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 the Hydro One Transmission's system.
- Connect load customers (load connections) and generating stations (generation connections) to the Hydro One Transmission's system.
- 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.

This exhibit does not include funding for pre-engineering work to support the development of major, long-term plans recommended by Ontario Power Authority ("OPA") in the Integrated Power System Plan ("IPSP") submitted to the Board in August 2007 for review. The costs associated with this pre-engineering work are discussed in

Exhibit C1, Tab 2, Schedule 4, but no funding has been included in the revenue requirement requested in this application. Instead, a variance account is being requested to capture the cost of pre-engineering work, as discussed in Exhibit F1, Tab1, Schedule 2.

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 OPA, and the Independent Electricity System Operator ("IESO") which utilizes its "Ontario Resource and Transmission Assessment Criteria" when conducting the System Impact Assessment for new transmission facilities. In particular, Hydro One is also 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 14, Schedule 4. A more detailed explanation of the planning for each different type of investment (i.e. Load Connection, Local Area Supply, Generation Connection, Network

Upgrades, Performance Enhancement, Risk Mitigation and Smart Grid) is provided in Sections 2.2.1 to 2.2.6 respectively. 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 3.5.

2.2.1 Planning for Load Connections

The planning for new load connections is driven primarily by customer requests. 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 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 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.

2.2.2 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, small 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 connectivity to the bulk transmission system.

There are several ways in which planning for local area supply is triggered:

- The OPA, through its work related to the development of the IPSP, recommends local area supply initiatives aimed at ensuring regional and local area reliability.
- Hydro One Transmission, on its own or in consultation with LDCs and other customers, carries out system studies to identify needs and potential solutions to resolve constraints related to local area supply adequacy. In these cases, 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.
- Hydro One Transmission monitors the transmission system and identifies concerns about equipment overloading, system performance constraints, or restricted operating and maintenance flexibility.

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 line 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 EA Act or Section 92/95 of the OEB Act as described below.

2.2.3 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 clean and renewable 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, improvements and/or modifications are normally required to Hydro One Transmission's network and up-stream connection facilities in order to incorporate the generation into the system. Examples of improvements 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 CCRA, are determined in accordance with the TSC, with clarification provided by the Compliance Bulletin #200606, dated September 11, 2006.

2.2.4 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 neighbouring 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:

- The OPA, through its work related to the development of the IPSP and/or 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 Ontario Government's initiatives and energy policies regarding renewable generation and/or phasing out of coal-fired generating stations in Ontario.
- Hydro One Transmission monitors the IESO's SIA reports for generation projects.
- 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.

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.

2.2.5 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 Trasmission'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 is required to file a proposal of its CDPP Standards outlining delivery points demonstrating poor performance and/or deteriorating trends in reliability performance. Hydro One Transmission is accountable to improve substandard delivery point performance.

2.2.6 Planning for Smart Grid

The planning for Smart Grid is focused on developing and implementing solutions for addressing the impacts of connecting renewable generation to Hydro One Transmission's system. Potential impacts are identified and plans established to analyse the impacts, develop and implement solutions and establish pilot projects where appropriate.

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, 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 1

Development Capital

	($ Millions)					
	Historical			Bridge	Test	
Investment Type	**2005**	**2006**	**2007**	**2008**	**2009**	**2010**
Inter Area Network Transfer Capability	37.3	68.0	81.6	152.8	396.5	509.6
Local Area Supply Adequacy	66.3	34.8	105.5	91.4	101.3	50.8
Load Customer Connection	37.2	52.8	63.7	53.6	66.9	171.6
Generation Customer Connection	3.4	37.5	55.8	29.3	11.9	32.3
Performance Enhancement and Risk Mitigation	3.5	12.4	2.5	2.9	7.2	14.2
Smart Grid	0	0	0	0	3.5	3.4
Gross Capital Total	**147.7**	**205.5**	**309.1**	**330.0**	**587.3**	**781.9**
Capital Contributions as per TSC	(13.1)	(26.1)	(36.6)	(19.1)	(33.9)	(123.1)
Net Capital Total	**134.6**	**179.4**	**272.6**	**310.9**	**553.4**	**658.8**

The overall spending on Development Capital work in the 2009 and 2010 test years has increased significantly over historical levels. The increase is largely attributable to a higher number of Inter Area Network projects with increasing scope and complexity. Also contributing to the overall increase in spending are the substantial increases in equipment and material costs in recent years. Further details for each Investment Type are provided in Sections 3.1 to 3.5 below which includes explanation about 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.

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 the 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 the Section 92 of the OEB Act). For these projects, the actual in-service costs would be included in the 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 (2009 or 2010) 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 (2009 or 2010), 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. These projects will have an in-service date beyond the test years. Hydro One Transmission is not seeking approvals for these projects within this 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, Michigan, Minnesota and New York, and can be connected to specific generators in Québec, 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. It also includes projects directly related to recommendations from the OPA based on direction and policy directives from the Ontario Government.

