrical supply reliability to the
downtown areas of major centres in Ontario, as well as increase environmental risks
associated with an increase in oil leaks from these aging cables.
DEVELOPMENT CAPITAL

1.0 INTRODUCTION

Transmission Development Capital covers funding for projects related to new or upgraded transmission facilities to:

- Provide inter-area network transfer capability to enable electricity to be delivered from areas with sources of supply to load centers.
- Provide adequate capacity to reliably deliver electricity to the local areas connected to Hydro One’s Transmission system.
- Connect load customers (load connections) and generating stations (generation connections) to Hydro One Transmission’s system.
- Carry out necessary mitigation measures to minimize high impact risk and ensure safe, secure and reliable operation of Hydro One Transmission’s system in accordance with the Market Rules, TSC and other mandatory industry standards such as NERC and NPCC.
- Maintain the performance of Hydro One Transmission’s system in accordance with Customer Delivery Point Performance (“CDPP”) Standards.
- Develop and implement cost effective solutions to enable better use of existing infrastructure or for upgrading the infrastructure to address the impacts of the connection of renewable generation.

The projects take into consideration the need to plan and operate the interconnected Bulk Electric System in a safe, secure and reliable manner that meets Hydro One Transmission’s license requirements and complies with criteria and standards based on good utility practice.
2.0 DEVELOPMENT CAPITAL PLANNING PROCESS

2.1 Summary of Guidelines and Criteria

Reliability is a key business value for Hydro One Transmission and thus, the Company focuses heavily on achieving its reliability objectives and on contributing to adequacy of electricity supply in the province. The importance of reliability is reinforced by obligations placed by various regulatory and reliability authorities on Hydro One Transmission to maintain acceptable voltages, keep equipment operating within established ratings, and maintain system stability during both normal operation and under recognized contingency conditions on the transmission system. These requirements of the Ontario Government and industry regulatory authorities include those of the North American Electric Reliability Council (“NERC”), the Northeast Power Coordinating Council (“NPCC”), the Ontario Energy Board (“OEB”), the Ontario Power Authority (“OPA”), and the Independent Electricity System Operator (“IESO”) which utilizes its Ontario Resource and Transmission Assessment Criteria (“ORTAC”) when conducting System Impact Assessments (“SIA”) for new transmission facilities. In particular, Hydro One is required to comply with the Transmission System Code (“TSC”) and its Transmission License requirements.

2.2 Development Capital Planning Process

An overview of the Development Capital Planning process is provided in Exhibit A, Tab 16, Schedule 3. More detailed explanation of the planning for each different type of investment (i.e. Network Upgrades, Local Area Supply, Load Connection, Generation Connection, Protection and Control for Enablement of Distribution Connected Generation, Protection and Control Modifications for Consequences of Connected Distribution Generation, Performance Enhancement, Risk Mitigation and Smart Grid) is provided in Sections 2.2.1 to 2.2.8 of this exhibit. The details on specific projects that are
presently in various stages of conceptual or detailed planning, approval work and engineering and construction are outlined in Sections 3.1 to 3.8.

2.2.1 Planning for Network Upgrades

The planning for network upgrades is based on either increasing the inter-area transfer capability between generation and load centers within Ontario or increasing the interconnection capability with neighboring utilities. Constraints in the provincial transmission system can inhibit the efficient use of Ontario’s own generation resources and the import and export of power through interconnection facilities. In order to maintain or enhance the transfer capability; new or upgraded facilities are required to ensure adequacy of electricity supply for the province.

There are several ways in which planning for network upgrades is triggered:

- Hydro One Transmission monitors the transmission system and identifies projects based on concerns about equipment overloading, system performance constraints, or restricted operating and maintenance flexibility.
- Hydro One Transmission assesses significant and pervasive concerns expressed by load and/or generation customers, particularly when these concerns are in matters related to reliability or safety matters.
- Hydro One Transmission monitors the IESO’s SIA reports for load and generation projects. If any SIA suggests that network upgrades may be required, Hydro One Transmission undertakes additional studies to assess alternatives for the upgrades and to identify recommended transmission solutions. In performing these assessments, Hydro One consults with the IESO, OPA, and the customers as appropriate.
- The OPA, through its initiatives related to procurement of additional supply resources for the province, recommends the need for inter-area transmission reinforcements. Typically, this recommendation is based on the Ontario Government’s initiatives and
energy policies regarding renewable generation and/or phasing out of coal-fired generating stations in Ontario.

The solutions for improving transfer capability range from the installation of capacitor banks or static-var compensation to major transmission reinforcement or interconnection projects. The major network upgrades may involve long lead-times in the approval process (based on requirements under the EA Act and/or Section 92/95 of the OEB Act) and construction phase of the project.

2.2.2 Planning for Local Area Supply

The planning for local area supply is driven by load growth and local area reliability. New or upgraded facilities may be required in order to maintain acceptable voltages, equipment operating within the ratings, system stability, and/or operating flexibility. The term ‘Local Area’, for the purpose of this exhibit, refers to a confined subsystem or radial portion of the system supplying multiple transmission delivery points serving one or more customers. The geographic and electrical size of a local area varies based on the area system characteristics and connectivity to the bulk transmission system.

There are several ways in which planning for local area supply is triggered:

- Hydro One Transmission leads local area supply planning for the regions of the province where they are designated as the lead transmitter. Hydro One is the lead transmitter for 19 of the 21 regions. As part of the regional planning process, Hydro One will conduct regional planning studies on a regular basis in coordination with the OPA and the Local Distribution Companies (LDCs). The Board’s current expectation is that all 21 regions will be reviewed on a cyclical basis of 5 years as a minimum.
• Hydro One Transmission monitors the transmission system and identifies concerns about equipment overloading, system performance constraints, or restricted operating and maintenance flexibility.

• Hydro One Transmission may, on its own or in consultation with LDCs and other customers, carry out additional studies to identify needs and potential solutions to resolve constraints related to local area supply adequacy that may arise between regional plan review cycles. In cases which require coordination of potential resources or pool funded facilities, Hydro One Transmission always consults with the OPA to confirm that the need and potential solutions are consistent with the OPA’s plans.

• Hydro One Transmission monitors the IESO’s SIA reports for Load Connections and other projects. If any SIA suggests that transmission reinforcements may be required in the local areas where the load connections or other projects are being contemplated, Hydro One Transmission undertakes additional studies to assess alternatives for Local Area Supply and to identify recommended transmission solutions. In performing these assessments, Hydro One consults with the LDCs and the OPA, where appropriate.

Solutions for local area supply range from the utilization of special protection systems or installation of capacitor banks to maximize the use of existing facilities (in order to defer the need for a major investment) to major transmission expansion projects to meet long-term needs. Major transmission expansion projects may include construction of new transmission lines into the area, and/or new or additional 230/115kV autotransformer capacity. These major projects typically require long lead-times, particularly if there are approval requirements under the Environmental Assessment (“EA”) Act or Section 92/95 of the OEB Act.
2.2.3 Planning for Load Connections

The planning for new or modified load connections is driven primarily by customer requests but it can also arise from regional planning studies and the need to address end-of-life facilities. The connection needs may be satisfied through new and/or modified transmission connection facilities, including: new line connections, new feeder positions at existing Transformer Stations (“TSs”), increase of capacity at existing TSs, or construction of new TSs.

In accordance with the TSC, new load connections driven by customer requests may be self-provided by the transmission customer or, at the discretion of the transmission customer, they may be provided by Hydro One Transmission. If requested, Hydro One Transmission is required by the TSC and its Transmission Licence to provide a pool funded option for new line connections and transformation connection. The costs of these investments are the responsibility of the benefiting customer(s) and the costs are fully recovered from these customers via incremental connection revenues and/or capital contribution as per a Connection Cost Recovery Agreement (“CCRA”), the calculation of which is based on Hydro One Transmission's Connection Procedures approved by the OEB.

2.2.4 Planning for Transmission Connected Generation

The planning for transmission connected generation is based solely on customer requests and it is significantly impacted by external factors such as: the Ontario Government’s initiatives, the OPA initiatives for procurement of renewable, clean and high efficiency energy, and private sector investments.
In accordance with Hydro One's Transmission License, Hydro One Transmission is required to connect new generators that meet the requirements of the Market Rules and all other applicable codes, standards and rules while maintaining system security and reliability for existing connected customers. In addition to the specific radial connection itself, modifications may be required to Hydro One Transmission’s network and upstream connection facilities in order to incorporate the generation into the system. Examples of modifications that may be required include enhancements to protection systems, voltage or reactive power support, and/or breaker and station upgrades due to increased short circuit levels contributed by the generator. The customer capital contributions, as per a Capital Cost Recovery Agreement (CCRA), are determined in accordance with the TSC, with clarification provided by the Compliance Bulletin #200606, dated September 11, 2006.

2.2.5 Planning for Protection and Control for Enablement of Distribution Connected Generation

The connection of generation to the distribution system (“DG”) requires changes and additions to the protection and control facilities in transmission stations. These changes are required to ensure the reliability and capacity of the distribution system feeders and maintain protection of transmission assets. The need for them is determined as part of the Connection Impact Assessment process.

However, the required changes do not have a one-to-one correspondence with individual DG projects. Instead, specific changes will support different groupings of generators at the station. They become necessary at certain thresholds of aggregate DG capacity at a feeder, at a bus, and at the entire station. In accordance with the Transmission System Code the costs must be recovered from the generator whose actual connection requires the investment. Thus cost recovery is based on the sequence of actual connection and not, as with the Distribution System Code, the sequence in which the capacity was reserved.
When the Connection Impact Assessment is done, the actual connection sequence is not known and hence neither is the specific generator that will cross the threshold and be the target for cost recovery. Consequently, all generators connecting to the station, even those with very small capacity, must be allocated these full costs at time of Connection Impact Assessment. As these costs will be prohibitive to smaller generators, Hydro One is also implementing a system to rebate the first generator to actually cross the threshold, from the funds collected from other generators that connect after the threshold has been crossed. This rebating needs to be tracked at four grouping levels:

a. all generators connecting to an individual feeder beyond the point at which feeder protection directioning is required.
b. all generators connecting to a station bus after the bus protection needs to be directioned
c. all generators connecting to a station that require transfer trip
d. all generators connecting to a transmission line that require transfer trip

Databases and necessary staffing have been put into place to track the actual connection sequences and cost incurred for the protection modifications at these levels and to ensure the costs are allocated as fairly as possible to all generators.

2.2.6 Planning for Protection and Control for Consequences of Distribution Connected Generation

Hydro One tries to identify all costs associated with the connection of generators to the distribution system at the time of the connection impact assessment so that they can be recovered from the generators as a condition for obtaining the connection. However, there are two categories of costs for which this is not possible:

a. Occasionally some consequences of generation connection are not foreseen
b. Some costs can be anticipated but the exact timing of their need cannot be. These are costs associated with protection and control systems that span all, or large portions, of the grid network. The exact threshold when they will be required depends on factors which are less predictable such as changes in load patterns and real time generation patterns.

When unforeseen consequences arise, Hydro One experts analyze the problem to determine the underlying cause and then determine the scope of remedial program required. For the anticipated consequences, Hydro One monitors trends and tries to determine the most likely timing of need in order that resources and standards can be in place to achieve a planned and cost-effective implementation.

2.2.7 Planning for Smart Grid

The planning for smart grid system deployment in Transmission Stations (TS’s) is oriented to offering value to Hydro One Transmission's LDC customers through improvements in protection and control systems at TS’s to interface with, and support the objectives of an LDC’s Smart Grid systems.

In developing its TS Smart Grid interface systems, Hydro One Transmission is learning from the strategies for smart grid being evaluated in Hydro One Distribution's Smart Zone pilot. These range from implementing and testing automatic fault isolation and restoration systems, managing reactive power with a DVAR controller at transformer stations with high DG penetration, enhancing monitoring and control of DG’s at transformer stations, and installing new technologies and next generation intelligent electronic devices (IEDs) at transformer stations that employ the open standards best suited for interfacing with Distribution System Smart Grid equipment.
The plans for actual deployment of these systems will be driven by requests from LDC’s for TS interfaces to their Smart Grid systems.

2.2.8 Planning for Performance Enhancement and Risk Mitigation

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

In accordance with the requirements of the TSC, Hydro One Transmission on January 17, 2008 filed its CDPP Standards proposal (EB-2004-0424) outlining the process to identify and address delivery points demonstrating poor performance and/or deteriorating trends in reliability performance. The proposal was approved by the Board in its Decision with Reasons of April 2, 2008.

3.0 DEVELOPMENT CAPITAL INVESTMENTS

Development Capital includes work on both network and connection facilities. The type of transmission development investments covered in this exhibit are: Inter-Area Network Transfer Capability, Local Area Supply Adequacy, Load Customer Connection, Generation Customer Connection, Protection and Control for Enablement of Distributed Generation, Protection and Control Modifications for Consequences of Connected Distribution Generation, Smart Grid, and Performance Enhancement and Risk Mitigation.

Hydro One Transmission’s development capital programs and proposed spending levels under these investment types are summarized below.
<table>
<thead>
<tr>
<th>Investment Type</th>
<th>Historical</th>
<th>Bridge</th>
<th>Test</th>
</tr>
</thead>
<tbody>
<tr>
<td>Inter Area Network Transfer Capability</td>
<td>269.3</td>
<td>118.2</td>
<td>41.8</td>
</tr>
<tr>
<td>Local Area Supply Adequacy</td>
<td>64.0</td>
<td>98.0</td>
<td>63.1</td>
</tr>
<tr>
<td>Load Customer Connection</td>
<td>68.1</td>
<td>76.2</td>
<td>42.5</td>
</tr>
<tr>
<td>Generation Customer Connection</td>
<td>11.3</td>
<td>18.8</td>
<td>68.5</td>
</tr>
<tr>
<td>Station Equipment Upgrades &amp; Additions to Facilitate Renewables (Government Instruction)</td>
<td>16.0</td>
<td>32.8</td>
<td>15.8</td>
</tr>
<tr>
<td>Protection and Control Modifications for Enablement of Distribution Connected Generation</td>
<td>14.1</td>
<td>22.5</td>
<td>22.6</td>
</tr>
<tr>
<td>Protection and Control Modifications for Consequences of Connected Distribution Generation</td>
<td>0.0</td>
<td>2.5</td>
<td>1.2</td>
</tr>
<tr>
<td>Smart Grid</td>
<td>5.8</td>
<td>10.7</td>
<td>8.8</td>
</tr>
<tr>
<td>Performance Enhancement</td>
<td>1.2</td>
<td>0.7</td>
<td>0.1</td>
</tr>
<tr>
<td>Risk Mitigation</td>
<td>17.9</td>
<td>18.1</td>
<td>28.4</td>
</tr>
<tr>
<td><strong>Gross Capital Total</strong></td>
<td>467.7</td>
<td>398.5</td>
<td>292.8</td>
</tr>
<tr>
<td>Capital Contributions as per TSC</td>
<td>(51.8)</td>
<td>(69.1)</td>
<td>(121.1)</td>
</tr>
<tr>
<td><strong>Net Capital Total</strong></td>
<td>415.9</td>
<td>329.4</td>
<td>171.7</td>
</tr>
</tbody>
</table>

The overall gross spending on Development Capital work in the test years is below the historical levels. The net spending on Development Capital work in the test years is also largely below the historical levels. The primary reason for the lower capital expenditure levels is the reduction in number of generation connection projects, equipment upgrades to facilitate renewables and risk mitigation work. Further details for each Investment Type are provided in Sections 3.1 to 3.8 below which include explanations of changes in spending patterns compared to historical levels, a brief summary of major projects and, where appropriate, a summary of aspects related to prudency of cost for these projects.
As initiated in proceeding EB-2008-0272, based on input received during the previous
Transmission Revenue Requirement proceeding EB-2006-0501, Hydro One
Transmission has adopted the following Capital Project Category classification to provide
an indication as to when specific projects would be considered approved for inclusion in
rate base.

- **Category 1** - Development capital projects for which the OEB has already granted
  project-specific approval in another proceeding (for example, a proceeding for
  approval of the project under Section 92 of the OEB Act). For these projects, the
  actual in-service costs would be included in rate base when the project goes in-
  service.

- **Category 2** - Development capital projects that have an in-service date in one of the
test years (2015 or 2016) and that do not require an approval under Section 92 of the
OEB Act or any other such Board proceeding. Through the current proceeding,
Hydro One Transmission is seeking approval for these projects to be included in the
rate base when the projects are declared in-service (i.e. upon energization of the
facilities).

- **Category 3** - Development capital projects that have significant spending within the
test years (2015 or 2016), yet do not have an in-service date in any of the test years
and do not require project-specific approvals from the OEB. For these projects, Hydro
One Transmission is seeking guidance from the OEB on the appropriateness of the
need, the proposed solution, and the recoverability of the project cost. The actual in-
service costs would be included in rate base when the project goes in-service subject
to Board approval at a future revenue requirement proceeding.

- **Category 4** - Development capital projects that have significant cash flows within the
test years but they will require future project-specific approvals from the OEB in the
form of Section 92 applications. Hydro One Transmission is not seeking approvals
for these projects within this proposed application since the prudency review for these
projects will be tested during the Section 92 process.
3.1 Inter-Area Network Transfer Capability

3.1.1 Description of Inter-Area Network Transfer Capability Investments

The integrated inter-area network, or bulk electric system, operates primarily at 500kV or 230kV over relatively long distances incorporating major generation resources and delivering their output to major load centers in the Province through interconnection points to major transmission stations. The network is also interconnected with the transmission systems in Manitoba, Québec, Michigan, Minnesota, and New York enabling imports and exports.

The investments in the Inter-Area Network Transfer Capability category provide new or upgraded transmission facilities to increase the transfer capability between generation areas and load centers within Ontario and/or with neighbouring utilities, on the basis of planned changes in generation sources and load patterns.

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

Funding levels for 2015 and 2016 for Inter-Area Network Transfer Capability projects, along with the spending levels for the bridge and historic years are provided in Table 2 of Appendix A to this exhibit. Projects with gross total funding requirements in excess of $3 million in either of the test years are separately identified in Table 2.
Total capital expenditures for these projects have decreased significantly in years 2013 and 2014 compared to the respective values of $149M and $185M from the last rate filing. Also, overall spending in Inter-Area Network Transfer Capability projects in the Test Years is higher than the 2013 Historical and 2014 Bridge year. The main reasons for the changes are as follows:

- A deferral of the in-service date of Clarington TS from 2015 to 2017. The OPA had initially asked Hydro One to have Clarington in-service by summer 2015 in preparation of Pickering NGS retirement. However, with the extension of the Pickering NGS operating license to August 2018, the in-service date for the new station was moved to fall 2017. Expenditures previously forecast for 2013 and 2014 will now be incurred in 2015 and 2016.

- The cancellation of the Milton SVC project. The OPA advised Hydro One in August 2013 that the project was not required following the reduction in generation procurement announced by the Provincial Government in June 2013. There were significant expenditures of $30M and $40M previously forecasted for 2013 and 2014 respectively.

3.1.2 Summary of Inter-Area Network Transfer Capability Projects

The following summarizes the major inter-area network transfer capability projects separately identified in Table 2. Additional details for the projects identified below are provided in the Investment Summary Documents in Exhibit D2, Tab 2, Schedule 3.

All of the projects described below are non-discretionary (as defined in the OEB Filing Requirements for Transmission and Distribution Applications).
Project D1: New 500 kV Bruce to Milton Double Circuit Transmission Line

This project comprises building a new 500kV double circuit transmission line between the Bruce Complex and Milton SS to securely incorporate the generation from all eight units from Bruce NGS and the committed renewable generation in the Bruce Area. The project was approved by the OEB under Section 92 of the OEB Act in its Decision and Order dated September 15, 2008 under Proceeding EB-2007-0050, and is classified as Category 1.

The current cost estimate of this project is $709.4M which is essentially the same amount outlined in Proceeding EB-2012-0031.

The project construction was completed in May 2012 with project closeout work including removal of temporary access roads and right-of-way environmental mitigation that continued into 2013. As well, expenditures (2014 - $6.9M, 2015 - $3.3M, 2016 - $3.2M, 2017 - $6.5M) will be incurred between 2014 and 2017 for real estate costs associated with the expropriation of lands that were approved by the OEB under Section 99 of the OEB Act in its Decision and Order dated March 15, 2011 under Proceeding EB-2010-0023.

Projects D2, D3: Clarington TS: Build new 500/230kV Station, and Installation of Shunt Capacitor Banks at Cherrywood TS

These projects are required to reinforce the 230kV supply capability in the east GTA following the upcoming retirement of the Pickering Nuclear Generating Station (NGS). The need for this project was previously described by the OPA in their evidence provided in EB-2012-0031 entitled “OPA Information on the Description of Need and Rationale for Oshawa Area TS (Clarington TS)”.
The proposed plan covers building a new 500/230 kV station on Hydro One owned lands at the Clarington Junction Site. Hydro One has obtained all necessary approvals for building the new station and the project is now under construction. With the extension of the Pickering NGS operating license to 2018, the project in-service date was revised from Q2 2015 to Q3 2017. The OPA provided concurrence of this revised in-service date in the letter dated April 16, 2014 which is attached in Appendix B of this exhibit. The current cost projection for the Clarington TS project is $294.1M.

The OPA had also identified that additional reactive support at Cherrywood TS is required and recommended the installation of two 300 MVar capacitor banks coincident with Pickering NGS retirement. Hydro One has initiated preliminary engineering and project development work for the Cherrywood TS capacitor bank. The current cost projection for the Cherrywood project is $14M with an in-service date of 2018.

Projects D2 and D3 are classified as Category 3 since the in-service dates are beyond the test years although significant funding is required within the test years.

3.2 Local Area Supply Adequacy

3.2.1 Description of Local Area Supply Investments

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

Local Area Supply investments provide for new or upgraded facilities in order to provide for area supply adequacy, and to meet load forecast requirements in an area where the loading on existing transmission facilities reach capacity. These investments typically affect many customers over a significant period of time and the benefits cannot be allocated in a practical and fair manner to specific customers.
The consequences of not proceeding with these investments are dependent on the specific situation, for example:

- Curtailment of load in order to ensure that the power system operates in a reliable mode and within the equipment rating.
- Insufficient reactive support causing system and voltage instability that would lead to widespread adverse impact in the local area.
- System constraints that restrict the ability of new renewable or high efficiency generation to be connected.

Funding levels for 2015 and 2016 for Local Area Supply Adequacy projects, along with the spending levels for the bridge and historic years are provided in Table 3 in Appendix A to this exhibit. Projects with gross total funding requirements in excess of $3 million in either of the test years are separately identified in Table 3. Customer capital contributions, where applicable, were determined in accordance with the TSC and Hydro One Transmission’s Connection Procedures approved by the Board.

The overall spending in Local area Supply projects in the test years is comparable to Historical spending. A conservative estimate of additional capital expenditures of $15 million in 2016 has been included to reflect potential projects that may arise from the regional plans and that may need to be started by 2016. The scope of such projects will be better understood once the regional plans have been developed. These projects are not planned to be in service in 2016 so they will not impact the calculation of rates for that year.

3.2.2 Summary of Local Area Supply Projects

The following summarizes the major local area supply adequacy projects identified in Table 3. Additional details for the projects identified below are provided in the Investment Summary Documents in Exhibit D2, Tab 2, Schedule 3.
Project D4: Midtown Transmission Reinforcement Plan

This project is planned to provide reliable supply capacity to the City of Toronto. This project is required to reliably accommodate existing load since the existing 115kV transmission supply is inadequate to meet the coincident summer peak loading under the contingency condition where there is a loss of one circuit. The project was approved by the OEB under Section 92 of the OEB Act in its Decision and Order dated June 17, 2010 under Proceeding EB-2009-0425, and is classified as Category 1.

The in-service date has been delayed from Q3-2014 reported in Proceeding EB-2012-0031 to Q4-2015 due to a tunnel shaft shoring failure and difficulty in obtaining outages. The project cost projection remains unchanged at $114.8M.

Projects D5, D6 Guelph Area Transmission Reinforcement, and Preston TS Transformation

These projects are planned to provide reliable transmission supply capacity for load growth in the South-Central Guelph Area and the Kitchener/Cambridge Area. The projects are required as the transmission system is inadequate to meet the local area’s existing demand and forecast load requirements.

The proposed plan consists of building a new 230/115 kV station at Cedar TS. The project will also provide new switches at the Guelph North Junction to address restoration performance requirements, reliability and operational issues. The project is currently underway following OEB approval for “Leave to Construct” under Proceeding EB-2013-0053 and the expected project in-service date is Q2 2016. The cost of the Guelph Area Transmission Refurbishment project is projected at $94.3 M. This is higher than the $88M cost estimate submitted in EB-2013-0053 and is mainly due to the increased cost based on vendor bids for the station work at Cedar TS, the increased scope
of work identified during detailed engineering for protection and control at remote sites and for drainage work at Cedar TS.

The second project covers provision of an additional 230/115kV autotransformer and associated switching at the existing Preston TS. Project development and preliminary engineering studies are currently underway in accordance with the Regional Infrastructure Planning process led by Hydro One. The current cost projection for the Preston TS project is $24.9M and the earliest projected in-service date is Q2 2017.

Project D5 for Guelph Reinforcement is classified as Category 1 and has received Section 92 approval from the Board; and Project D6 at Preston TS is classified as Category 3 since the in-service date is beyond the test years but significant expenditures are required within the test years.

Project D7: Toronto Area Station Upgrades for Short Circuit Capability: Manby TS Equipment Uprate

This project is planned to address both the aging infrastructure and under-rated equipment that limits the connection of renewable generation in the City of Toronto. The project consists of replacing the aging 115 kV breakers and associated 115kV switchyard facilities at Manby TS in order to improve short circuit ratings at these stations to comply with the Transmission System Code.

The project is classified as Category 1 and was previously reported in Proceeding EB-2012-0031 with an estimated cost of $17.5M and an in-service date of Q4 2014. However, additional deficiencies were identified during the execution phase – station service, new cable trenches and trays and more protection and control work. Significant delays were also introduced due to the necessity to coordinate outages with a number of other major projects in the area. The current project cost is estimated at $24.3M and the in-service date is Q2-2016. However, to facilitate renewable and high efficiency
generation connections in the Toronto 115kV area, the breaker replacement work is targeted for completion by Q4 2014.

**Project D8: Hawthorne TS: Replace 2 existing Transformers**

The preliminary results of the Ottawa Area Regional Planning Study have found that the load meeting capability of the Ottawa 230/115kV transmission system is limited due to the ratings of aging transformers. The study determined that more transformation capacity is needed in order to meet the forecasted load growth in the area. As a result, the most cost effective approach to meet the 230/115 kV autotransformer capacity need is to replace the older lower rated 225MVA transformers with standard 250MVA units.

The project cost is $12.5M and the planned in-service date for the new transformers is Q2 2017. It is classified as Category 3 since the in-service date is beyond the test years but significant expenditures are required within the test years. The risk in not proceeding with this project would result in increased risk of customer interruptions affecting supply reliability to customers and would not support future area growth.

**Project D9: York Region – Increase Transmission Capability for B82V/B83V Circuits**

As a result of an Area Supply Study of the York Region, the OPA, in its letter dated June 14, 2013 (see Exhibit A, Tab 16, Schedule 9, Attachment 2) asked Hydro One to proceed with work to increase the load meeting capability of circuits B82V and B83V. The work requires the installation of new breakers, and the design and implementation of a new Load Rejection scheme for stations connected to these circuits. These measures will increase the circuits’ load meeting capability to improve reliability for the near and medium term and allow the line to supply additional customer loads in northern Vaughan and northern York Region. It will also allow restoration of customer loads with York
As this project provides for future load meeting capability and meeting restoration needs for the broader northern York Region area, the costs will be recovered from the network rate pool and no capital contribution is required from customers. The total cost of this project is $20M with an in-service date of Q2 2017, and it is classified as Category 3 since the in-service date is beyond the test years but significant expenditures are required within the test years.

3.3 Load Customer Connection

3.3.1 Description of Load Customer Connection Investments

Load customer connections can be addressed by new or modified transformation connection facilities including new feeder positions at existing transformer stations, increase of capacity at existing stations, or construction of new lines and stations. The projects are initiated based on the customers’ requirements for capacity, reliability and/or power quality. The projects may also be initiated by regional planning or the need to address end-of-life facilities. Because these types of projects are primarily customer driven, the magnitude and volume of work can vary significantly year over year.

The consequences of not proceeding with these projects include: impairment of customers’ ability to supply their current and expected loads, increased risk of rotating blackouts where existing facilities are overloaded, and/or violation of Hydro One Transmission’s license, specifically, Section 8, “Obligation to Connect”, and clause 5 which ensures that the company shall not refuse to make an offer to connect.
Funding levels for 2015 and 2016 for Load Customer Connection projects, along with the spending levels for the bridge and historic years are provided in Table 4 in Appendix A to this exhibit. Projects with gross total funding requirements in excess of $3 million are separately identified in Table 4.

The overall spending in the test years is comparable to historical spending. A provision of $12 million in 2016 for additional projects has also been included. This provision is a conservative estimate intended to reflect a number of potential connection requests or load connection projects arising from regional planning for which there is limited scope definition and that may need to begin work in 2016.

### 3.3.2 Summary of Load Customer Connection Projects

The following is a summary listing of the load customer transformation connection projects by Category Type for which cash flow details are provided in Table 4. All of these projects are non-discretionary and customer driven.

<table>
<thead>
<tr>
<th>Category 1 Projects</th>
<th>Category 2 Projects</th>
<th>Category 3 Projects</th>
<th>Category 4 Projects</th>
</tr>
</thead>
<tbody>
<tr>
<td>D10: Copeland MTS</td>
<td>D11: Seaton TS</td>
<td>D12: Supply to Essex County Transmission Reinforcement</td>
<td></td>
</tr>
</tbody>
</table>

These projects are funded by customers through a combination of future rate revenues and a capital contribution, where required, as determined in accordance with the TSC and Hydro One Transmission’s Connection Procedures approved by the OEB. Additional details about these projects are provided in the Investment Summary Documents in Exhibit D2, Tab 2, Schedule 3.
3.4 Generation Customer Connection

3.4.1 Description of Generator Customer Connection Investments

Generation customer connections are typically addressed by radial connection facilities; however, in some cases other modifications may be required to Hydro One’s local area connection or network facilities in order to incorporate the generation into the system.

Since mid-2004, there has been growing generation connection activity in direct response to the initiatives taken by the Ontario Government and the OPA. These initiatives include Renewables Request for Proposals (“RFPs”), Clean Generation RFPs, Combined Heat and Power RFPs, the FIT program, and other project procurements.

With the signing of the Green Energy Investment Agreement with the Korean Consortium in January 2010, and the release of 25 large-scale renewable energy projects under Ontario’s Clean Energy Feed-In Tariff program in July 2011; there was significant generation connection activity in 2013 and 2014. This generation activity is expected to continue albeit at a slower pace as the OPA has initiated new generation procurement programs in 2014 for Large Renewable and Combined Heat and Power generation.

The consequences of not proceeding with these investments include:

- Failure to connect generators which have been contracted by the Ontario Government or OPA or which have otherwise developed appropriately under the applicable codes and rules, many of which contribute to meeting the Ontario Government’s targets for renewable electricity capacity
- Failure to meet Hydro One Transmission’s obligation to connect new generators under its Transmission License and the TSC.
Funding levels for 2015 and 2016 for Generation Customer Connection projects, along with the spending levels for the bridge and historic years, are provided in the attached Table 5 in Appendix A to this exhibit. Projects with gross capital spending in excess of $3 million in either of the test years are separately identified in Table 5.

The overall spending in the test years is significantly lower than historical spending. This reflects the fact that a significant number (19) of generation projects representing 2546 MW has been or will be connected in 2013/14. It also reflects approximately 10 projects that have OPA contract awards but continue to experience delays. Because the connection dates of these projects cannot be established, the cash flows cannot be projected with sufficient confidence. Given the status of these projects, it is unlikely there will be significant capital expenditures for these projects in the test years.

A provision of $2M and $5M in 2015 and 2016 respectively for additional generation connections has been included to account for unforeseen connections that may be required within the test years. Such connections could be merchant projects, delayed projects that are able to proceed sooner than anticipated or projects from the OPA’s Large Renewable Program or Combined Heat and Power Program that are able to begin connection work in the test years.

Generation connection projects are categorized as “Customer Driven” because they are requested by the customer to accommodate new generation and these connection facilities are normally fully funded by the customer.

In some cases, network facilities may be triggered which would be the responsibility of Hydro One in accordance with the TSC, and in other cases, Hydro One Transmission takes the opportunity to upgrade or refurbish its equipment while providing a new or modified generation connection. In such cases, the project may include some net cash flow (to be funded by Hydro One Transmission) associated with the refurbishment work.
Additional details about these projects are provided in the Investment Summary Documents in Exhibit D2, Tab 2, Schedule 3.

3.4.2 Summary of Generator Customer Connection Projects

The following summarizes the major generation connection project identified in Table 5. Additional details for the project are provided in the Investment Summary Document in Exhibit D2, Tab 2, Schedule 3.

Project D13: Napanee Gas Generation Connection

This project covers the connection of the Napanee Generating Station. A contract has been awarded by the OPA to Trans Canada Inc. to build this 910MW gas turbine generation plant in the County of Lennox and Addington near the Town of Napanee. The new Napanee GS will connect to the Lennox TS 500kV switchyard.

The planned in-service date for Napanee GS is Q1 2017.

3.5 Protection and Control Modifications for Enablement of Distribution Connected Generation

3.5.1 Description of Protection and Control Modification Investments for Enablement of Distribution Connected Generation

The connection of generation to the Distribution Systems supplied from the Hydro One Transmission System requires a number of modifications and additions to the Protection and Control systems in the Transmission Stations. These modifications are required to preserve the reliability and loading capability of the feeders, to protect loads and
generators from islanding, to preserve the proper function of station protections and to minimize disruption to the operation of the generators.

The consequences of not proceeding with these programs include:

- Severe restriction on the amount of generation that can be connected to distribution systems.
- Lost production periods for station generator customers as a result of planned or forced transmission conditions for which transfer trip protections are not valid.

Funding levels for 2015 and 2016 for Protection and Control Modification projects, along with the spending levels for the bridge and historic years, are provided in Table 6 in Appendix A to this exhibit. Projects with gross capital spending in excess of $3 million in either of the test years are separately identified in Table 6.

**Project D14: Transmission Station P&C Upgrades for Distribution Connected Generation**

Certain upgrades to or replacements of the Protection and Control (P&C) systems at Transmission Stations are required in order to accommodate generation connected to distribution systems supplied from the TS. These costs are fully recovered through customer contributions.

Additional details on those Programs with annual gross capital spending in excess of $3 million in either of the test years as identified in Table 6 are provided in the Investment Summary Documents in Exhibit D2, Tab 2, Schedule 3.
3.6 Protection and Control Modifications for Consequences of Connected Distribution Generation

3.6.1 Description of Protection and Control Modification Investments for Consequences of Connected Distribution Generation

As the connection of generation to the Distribution Systems supplied from the Hydro One Transmission System accumulates, certain consequences can emerge that require further investment to address. Some of these are consequences that are unforeseen, others can be anticipated but the exact threshold when they will be required depends on factors which are less predictable such as load growth and changes to generation patterns.

The consequences of not proceeding with these programs include:

- Contravention of Hydro One’s reliability compliance obligations, as they pertain to the NPCC’s requirements for under frequency load shedding, and the reliability of Special Protection Schemes.
- Power quality problems for distribution load customers
- Deterioration in reliability and performance of system control functions
- Inability to manage operation during planned or forced outage conditions

Funding levels for 2015 and 2016 for Protection and Control Modification projects for the Consequences of Distributed Generation, along with the spending levels for the bridge and historic years, are provided in Table 7 in Appendix A to this exhibit.

The following sections summarize the investments identified under the Protection and Control for Consequences of Connected Distribution Generation program. All of these programs are non-discretionary.
3.6.1.1 Under Frequency Load Shedding and Load Rejection Modifications for DG

Some contingencies on the interconnected transmission system can cause a loss of generation. The resulting imbalance between generation and load will cause a downward trend in the system frequency. If this trend is not corrected, other generation will trip and a widespread blackout would result. To prevent this, NERC and NPCC mandate under frequency load shedding (UFLS) schemes which disconnect load from the system automatically until the generation load imbalance is corrected. Hydro One has about 130 Transmission Stations equipped for under frequency load shedding. The loads are shed by tripping feeder breakers. As generation connects to the feeders, the number of feeder breakers that trip only load is being reduced and alternate arrangements will need to be implemented to maintain required UFLS capability.

Special Protection Schemes (SPS’s) initiate tripping of generation, load or both, in response to contingencies on the transmission system, to prevent overloads or system instability. As with UFLS, the tripping of load is accomplished by tripping of the feeder breakers at Transmission Stations. With generation connected to the feeders, the amount of load available for rejection is reduced and alternate arrangements will need to be implemented to maintain required SPS capability.

These are system driven schemes associated with the transmission network. They are not connection assets and are not for connection purposes. Consequently, these costs will be allocated to the network pool.

3.6.1.2 Transmission work to mitigate distance limitation

This encompasses the protection works required on transmission assets which are required to address the power-distance limitation problems observed at connected projects. This work was approved in the OEB proceeding EB-2010-0229 (Hydro One’s
exemption application). For example, in the case where a DG is relocated to a shorter feeder the cost of installing transfer trip and other protection modifications on the shorter feeder will be a Transmission cost incurred to mitigate power-distance limitations.

3.7 Smart Grid

3.7.1 Description of Smart Grid Investments

The major portion of Hydro One’s Smart Grid investments are in Hydro One Distribution on the development of the Advanced Distribution System (ADS) Smart Zone Pilot which is located in the area around Owen Sound. However, Hydro One Transmission also requires investments for upgrading of the Protection and Control (P&C) systems in some Transmission Stations to make them capable of the necessary interactions with the intelligent devices on the distribution systems (Hydro One’s or those of other LDC’s) supplied from those stations.

The main objective of the Smart Grid transmission investments is to test the implementation and integration of new P&C technologies that are best suited to interfacing with, and supporting the functions planned for ADS implementations. Hydro One needs to establish standards that will support the ADS implementations of many distributors.

3.7.2 Summary of Smart Grid Investments

The smart grid capital expenditures in 2015 and 2016 for transmission related work represent the costs associated with the final commissioning of the new systems in Owen Sound TS that interface to the Smart Zone Pilot and costs to test wireless communication from TS sites to ADS devices. Based on the findings from this pilot work, new programs may be created in the future.
Funding levels for 2015 and 2016 for Smart Grid projects, along with the spending levels for the bridge and historic years are provided in Table 8 in Appendix A to this exhibit.

3.8 Performance Enhancement and Risk Mitigation Programs

The program investments in this category are grouped into two categories; Performance Enhancement and Risk Mitigation as outlined below:

3.8.1 Performance Enhancement

There are two types of Performance Enhancement programs: Delivery Point Performance and Power Quality.

a) Delivery Point Performance

Delivery Point Performance investments are initiated to improve the performance to customers at their delivery point. As per the Customer Delivery Point Performance Standard issued by the Board under Proceeding EB-2002-0424, a delivery point for a customer is defined as an outlier delivery point (“ODP”) when the reliability performance of that delivery point is worse than its historical baseline performance over a defined period of time or when the reliability performance of the delivery point is worse than the historical baseline of a group of delivery points in the same load category (0-15MW, 15-40MW, 40-80MW and greater than 80 MW).
There are two types of investments undertaken to address ODPs. The first are investments associated with the regular maintenance program (e.g. pole replacement program) and the second are investments to address a specific problem or to implement a corrective solution (e.g. installation of fault indicators to target the location of phase spacers or surge arrestors).

b) Power Quality

Power Quality issues are complex and generally mitigation measures are unique to customer operations. The installation of Power Quality monitors are needed to collect and assess Power Quality data to understand the issues and then work with individual customers to address their issue.

The consequences of not proceeding with these Performance Enhancement investments include: non-compliance with the applicable regulatory requirements, increased customer complaints, and reliability issues.

Funding levels for 2015 and 2016 for Performance Enhancement projects, along with the spending levels for the bridge and historic years, are provided in Table 9 in Appendix A to this exhibit.

3.8.2 Risk Mitigation

Work to ensure compliance with mandatory standards (such as NERC, NPCC) is met, and high risk situations are mitigated, is funded through this development program.

With the exception of Force Majeure events such as the 1998 ice storm and the 2003 blackout, events presenting unacceptable risks to supply reliability are identified. Projects are identified to address needs on a priority basis considering legislative,
regulatory, environmental and safety requirements. Accordingly, the funding levels under this program can vary based on the issues to be addressed and the required remedial actions.

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

There were four projects identified under this development program in EB-2012-0031. The two projects to address reliability were the 115kV breaker upgrades at Hawthorne TS and Allanburg TS. High short circuit levels have required interim operating measures to reduce the short circuit levels. These operating measures involve opening bus tie breakers and splitting the bus at the 115kV stations which substantially reduces the capability and the redundancy of these stations to supply their respective areas. Completing the breaker upgrades at Allanburg TS and Hawthorne TS will restore the reliability back to levels prior to the deployment of the interim measures. The Allanburg project is expected to be complete by Q4 2014. The Hawthorne project is expected to be complete by Q3 2015. However, to facilitate renewable and high efficiency generation connections in the Ottawa 115kV area, the 115kV breaker work is targeted for completion by Q2 2014 and remaining work covering bus conductor upgrade and insulator replacements will be done after the breaker work is complete.

Two other projects under this development program to address equipment and safety risk were the addition of reactors at Basin TS (in-service 2014) and the high voltage breakers at Main TS (in-service 2014). These investments were required to address risk of damage to cables due to excessive temporary over-voltages in the 115kV downtown Toronto system.

There are no additional projects identified under this program. Funding levels for 2015 and 2016 for Risk Mitigation projects are based on an allowance for unforeseen work and
are provided in Table 10 of Appendix A of this exhibit along with the spending levels for the bridge and historic years.

3.9 **Large Capital Projects with Limited Scope Definition**

The purpose of this section is to highlight certain large capital projects which have not been included in the business plan or this proposed rate application due to limited scope definition and project information but could have significant capital expenditures in the test years.

There are currently four large capital projects which are in the study and scope definition phase. These projects are expected to be in-service beyond the test years so they will not impact the rates being sought in this proposed application. Unlike Category 3 projects, specific projection of yearly capital expenditures at a project level cannot be established at this time.

While these projects will not impact rates in the test years, there may be significant capital expenditures in the test years for project development work, including approvals work, and early ordering of major materials that require long delivery times. Should this work materialize significant planning, engineering, approvals, stakeholder consultation and real estate resources will be required to carry out the work.

Further descriptions of the four projects are provided below.

3.9.1 **East West Tie Expansion – Station Work**

Robust growth in the mining sector in the Northwest coupled with a changing supply mix in the region, including the shutdown of coal-fueled power plants at Thunder Bay and Atikokan, is driving a need to reinforce the supply in the Northwest in order to maintain an acceptable standard of reliability in the region. While this can be accomplished by
either transmission or local resource solutions, the OPA has recommended the expansion of the East-West Tie as the preferred solution option based on technical, economic and other considerations. The proposed transmission solution is the construction of a second double-circuit 230 kV line between Wawa TS, Marathon TS and Lakehead TS, and the addition of switching and reactive support facilities at the three stations. The augmented East-West Tie will have a firm transfer capability of about 650 MW.

The OEB has designated Upper Canada Transmission (NextBridge trade name) to undertake the development of the proposed line, while Hydro One is the Incumbent Transmitter of the station facilities. Hydro One’s project will provide the necessary station work and facilities, including the switchgear and reactive facilities to connect NextBridge’s proposed 230 kV double-circuit line to Wawa TS, Marathon TS and Lakehead TS, with required facilities identified by the IESO.

The in-service date of the new facilities is currently expected to be between late 2017 and late 2018. Both the scope and timing of the required facilities will be better understood following the Leave to Construct application, expected in early 2015, for the construction of the new lines from Wawa TS to Marathon TS and from Marathon TS to Lakehead TS.

3.9.2 TransCanada - Energy East

TransCanada Energy (TCE) plans to convert one of its existing Canadian pipelines from natural gas transmission to oil. The pipeline will transport crude oil from Western Canada to Eastern Canadian refineries, and the new pumping stations will require electric power supply from all provinces along the route.

In Ontario, 30 new pumping stations will be built in locations along the existing pipeline route, with 19 stations requiring electric supply from the Hydro One Transmission system. The remaining 11 stations will be supplied by entities other than Hydro One Transmission or via TransCanada’s natural gas supply. The connections could involve
lines, stations and protection and control work. Hydro One is currently working with TCE to scope the development and estimating work. Further scope development may be required following the outcome of the preliminary System Impact Assessment that the IESO is conducting.

The in-service date of the new facilities is currently expected to be between late 2017 and late 2018.

3.9.3 **Northwest Bulk Transmission Line Project**

The Northwest Bulk Transmission Line is a priority project identified in the 2013 Long-Term Energy Plan (LTEP). This project will provide additional supply capability to support growing load and new customers in the area west of Thunder Bay including the area north of Dryden. On November 17, 2013, the Minister of Energy issued a directive to the OEB to amend Hydro One’s transmission license to proceed with the development of network transmission expansion in the area west of Thunder Bay subject to the scope and timing recommended by the OPA. At the time of this rate submission, Hydro One has not received scope and timing recommendations from the OPA. The OPA plans to provide Hydro One this information later in 2014, after it has updated the demand forecast for the Northwest. Subject to the ultimate scope for this project, it is expected that the earliest in-service date of the new transmission facilities may be in the 2020 timeframe, dependent on demand.

3.9.4 **GTA Reactors**

This project is to provide additional reactive power absorption capability to manage high voltages in the Greater Toronto Area (GTA) under light load conditions and/or generator/station equipment outage conditions. The IESO has observed, in the past year, a number of occasions of high voltages (i.e. voltages exceeding 550 kV on the 500 kV
system and 250 kV on the 230 kV system) across the transmission system in the GTA.  
The IESO System Operators dealt with these incidences by opening lightly loaded 
transmission circuits connected to the GTA system. However, the IESO does not consider 
this action an appropriate long term remedy to this problem and a more permanent 
solution involving facilities to better regulate voltages and absorb reactive power in the 
GTA is required.  

Preliminary studies conducted by the IESO and the OPA have identified that the 
frequency and magnitude of the high voltage problem in the GTA will worsen with the 
retirement of the Pickering Nuclear Generating Station near the end of this decade (the 
Pickering generators provide reactive power control as part of its operation).  

It is estimated that between four and six reactors may be required in the GTA. More 
detailed studies are underway to further refine the scope of work, including the number, 
type, size and location of reactors needed. As the high voltage problem already exists 
today, an in-service date of late 2017 is being planned, in consideration of the lead time 
required for this project.
OPERATIONS CAPITAL

1.0 INTRODUCTION

Operations Capital investments fund enhancements and replacements of facilities required to operate Hydro One’s Transmission System and to meet requirements established by operating agreements, market rules and regulatory authorities as a transmission owner and operator. Planned investments will enable Hydro One to achieve its vision as a leading transmission company by employing “best in class” commercially available operations systems and equipment. These investments will provide monitoring and control functionality to maintain top-quartile system reliability, accurate up to date information, improved customer satisfaction, reduced outage restoration time and public and worker safety. The process to develop capital investments for Operations assets is discussed in Exhibit A, Tab 16, Schedule 3.

Operations capital investments are required to:

- sustain assets that are at or near end of life;
- perform major refurbishments; and
- implement, enhance and modify the physical infrastructure, systems and tools necessary for transmission operations.

Failure to sustain the Network Operating systems and tools will lead to increased business and operational risk as aging assets become less reliable, require more maintenance and lack vendor support. Network Operating system and/or tool failures negatively impact customer service, system reliability and regulatory compliance. It is important to our customers, the province of Ontario and our interconnected neighbours that Hydro One Transmission Operations prudently undertake investments necessary to operate the Transmission System to provide efficient, safe and reliable service.
The Operations Capital program for the test years is divided into two categories:

- **Grid Operations Control Facilities**: These investments fund enhancements and replacement of computer tools and systems that support the transmission operating functions at the Ontario Grid Control Centre (“OGCC”) and the Back-up Control Centre (“BUCC”).

- **Operating Infrastructure**: These investments fund enhancements and modifications to the physical infrastructure outside of the control centres, required for the effective operation of the Transmission System.

The required funding for the test years and the spending levels for the bridge and historic years is provided in Table 1.

<table>
<thead>
<tr>
<th>Description</th>
<th>Historic</th>
<th>Bridge</th>
<th>Test</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>2011</td>
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<td>2013</td>
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<tr>
<td>Grid Operations Control Facilities</td>
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<tr>
<td>Operating Infrastructure</td>
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<td>11.9</td>
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<td><strong>Total</strong></td>
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<tr>
<td></td>
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<td>Grid Operations Control Facilities</td>
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<td>Operating Infrastructure</td>
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<tr>
<td><strong>Total</strong></td>
<td>38.6</td>
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</tr>
</tbody>
</table>

### 1.1 Grid Operations Control Facilities

The increased spend in Grid Operations Control Facilities from $3.4 million in 2012 to $11.3 million in 2013 was caused by significant unplanned expenditures related to flood
restoration of the BUCC and costs associated with the Network Management System (NMS) Capital Sustainment project (formerly approved and named NMS Upgrade project in EB-2012-0031).

The planned spending in the bridge and test years, of $18.1 million in 2014, $14.2 million in 2015 and $12.5 million in 2016, is higher than the historic years due to the continuation of the NMS Capital Sustainment project and the commencement of the new BUCC facility development project. Both of these projects are discussed further in Section 3.3 and 3.4 of this exhibit.

Additional planned Capital projects include: Integrated Voice Communications & Telephony System Replacement, Network Outage Management System (“NOMS”) Sustainment project and Control Room displays. These projects are discussed further in Section 3.5 and 3.6 of this exhibit.

1.2 Operating Infrastructure

The decreased spending in Operating Infrastructure from $11.9 million in 2012 to $6.4 million in 2013 can be mainly attributed to deferred implementation of the Wide Area Network (WAN) Project in order to re-assess the project scope in the context of other infrastructure and system needs.

The planned spending in the bridge and test years, of $20.4 million in 2014, $24.1 million in 2015 and $24.9 million in 2016, is higher than the historic years due to the WAN Outreach Program, funding of Grid Control Network Sustainment equipment and expansion of the Fault Location (Distance to Fault) Project. Implementation of Hubsite realignment was delayed in the historic years to allow for a detailed review of
requirements to address adjacency and reliability concerns. Program spending continues
on the deployment of the Station Local Area Networks (LAN) Infrastructure Program, as
well as specific telecommunication network improvements and additional work related to
the Frame Relay Replacement project. These projects are discussed further in Section 4.3
of this exhibit.

2.0 DESCRIPTION OF THE SYSTEMS AND TOOLS

Hydro One operates and controls the Hydro One Transmission System from the OGCC.
Back-up facilities are provided at a separate location in the event that the OGCC or its
computer systems are rendered unavailable. A suite of centralized systems and tools,
supported by province wide telecommunication and station control infrastructure, is used
to execute monitoring and control of transmission assets, the planning and scheduling of
outages and the provision of Transmission System performance information. Hydro One
continually assesses and implements technologies to improve the performance and
efficiency of its transmission operating function. However, the operating function faces
growing challenges:

- The efficient scheduling and real time management of an increasing number of
equipment outages required to support the growing Sustainment and Development
work programs.
- Challenges associated with aging assets that require closer monitoring and
management of operating limits and equipment de-ratings resulting in increased
workload.
- The Green Energy & Economy Act 2009 continues to drive the installation of
renewable generation directly connected to transmission lines or the distribution
systems. Many of these installations will necessitate enhancements to the suite of systems and tools for control and monitoring to effectively manage system impacts, performance and customer requirements. NMS functionality has been extended to allow monitoring of Distributed Generation facilities from the OGCC in the interim.

2.1 Grid Operation Control Facilities

The primary systems used in the monitoring and control of the Transmission System include:

- **The Network Management System** ("NMS") is the transmission network monitoring and control tool which performs the following functions: data acquisition, supervisory control, real-time and study mode network analysis, predictive assessment tools and training simulation. It provides the real time voltages, frequency, loading, equipment status and annunciates alarms for the change in status of equipment or if the equipment is in an abnormal condition in the Transmission System. The NMS also provides control of Hydro One Transmission assets in order to switch equipment in and out of service for outages, react to contingencies and change system configuration to provide reliable service to customers.

- **Operations Support Tools** enable the integration of outage management, and Utility Work Protection Code and electronic logging functions:
  
  o **Network Outage Management System** ("NOMS") is the transmission outage management tool used for planning, scheduling, assessing and executing transmission equipment outages and for transmitting outage approval requests, via
a direct communication link, to the Independent Electricity System Operator ("IESO"). NOMS Version II was placed in production October 2010.

- The **Utility Work Protection** Code is used by Hydro One to establish conditions which, when combined with appropriate work practices, procedures and work methods will provide employees with a guaranteed safe work area. This electronic work permit forms system contains the necessary information to support the development of required Work Protection documentation.

- The **Electronic Log** is the records system for the daily control room activity. It has automated features to capture manual and automatic operations of transmission assets using the NMS. Other pertinent information including Utility Work Protection Code, asset condition and status and communications with customers and various entities are manually logged to create a chronological record of the daily activity. The electronic log provides system data for asset management and system planning.

- **Transmission and Station Operating Diagrams** provide detailed information on the normal operating configuration of the Transmission System and the electrical connection of the transmission system and station equipment. This information is essential for Work Protection applications and to ensure the safe and reliable operation of the Transmission System.

- The **Integrated Voice Communications & Telephony System** ("IVCT") is designed to allow OGCC Operations to effectively manage voice communications between the OGCC and IESO, interconnected utilities, transmission connected customers, emergency services and field staff. Satellite phone systems and Hydro One’s provincial mobile radio system are also available for emergency use.
• The **Emergency Services Information System** ("ESIS") provides verified up-to-date contact numbers for all emergency response services (e.g. police, fire, ambulance, ministry of environment, gas utilities, etc.) across the Province. This system is designed to enable Hydro One staff to quickly and effectively contact emergency personnel.

2.2 **Operating Infrastructure**

Operating Infrastructure comprises the systems and telecommunications required to connect the OGCC and Back-up centre to transmission stations, to support real time field operations and to fulfill Hydro One’s obligations for real time telemetry under the Market Rules and Transmission System Code. Specifically, the Operating Infrastructure includes:

• **Gateway Systems** that connect legacy station control systems at the approximately 460 transmission switchyards to modern systems used at the OGCC and Back-up Centres and to the systems at the IESO. There are 110 gateway systems located at 37 sites, referred to as Hub Sites, across the province. The station control systems themselves, also generally referred to as Remote Terminal Units (RTUs), are considered part of the station asset and not Operating Infrastructure.

• The **Wide Area Telecommunications Network** (WAN) that provides multiple independent paths, on Hydro One’s Fibre Optic system, on third party leased telecom, and by various wireless media, to all stations that are of critical importance to the operation of the grid and its restoration following any major disturbance event. This network also carries real time data that Hydro One is obliged to provide to Transmission Connected Customers from the OGCC or Back-up Centre to local points of presence for these customers.
• The **Fault Locating Systems** which are new systems being deployed to promptly identify the location of failures on transmission circuits. This will save on costs and time for restoring circuits to service.

• The **Provincial Mobile Radio System** is the means by which both the OGCC and the field operations centres maintain continuous high reliability contact with field crews. It is designed to be reliable in the event of localized or widespread blackouts and capable of accessing all remote, and electrically noisy, locations where Hydro One field crews would be dispatched. For health, safety and operational reasons, it is essential to provide crews with an assured means of communication in case of emergency.

• **Underground Cable Monitors** which are probes that monitor the surface temperature of the cable jacket, soil temperature gradients and cathodic protection voltages in order to ensure the healthy and optimum operation of cables which are critical to the supply of large downtown load centres.

• **Geomagnetically Induced Current Monitors** which detect currents flowing through the Transmission System induced by the earth’s magnetic field during solar disturbances. These currents can disrupt protection systems and cause outages.

• **Weather Stations** to acquire location specific weather data required for determining accurate operating limits on equipment, or other key condition information of vital importance to grid operation such as accumulation of insulator contamination and ice build-up.
3.0 GRID OPERATIONS CONTROL FACILITIES

3.1 Overview

Grid Operations Control Facilities provide critical capabilities to support transmission operations at the OGCC and BUCC. These investments fund enhancements and capital sustainment of computer tools and systems to maintain equipment performance, reliability and service quality of all critical systems, and to satisfying regulatory requirements.

Computer and network systems typically require renewal every five years due to advancing technology. Grid Operations Control Facilities requiring upgrades are at end of life and are subject to increased reliability risk and maintenance costs as a result of lack of vendor support.

The Capital projects for the Grid Operations Control Facilities are provided in Table 2.
Table 2

Grid Operations Control Facilities

Capital Projects ($ Millions)

<table>
<thead>
<tr>
<th>Description</th>
<th>Historic</th>
<th>Bridge</th>
<th>Test</th>
</tr>
</thead>
<tbody>
<tr>
<td>NMS Capital Sustainment project</td>
<td>0.0</td>
<td>0.0</td>
<td>7.0</td>
</tr>
<tr>
<td>BUCC New Facility Development</td>
<td>0.0</td>
<td>0.0</td>
<td>0.0</td>
</tr>
<tr>
<td>Integrated Voice Communications and Telephony System Replacement</td>
<td>0.0</td>
<td>0.0</td>
<td>0.0</td>
</tr>
<tr>
<td>Operations Support Tools (NOMS Sustainment project)</td>
<td>0.0</td>
<td>0.0</td>
<td>0.0</td>
</tr>
<tr>
<td>Miscellaneous</td>
<td>3.7</td>
<td>3.4</td>
<td>4.3</td>
</tr>
<tr>
<td>Total</td>
<td><strong>3.7</strong></td>
<td><strong>3.4</strong></td>
<td><strong>11.3</strong></td>
</tr>
</tbody>
</table>
3.2 Description of Investments

Table 3
Grid Operations Control Facilities

Capital Projects > $3 Million in Test Year 2015 or 2016 ($ Millions)

<table>
<thead>
<tr>
<th>Ref #</th>
<th>Description</th>
<th>Cash Flow</th>
<th>Total Cost</th>
<th>Removal Cost</th>
<th>Capital Cost</th>
</tr>
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<tbody>
<tr>
<td></td>
<td></td>
<td>Test Years</td>
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<td></td>
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<td>2015</td>
<td>2016</td>
<td></td>
<td></td>
</tr>
<tr>
<td>O01</td>
<td>NMS Capital Sustainment</td>
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<td>12.6</td>
<td>0.0</td>
</tr>
<tr>
<td>O02</td>
<td>BUCC New Facility Development</td>
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<td>11.0</td>
<td>11.5</td>
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</tr>
<tr>
<td></td>
<td>Other Projects/ Programs &lt; $3M</td>
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<td>2.6</td>
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<td></td>
<td>Total Cost</td>
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<td>12.5</td>
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<td>0.0</td>
</tr>
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<tr>
<td></td>
<td>Capital Cost</td>
<td>14.2</td>
<td>12.5</td>
<td>26.7</td>
<td>0.0</td>
</tr>
</tbody>
</table>

3.3 Network Management System Capital Sustainment (ISD O01)

The NMS is the mission critical operating tool used for monitoring and control of the Hydro One Transmission System. The reliable operation of the Ontario Power System is dependent on the continued availability and high performance of the NMS.

The NMS Capital Sustainment project started in 2013 (approved in EB-2012-0031) and will continue into the bridge and test years, upgrading end of life components such as power system software, server operating system, database software and monitoring and control infrastructure hardware. This investment will maintain required levels of NMS
performance, reliability, availability and regulatory compliance for continued sustainability. It also provides for additional capacity required for Transmission System growth, opportunity to leverage new baseline functionality and ensures the NMS remains a fully supported system at both the OGCC and BUCC.

The cost for the investment is $12.6 million in 2015.

The Investment Summary Document for the NMS Capital Sustainment project is filed under Exhibit D2, Tab 2, Schedule 3.

3.4 **Network Operations BUCC New Facility Development Project (ISD O02)**

The BUCC facility is required to manage and maintain control of the Hydro One Transmission System in the event the OGCC or its computer systems are rendered unavailable and to satisfy North American Electric Reliability Corporation (NERC) compliance standards.

The BUCC facilities consist of the building, computer tools, systems and infrastructure to support the Control Room and back office Operating functions. The existing BUCC facility is more than forty years old. The design and infrastructure are no longer capable of sustaining and meeting modern control centre requirements and standards. The existing BUCC computer rooms are at design limits in terms of physical space, power supplies and environmental controls. As a result, full redundancy of all systems is not currently available and the reliability of transmission operating facilities is reduced.
This investment will fund a new BUCC building at a new location and provides for growth and expansion to accommodate existing and future requirements of the Network Operating Division. Not proceeding with this investment will result in continued risk to the BUCC facility, systems and tools and may affect the reliability of the transmission system.

The costs for the investments are $0.5 million in 2015 and $11.0 million in 2016.

The Investment Summary Document for the BUCC New Facility Development is filed under Exhibit D2, Tab 2, Schedule 3.

3.5 Integrated Voice Communications and Telephony (“IVCT”) System Replacement

The IVCT is used in 24-hour, seven day operations at the OGCC and the BUCC. This mission critical system provides effective voice communication management between the control centres and Hydro One field staff, connected customers, emergency services and the IESO. The current system was placed in-service with the inception of the OGCC in 2003. This investment is required to mitigate the risk of a system failure as it has reached end-of-life due to technological obsolescence and lack of vendor support.

The costs for this investment in the bridge and test years consist of $1.1 million in 2014 and $1.1 million in 2015.
3.6 Network Outage Management System (“NOMS”) Sustainment

NOMS is an essential tool for planning, scheduling, assessing and executing transmission and distribution equipment outages. The current version of NOMS was placed in production in October 2010 and this investment is required in 2016 in order to ensure continued vendor support. This investment will review the viability of the tool and investigate the potential options including the implementation of a version upgrade or a total replacement of NOMS. Factors to be considered will be system growth, compatibility with other Operations systems and applications and the availability of new technologies.

This investment provides for the capital sustainment of the Network Outage Management System (NOMS). Planned investments include hardware refresh, operating system upgrade and the investigation of the refresh or replacement of the application, including but not limited to: software, system components, interfaces with corporate systems and other hardware as required.

The costs for this investment in the test years consist of $0.0 million in 2015 and $1.6 million in 2016.
4.0 OPERATING INFRASTRUCTURE

4.1 Overview

Operating Infrastructure provides support for transmission operations at the OGCC and BUCC. These investments fund enhancements, expansion and end of life replacement of the physical infrastructure, beyond the walls of the OGCC and BUCC, required for the operation of the Transmission System and to maintain equipment performance, reliability and service quality of all critical systems and to satisfy regulatory requirements.

Computer and Network systems typically require upgrades every five years due to technology advancements and increased demands on functionality. As these systems reach end of life, they are replaced and/or expanded to manage increased reliability risks and maintenance costs and to provide improved functionality.

The Capital projects/programs for Operating Infrastructure are provided in Table 4.
Table 4

Operating Infrastructure

Capital Projects ($ Millions)

<table>
<thead>
<tr>
<th>Ref #</th>
<th>Description</th>
<th>Historic</th>
<th>Bridge</th>
<th>Test</th>
</tr>
</thead>
<tbody>
<tr>
<td>O03</td>
<td>Wide Area Network Outreach Program</td>
<td>-</td>
<td>-</td>
<td>-</td>
</tr>
<tr>
<td>O04</td>
<td>Station LAN Infrastructure Program</td>
<td>0.9</td>
<td>4.0</td>
<td>4.0</td>
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<tr>
<td>O05</td>
<td>Fault Locating Program</td>
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<td>0.0</td>
<td>0.0</td>
</tr>
<tr>
<td>O06</td>
<td>Grid Control Network Sustainment</td>
<td>-</td>
<td>-</td>
<td>-</td>
</tr>
<tr>
<td>O07</td>
<td>Hub Site Management Program</td>
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<td>0.0</td>
<td>0.0</td>
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<tr>
<td></td>
<td>Mobile Radio System Replacement</td>
<td>-</td>
<td>-</td>
<td>-</td>
</tr>
<tr>
<td></td>
<td>Telemetry Expansion Program</td>
<td>-</td>
<td>-</td>
<td>-</td>
</tr>
<tr>
<td></td>
<td>Underground Cable Monitoring Project</td>
<td>-</td>
<td>-</td>
<td>-</td>
</tr>
<tr>
<td></td>
<td>Wireless Transformer Station Camera Installation</td>
<td>-</td>
<td>-</td>
<td>-</td>
</tr>
<tr>
<td></td>
<td>Telecommunication Performance Improvement</td>
<td>-</td>
<td>-</td>
<td>-</td>
</tr>
<tr>
<td></td>
<td>Miscellaneous</td>
<td>-</td>
<td>-</td>
<td>-</td>
</tr>
<tr>
<td></td>
<td><strong>Total</strong></td>
<td>-</td>
<td>-</td>
<td>-</td>
</tr>
</tbody>
</table>
### 4.2 Description of Investments

#### Table 5

**Operating Infrastructure**

**Capital Projects > $3 Million in Test Year 2015 or 2016 ($ Millions)**

<table>
<thead>
<tr>
<th>Ref #</th>
<th>Description</th>
<th>Cash Flow</th>
<th>Total Cost</th>
<th>Removal Cost</th>
<th>Capital Cost</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td></td>
<td>Test Years</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td></td>
<td></td>
<td>2015</td>
<td>2016</td>
<td></td>
<td></td>
</tr>
<tr>
<td>O03</td>
<td>Wide Area Network Outreach Program</td>
<td>4.0</td>
<td>4.0</td>
<td>8.0</td>
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<tr>
<td>O04</td>
<td>Station LAN Infrastructure Program</td>
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<td>4.9</td>
<td>8.9</td>
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<td>O05</td>
<td>Fault Locating Program</td>
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<td>3.0</td>
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<td>O06</td>
<td>Grid Control Network Sustainment</td>
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<tr>
<td>O07</td>
<td>Hub Site Management Program</td>
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<td>3.0</td>
<td>5.0</td>
<td>0.0</td>
</tr>
<tr>
<td></td>
<td>Other Projects/ Programs &lt; $3M</td>
<td>8.1</td>
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<td>16.3</td>
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<td><strong>Removal Cost</strong></td>
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</tr>
<tr>
<td></td>
<td><strong>Capital Cost</strong></td>
<td>24.1</td>
<td>24.9</td>
<td>49.0</td>
<td>0.0</td>
</tr>
</tbody>
</table>
4.3 Wide Area Network (WAN) Outreach Program (ISD O03)

Hydro One requires expanded telecommunication capacity into many of its transmission stations to support: protection and control for transmission development, advanced distribution system, video surveillance for security and operating, cyber security and enterprise systems such as conferencing and mobile workforce enablement. If the capacity on Hydro One’s network is not expanded, existing and future telecom services will be displaced onto leased telecom services.

The cost for this investment is $4.0 million in 2015 and $4.0 million in 2016.

Additional detail for this program is provided in the Investment Summary Document in Exhibit D2, Tab 2, Schedule 3.

4.4 Station Local Area Network (LAN) Infrastructure Project (ISD O04)

Modern digital protection, control and monitoring devices located in a Transmission Station have the ability to be networked together. The networking of these devices provides many benefits in the form of reduced cabling costs, reduced cost for primary measuring devices or transducers, reduced design costs, and the ability to achieve business efficiencies by remote interrogation of the devices for fault locating, event analysis and asset utilization information.

This program installs a standardized LAN infrastructure, appropriate to the class of station, which incorporates Cyber Security, remote monitoring and has the capacity, or expandability, to meet all forecast needs.
The cost for this investment is $4.0 million in 2015 and $5.0 million in 2016.

Additional detail for this program is provided in the Investment Summary Document in Exhibit D2, Tab 2, Schedule 3.

4.5 Fault Location (Distance to Fault) Project (ISD O05)

This program funds facilities required to accurately compute and promptly transmit the location of transmission line failures (faults) from the line terminal stations to the OGCC. Digital protection and monitoring devices are now in place in most stations which have the ability to collect raw information that can be used to compute the fault location on transmission lines emanating from the station. Presently, information regarding a fault’s location is communicated verbally to the OGCC by protection and control staff once they have travelled to the station, interrogated the devices and performed the necessary calculations manually. This investment will allow for determination of the likely fault location in nearly real time, enable faster restoration and will result in improved efficiency and reduced cost and carbon footprint as the time spent in vehicle and helicopters searching for the fault will be greatly reduced.

The rollout of this program had to be delayed to reassess compliance with NERC Cyber Security Standards that came into effect in 2009. This resulted in changes to the functional and design requirements and the need to correct deficiencies at stations that were part of the first phase of the rollout.

The cost for this investment is $3.0 million in 2015 and $3.0 million in 2016.
Additional detail for this program is provided in the Investment Summary Document in Exhibit D2, Tab 2, Schedule 3.

4.6 Grid Control Network Sustainment Program (ISD O06)

This is a new program to manage the end-of-life replacement of Grid Control Network elements. The program ensures the ongoing reliability and performance of control of the Grid by containing the rate of loss-of-control events to acceptable rates by replacement of network equipment just before end-of-life failure rates begin increasing. Additionally, the program avoids cost increases associated with maintenance of aging and obsolete equipment.

The cost for this investment is $3.0 million in 2015 and $2.0 million in 2016.

Additional detail for this program is provided in the Investment Summary Document in Exhibit D2, Tab 2, Schedule 3.
4.7 Hub-Site Management Program (ISD O07)

This program is needed to continuously expand the gateway systems located at thirty-seven Hub-sites across the province to provide capacity for monitoring and control of new assets, stations and generators that are connected to the transmission system. As new assets are built, the additional telemetry required increases the utilization of the gateways. When a gateway approaches capacity, additional gateways and hub sites need to be added. After a period of approximately six years, the gateway boxes need to be replaced due to obsolescence. The Hub-site management program continually manages these factors to ensure the capacity and reliability of the grid control infrastructure is in place to meet the needs of the development, load connection and transmission generation connection programs.

This program was introduced in 2007; about four years after most of the gateways went into service for the creation of the OGCC. From 2007 to 2009 many gateway systems were upgraded to larger systems to address full capacity utilization problems of many systems. By 2011, grid expansion and generation connections had pushed six Hub-sites beyond design limits. The plan to begin addressing the need for hub site infrastructure improvements has been delayed due to:

- a review of the overall protection and control (P&C) architecture strategy and reliability requirements;
- to ensure alignment with evolving Cyber Security standards;
- to ensure compatibility with the Advanced Distribution System (“ADS”) interface requirements; and
- to negotiate a more optimum arrangement for telemetry provision to the IESO.

The cost for this investment is $2.0 million in 2015 and $3.0 million in 2016.
Additional detail for this program is provided in the Investment Summary Document in Exhibit D2, Tab 2, Schedule 3.

4.8 Provincial Mobile Radio System Replacement

The Provincial Mobile Radio System (PMRS) is the communication medium used for the OGCC and field operations centre to maintain effective communication with field crews. This project will refresh end-of-life PMRS base stations. The PMRS base station radio equipment is reaching end of life and needs to be replaced over the next five years. A study was underway in 2013 to examine possible replacement technologies and integration strategies. Rollout of replacement radios is planned to ramp up in 2015 and reach full project replacement rates in 2017. Completion is planned by 2018. The cost for this investment is $4.5 million total for 2015 and 2016.

4.9 Telemetry Expansion Program

The key deliverables of this program are the splitting of critical bundled alarms and the addition of more detailed monitoring of transmission equipment. This will enable OGCC to make an immediate determination of the cause of an alarm and the appropriate response. This will eliminate the need for unnecessarily removing equipment from service and urgent costly field staff dispatches to investigate the cause of the alarms. This program is required to eliminate unnecessary equipment outages, make more efficient use of field staff, better manage aging assets and improve grid reliability. The removal of any piece of equipment from service can place load supply at risk and may result in the delay of other outages required to complete sustainment or development work. Delay or cancellation of outages can be very disruptive to the execution of work affecting both schedules and costs.
The total cost for this investment is $1.975 million total for 2015 and 2016.

5.0 UNDERGROUND CABLE MONITORING PROJECT

The Underground Cable Monitoring Project is the installation of probes to monitor the condition of the high voltage underground cables supplying downtown Toronto. These monitors will help ensure the health of the cables and cable jackets, detect and initiate an alarm annunciation at the OGCC in the event of a puncturing or deterioration of the cable insulation jacket. This will increase optimal operation of the Hydro One underground plants.

The cost for this investment is $0.7 million total for 2015 and 2016.

5.1 Wireless Transformer Station Camera Installation Project

This project will fund the development of a wireless camera standard to be used by OGCC to view remote transformer station status and provide operational awareness. In recent years Hydro One has seen a major increase in the security breach of transformer stations and theft of copper. Copper theft can result in high replacement costs, power quality issues, the removal of transmission equipment from service jeopardizing supply to customers and present a safety issue to electric utility staff and the public. The installation of wireless cameras will provide remote station security viewing capability prior to dispatching security staff.

The cost of this investment is $3.0 million total for 2015 and 2016.
5.2 Telecommunication Performance Improvement

This investment will fund improvements to resolve reliability and performance problems with third party telecommunications Hydro One uses to control and monitor some remote Transmission Stations. There are a number of stations where improvements to reliability is required due to recurring “last mile” telecom problems. Telecommunication failures can result in the removal from service of high voltage equipment due to the lack of protective relaying. This program addresses those issues by providing an alternate independent path or by addressing infrastructure problems which allow common mode failure issues.

The cost of this investment is $1 million total for 2015 and 2016.
SUMMARY OF COMMON CORPORATE COSTS CAPITAL

Capital expenditures under the Common Corporate Costs program support the Sustainment, Development, and Operations work programs of Hydro One Networks Inc. As such, they consist of assets that are largely shared by both the Transmission and Distribution businesses. Common Corporate Costs include information technology (IT) installations such as applications software and computer equipment, buildings, office equipment, transportation and work equipment (“T&WE”), tools, and service equipment.

Table 1 provides a summary of the Transmission portion of the Common Corporate Costs Capital over the Historic, Bridge and Test years.

<table>
<thead>
<tr>
<th>Description</th>
<th>Historic</th>
<th>Bridge</th>
<th>Test</th>
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<td>Information Technology</td>
<td>32.9</td>
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<tr>
<td>Facilities &amp; Real Estate</td>
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<td>11.6</td>
<td>7.4</td>
</tr>
<tr>
<td>Transport &amp; Work, and Service Equipment</td>
<td>13.1</td>
<td>14.6</td>
<td>18.8</td>
</tr>
<tr>
<td>Other (including Distribution Line Loss and CDM)</td>
<td>(1.5)</td>
<td>(14.7)</td>
<td>0.0</td>
</tr>
<tr>
<td>Total</td>
<td>52.3</td>
<td>42.1</td>
<td>49.1</td>
</tr>
</tbody>
</table>

Exhibit C1, Tab 6, Schedule 3 outlines the appropriate cost drivers that have been utilized to derive the Transmission allocation of this capital.
The level of spending in Information Technology capital for the test years is consistent with the levels of spending in the historical and bridge years. Exhibit D1, Tab 4, Schedule 2 details the capital requirements for Information Technology.

The Cornerstone initiative has been a major business transformation initiative in the historical and bridge years; it deals with end of life replacement of enterprise systems and also provides a platform for further effectiveness and efficiency gains at Hydro One. The capital spending for the Cornerstone project will be completed in 2014, which includes the CIS system that was placed in service in 2013.

The primary driver for the spending in Facilities and Real Estate is the need to provide suitable space to accommodate staff and equipment required to handle the growth in Sustaining, Development and Operations work programs over the test years. Exhibit D1, Tab 4, Schedule 3 details the capital requirements for Facilities and Real Estate.

The decrease in Transportation & Work Equipment spending in 2015 from the bridge year is related to the stabilization in work programs for the Electro-Forestry Journey Person Program, the Forestry and Provincial Lines Apprenticeship Program and the helicopter replacement schedule. Overall spending in the test years rises slightly with a funding increase in 2016 driven by the helicopter replacement schedule. Service Equipment spending decreases from 2014 to 2016 as capital requirements for replacing specialized equipment decreases and Health, Safety and Environment costs for automated external defibrillators also decreases. Exhibit D1, Tab 4, Schedule 4 details the capital requirements for T&WE and Service Equipment.
# STATEMENT OF UTILITY RATE BASE

HYDRO ONE NETWORKS INC.
TRANSMISSION
Statement of Utility Rate Base
Test Years (2015 and 2016)
Year Ending December 31
($ Millions)

<table>
<thead>
<tr>
<th>Line No.</th>
<th>Particulars</th>
<th>2015</th>
<th>2016</th>
</tr>
</thead>
<tbody>
<tr>
<td>1</td>
<td>Gross plant at cost</td>
<td>$15,665.6</td>
<td>$16,353.0</td>
</tr>
<tr>
<td>2</td>
<td>Less: accumulated depreciation</td>
<td>(5,515.7)</td>
<td>(5,819.3)</td>
</tr>
<tr>
<td>3</td>
<td>Net plant in service</td>
<td>$10,149.9</td>
<td>$10,533.7</td>
</tr>
<tr>
<td>4</td>
<td>Construction work in progress</td>
<td>0.0</td>
<td>0.0</td>
</tr>
<tr>
<td>5</td>
<td>Net utility plant</td>
<td>$10,149.9</td>
<td>$10,533.7</td>
</tr>
<tr>
<td>4</td>
<td>Cash working capital</td>
<td>$12.9</td>
<td>$10.3</td>
</tr>
<tr>
<td>5</td>
<td>Materials and Supplies Inventory</td>
<td>13.7</td>
<td>14.0</td>
</tr>
<tr>
<td>6</td>
<td>Total working capital</td>
<td>$26.6</td>
<td>$24.2</td>
</tr>
<tr>
<td>7</td>
<td>Total rate base</td>
<td>$10,176.5</td>
<td>$10,558.0</td>
</tr>
</tbody>
</table>
REVENUE REQUIREMENT

1.0  SUMMARY OF REVENUE REQUIREMENT

Hydro One Transmission has followed standard regulatory practice in the calculation of revenue requirement as follows:

<table>
<thead>
<tr>
<th>Particulars</th>
<th>2015</th>
<th>2016</th>
<th>Reference</th>
</tr>
</thead>
<tbody>
<tr>
<td>OM&amp;A</td>
<td>452.0</td>
<td>457.4</td>
<td>C1, Tab 2, Schedule 1</td>
</tr>
<tr>
<td>Depreciation</td>
<td>394.2</td>
<td>404.0</td>
<td>C1, Tab 7, Schedule 1</td>
</tr>
<tr>
<td>Income Taxes</td>
<td>71.8</td>
<td>82.8</td>
<td>C1, Tab 8, Schedule 1</td>
</tr>
<tr>
<td>Cost of Capital1</td>
<td>699.3</td>
<td>744.9</td>
<td>B1, Tab 1, Schedule 1</td>
</tr>
<tr>
<td><strong>Total Revenue Requirement</strong></td>
<td><strong>1,617.1</strong></td>
<td><strong>1,689.2</strong></td>
<td>E2, Tab 1, Schedule 1</td>
</tr>
</tbody>
</table>

1 Includes Interest Capitalized recovery on the Niagara Reinforcement Project (2015 - $5.0 million and 2016 - $5.0 million).

The resultant revenue requirement of $1,617.1 million for 2015 and $1,689.2 million for 2016 are the amounts required by Hydro One Transmission to safely address customer service and system reliability needs at the lowest practical cost.

2.0  CALCULATION OF REVENUE REQUIREMENT

The details of the OM&A and Depreciation components of the revenue requirement are as follows:
2.1 OM&A Expense

<table>
<thead>
<tr>
<th></th>
<th>2015</th>
<th>2016</th>
</tr>
</thead>
<tbody>
<tr>
<td>Sustaining</td>
<td>238.7</td>
<td>241.1</td>
</tr>
<tr>
<td>Development</td>
<td>12.9</td>
<td>13.4</td>
</tr>
<tr>
<td>Operations</td>
<td>58.5</td>
<td>59.1</td>
</tr>
<tr>
<td>Customer Care</td>
<td>5.5</td>
<td>5.5</td>
</tr>
<tr>
<td>Shared Services and Other Costs</td>
<td>70.2</td>
<td>71.3</td>
</tr>
<tr>
<td>Taxes Other Than Income Tax</td>
<td>66.3</td>
<td>67.0</td>
</tr>
<tr>
<td><strong>Total OM&amp;A</strong></td>
<td>452.1</td>
<td>457.5</td>
</tr>
</tbody>
</table>

2.2 Depreciation Expense

<table>
<thead>
<tr>
<th></th>
<th>2015</th>
<th>2016</th>
</tr>
</thead>
<tbody>
<tr>
<td>Depreciation</td>
<td>387.7</td>
<td>397.9</td>
</tr>
<tr>
<td>Amortization</td>
<td>6.5</td>
<td>6.1</td>
</tr>
<tr>
<td><strong>Total Expense</strong></td>
<td>394.2</td>
<td>404.0</td>
</tr>
</tbody>
</table>

3.0 RATES REVENUE REQUIREMENT - COMPARISON OF YEAR 2014 TO YEAR 2015

Table 2 compares, by element, the 2014 rates revenue requirement (as per EB-2012-0031) against the 2015 proposed rates revenue requirement.
### Table 2

**Comparison of Rates Revenue Requirements: Board Approved 2014 vs. 2015**

**($Millions)**

<table>
<thead>
<tr>
<th>Line no.</th>
<th>Description</th>
<th>Year 2014</th>
<th>Year 2015</th>
<th>Difference</th>
</tr>
</thead>
<tbody>
<tr>
<td>1</td>
<td>OM&amp;A</td>
<td>449.7</td>
<td>452.1</td>
<td>2.3</td>
</tr>
<tr>
<td>2</td>
<td>Depreciation</td>
<td>371.5</td>
<td>394.2</td>
<td>22.7</td>
</tr>
<tr>
<td>3</td>
<td>Capital Taxes</td>
<td>-</td>
<td>-</td>
<td>-</td>
</tr>
<tr>
<td>4</td>
<td>Income Taxes</td>
<td>54.5</td>
<td>71.8</td>
<td>17.2</td>
</tr>
<tr>
<td>5</td>
<td>Cost of Capital (^1)</td>
<td>659.6</td>
<td>699.3</td>
<td>39.6</td>
</tr>
<tr>
<td></td>
<td><strong>Total Revenue Requirement</strong></td>
<td><strong>1,535.3</strong></td>
<td><strong>1,617.1</strong></td>
<td><strong>81.8</strong></td>
</tr>
<tr>
<td>6</td>
<td>Deduct External Revenues (^2)</td>
<td>(36.6)</td>
<td>(28.4)</td>
<td>8.2</td>
</tr>
<tr>
<td></td>
<td><strong>Revenue Requirement less External Revenues</strong></td>
<td><strong>1,498.7</strong></td>
<td><strong>1,588.7</strong></td>
<td><strong>90.0</strong></td>
</tr>
<tr>
<td>7</td>
<td>Deduct Export Revenue Credit (^3)</td>
<td>(34.1)</td>
<td>(33.4)</td>
<td>0.7</td>
</tr>
<tr>
<td>8</td>
<td>Deduct Regulatory Accounts Disposition (^4)</td>
<td>(30.3)</td>
<td>(17.6)</td>
<td>12.6</td>
</tr>
<tr>
<td>9</td>
<td>Add Low Voltage Switch Gear (^5)</td>
<td>12.1</td>
<td>13.2</td>
<td>1.2</td>
</tr>
<tr>
<td></td>
<td><strong>Rates Revenue Requirement</strong></td>
<td><strong>1,446.4</strong></td>
<td><strong>1,550.9</strong></td>
<td><strong>104.5</strong></td>
</tr>
</tbody>
</table>

\(^1\) Includes recovery of Interest Capitalized on the Niagara Reinforcement Project.

\(^2\) External revenues addressed in Exhibit E1, Tab 2, Schedule 1.

\(^3\) Export revenue is addressed in Exhibit H1, Tab 5, Schedule 1.

\(^4\) See Exhibit F1, Tab 1, Schedule 3 for further details.

\(^5\) Low Voltage Switch Gear is addressed in Exhibit G1, Tab 4, Schedule 1.

There are a number of key operational and financial factors contributing to the increased rates revenue requirement that have an impact across the cost components in Table 2. The increase in total rates revenue requirement is largely attributable to the impact of rate base growth reflected in the increase in depreciation, as well as higher cost of debt and allowed ROE. Also contributing to the difference is higher income taxes, lower external revenues, and reduced regulatory account disposition.
Table 3 illustrates the value of the key impacts on the increase in the rates revenue requirement.

<table>
<thead>
<tr>
<th>Description</th>
<th>Amount ($M)</th>
</tr>
</thead>
<tbody>
<tr>
<td>Increase in OM&amp;A</td>
<td>2.3</td>
</tr>
<tr>
<td>Rate Base Growth</td>
<td>49.5</td>
</tr>
<tr>
<td>Increase in Cost of Debt</td>
<td>9.2</td>
</tr>
<tr>
<td>Increase in Cost of Equity</td>
<td>14.4</td>
</tr>
<tr>
<td>Tax - timing differences and other</td>
<td>6.4</td>
</tr>
<tr>
<td>External Revenue</td>
<td>8.2</td>
</tr>
<tr>
<td>Increase in Export Revenue Credit</td>
<td>0.7</td>
</tr>
<tr>
<td>Increase in Regulatory Accounts Disposition</td>
<td>12.6</td>
</tr>
<tr>
<td>Increase in Low Voltage Switch Gear</td>
<td>1.2</td>
</tr>
<tr>
<td>Other</td>
<td>0.1</td>
</tr>
<tr>
<td><strong>Total Change</strong></td>
<td><strong>104.5</strong></td>
</tr>
</tbody>
</table>

4.0 RATES REVENUE REQUIREMENT - COMPARISON OF YEAR 2015 TO YEAR 2016

Table 4 compares, by element, the 2015 rates revenue requirement against the 2016 rates revenue requirement.

1 2014 Amounts as per Hydro One Transmission’s 2014 Revenue Requirement and Charge Determinants for EB-2012-0031 and EB-2011-0268.
Table 4
Comparison of Rates Revenue Requirements 2015 vs. 2016 ($ Millions)

<table>
<thead>
<tr>
<th>Line no.</th>
<th>Description</th>
<th>Year 2015</th>
<th>Year 2016</th>
<th>Difference</th>
</tr>
</thead>
<tbody>
<tr>
<td>1</td>
<td>OM&amp;A</td>
<td>452.0</td>
<td>457.4</td>
<td>5.4</td>
</tr>
<tr>
<td>2</td>
<td>Depreciation</td>
<td>394.2</td>
<td>404.0</td>
<td>9.9</td>
</tr>
<tr>
<td>3</td>
<td>Income Taxes</td>
<td>71.8</td>
<td>82.8</td>
<td>11.1</td>
</tr>
<tr>
<td>4</td>
<td>Cost of Capital(^1)</td>
<td>699.3</td>
<td>744.9</td>
<td>45.7</td>
</tr>
<tr>
<td></td>
<td><strong>Total Revenue Requirement</strong></td>
<td><strong>1,617.1</strong></td>
<td><strong>1,689.2</strong></td>
<td><strong>72.1</strong></td>
</tr>
<tr>
<td>5</td>
<td>Deduct External Revenues(^2)</td>
<td>(28.4)</td>
<td>(28.8)</td>
<td>(0.4)</td>
</tr>
<tr>
<td></td>
<td><strong>Revenue Requirement less</strong></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td></td>
<td><strong>External Revenues</strong></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>6</td>
<td>Deduct Export Revenue Credit(^3)</td>
<td>(33.4)</td>
<td>(34.3)</td>
<td>(0.9)</td>
</tr>
<tr>
<td>7</td>
<td>Deduct Regulatory Accounts</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td></td>
<td>Disposition(^4)</td>
<td>(17.6)</td>
<td>(17.6)</td>
<td>-</td>
</tr>
<tr>
<td>8</td>
<td>Add Low Voltage Switch Gear(^5)</td>
<td>13.2</td>
<td>13.9</td>
<td>0.6</td>
</tr>
<tr>
<td></td>
<td><strong>Rates Revenue Requirement</strong></td>
<td><strong>1,550.9</strong></td>
<td><strong>1,622.0</strong></td>
<td><strong>71.4</strong></td>
</tr>
</tbody>
</table>

\(^1\) Includes recovery of Interest Capitalized on the Niagara Reinforcement Project.
\(^2\) External revenues addressed in Exhibit E1, Tab 2, Schedule 1.
\(^3\) Export revenue is addressed in Exhibit H1, Tab 5, Schedule 1.
\(^4\) See Exhibit F1, Tab 1, Schedule 3 for further details.
\(^5\) Low Voltage Switch Gear is addressed in Exhibit G1, Tab 4, Schedule 1.

The increase in 2016 rates revenue requirement is primarily due to the increase in core rate base as reflected in the increase in return on capital and depreciation. Other contributing factors include higher income taxes and slightly higher OM&A work program requirements.

Table 5 illustrates the value of the key impacts on the movement in the rates revenue requirement.
## TABLE 5

**COMPONENTS OF CHANGE TO RATES REVENUE REQUIREMENT:**

2015 vs. 2016

<table>
<thead>
<tr>
<th>Description</th>
<th>Amount ($M)</th>
</tr>
</thead>
<tbody>
<tr>
<td>Increase in OM&amp;A</td>
<td>5.4</td>
</tr>
<tr>
<td>Rate Base Growth</td>
<td>45.6</td>
</tr>
<tr>
<td>Increase in Cost of Debt</td>
<td>9.0</td>
</tr>
<tr>
<td>Increase in Cost of Equity</td>
<td>10.6</td>
</tr>
<tr>
<td>Tax - timing differences and other</td>
<td>1.4</td>
</tr>
<tr>
<td>External Revenue</td>
<td>(0.4)</td>
</tr>
<tr>
<td>Increase in Export Revenue Credit</td>
<td>(0.9)</td>
</tr>
<tr>
<td>Increase in Regulatory Accounts Disposition</td>
<td>-</td>
</tr>
<tr>
<td>Increase in Low Voltage Switch Gear</td>
<td>0.6</td>
</tr>
<tr>
<td>Other</td>
<td>0.1</td>
</tr>
<tr>
<td><strong>Total change</strong></td>
<td><strong>71.4</strong></td>
</tr>
</tbody>
</table>

1 Net of External Revenue

Exhibit G1, Tab 1, Schedule 1 provides information on how the rates revenue requirements will be recovered through rates.
EXTERNAL REVENUES

1.0  STRATEGY

Hydro One Transmission’s strategy is to focus on core work, while continuing to be responsive to external customer work requests where Hydro One Transmission has available resources and/or assets to accommodate the request.

External revenues earned through the provision of services to third parties are forecast to be $28.4 million in 2015 and $28.8 million in 2016 and account for approximately 1.8% of Hydro One Transmission revenues. These external revenues are used to offset the revenue requirement from Hydro One Transmission tariffs and thereby reduce the required revenue to be collected from transmission ratepayers.

2.0  COSTING AND PRICING

The costing of external work is determined on the basis of cost causality, with estimates calculated in the same way as internal work estimates, using the standard labour rates, equipment rates, material surcharge, and overhead rates (see Exhibit C1, Tab 5, Schedule 1 for a description of costing of work). An appropriate margin is added to cover, at a minimum, market level pricing in order to ensure there is an overall benefit for the transmission ratepayers.

This exhibit identifies the revenues for external work. The associated costs for this work are described in Exhibit C1, Tab 3, Schedule 6.
3.0 DESCRIPTION

<table>
<thead>
<tr>
<th></th>
<th></th>
<th></th>
<th></th>
<th></th>
<th></th>
<th></th>
</tr>
</thead>
<tbody>
<tr>
<td>Secondary Land Use</td>
<td>20.8</td>
<td>22.0</td>
<td>21.1</td>
<td>14.1</td>
<td>14.3</td>
<td>14.5</td>
</tr>
<tr>
<td>Station Maintenance</td>
<td>11.4</td>
<td>13.9</td>
<td>12.6</td>
<td>7.1</td>
<td>7.2</td>
<td>7.3</td>
</tr>
<tr>
<td>Engineering &amp; Project Delivery</td>
<td>4.8</td>
<td>2.3</td>
<td>2.2</td>
<td>0.2</td>
<td>0</td>
<td>0</td>
</tr>
<tr>
<td>Other External Revenues</td>
<td>4.6</td>
<td>3.8</td>
<td>10.7</td>
<td>6.9</td>
<td>6.9</td>
<td>7.0</td>
</tr>
<tr>
<td><strong>Totals</strong></td>
<td><strong>41.6</strong></td>
<td><strong>42.0</strong></td>
<td><strong>46.6</strong></td>
<td><strong>28.3</strong></td>
<td><strong>28.4</strong></td>
<td><strong>28.8</strong></td>
</tr>
</tbody>
</table>

3.1 Secondary Land Use

Hydro One Transmission manages the Provincial Secondary Land Use Program (“PSLUP”) on behalf of the Province, to whom Hydro One Transmission’s transmission corridor lands were transferred under Bill 58 on December 31, 2002. The program focuses on licensing and leasing the transmission corridor lands to external parties for “secondary” land use purposes that are compatible with Hydro One Transmission’s primary transmission business operations. Typical uses include parking lots, municipal roadways, parks and trails, agricultural areas, water mains and other municipal infrastructure occupations, as well as public transit parking lots and station operations. The PSLUP revenue stream is generated by charging land rentals to external parties for new license and lease occupations and subsequent agreement renewals, as well as lump sum consideration for easements granted (e.g., water mains) and operational land sales completed (e.g., roadway).
Under Bill 58 provisions (An Act to amend certain statutes in relation to the energy sector, c.1, S.O. 2002) and subsequently negotiated arrangements, all expiring corridor PSLUP agreements were transferred to the Province as of December 31, 2002. Remaining unexpired corridor agreements and associated revenue streams are retained by Hydro One until such time as these agreements expire. Upon expiration, the previously retained agreements and revenue streams by Hydro One are then also transferred to the province under the PSLUP.

Notwithstanding this transfer, Hydro One Transmission has provided front-line delivery services for the PSLUP on behalf of the Province since 2002. Under arrangements made on April 1, 2005, Hydro One Transmission was granted the right under agreement to continue delivery of the program through March 31, 2010. This agreement was extended for another five (5) years and is scheduled to expire on March 31, 2015. Hydro One Transmission anticipates that this agreement will be renewed or extended. The arrangements set out in the agreement include Hydro One Transmission’s retention of PSLUP revenues for unexpired agreements until their expiry, as well as a results-based compensation model involving the sharing of revenues between Hydro One Transmission and the Province for new PSLUP agreements and for renewals of expired agreements which were previously transferred to the Province. Hydro One also manages a small portion of secondary land use revenue that does not fall under current PSLUP arrangements.

As a result, responsibility for the management and re-negotiation (as required) of all existing secondary land use agreements (including those previously transferred to the Province under the corridor land transfer arrangements) now rests with Hydro One Transmission. Hydro One Transmission will continue promoting and negotiating all new secondary land use business opportunities, where these are consistent with Hydro One Transmission’s short and longer-term operational requirements.
The Secondary Land Use Revenue levels are forecasted to be $14.3 million in 2015 and $14.5 million in 2016. Historical figures in years 2011 to 2013 are higher due to unbudgeted one-time transactions involving easement grants (e.g. water mains) and operational land sales (e.g. roadways).

3.2 Station Maintenance

Revenues from external work in the Station Services segment include specialized activities similar to those performed internally for Hydro One Transmission. These activities include repairing electrical equipment (such as transformers, breakers and switches), specialty machining (spindles), protective relay installation, maintenance and calibration, coordinating services to reconnect modified systems to the network, as well as providing meter services and emergency services. Customers seek out station services skills resident within Hydro One Transmission, requiring highly specialized staff able to perform work on a variety of high voltage equipment in a variety of work settings (such as nuclear environments). Work is performed according to commercially negotiated contracts which reflect market level pricing.

Hydro One Transmission provides support to the external market place in areas which are related to the Company’s transmission business. This work is primarily tied to support Ontario’s key generation suppliers: Bruce Power LLP, Ontario Power Generation Inc. and Siemens Westinghouse Inc. in support of Ontario Power Generation Inc.

As can be seen in Table 1, this segment of external revenue is expected to decrease in 2014 through to 2016, primarily due to the expected shift in resources to Hydro One Transmission’s growing work programs.
3.3 Engineering and Project Delivery

Hydro One Transmission’s Engineering & Project Delivery activities continue to focus on internal work supporting the growing transmission work program, while striving to reduce external work to a minimal level. This segment of external revenue is derived from upgrading revenue meters at various sites per IESO requirements.

The 2014 amount of $0.2 million reflects the lower volume of activities related to revenue metering installations pursuant to the IESO requirements. This program will be completed in 2014.

3.4 Other External Revenues

<table>
<thead>
<tr>
<th>Other External Revenues</th>
<th>2011 Historic</th>
<th>2012 Historic</th>
<th>2013 Historic</th>
<th>2014 Bridge</th>
<th>2015 Test</th>
<th>2016 Test</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>4.6</td>
<td>3.8</td>
<td>10.7</td>
<td>6.9</td>
<td>6.9</td>
<td>7.0</td>
</tr>
</tbody>
</table>

Other external revenues set out in Table 2 include royalties that Hydro One Transmission receives under the current outsourcing agreement with Inergi LP, details of which are provided in Exhibit C1, Tab 3, Schedule 2. They also include revenues from providing telecommunications services to Ontario Hydro successor companies (such as lease of fiber), revenues from special transmission planning studies, customer shortfall payments (e.g. true-ups, temporary bypass), and other miscellaneous external revenues. These include a transfer price charge to Telecom and Remotes described in Exhibit C1, Tab 6, Schedule 3. In 2015 and 2016, forecasted revenues include $4.0 million each year for the lease of idle transmission lines.
REGULATORY ACCOUNTS

1.0 INTRODUCTION

The purpose of this evidence is to provide a description of Hydro One Transmission’s Regulatory Accounts.

All of the Regulatory Accounts reported by Hydro One Transmission have been established consistent with the Board’s requirements as set out in the Accounting Procedures Handbook, subsequent Board direction, or as per specific requests initiated by Hydro One Transmission.

Hydro One Transmission’s outstanding deferral and variance accounts balances are summarized in Table 1 below:

<table>
<thead>
<tr>
<th>Description</th>
<th>Balance as at Dec 31, 2012</th>
<th>Balance as at Dec. 31, 2013</th>
<th>Balance as at Dec. 31, 2014 (Forecast)</th>
</tr>
</thead>
<tbody>
<tr>
<td>Total Regulatory Accounts</td>
<td>(52.8)</td>
<td>(67.4)</td>
<td>(36.1)</td>
</tr>
</tbody>
</table>

The forecast interest for 2014 is calculated by applying simple interest on the December 31, 2013 year-end principal balances using the forecast bankers’ acceptance-3 month rate (1.20%) plus 0.25% spread as prescribed by the Board. Simple interest is applied to the monthly opening principal balance in this account according to the Board prescribed
interest rate. Moreover, the balance includes the disposition approved by the Board in EB-2012-0031.

Information on each account and its balance is described in Section 2.0 and Section 3.0 of this exhibit. Detail on regulatory accounts requests is discussed in Exhibit F1, Tab 1, Schedule 2. Detail on the disposition of the account balances is discussed in Exhibit F1, Tab 1, Schedule 3. Further details on deferral and variance accounts are provided in:

- Exhibit F2, Tab 1, Schedule 1: Regulatory Accounts for Approval
- Exhibit F2, Tab 1, Schedule 2: Planned Disposition of Regulatory Accounts - Schedule of Annual Recoveries
- Exhibit F2, Tab 1, Schedule 3: Continuity Schedule Regulatory Accounts

2.0 REGULATORY ACCOUNTS REQUESTED FOR APPROVAL

The Board’s decision on Hydro One’s Transmission Rates for 2013 and 2014 (EB-2012-0031) approved or required the establishment or continuance of certain regulatory accounts. Table 2 below, provides a list of the Transmission Regulatory Account balances requested for approval and disposition as part of 2015 and 2016 Transmission Rates.
Table 2

Transmission

Regulatory Accounts Requested for Approval ($ Millions)

<table>
<thead>
<tr>
<th></th>
<th></th>
<th></th>
<th></th>
<th></th>
</tr>
</thead>
<tbody>
<tr>
<td>Excess Export Service Revenue</td>
<td>2405</td>
<td>(31.8)</td>
<td>(41.9)</td>
<td>(23.5)</td>
</tr>
<tr>
<td>External Secondary Land Use Revenue</td>
<td>2405</td>
<td>(24.4)</td>
<td>(32.8)</td>
<td>(18.5)</td>
</tr>
<tr>
<td>External Station Maintenance, E&amp;CS Revenue and Other External Revenue</td>
<td>2405</td>
<td>(5.0)</td>
<td>(6.4)</td>
<td>(1.3)</td>
</tr>
<tr>
<td>Tax Rate Changes</td>
<td>1592</td>
<td>(3.5)</td>
<td>(3.6)</td>
<td>0.8</td>
</tr>
<tr>
<td>Rights Payments</td>
<td>2405</td>
<td>2.7</td>
<td>(3.6)</td>
<td>(1.9)</td>
</tr>
<tr>
<td>Pension Costs Differential</td>
<td>2405</td>
<td>14.7</td>
<td>20.8</td>
<td>8.2</td>
</tr>
<tr>
<td>Long Term Future Corridor</td>
<td>1508</td>
<td>0.0</td>
<td>0.1</td>
<td>0.1</td>
</tr>
<tr>
<td>Total Regulatory Accounts for Disposition</td>
<td></td>
<td>(52.8)</td>
<td>(67.4)</td>
<td>(36.1)</td>
</tr>
</tbody>
</table>

2.1 Excess Export Service Revenue

This variance account was initially created as a result of the Board’s decision of May 28, 2009 (EB-2008-0272). In its EB 2012-0031 decisions, the OEB approved continuance of this account. The Board requested that Hydro One Transmission continue to capture any differences between forecast export service revenue approved by the Board as part of 2013 and 2014 Transmission Rates and the actual export service revenue. As part of its decision, the Board ordered that the Export Transmission Services (ETS) rate be held at $2/MWh and approved the Hydro One Transmission forecast at $27.0 million and $34.1 million in revenue for both 2013 and 2014 respectively. The balance in this account is reported to the Board on a quarterly basis, consistent with the Board's Reporting and Record Keeping Requirements.
Included in the balance submitted for approval is interest forecast through to December 31, 2014 to reflect carrying charges anticipated through to the proposed implementation date, reduced by the $19.0 million balance approved by the Board for disposition in 2014 as part of the EB-2012-0031 decision. This will result in a forecast liability account balance of $23.5 million at the end of the bridge year 2014.

2.2 External Secondary Land Use Revenue

This variance account was created as a result of the Board’s decision of May 28, 2009 (EB-2008-0272). The Board approved continuance of the account in its decision of EB-EB-2012-0031 requesting that Hydro One Transmission maintain a variance account to capture any difference between the $13.2 million of forecast external secondary land use revenues approved by the Board, for each test year, as part of 2013 and 2014 Transmission Rates, and the actual secondary land use revenues for each of these years.

As at December 31, 2013, Hydro One Transmission had an excess external secondary land use revenue balance of $32.8 million, inclusive of accrued interest. This account is reported to the Board on a quarterly basis consistent with the Board's Reporting and Record Keeping Requirements.

Included in the balance submitted for approval is interest forecast through to December 31, 2014 to reflect carrying charges anticipated through to the proposed implementation date, reduced by the $14.6 million balance approved by the Board for disposition in 2014 as part of the EB-2012-0031 decision. This will result in a forecast liability account balance of $18.5 million at the end of the test year 2014.
2.3 External Station Maintenance, E&CS Revenue and Other External Revenue Account

This variance account was created as a result of the Board’s decision of May 28, 2009 (EB-2008-0272). The Board approved continuance of the account in its decision of EB-EB-2012-0031. The Board requested that Hydro One Transmission continue to capture any differences between the Board approved and actual net external station maintenance, E&CS revenue and Other external revenue. As a result of the settlement agreement approved by the Board in EB-2013-0031, Hydro One expanded the scope of this account to capture the difference between forecast net other revenues and actual net other revenues received.

As at December 31, 2013, Hydro One Transmission had excess external station maintenance, engineering and construction services and other external net revenues of $6.4 million, inclusive of interest accrued. The balance in this account is reported to the Board on a quarterly basis consistent with the Board's Reporting and Record Keeping Requirements.

Included in the balance submitted for approval is interest forecast through to December 31, 2014 to reflect carrying charges anticipated through to the proposed implementation date, reduced by the $5.2 million balance approved by the Board for disposition in 2014 as part of the EB-2012-0031 decision. This will result in a forecast liability account balance of $1.3 million at the end of the test year 2014.

2.4 Tax Rate Changes

This variance account was created as a result of the Board’s decision of August 16, 2007 (EB-2006-0501). The Board approved continuance of the account in its decision of EB-
EB-2012-0031. The variance account captures the tax impact to Hydro One Transmission of:

- differences that result from a legislative or regulatory change to the tax rates or rules; and
- differences that result from a change in, or a disclosure of, a new assessment or administrative policy that is published in the public tax administration or interpretation bulletins by relevant federal or provincial tax authorities.

Specifically, relative to this filing, in 2012, $0.8 million of under-collections from customers were recognized as a result of the difference between the actual effective tax rate (26.50%) and the rate incorporated in approved rates (26.25%). In 2013 the effective and Board-approved tax rates were equal.

This account is reported to the Board on a quarterly basis consistent with the Board's Reporting and Record Keeping Requirements.

As at December 31, 2013, Hydro One Transmission has recognized a liability balance of $3.6 million, inclusive of interest accrued.

Included in the balance submitted for approval is interest forecast through to December 31, 2014 to reflect carrying charges anticipated through to the proposed implementation date, reduced by the $4.3 million balance approved by the Board for disposition in 2014 as part of the EB-2012-0031 decision. This will result in a forecast asset account balance of $0.8 million at the end of the test year 2014.

**2.5 Rights Payments**

This account was established based on the Board’s decision on Hydro One’s Transmission Rates for 2011 and 2012 (EB-2010-0002) and the Board approved continuance of the account in its decision of EB-2012-0031. The Board requested that
Hydro One Transmission use a variance account to capture the difference between the forecast $4.5 million approved by the Board for both test years as part of 2013 and 2014 Transmission Rates and the actual Rights Payments. This account is reported to the Board on a quarterly basis consistent with the Board's Reporting and Record Keeping Requirements.

As at December 31, 2013, Hydro One Transmission has recorded a liability balance of $3.6 million, inclusive of interest accrued.

Included in the balance submitted for approval is interest forecast through to December 31, 2014 to reflect carrying charges anticipated through to the proposed implementation date, reduced by the $1.8 million balance approved by the Board for disposition in 2014 as part of the EB-2012-0031 decision. This will result in a forecast liability account balance of $1.9 million at the end of the test year 2014.

2.6 Pension Costs Differential

This account tracks the difference between the OM&A pension cost estimates based on actuarial assessments used for Hydro One’s Proposed Transmission Rate application and the actual OM&A pension contributions.

This account was established based on the Board’s decision on Hydro One Transmission’s Rates for 2011 and 2012 (EB-2010-0002) which accepted the continuation of the Pension Costs Differential account. The Board further approved continuance of the account in its decision of EB-2012-0031. This account is reported to the Board on a quarterly basis consistent with the Board's Reporting and Record Keeping Requirements.
As at December 31, 2013, Hydro One Transmission has recognized an asset balance of $20.8 million, inclusive of interest accrued.

Included in the balance submitted for approval is interest forecast through to December 31, 2014 to reflect carrying charges anticipated through to the proposed implementation date, reduced by the $12.8 million balance approved by the Board for disposition in 2014 as part of the EB-2012-0031 decision. This will result in a forecast asset account balance of $8.2 million at the end of the test year 2014.

2.7 East West Tie Deferral Account

This account was approved by the Board on July 12, 2012 in Hydro One’s application (EB-2012-0180) to establish a deferral account related to the East-West Tie Line proceeding (EB-2011-0140).

Hydro One was permitted to track costs in the EWTDA that relate to the following two categories:

1. costs incurred by Hydro One Transmission as incumbent transmitter to support the Board through the designation process and to eventually facilitate the line’s connection; and
2. expenditures incurred relating to preliminary engineering and other station connection work required to accommodate the East West Tie line.

With the OEB having announced the successful bidder for the EWT project, Hydro One is seeking only to continue the second category of the prior approved account, that as the incumbent transmitter, will track costs for expenditures incurred relating to preliminary engineering and other station connection work required to accommodate the East West Tie line.
2.8 Long-Term Transmission Future Corridor Acquisition and Development Account

This deferral account, approved during EB-2012-0031, records transmission planning and study costs associated with preliminary corridor routing considerations for new transmission infrastructure. In order to ensure land corridor availability in near-urban areas, long term investment planning is required. The costs recorded in the account will be associated with land assessment work such as environmental studies and assessments, preliminary engineering studies, public and First Nations/Métis consultations, etc. The outcome of this work will be helpful in making siting determinations for new corridors and in setting aside the required land for planning purposes, thus ensuring its availability and affordability when the project proceeds.

As at December 31, 2013, Hydro One Transmission has recognized an asset balance of $0.1 million, inclusive of interest accrued. This amount is expected to grow over the next few years.

Included in the balance submitted for approval is interest forecast through to December 31, 2014 to reflect carrying charges anticipated through to the proposed implementation date. This will result in a forecast asset account balance of $0.1 million at the end of the test year 2014.

2.9 External Revenue – Partnership Transmission Projects Account

This account was established based on the Board’s decision on Hydro One Transmission’s Rates for 2013 and 2014 in EB-2012-0031. The deferral account records costs for services provided by Hydro One employees for work they are/will perform for partnership companies, whether partnered with Hydro One
Networks Inc. or Hydro One Inc., working on competitive or other partnership transmission projects.

Hydro One will identify specific employees to work with partnership companies in which the company has a vested interest. The company will track employee time and any expenses and the resulting costs will be invoiced to the appropriate partnered company. The amount of invoiced costs will be recorded in the External Revenue Partnership Transmission Project Account for reduction to future revenue requirements.

2.10 LDC CDM and Demand Response Variance Account

This account was established as a result of the settlement agreement which was approved by the Board for Hydro One Transmission’s Rates for 2013 and 2014 in EB-2012-0031.

The account will track the impact of actual CDM and Demand Response results on the Load Forecast and the resulting impact on revenue requirement.

Hydro One Transmission proposes to record the following two elements in the CDM Variance account:

1) **CDM Variance** - Hydro One Transmission will track the difference between the forecast for 2013 and 2014 and the actual CDM savings related to the OPA-funded, LDC-delivered programs.

2) **Demand Response Variance** - Hydro One Transmission will track the actual Demand Response results against the forecast for 2013 and 2014 in this variance account.
Hydro One will use the annual results reported by the OPA in September of each year for the verified results of the previous year in accordance with the CDM Guidelines issued by the Board in EB-2012-0003.

No balance has been recorded in this account as 2013 actual results will not be reported by the OPA until September 2014.
PLANNED DISPOSITION OF REGULATORY ACCOUNTS

1.0 INTRODUCTION

The purpose of this evidence is to outline the planned disposition of Hydro One Transmission’s Regulatory Accounts.

2.0 PLANNED DISPOSITION OF REGULATORY ACCOUNTS

Hydro One Transmission is requesting disposition of the actual audited Regulatory Account values as at December 31, 2013, plus forecast interest for 2014 on the principal balances as at December 31, 2013, less any amounts approved for disposition in 2014 by the Board in the EB-2012-0031 rate filing for Transmission’s rate years 2013 and 2014.

It is expected that new Transmission rates will be effective and implemented on January 1, 2015 and that disposition of the accounts requested will commence on that date.

Hydro One Transmission's requested reduction to the Revenue Requirement of $36.1 million is detailed in Table 1:
<table>
<thead>
<tr>
<th>Description</th>
<th>Forecast Balance as at Dec 31, 2014</th>
</tr>
</thead>
<tbody>
<tr>
<td>(a) Excess Export Service Revenue</td>
<td>(23.5)</td>
</tr>
<tr>
<td>(b) External Secondary Land Use Revenue</td>
<td>(18.5)</td>
</tr>
<tr>
<td>(c) External Station Maintenance, E&amp;CS Revenue and Other External Revenue</td>
<td>(1.3)</td>
</tr>
<tr>
<td>(d) Tax Rate Changes</td>
<td>0.8</td>
</tr>
<tr>
<td>(e) Rights Payments</td>
<td>(1.9)</td>
</tr>
<tr>
<td>(f) Pension Cost Differential</td>
<td>8.2</td>
</tr>
<tr>
<td>(g) Long Term Future Corridor</td>
<td>0.1</td>
</tr>
<tr>
<td>(h) Total Regulatory Accounts for Approval</td>
<td>(36.1)</td>
</tr>
</tbody>
</table>

With the setting of new uniform Transmission rates in 2015 and 2016, Hydro One Transmission is requesting an adjustment to the Revenue Requirement over the standard 24-month period, which is consistent with the test years of this proposed application. Refer to Exhibit F2, Tab 1, Schedule 2 for the proposed annual amounts.

For 2015 and 2016, this reduction will be factored into the Revenue Requirement per Exhibit E1, Tab 1, Schedule 1.
COST ALLOCATION AND CHARGE DETERMINANTS

1.0 PURPOSE

The purpose of Exhibit G1 is to describe the process followed by Hydro One Transmission to allocate the Transmission revenue requirement identified in Exhibit E1, Tab 1, Schedule 1 into the four rate pools.

This Exhibit sets the context for the Transmission Cost Allocation and Charge Determinants for this Proposed Application. This information will be Hydro One Transmission’s input towards determining the Uniform Transmission Rates [UTR] applicable to all Ontario transmission customers.

2.0 SUMMARY

The rates revenue requirement outlined in Exhibit E1, Tab 1, Schedule 1, Table 4 is the starting point for the revenues to be allocated into the Rate Pools using the process described in this exhibit.

Table 1 summarizes the allocation of the 2015 and 2016 transmission rates revenue requirement to the four rate pools. The details of the cost allocation methodology are provided in Exhibit G1, Tab 2, Schedule 1. Also provided in Table 1 are the associated charge determinants per Rate Pool which will be used as Hydro One Transmission’s inputs into the determination of the provincial UTRs. The Charge Determinants are discussed in Exhibit H1, Tab 3, Schedule 1.
### Table 1

**Summary of Rate Pool Revenue Requirement and Charge Determinants**

<table>
<thead>
<tr>
<th></th>
<th>Network</th>
<th>Line Connection</th>
<th>Transformation Connection</th>
<th>Wholesale Meter</th>
<th>Total</th>
</tr>
</thead>
<tbody>
<tr>
<td><strong>2015 Revenue Requirement</strong> ($ Millions)</td>
<td>933.6</td>
<td>206.3</td>
<td>410.8</td>
<td>0.3</td>
<td>1,550.9</td>
</tr>
<tr>
<td><strong>2015 Charge Determinants:</strong></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Ave Monthly MWs</td>
<td>20,457</td>
<td>19,752</td>
<td>16,975</td>
<td></td>
<td>35</td>
</tr>
<tr>
<td>Meter Points</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td><strong>2016 Revenue Requirement</strong> ($ Millions)</td>
<td>972.0</td>
<td>218.0</td>
<td>432.1</td>
<td>0.2</td>
<td>1,622.3</td>
</tr>
<tr>
<td><strong>2016 Charge Determinants:</strong></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Ave Monthly MWs</td>
<td>20,676</td>
<td>20,050</td>
<td>17,231</td>
<td></td>
<td>25</td>
</tr>
<tr>
<td>Meter Points</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
</tbody>
</table>

### 3.0 COST ALLOCATION METHODOLOGY

The Cost Allocation and Charge Determinants methodologies remain unchanged from what was approved by the Board in the Decision and Rate Order in Proceeding EB-2012-0031.

The charges for transmission service are collected by the Independent Electricity System Operator (IESO) from Market Participants who are defined transmission customers, using Board-approved transmission rates. These rates are Uniform Transmission Rates that apply to the transmission customers of all transmitters in the Province of Ontario.
The remaining schedules of Exhibit G1 comprise the following:

- Exhibit G1, Tab 2, Schedule 1 details the cost allocation methodology used to determine the revenue requirement for the rate pools;
- Exhibit G1, Tab 3, Schedule 1 describes the Network, Line Connection and Transformation Connection rate pools, and the Low Voltage Switchgear Compensation;
- Exhibit G1, Tab 4, Schedule 1 describes the Wholesale Meter rate pool.
TRANSMISSION CUSTOMERS LOAD FORECAST

1.0 INTRODUCTION

This schedule summarizes the forecast customer demand by customer delivery point based on the load forecast methodology described in Exhibit A, Tab 15, Schedule 2. The forecast provides the information necessary for cost allocation, and to determine the charge determinants for the Network, Line Connection and Transformation Connection rate pools.

2.0 LOAD FORECAST FOR TRANSMISSION CUSTOMERS

2.1. Load Forecast Data for Cost Allocation

The load forecast data required to calculate the cost allocation of Dual Function Line Assets described in Exhibit G1, Tab 2, Schedule 1, Section 4.1.1 is the monthly coincident peak demand, adjusted for applicable losses, for each customer’s transmission delivery point downstream of a Dual Function Line. The resulting allocation factors are listed in Exhibit G2, Tab 2, Schedule 1.

The sum of the forecasted monthly maximum non-coincident peak demand, adjusted for applicable losses for each customer’s transmission delivery point downstream of Generation Connection Assets is required to calculate the allocation factors for Generation Connection Assets, as described in Exhibit G1, Tab 2, Schedule 1, Section 4.1.2. The resulting allocation factors are listed in Exhibit G2, Tab 3, Schedules 1 and 2.
2.2. Load Forecast Data for Charge Determinants

The load forecast data required to calculate the charge determinants for the rate pools is as follows:

- The monthly Coincident Peak demand values, adjusted for applicable losses, for each customer’s transmission delivery point at the time of the monthly system peak demand.
- The monthly Non-Coincident Peak demand values, adjusted for applicable losses, for each customer’s transmission delivery point, independent of the monthly system peak demand.
- The monthly demand values, adjusted for applicable losses, for each customer’s transmission delivery point that is the higher of a) the monthly Coincident Peak demand or b) 85% of the monthly Non-Coincident Peak demand between 7 AM and 7 PM on working weekdays for each customer delivery point.

The load forecast data shown in Table 1 and Table 2 at the end of this Schedule is for all transmission customer delivery points, irrespective of the transmission service charges they attract. The charge determinants for the Line Connection and Transformation Connection pools will be a subset of the non-coincident peak demand totals shown in Tables 1 and 2. The determination of which customer delivery points are included for the purpose of calculating the charge determinants for the Network, Line Connection and Transformation Connection pools is discussed in Exhibit H1, Tab 3, Schedule 1.

As Tables 1 and 2 illustrate, LDCs represent roughly 90% of the demand. The average monthly non-coincident peak demand for LDCs is forecast to be only about 10% higher than their average monthly coincident peak demand. For end-use transmission customers the non-coincident peak is about 53% higher than their coincident peak. This illustrates that LDC demand is largely what drives the overall system peak demand, and it also
reflects the increased ability of end-use transmission customers to shift load away from
the system peak, or have maximum demands at different times than LDCs.

Table 1
2015 Forecast Demand by Customer Category
(The forecast demand in this table is for all customers, irrespective of whether they pay Connection Service charges)

<table>
<thead>
<tr>
<th>Category</th>
<th># of Customer Delivery Points</th>
<th>Sum of Average Monthly Coincident Peak (CP) Demand</th>
<th>Sum of Average of [Higher of Monthly CP or 85% of NCP from 7AM to 7PM]</th>
<th>Sum of Average Monthly Non-Coincident Peak (NCP) Demand</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>MW</td>
<td>% of Total</td>
<td>MW</td>
<td>MW</td>
</tr>
<tr>
<td>LDCs</td>
<td>445</td>
<td>18,127</td>
<td>92.8%</td>
<td>18,425</td>
</tr>
<tr>
<td>End-Use Customers</td>
<td>94</td>
<td>1,340</td>
<td>6.9%</td>
<td>1,719</td>
</tr>
<tr>
<td>Transmission-Connected Generators</td>
<td>103</td>
<td>59</td>
<td>0.3%</td>
<td>313</td>
</tr>
<tr>
<td>TOTAL TRANSMISSION</td>
<td>642</td>
<td>19,526</td>
<td>100.0%</td>
<td>20,457</td>
</tr>
</tbody>
</table>

Table 2
2016 Forecast Demand by Customer Category
(The forecast demand in this table is for all customers, irrespective of whether they pay Connection Service charges)

<table>
<thead>
<tr>
<th>Category</th>
<th># of Customer Delivery Points</th>
<th>Sum of Average Monthly Coincident Peak (CP) Demand</th>
<th>Sum of Average of [Higher of Monthly CP or 85% of NCP from 7AM to 7PM]</th>
<th>Sum of Average Monthly Non-Coincident Peak (NCP) Demand</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>MW</td>
<td>% of Total</td>
<td>MW</td>
<td>MW</td>
</tr>
<tr>
<td>LDCs</td>
<td>445</td>
<td>18,393</td>
<td>93.0%</td>
<td>18,694</td>
</tr>
<tr>
<td>End-Use Customers</td>
<td>94</td>
<td>1,332</td>
<td>6.7%</td>
<td>1,705</td>
</tr>
<tr>
<td>Transmission-Connected Generators</td>
<td>103</td>
<td>53</td>
<td>0.3%</td>
<td>277</td>
</tr>
<tr>
<td>TOTAL TRANSMISSION</td>
<td>642</td>
<td>19,778</td>
<td>100.0%</td>
<td>20,676</td>
</tr>
</tbody>
</table>
CHARGE DETERMINANTS

1.0 INTRODUCTION

This exhibit provides the derivation of Hydro One Transmission’s charge determinants for the approved rate pools, which when combined with the charge determinants of the other transmitters for the Network, Line Connection and Transformation Connection rate pools can be used by the Board to determine Uniform Transmission Rates (UTRs).

2.0 SUMMARY OF CHARGE DETERMINANTS

The rate pool charge determinants are summarized in Table 1 for the 2015 and 2016 Test Years. All charge determinants have been calculated per the methodology approved in the Board’s EB-2012-0031 Decision.

<table>
<thead>
<tr>
<th>Charge Determinant [average monthly]</th>
<th>Network (MW)</th>
<th>Line Connection (MW)</th>
<th>Transformation Connection (MW)</th>
<th>Wholesale Meter (Meter Points at Mid-Year)</th>
</tr>
</thead>
<tbody>
<tr>
<td>2015</td>
<td>20,457.1</td>
<td>19,751.9</td>
<td>16,975.0</td>
<td>35</td>
</tr>
<tr>
<td>2016</td>
<td>20,675.8</td>
<td>20,049.8</td>
<td>17,231.0</td>
<td>25</td>
</tr>
</tbody>
</table>

3.0 NETWORK CHARGE DETERMINANT AND PAYMENT OBLIGATIONS

The Network Service charge determinant is the higher of a customer’s demand coincident with the monthly system peak or 85% of the customer’s non-coincident monthly peak demand between 7 AM to 7 PM as detailed in the currently approved Ontario Transmission Rate Schedules provided in Exhibit H2, Tab 1, Schedule 1 (Attachment 1).
The Network charge determinant provides customers with time-of-use signals that encourage use of the transmission system outside the 7 AM to 7 PM period, for which no transmission Network charges apply. It also encourages customers to avoid the monthly system peak, with the potential for lowering their Network charges by up to 15% of their non-coincident peak demand between the hours of 7 AM to 7 PM multiplied by the Network rate.

All customers that are connected to Hydro One’s transmission system incur Network Service charges on a per Transmission Delivery Point basis. The 2015 and 2016 load forecast data for each customer’s Transmission Delivery Points, adjusted for losses as appropriate, is used to calculate the total charge determinants that attract Network Service charges.

4.0 LINE CONNECTION CHARGE DETERMINANT AND PAYMENT OBLIGATIONS

The Line Connection Service charge determinant is the customer’s non-coincident monthly peak demand as detailed in the currently approved Ontario Transmission Rate Schedules provided in Exhibit H2, Tab 1, Schedule 1.

All customers that utilize Line Connection assets owned by Hydro One Transmission incur Line Connection Service charges on a per Transmission Delivery Point basis. The customer demand supplied from a Transmission Delivery Point will not incur Line Connection Service charges if a customer fully owns, or has fully contributed toward the costs of, all Line Connection assets that connect the transmission delivery point to a Network station. Similarly, customers will not incur Line Connection Service charges for demand at a Transmission Delivery Point located at a Network station.
The Billing Demand for Line Connection Service is the customer’s loss-adjusted demand supplied from the transmission system plus the demand that is supplied by embedded generation for which the required government approvals are obtained after October 30, 1998 and which have installed capacity of 2 MW or more for renewable generation\(^1\) and 1 MW or higher for non-renewable generation.

The 2015 and 2016 load forecast data for each customer’s Transmission Delivery Points, adjusted for losses as appropriate, is used to calculate the total charge determinants that attract Line Connection Service charges.

5.0 TRANSFORMER CONNECTION CHARGE DETERMINANTS AND PAYMENT OBLIGATION

The Transformation Connection Service charge determinant is the customer’s non-coincident monthly peak demand as detailed in the currently approved Ontario Transmission Rate Schedules provided in Exhibit H2, Tab 1, Schedule 1.

All customers that utilize transformation connection assets owned by the Hydro One Transmission incur charges on a Transmission Delivery Point basis. The customer demand supplied from a Transmission Delivery Point will not incur Transformation Connection Service charges if a customer fully owns, or has fully contributed toward the costs of, all transformation connection assets associated with that Transmission Delivery Point.

The Billing Demand for Transformation Connection Service is the customer’s loss-adjusted demand supplied from the transmission system plus the demand that is supplied by embedded generation for which the required government approvals were obtained.

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\(^1\) This change was approved in the Transmission System Code Phase 1 Policy Decision with Reasons, Proceeding RP-2002-0120 and subsequently incorporated into the Rate Schedules issued as part of Proceeding EB-2005-0241.
after October 30, 1998 and which have installed capacity of 2 MW or more for renewable
generation and 1 MW or higher for non-renewable generation.

The 2015 and 2016 load forecast data for each customer’s Transmission Delivery Point,
adjusted for losses as appropriate, is then used to calculate the total charge determinants
that attract Transformation Connection Service charges.

6.0 WHOLESALE METER POINTS

The forecasted number of Wholesale Meter Points is based on the 2013 year end
Wholesale Meter Points and the meters anticipated to exit the wholesale meter pool based
on the experience gained in the number of conversions completed to date, as well as
knowledge of the conversion requirements for the remaining meter points.

The forecasted remaining Wholesale Meter Points are:

<table>
<thead>
<tr>
<th># of Meter Points</th>
</tr>
</thead>
<tbody>
<tr>
<td>#</td>
</tr>
<tr>
<td>Year End</td>
</tr>
<tr>
<td>2013</td>
</tr>
<tr>
<td>65</td>
</tr>
<tr>
<td>Mid Year</td>
</tr>
<tr>
<td></td>
</tr>
</tbody>
</table>
RATES FOR WHOLESALE METER SERVICE

1.0 INTRODUCTION

This Exhibit summarizes the derivation of rates applicable to the provision of Wholesale Meter Service. The Wholesale Meter Service rates are designed to recover the Wholesale Meter Pool revenue requirement identified in Exhibit G1, Tab 4, Schedule 1.

2.0 CHARGE DETERMINANT AND PAYMENT OBLIGATIONS

Per the existing Rate Schedules approved by the Board in EB-2012-0031, the revenue requirement for the wholesale revenue meter function is collected from the meter service customers that are served by the Hydro One Transmission-owned wholesale revenue meters that form the Wholesale Meter Pool.

The revenue requirement for the Wholesale Meter Pool will continue to be collected using a uniform Wholesale Meter Service rate determined on a “per meter point” basis\(^1\). This is consistent with the approach used to set rates in Proceeding EB-2012-0031, and it is the same basis on which customers pay the exit fee when exiting the Wholesale Meter pool.

Table 1 below provides data for 2015 and 2016 on the forecast number of meter points, the revenue requirement to be recovered and the applicable rate (in $ / meter point / year) for Wholesale Meter service. An average rate of $8,000 per Meter Point per year for 2015 and 2016 is proposed.

---

\(^1\) A unique meter point is deemed to exist with respect to each instrument transformer associated with a metering installation that is used for the purpose of billing and settlement by the IESO.
Table 1

<table>
<thead>
<tr>
<th>Year</th>
<th>Annual Revenue Requirement ($ Million)</th>
<th>Forecast Number of Meter Points</th>
<th>Wholesale Meter Service Rate ($ / Meter Point / Year)</th>
</tr>
</thead>
<tbody>
<tr>
<td>2015</td>
<td>0.28</td>
<td>35</td>
<td>7,990</td>
</tr>
<tr>
<td>2016</td>
<td>0.20</td>
<td>25</td>
<td>8,046</td>
</tr>
</tbody>
</table>

The increase in rates from the current level of $7,900 reflects the fact that the remaining metering installations on average are more complex and thus more expensive to service than those that comprised the pool of 140 wholesale meter points in 2011.

Regulated Wholesale Meter Service charges shall not apply to any metering installation(s), and associated meter points, that have exited from the Wholesale Meter pool. It is proposed that the Exit Fee for meter installations, which is based on the average Net Book Value of stranded wholesale revenue metering assets, remain at $5,200 per meter point as approved by the Board in EB-2012-0031.

The Rate Schedule for Wholesale Meter Service, including the Exit Fee, is provided in Exhibit H2, Tab 2, Schedule 1. As currently approved by the Board, the Wholesale Meter service charge is administered by Hydro One Transmission.
RATES FOR EXPORT TRANSMISSION SERVICE

1.0 INTRODUCTION

The Export Transmission Service (ETS) rate was increased to $2/MWh, effective January 1, 2011, as directed by the OEB in the EB-2010-0002 Decision with Reasons. The previous rate of $1/MWh had been in effect since market opening.

Hydro One Transmission proposes that the recommendation of the Elenchus report be adopted. A copy of the report is provided as Attachment 1 to this Exhibit.

2.0 BACKGROUND

The IESO collects ETS revenues and remits them on a monthly basis to Hydro One, whose transmission system is used to facilitate export and wheel-through transactions at the point of interconnection with the neighbouring markets. The ETS tariff was initially set at a rate of $1/MWh and remained at this level until December 31, 2010. When initially set, the tariff was considered by the Ontario Energy Board (“Board”) to be a reasonable compromise between the many competing interests and proposals that were advanced by stakeholders in the course of Hydro One’s transmission rate proceeding. Moreover, the tariff was considered by the Board to be an interim solution to a rather complex and contentious set of issues. Among other things, the contention emerged from what stakeholders believed should be the basis of, or purpose of, the tariff design and what ought to be an appropriate charge level to help defray the costs to domestic customers for the use of network transmission facilities to facilitate export and wheel-through transactions. As well, there were concerns about potential impacts of the tariff on international trade agreements and reciprocity obligations, the development of open
and efficient regional markets, as well as the potential environmental consequences from higher exports that may be influenced by the tariff.1

In Hydro One’s Transmission Rate Application EB-2006-0501, the Board approved a stakeholder settlement agreement which called for the ETS tariff of $1/MWh to be maintained for the time being; however, the IESO was identified as the entity responsible for undertaking a study of an appropriate ETS tariff and, through negotiation with neighbouring jurisdictions, to pursue acceptable reciprocal arrangements with the intention to jointly eliminate all ETS tariffs. It was understood that any proposed change to the tariff must be reviewed and approved by the Board as part of Hydro One’s transmission rate review and approval process.

The IESO’s initial ETS tariff study and recommendation was filed with the Board on August 28, 2009 and reviewed under proceeding EB-2010-0002.

In the EB-2010-0002 Decisions with Reasons the Board concluded that an additional study was required.

“The Board concludes therefore that the most pressing requirement is that a genuinely comprehensive study be undertaken to identify a range of proposed rates and the pros and cons associated with each proposed rate in time for the next transmission rate application. In the Board’s view, the most appropriate party to undertake the study is the IESO.”

The OEB also directed Hydro One to increase the ETS rate to $2/MWh in the EB-2010-0002 Decision with Reasons.

---

1 Decision with Reasons, Ontario Hydro Networks Company Inc. Transmission Rate Application, RP-1999-0044, Export and Wheel-through Transactions.
The IESO engaged Charles River Associates (“CRA”) to perform a new ETS study, which was filed in May 2012 as a part of the evidence in proceeding EB-2012-0031. The Association of Power Producers of Ontario (“APPrO”) and Hydro Quebec Energy Marketing Inc. (“HQEM”) each filed expert evidence in response to the CRA Study. The Board considered their responses, and in the EB-2012-0031 Decision with Reasons, the Board directed Hydro One to:

“…prepare a cost allocation study involving the network assets utilized by export transmission customers and report the results of this study, including a proposal of the appropriate cost based ETS rate with supporting rationale, to the Board at its next transmission rates application.”

Hydro One engaged Elenchus Research Associates (“Elenchus”) to perform this study.

3.0 EXPORT TRANSMISSION SERVICE STUDY

The Elenchus report proposes an ETS rate of $1.7/MWh for 2015 and 2016 using cost causality principles to allocate Hydro One’s transmission costs between domestic and export customer groups. The Elenchus Report is be provided as Attachment 1 to this Exhibit.

Hydro One identified the Network asset value dedicated to interconnections which was provided to Elenchus for developing allocation factors between domestic and export demand. Hydro One also provided Elenchus information on the revenue requirement and rate base for the Network functional category.

Elenchus obtained provincial load forecast information from the IESO’s website.
Elenchus performed a preliminary analysis, based on forecast data for 2013 consistent with what was submitted by Hydro One in Proceeding EB-2012-0031. Elenchus presented their methodology and preliminary results at a stakeholder session hosted by Hydro One on March 24, 2014. Details of the stakeholder session are provided at Exhibit A, Tab 19, Schedule 1.

Hydro One subsequently provided Elenchus with updated 2013 data and forecast data for 2015 and 2016 consistent with this proposed application, for inclusion in Elenchus’ final report.

4.0 EXPORT TRANSMISSION SERVICE REVENUE

Hydro One’s Export Transmission Service (ETS) revenues used for establishing the rates revenue requirement in this proposed application are determined based on the currently approved tariff of $2/MWh and the 3 year historical average volume of electricity exported from, or wheeled-through, Ontario over its transmission system.

For 2015 and 2016 the ETS revenue will continue to be disbursed through a decrease to the revenue requirement for the Network Pool, as per the cost allocation process approved by the Board in EB-2012-0031. The forecast for ETS revenue is $33.4 million and $34.3 million per year for 2015 and 2016, respectively.

Hydro One proposes to revise its rates revenue requirement to reflect the OEB’s Decision and Order with respect to the ETS tariff as part of the Draft Rate Order to be submitted in connection with finalizing the 2015 Uniform Transmission Rates to be approved.
Export Transmission Service Rate

Cost Allocation Methodology

Report Prepared by
Michael Roger
Elenchus Research Associates Inc.

On Behalf of HONI

May 7, 2014
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This report presents Elenchus’ recommendation on the cost allocation methodology that should be used to determine a cost-based Export Transmission Service rate in Ontario.

The recommended methodology should be based on:

- Using prior year actual hourly data for domestic and export customers,
- 12 CP should be the allocator used in apportioning assets between domestic and export customers in order to develop composite allocators to allocate shared OM&A expenses,
- Only dedicated assets used to serve export customers and the related costs should be allocated to the export customer class,
- OM&A expenses related to the use of shared assets should be allocated to export customers using composite assets as allocator,
- No external revenues should be allocated to the export customer class,
- The ETS rate should be based on HONI’s OEB approved Network revenue requirement, as used in determining the Uniform Transmission Rates, marked-up to include other transmitters’ approved revenue requirement as reflected in the Uniform Transmission Rates.

The proposed cost allocation methodology determines the ETS rate based on cost causality principles. Given the range of values calculated using 2013, 2015, 2016 data in the proposed methodology and the related scenario sensitivity results, a value between $1.7/MWh and $1.8/MWh for the ETS rate can be considered to be cost-based.

Based on the proposed 2015 and 2016 HONI financial data, Elenchus recommends an ETS rate of $1.7 MWh be implemented for 2015 and that the ETS rate be maintained for at least 2 years to provide stability in determining the rate.
1 INTRODUCTION

Hydro One Networks Inc. (“HONI”) retained Michael Roger of Elenchus Research Associates Inc. in order to develop a cost-based methodology to establish the Export Transmission Service (“ETS”) rate.

In its Decision with Reasons dated June 6, 2013 on 2013 Export Transmission Service rates, (EB-2012-0031, Decision and Order, page 10), the Ontario Energy Board (“OEB”) directed HONI to include a proposal of the appropriate cost-based ETS rate, with supporting rationale, to the OEB at its next transmission rates application.

More specifically the OEB stated on page 9 of its Decision with Reasons in Proceeding EB-2012-0031 that:

“The Board will require Hydro One to perform a cost allocation study to establish a cost basis for the ETS rate. Some parties have suggested that such a study would be prohibitively costly. However, the Board accepts the Elenchus testimony that a study could be properly scaled to address the magnitude of the issue and could be completed for a reasonable cost. The Board expects that this study will be completed in time for Hydro One’s next cost of service transmission rate application. While Hydro One has the responsibility for completing this study, the Board expects that the IESO will assist Hydro One as required to fully address the ETS rate issue.”

This report presents the results of the cost-based methodology developed by Elenchus to establish the ETS rate.

This report is divided into 5 main sections. Section 2 provides a background on the evolution of the ETS rate from market opening in 2002 until now, section 3 presents the principles of cost allocation methodology, section 4 describes the proposed cost allocation methodology to determine the ETS rate, section 5 presents the results of applying the recommended methodology using 2013 proposed data and 2015 and 2016 proposed data and section 6 presents conclusions and recommendations to the OEB on the proposed cost allocation methodology and the ETS rate. Appendix A contains the CV for Michael Roger.
Michael Roger has been an expert dealing with cost allocation, rate design and rate regulation issues for over 35 years. Michael worked for over 32 years at Ontario Hydro, Ontario Power Generation and Hydro One and spent most of his career dealing with Cost Allocation and Rate Design issues for wholesale and retail electricity customers in Ontario. He has also testified on numerous occasions at OEB proceedings on behalf of utilities and other stakeholders and also has provided expert advice to the OEB in various task forces dealing with cost allocation and rate design issues. Michael’s vast experience with Cost Allocation issues was applied in developing the cost-based cost allocation methodology to develop the ETS rate and forms the basis for Elenchus recommended methodology to the OEB.

2 BACKGROUND

In Proceeding RP-1999-0044 the OEB reviewed the issue of establishing an ETS rate to be implemented at market opening.

In its Decision with Reasons dated May 26, 2000, the OEB summarized the various arguments presented by stakeholders in this proceeding on what the ETS rate should be. The OEB decided that as an interim measure, the ETS rate should be fixed at $1/MWh. This was seen as a reasonable compromise between the competing interests and proposals presented by stakeholders in the proceeding on what was described as a complex and contentious issue. Among other things, the contention emerged from what stakeholders believed should be the basis of, or purpose of, the tariff design and what ought to be an appropriate charge level to help defray the costs to domestic customers for the use of the network transmission facilities to facilitate export and wheel-through transactions.

The OEB directed that HONI monitor and report at its next main rate submission how the export market was functioning and the developments in interconnected jurisdictions and whether the ETS rate should be reviewed.
HONI retained R. J. Rudden to do a “Jurisdictional Survey of Export and Wheel-through Service Rates”. The survey was filed with the OEB on June 26, 2006 and was reviewed in proceeding EB-2006-0501.

As part of EB-2006-0501, the OEB approved a stakeholder settlement agreement which maintained the ETS rate of $1/MWh. In the agreement, the Independent Electricity System Operator (“IESO”) was identified as the entity responsible for undertaking a study on the appropriate ETS rate. The settlement agreement stated that:

“...the IESO should now be identified as entity responsible to pursue and negotiate, with neighbouring jurisdictions, acceptable reciprocal arrangements with the intention to eliminate the ETS tariff, and study the appropriate ETS tariff, including those options identified in H1/T5/S1. The IESO will seek input from market participants and interested intervenors in this proceeding and keep the parties informed of the progress of negotiations and the study. It is agreed that the IESO will make its report available to the Board upon completion which will be no later than June 1, 2009 with the results of reciprocal arrangement negotiations and the study including recommendations for an appropriate ETS tariff. Hydro One Networks Inc. remains responsible for seeking changes to its approved transmission revenues and rates and will do so as part of the 2010 transmission rate-resetting process period, following the publishing of the study.”¹

The IESO retained Charles River Associates (“CRA”) to do a quantitative analysis of the future effect of several export rate scenarios, with respect to exports and wheel-through volumes, ETS tariff revenue, and the Hourly Ontario Energy Price. The IESO’s ETS study and recommendation was filed with the OEB on August 28, 2009 and was reviewed in proceeding EB-2010-0002. The IESO study reviewed four alternatives for setting the ETS rate:

1. Status Quo;
2. Equivalent average network charge;
3. Reciprocal treatment, and
4. Elimination.

¹ EB-2006-0501, Exhibit M, Tab I, Schedule 1, page 17, April 3, 2007
The IESO recommended the status quo alternative to the OEB.

In the Decision with Reasons in proceeding EB-2010-0002, page 75, the OEB concluded that an additional study was required. The OEB stated that:

“The Board concludes therefore that the most pressing requirement is that a genuinely comprehensive study be undertaken to identify a range of proposed rates and the pros and cons associated with each proposed rate in time for the next transmission rate application. In the Board's view, the most appropriate party to undertake this study is the IESO. In procuring the study, the IESO should circulate the terms of reference to the Applicant and the intervenors of record in this case with a view to ensuring that the resulting study will provide detailed analysis on the issues.

This review of the terms of reference is not intended to be a strategic negotiation, but rather a technical exercise to ensure that the scope of the project is sufficiently broad and well-defined to ensure a useful and appropriate outcome. Work on this study should begin soon, to ensure completion well in advance of the time for the filing of the next transmission rates application by Hydro One.”

The OEB in the same proceeding increased the ETS rate to $2/MWh, providing the following rationale:

“Accordingly, the Board will direct that a change be made to the ETS rate for 2011 and 2012, increasing the rate to two dollars per MWh. In making this change the Board seeks to recognize the directional preference of the CRA study, and the absence of any particular analytical underpinning for the current rate. Subsequent panels assessing the level of this rate should not, however regard this new rate as having any particular precedential value. It is the Board's view that the new rate has more analytical support than the status quo, but that in order to arrive at a genuinely robust and valid rate, more study is required.”

In response to the OEB directive, the IESO engaged CRA to conduct a further review of the ETS rate. CRA reviewed the tariff and structures in neighbouring markets and assessed five proposed rate options against generally accepted rate making principles (consistency, simplicity, fairness and efficiency). The rate options considered were:

1. Status Quo
2. Elimination
3. Equivalent average network charge
4. Tiered rates (two alternatives)

The CRA study was filed and reviewed in proceeding EB-2012-0031.

In the IESO’s submission to the OEB, the IESO indicated that none of the ETS tariff options materially impact reliability, but elimination of the tariff would best promote efficient operation of the wholesale electricity market.

As stated in the introduction in this report, the OEB directed HONI in proceeding EB-2012-0031 to develop a cost-based methodology to determine the ETS rate.

3 PRINCIPLES OF COST ALLOCATION

In order to determine cost-based rates, a cost allocation study is performed by a utility to fairly allocate shared assets and expenses to the customer groups served by the utility.

The cost allocation study is based on actual historical or forward looking test year data and reflects the operating circumstances of the utility at a particular point in time, either the last year for which actual historical information is available, or for the future test year for which rates are being established.

Traditionally three steps are followed in a cost allocation study: Functionalization, Categorization or Classification, and Allocation.

Assets and expenses that are identified with a particular customer class and that are not shared with other customer classes are “Directly” allocated to that particular customer class.

Functionalization of assets and expenses is the process of grouping assets and expenses of a similar nature, for example, generation, high voltage transmission, customer service, meter reading, etc. Hence, as a first step in a cost allocation study, the function(s) served by the assets or expenses of the utility are identified so that costs can be attributed appropriately to the identified functions.
Categorization or Classification is the process by which the functionalized assets and expenses are classified as energy, demand and/or customer related. Hence, the costs associated with each function are attributed to these categories based on the principle that the quantum of costs is reflective of the quantum of volume, system demand, or number of customers.

Allocation, which is the final step, is the process of attributing the energy, demand, and customer related assets and expenses to the customer classes being served by the utility. This allocation is accomplished by identifying allocators related to energy, demand, or customer counts that are reflective of the relationship between different measures of these cost drivers and the costs that are deemed to be caused by each customer class.

It is in this Allocation step that customers are grouped based on common characteristics, or utility asset utilization reflecting cost causality.

4 PROPOSED COST ALLOCATION METHODOLOGY

Elenchus proposes a cost allocation methodology to determine the ETS rate that is based on cost causality, is simple and follows the traditional three steps of a cost allocation methodology.

Elenchus looked at how transmission assets are being used to sell electricity, either to domestic customers of to neighbouring jurisdictions by exporters.

In Ontario generators do not pay for the use of the transmission system when they inject power into the grid in order to supply domestic electricity needs. Elenchus applied this same principle when evaluating the interconnected assets with neighbouring jurisdictions used by exporters. The interconnected assets are used to both export and import power and since generators in Ontario do not pay for the use of the transmission assets and the ETS rate is not applied to power imported into Ontario, Elenchus assumed that importers would also continue to not be charged for the use of the transmission system.
The proposed methodology considered the sale of electricity to domestic customers and neighbouring jurisdictions, not how the electricity was sourced and made available to satisfy sales.

HONI’s 2013 transmission assets and revenue requirements were used in developing the recommended approach.

The proposed cost allocation methodology to determine the ETS rate reflects the interruptible nature of exports. The basis for treating exports as interruptible loads is found in the OEB’s Decision with Reason in proceeding EB-2012-0031 that on page 5 states that:

“First, whether curtailments originate from generation issues or transmission issues, the Board agrees that export service does not receive the same priority access as domestic service. The Board accepts that the market rules treat exporters more as an interruptible load. This difference in treatment related to generation capacity has consequences for the overall service, even if export transmissions rights are technically as firm as domestic transmission rights. As a result, the Board finds that it may be appropriate for the export service to be viewed as a separate class.”

This has implications for how costs are allocated, as discussed in Section 4.3.

4.1 **FUNCTIONALIZATION**

In consultation with HONI, Elenchus determined that the assets and expenses associated with export activities can be found in the following HONI’s transmission functions:

- Network (500 kV, 230 kV, and 115 kV lines)
- Dual Function lines (Network portion)
- Generation Line Connection
- Generation Transformation Connection
- Common (telecommunication equipment, control centre)
- Other (facilities not allocated to other functions under normal operating conditions)
These functions include dedicated and shared assets, and related expenses used by domestic and export customers.

The remaining functions used by Hydro One Transmission in determining its revenue requirement (e.g. transformation, line connection, line connection portion of dual function lines) are considered to be used only by domestic customers.

External revenues were also considered in the development of the cost allocation methodology. These revenues result mainly from secondary land use in right of ways and from providing maintenance services to other entities. These revenues are the result of using HONI’s assets which have been designed to serve domestic customers only, therefore, no external revenues are proposed to be allocated to export customers.

4.2 Classification

Generally in costs allocation, transmission assets and expenses are classified as demand related. Transmission assets are designed to meet the maximum demand imposed by users of the system. Based on the functions evaluated, it was determined that the assets and expenses considered in the development of the ETS rate methodology are all demand related. There are no energy related or customer related assets and expenses.

4.3 Allocation

In the cost allocation methodology developed to determine the ETS rate two customer groups are considered: domestic and export.

Assets dedicated to domestic customers are assets that only serve to connect Hydro One customer’s load to the network.

Assets dedicated to interconnect (export) are assets that only serve to connect to another transmission utility.

Shared assets are those that serve both domestic and export customers, including assets associated with generation connection.
As export is considered to be interruptible service, no asset related costs associated with shared assets are proposed to be allocated to the export customer class.

This is considered appropriate because, as confirmed by Hydro One staff, HONI’s planning of the Network transmission system does not take into consideration the capacity needed to supply export customers, transmission planning is only based on the capacity needs of domestic customers.

The assets dedicated to serve export customers have been directly allocated to the export customer class as well as the related expenses.

The OM&A expenses related to the use of shared assets have been allocated between domestic and export customers using the allocators described below.

### 4.3.1 Coincident Peak Allocator

In cost allocation, the allocation of demand related assets that are closest to the customer are allocated based on the non-coincident demand of the customer. The required assets are sized reflecting the maximum customer electricity demand.

Further away from the customer and closer to the generation system, it is the aggregate electricity demand of all customers, and not the sum of the individual customer demands, that determines the size of the facilities required to satisfy customers’ electricity needs. In cost allocation, when apportioning assets and expenses further away from the customer (e.g. generation, transmission) and closer to the generation of electricity, it is the coincident demand that is used as an allocator, reflecting the criteria used to size the required assets.

Using 2010, 2011 and 2012 actual hourly load data for domestic and export customers from the IESO, coincident peak (“CP”) allocators were developed.

Coincident peak is the hourly demand of domestic and export customers at the hour of maximum demand in the Ontario electricity system.

1 CP is the demand for each customer class at the hour of maximum system demand in a year. 12 CP is the average of the demand for each customer class at the hour of each month’s maximum system demand.
1 CP or 12 CP are used by utilities in cost allocation studies to apportion generation and transmission costs amongst customer groups.

The following table includes the values developed for coincident peak.

### Table 1

**Coincident peak 2010 to 2012**

<table>
<thead>
<tr>
<th></th>
<th>2010</th>
<th>2011</th>
<th>2012</th>
<th>Average</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>Export</td>
<td>Domestic</td>
<td>Total</td>
<td>Export</td>
</tr>
<tr>
<td>1CP</td>
<td>2,687</td>
<td>25,048</td>
<td>27,735</td>
<td>2,549</td>
</tr>
<tr>
<td>12CP</td>
<td>30,897</td>
<td>255,485</td>
<td>286,382</td>
<td>31,343</td>
</tr>
</tbody>
</table>

The 1 CP and 12 CP percentage allocators using 2010 to 2012 data are show in the table below.

### Table 2

**Coincident peak %**

<table>
<thead>
<tr>
<th>Coincident Peak</th>
<th>2012 Data</th>
<th>Average 2010 – 2012 Data</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>Total</td>
<td>Domestic</td>
</tr>
<tr>
<td>1 cp</td>
<td>100.00</td>
<td>91.87</td>
</tr>
<tr>
<td>12 cp</td>
<td>100.00</td>
<td>89.94</td>
</tr>
</tbody>
</table>

The 1 CP and 12 CP values for the period 2011 to 2013 using actual hourly data are shown in the table below.
The 1 CP and 12 CP percentage allocators using 2011 to 2013 data are shown in the table below:

### Table 3
**Coincident peak 2011 to 2013**

<table>
<thead>
<tr>
<th></th>
<th>2,011</th>
<th>2,012</th>
<th>2,013</th>
<th>Average</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>Export</td>
<td>Domestic</td>
<td>Total</td>
<td>Export</td>
</tr>
<tr>
<td>1CP</td>
<td>2,549</td>
<td>25,450</td>
<td>27,999</td>
<td>2,179</td>
</tr>
<tr>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>12CP</td>
<td>31,343</td>
<td>250,819</td>
<td>282,161</td>
<td>28,164</td>
</tr>
</tbody>
</table>

Elenchus recommends that 12 CP should be used to allocate shared assets between domestic and export customers using the last year for which information is available.

When system loads are relatively flat and do not show a pronounced yearly peak, 12 CP is usually used by utilities to allocate demand related assets and expenses. In instances where there is a significant yearly peak compared to other peaks in the year, that is a very peaky load profile with low load factor, then 1 CP would be used to allocate demand related assets and expenses.

In Proceeding RP-1999-0044, the OEB reviewed allocators that could be used to recover Network assets and expenses and recommended against the use of non-
coincident peak and settled on the use of coincident peak. With respect to using 1 CP, in paragraph 3.4.27 of the OEB Decision it states that:

“A rate design aimed at customer demand reduction during the system’s coincident peak hours would meet the test of economic efficiency, but only if the network transmission system is generally capacity-constrained. This is not the case for the OHNC [Hydro One] network transmission system either today or in the foreseeable future.”

12 CP is used by HONI in apportioning assets and expenses when allocating Dual Function Line assets, (Proceeding EB-2012-0031, Exhibit G1, Tab 2, Schedule 1, pages 110-111).

4.3.2 Composite Allocators

The asset functions identified in section 4.1 were apportioned between domestic and export customers using the 12 CP allocator based on 2012 actual hourly data in order to develop composite allocators used to allocate shared OM&A expenses to domestic and export customer classes.

The OM&A expenses related to the identified shared functions were allocated in the cost allocation methodology to domestic and export customers using Net Shared Assets as composite allocators. Table 5 includes the percentage allocation of the composite allocators to the two customer classes based on 12 CP.

**Table 5**

<table>
<thead>
<tr>
<th>Composite Allocators using 2012 actual hourly data</th>
</tr>
</thead>
<tbody>
<tr>
<td><strong>Total</strong></td>
</tr>
<tr>
<td>Net Shared Assets</td>
</tr>
<tr>
<td>Dedicated to Domestic</td>
</tr>
<tr>
<td>Dedicated to Interconnect</td>
</tr>
</tbody>
</table>
Using 2013 actual domestic and export hourly data, the composite allocators are included in the following tables based on 12 CP and the 2015 and 2016 financial data.

**Table 6**

**Composite Allocators using 2013 actual hourly data for 2015**

<table>
<thead>
<tr>
<th></th>
<th>Total</th>
<th>Domestic</th>
<th>Export</th>
</tr>
</thead>
<tbody>
<tr>
<td>Net Shared Assets</td>
<td>100.00%</td>
<td>92.74%</td>
<td>7.26%</td>
</tr>
<tr>
<td>Dedicated to Domestic</td>
<td>100.00%</td>
<td>100.00%</td>
<td>0.00%</td>
</tr>
<tr>
<td>Dedicated to Interconnect</td>
<td>100.00%</td>
<td>0.00%</td>
<td>100.00%</td>
</tr>
</tbody>
</table>

**Table 7**

**Composite Allocators using 2013 actual hourly data for 2016**

<table>
<thead>
<tr>
<th></th>
<th>Total</th>
<th>Domestic</th>
<th>Export</th>
</tr>
</thead>
<tbody>
<tr>
<td>Net Shared Assets</td>
<td>100.00%</td>
<td>92.79%</td>
<td>7.21%</td>
</tr>
<tr>
<td>Dedicated to Domestic</td>
<td>100.00%</td>
<td>100.00%</td>
<td>0.00%</td>
</tr>
<tr>
<td>Dedicated to Interconnect</td>
<td>100.00%</td>
<td>0.00%</td>
<td>100.00%</td>
</tr>
</tbody>
</table>

**5 ETS RATE RESULTS**

The results of applying the proposed cost allocation methodology to develop a cost-based ETS rate are shown below.

The proposed cost allocation methodology was developed using 2012 actual hourly load data and 2013 proposed HONI financial data as submitted in proceeding EB-2012-0031.

The model was run again with 2013 actual hourly load data and the proposed 2015 and 2016 financial data being submitted by HONI at its rate submission.
5.1 **USING 2012 LOAD DATA AND 2013 HONI PROPOSED FINANCIAL DATA**

5.1.1 **BASE CASE ETS RATE**

The base case result for developing the ETS rate using the proposed cost allocation methodology is based on the following assumptions:

- Shared Assets are apportioned using 2012 actual hourly data between domestic and export customers using the 12 Coincident Peak method in order to develop the composite allocators to be used to allocate shared expenses.
- Only dedicated assets used to serve export customers and related expenses are being allocated to export customers.
- No asset related costs associated with shared assets are allocated to export customers.
- Shared OM&A expenses are allocated between domestic and export customers based on composite allocator of Net Shared Assets.
- No External revenue credit is allocated to export customers.
- HONI’s proposed 2013 data, (Assets and Expenses), as submitted in proceeding EB-2012-0031 were used to develop the ETS rate based on the proposed cost allocation model.

Using HONI’s export sales forecast for 2013, the resulting ETS rate is $1.77/MWh.

5.1.2 **ETS RATE INCLUDING OTHER TRANSMITTERS’ REVENUE REQUIREMENT**

The hourly data used from the IESO reflect all transmission electricity sales in Ontario, not just Hydro One’s, while the financial assets and expense data used in developing the cost allocation methodology reflects only Hydro One’s data. Marking-up the calculated ETS rate to reflect other transmitters approved Network revenue requirement would result in consistency between the sales data and the financial data, both of which would reflect all transmitters in Ontario.
As seen in the 2014 Uniform Transmission Rates, HONI’s Network function revenue requirement is $882.9 million. The revenue requirement for all Ontario transmitters is $912.8 million, or 3.4% higher than HONI’s revenue requirement.

Increasing the ETS rate of $1.77/MWh by 3.4%, results in an ETS rate of $1.83/MWh. This higher ETS rate would take into account the revenue requirement of all transmitters in Ontario.

5.1.3 Scenarios

The following scenarios were run in order to determine the results sensitivity of the proposed cost allocation methodology to various assumptions.
Table 8 Scenarios (2012 load data)

<table>
<thead>
<tr>
<th>Scenario</th>
<th>Description</th>
<th>ETS rate ($/MWh)²</th>
</tr>
</thead>
<tbody>
<tr>
<td>1</td>
<td>Same as Base case, but using 12 CP average of 3 years (2010 to 2012)</td>
<td>1.82</td>
</tr>
<tr>
<td>2</td>
<td>Same as Base case, but using 1 CP (2012)</td>
<td>1.59</td>
</tr>
<tr>
<td>3</td>
<td>Same as Base case, but using 1 CP average of 3 years (2010 to 2012)</td>
<td>1.67</td>
</tr>
<tr>
<td>4</td>
<td>Same as Base case, but allocation $0.16M External Revenue credit to Export customers</td>
<td>1.76</td>
</tr>
<tr>
<td>5</td>
<td>Allocating only shared OM&amp;A costs to Export customers, no dedicated export assets allocated to Export³</td>
<td>1.22</td>
</tr>
<tr>
<td>6</td>
<td>Allocating to Export customers same Network function assets and expenses as Domestic customers, $1.43M External Revenue credit, using 12 CP (2012)⁴</td>
<td>4.73</td>
</tr>
</tbody>
</table>

5.2 Using 2013 Load Data and 2015 and 2016 HONI Proposed Financial Data

5.2.1 Base Case ETS Rate

The same assumptions described in section 5.1.2 are used in developing the ETS rate:

- Shared Assets are apportioned using 2013 actual hourly data between domestic and export customers using the 12 Coincident Peak method in order to develop

² Using HONI 2013 export sales forecast
³ Assuming exporters do not pay for dedicated assets and related expenses
⁴ Assuming export is treated as firm load, similar to domestic load
the composite allocators to be used to allocate shared expenses to domestic and export customer classes

- Only dedicated assets used to serve export customers and related expenses are being allocated to export customers
- No asset related costs associated with shared assets are allocated to export customers
- Shared OM&A expenses are allocated between domestic and export customers based on composite allocator of Net Shared Assets
- No External revenue credit is allocated to export customers
- HONI’s proposed 2015 and 2016 data, (Assets and Expenses), as submitted in this proceeding are used to develop the ETS rate based on the proposed cost allocation model.

Using HONI’s 2015 and 2016 export sales forecast, the resulting ETS rate is $1.63/MWh for 2015 and $1.62/MWh for 2016.

5.2.2 ETS RATE INCLUDING OTHER TRANSMITTERS’ REVENUE REQUIREMENT

In HONI’s proposed 2015 and 2016 Uniform Transmission Rates, HONI’s Network function revenue requirements are $933.6 million and $972.0 million respectively. The revenue requirements for all Ontario transmitters are $963.0 million, and $1,001.3 million for 2015 and 2016, or 3.2% and 3.0% higher than HONI’s proposed revenue requirements.

Increasing the 2015 ETS rate of $1.63/MWh by 3.2%, and the 2016 ETS rate of $1.62/MWh by 3.0% results in ETS rate of $1.68/MWh for 2015 and $1.67/MWh for 2016. This higher ETS rates would take into account the revenue requirements of all transmitters in Ontario.

5.2.3 SCENARIOS

The following scenarios were run in order to determine the results sensitivity of the proposed cost allocation methodology to various assumptions.
### Table 9 Scenarios (2013 load data)

<table>
<thead>
<tr>
<th>Scenario</th>
<th>Description</th>
<th>ETS rate 2015 ($/MWh)$^5$</th>
<th>ETS rate 2016 ($/MWh)$^6$</th>
</tr>
</thead>
<tbody>
<tr>
<td>1</td>
<td>Same as Base case, but using 12 CP average of 3 years (2011 to 2013)</td>
<td>1.63</td>
<td>1.62</td>
</tr>
<tr>
<td>2</td>
<td>Same as Base case, but using 1 CP (2013)</td>
<td>1.34</td>
<td>1.33</td>
</tr>
<tr>
<td>3</td>
<td>Same as Base case, but using 1 CP average of 3 years (2011 to 2013)</td>
<td>1.42</td>
<td>1.41</td>
</tr>
<tr>
<td>4</td>
<td>Same as Base case, but allocation $0.12M External Revenue credit to Export</td>
<td>1.62</td>
<td>1.61</td>
</tr>
<tr>
<td></td>
<td>customers</td>
<td></td>
<td></td>
</tr>
<tr>
<td>5</td>
<td>Allocating only shared OM&amp;A costs to Export customers, no dedicated assets</td>
<td>1.15</td>
<td>1.13</td>
</tr>
<tr>
<td></td>
<td>allocated to Export$^7$</td>
<td></td>
<td></td>
</tr>
<tr>
<td>6</td>
<td>Allocating to Export customers same Network function assets and expenses as</td>
<td>4.84</td>
<td>4.88</td>
</tr>
<tr>
<td></td>
<td>Domestic customers, $1.3M External Revenue credit, using 12 CP (2013)$^8$</td>
<td></td>
<td></td>
</tr>
</tbody>
</table>

---

### 6 CONCLUSIONS AND RECOMMENDED METHODOLOGY

The results of the proposed cost allocation methodology to develop a cost-based ETS rate and the sensitivity scenarios run using 2010 to 2012 load data show a Base Case result of $1.77/MWh and a range for the ETS rate between $1.22/MWh to $1.82/MWh

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$^5$ Using HONI 2015 export sales forecast

$^6$ Using HONI 2016 export sales forecast

$^7$ Assuming exporters do not pay for dedicated assets and related expenses

$^8$ Assuming export is treated as firm load, similar to domestic load
for scenarios 1 to 5. The financial data is based on HONI’s 2013 proposed data and excludes other transmitter’s revenue requirement.

Using hourly load data for the period 2011 to 2013 and financial data for HONI as proposed for 2015 and 2016, the Base Case result for the ETS rate for 2015 is $1.63/MWh and for 2016 is $1.62/MWh. The range for the ETS rate is between $1.13/MWh to $1.63/MWh for scenarios 1 to 5. The financial data excludes other transmitter’s revenue requirement.

It is Elenchus’ recommendation that the cost allocation methodology to be used to develop the ETS rate should be based on:

- Using the last year of actual hourly data for domestic and export customers. Forecast domestic and export hourly data is not available either from HONI or IESO,
- 12 CP should be the allocator used in apportioning assets between domestic and export customers in order to develop composite allocators to allocate shared expenses.
- Only dedicated assets used to serve export customers and related expenses should be allocated to the export customer class,
- No asset related costs associated with shared assets should be allocated to export customers
- Expenses related to the use of shared assets should be allocated to export customers using composite assets as allocator,
- No External revenues should be allocated to the export customer class, and
- The ETS rate should be based on HONI’s OEB approved Network revenue requirement, as used in determining the Uniform Transmission rate, marked up to include other transmitters’ approved revenue requirement as reflected in the Uniform Transmission Rates.

The proposed cost allocation methodology provides a supporting basis for determining the ETS rate based on cost causality principles. Given the range of values calculated using 2013, 2015, 2016 data and the related scenario sensitivity results, a value
between $1.7/MWh and $1.8/MWh for the ETS rate can be considered to be cost-based.

Based on the proposed 2015 and 2016 HONI financial data, Elenchus recommends an ETS rate of $1.7 MWh be implemented for 2015 and that the ETS rate be maintained for at least 2 years to provide stability in determining the rate.
MICHAEL J. ROGER

34 King Street East, Suite 600 | Toronto, ON M5C 2X8 | 905 731 9322 | mroger@elenchus.ca

ASSOCIATE, RATES AND REGULATION

Michael has over 35 years of experience in the electricity industry dealing in areas of finance, cost allocation, rate design and regulatory environment. Michael has been an expert witness at numerous Ontario Energy Board proceedings and has participated in task forces dealing with his areas of expertise. Michael is a leader and team player that gets things done and gets along well with colleagues.

PROFESSIONAL OVERVIEW

Elenchus 2010 - Present
Associate Consultant, Rates & Regulation

• Provide guidance on the Regulatory environment in Ontario for distributors, with particular emphasis in electricity rates in Ontario and the regulatory review and approval process for cost allocation and rate design. Some of the clients that Michael provides advice include: Hydro Quebec Energy Marketing Inc., GTAA, Ontario Energy Board, City of Hamilton, Hydro One Transmission, Powerstream, Hydro Ottawa, Veridian, APPrO and Hydro 2000.

Hydro One Networks Inc. 2002 - 2010
Manager, Pricing, Regulatory Affairs, Corporate and Regulatory Affairs

• In charge of Distribution and Transmission pricing for directly connected customers to Hydro One’s Distribution system, embedded distributors and customers connected to Hydro One’s Transmission system. Determine prices charged to customers that conform to guidelines and principles established by the Ontario Energy Board, (OEB). Provide expert testimony at OEB Hearings on behalf of Hydro One in the areas of Cost Allocation and Rate Design. Keep up to date on Cost Allocation and Rate Design issues in the industry. Ensure deliverables are of high quality, defensible and meet all deadlines.
Keep staff focused and motivated and work as a team member of the Regulatory Affairs function. Provide support to other units as necessary.

**Ontario Power Generation Inc.**  
**Manager, Management Reporting and Decision Support, Corporate Finance**  
1999 - 2002

- In charge of producing weekly, monthly, quarterly and annual internal financial reporting products. Input to and coordination of senior management reporting and performance assessment activities. Expert line of business knowledge in support of financial and business planning processes. Coordination, execution of review, and assessment of business plans, business cases and proposals of an operational nature. Provide support to other units as necessary. Work as a team member of the Corporate Finance function.

**Ontario Hydro**  
**Acting Director, Financial Planning and Reporting, Corporate Finance**  
1998 - 1999

- In charge of the day to day operation of the division supporting the requirements of Ontario Hydro’s Board of Directors, Chairman, President and CEO, and the Chief Financial Officer, to enable them to perform their due diligence role in running the company. Interact with business units to exchange financial information.

**Financial Advisor, Financial Planning and Reporting , Corporate Finance**  
1997

- Responsible for co-ordinating Retail, Transmission, and Central Market Operation divisions’ support of Corporate Finance function of Ontario Hydro to ensure financial information consistency between business units and Corporate Office, review business units compliance with corporate strategy. Provide advice to Chief Financial Officer and Vice President of Finance on business unit issues subject to review by Corporate Officers.
- Participate or lead task team dealing with issues being evaluated in the company. Supervise professional staff supporting the function. Co-ordinate efforts with advisors for GENCO and Corporate Function divisions to ensure consistent treatment throughout the company.

**Section Head, Pricing Implementation, Pricing**  
1986 - 1997

- In charge of pricing experiments, evaluation of marginal costs based prices, cost-of-service studies for municipal utilities, analysis and comparison of prices in the electric industry, rate structure reform evaluation, analysis of cost of servicing individual
customers and support the cost allocation process used to determine prices to end users.

- The section was also responsible for the derivation of wholesale prices charged to Municipal Electric Utilities and retail prices for Direct Industrial customers, preparation of Board Memos presented to Ontario Hydro's Board of Directors and support the department's involvement at the Ontario Energy Board Hearings by providing expert witness testimony.

Section Head, (acting), Power Costing, Financial Planning & Reporting, Corporate Finance 1994 - 1995

- Responsible for the allocation of Ontario Hydro's costs among its customer groups and ensure that costs are tracked properly and are used to bill customers. Maintain the computer models used for cost allocation and update the models to reflect the structural changes at Ontario Hydro. Participate at the Ontario Energy Board Hearings providing support and expert testimony on the proposed cost allocation and rates.
  Provide cost allocation expertise to other functions in the company.

Additional Duties 1991

- Manager (acting) Rate Structures Department.
- Review of utilities' rates and finances for regulatory approval.
- Consultant. Sent by Ontario Hydro International to Estonia to provide consulting services on cost allocation and rate design issues to the country's electric company.

Analyst, Rates 1983 - 1986

- In charge of evaluating different marketing strategies to provide alternatives to customers for the efficient use of electricity. Co-ordinate and supervise efforts of a work group set up to develop a cost of service study methodology recommended for implementation by Municipal Electric Utilities and Ontario Hydro's Rural Retail System. Provide support data to Ontario Hydro's annual Rate Submission to the Ontario Energy Board. Participate in various studies analysing cost allocation areas and financial aspects of the company.

Forecasting Analyst, Financial Forecasts 1980 - 1983

- Evaluating cost data related to electricity production by nuclear plants and preparing short term forecasts of costs used by the company. Maintain and improve computer models used to analyse the data.
• Review Ontario Hydro's forecast of customer revenues, report actual monthly, quarterly and yearly results and explain variances from budget. Support the development of new computerized models to assist in the short-term forecast of revenues.

Project Development Analyst, Financial Forecasts 1979 - 1980
• In charge of developing computerized financial models used by forecasting analysts planning Ontario Hydro's short term revenue and cost forecasts and also in the preparation of Statement of Operations and Balance Sheet for the Corporation.

Assistant Engineer – Reliability Statics, Hydroelectric Generations Services 1978 - 1979
• In charge of analysing statistical data related to hydroelectric generating stations and producing periodic report on plants' performance.

ACADEMIC ACHIEVEMENTS

1975 Bachelor of Science in Industrial and Management Engineering, Technion, Israel Institute of Technology, Haifa, Israel.