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 2009 and 2010 for Inter-Area Network Transfer Capability projects, along with the spending levels for the bridge and historic years, are provided in Table 2 at the end of 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.

The overall spending in the 2009 and 2010 test years on Inter-Area Network Transfer Capability projects has increased over historical levels. The primary drivers for this increase are three major inter-area transmission reinforcement projects:

- The Bruce to Milton 500 kV Transmission Line project, which was approved by the Board in the EB-2007-0050 proceeding, has a cash flow of $170.3 million in 2009 (43% of total cash flow in the year) and $ 263.1 million (52%) in 2010.
- The two North-South transmission reinforcement projects – Installation of SVCs in Northeastern Ontario and Nobel Series Capacitors that are now being implemented – together account for $ 82.7 million (21%) in 2009 and $ 62 million (12%) in 2010.

Other projects that also require significant cash flows in 2009 are the Cherrywood TS x Claireville TS Unbundling Project, for which the in-service date has been deferred from 2009 to 2010 because of complexities related to procuring equipment, and the installation of seven shunt capacitor banks as near term measures for reinforcing transmission out of the Bruce area. Additional details about costs of these projects are provided below.

Together, the above projects provide transmission reinforcements to accommodate changing generation patterns and to incorporate renewable generation in Ontario.

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 have either already been approved (Category 1) or are non-discretionary (as defined in the OEB Filing Requirements for Transmission and Distribution Applications), unless otherwise noted below.

Project D1: ***Hydro One – Hydro Québec 1250MW Interconnection***

This project comprises the building of a new 230kV Hydro One - Hydro Québec Interconnection (1,250MW) that will enable increased transfer of electricity between Ontario and Québec. The project was approved by the OEB under its Proceeding RP-2000-0068, and is classified as a Category 1.

Project D2: ***New 500kV Bruce to Milton Double Circuit Transmission Line***

This project comprises building a new double circuit 500kV line from the Bruce area to load centres in central Ontario. It will provide for the incorporation of two refurbished Bruce GS units and contracted wind power from 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 a Category 1.

Projects D3: ***Installation of Seven 230kV Capacitor Banks in Southwestern Ontario***

This project comprises the installation of seven 230kV shunt capacitor banks to provide voltage support and to provide for near-term measures to reinforce transmission capability from the Bruce Area. This project, which was referenced during the aforementioned Proceeding EB-2007-0050 on the Bruce – Milton Reinforcement Project, is required to support voltage and accommodate new generation in southwestern Ontario as recommended by the OPA. The projects are classified as Category 2 as the in-service dates are within the test years.

The primary reason for the increase in cost over the estimate submitted in the 2007/2008 Rate Case (Proceeding EB-2006-0501) is attributable to scope change – i.e. from installation of four capacitor banks, assumed in previous proceeding, to seven banks that are now required. In addition, these are the first high voltage shunt capacitor installations to be specified since the explosive failure of Richview TS Capacitor Bank SC22 in January 2007. The cost of measures identified by the subsequent investigation to mitigate against similar failures are included in the present cost estimate. These measures include the addition of surge capacitors to mitigate the rapid rise of recovery voltage (RRRV) and the use of breakers with a greater transient recovery (TRV) characteristic than the Richview capacitor bank breakers. This is accomplished by using 63 kA or higher rated breakers which cost significantly more (about three times more) than those assumed for estimating the cost for earlier proceeding. Also, as a direct result of the Richview incident, two existing capacitor banks at Buchanan TS – where a new bank is being added under this plan – are being retrofitted with surge capacitors as a part of this project, further adding to the cost of the project.

Project D4: ***Bruce Special Protection System ("BSPS") Modifications for Bruce Area***

This project comprises the modification of the BSPS to increase the generation and load rejection coverage, as an interim measure to help bridge the gap between the return to service of Bruce units and in-service of a new 500kV line from Bruce to Milton. This project, which was referenced during the aforementioned Proceeding EB-2007-0050 on the Bruce – Milton Reinforcement Project, is required to accommodate new generation as recommended by the OPA. The project is classified as a Category 2 project as the in-service date is within the test years.

Project D5: ***Cherrywood TS x Claireville TS: Unbundle 500kV Circuits***

The project comprises the unbundling of the two 500kV "super circuits" between Cherrywood TS and Claireville TS. The project will provide for an increase in transfer capability on the 500kV lines to address the increase flow from Portlands Energy Centre and Québec Interconnection across the 500kV interface into southwestern Ontario. The project is partially discretionary and is classified as a Category 2 project as the in-service date is within the test years.

A detailed explanation of the need and benefits of the Cherrywood TS x Claireville TS project was provided during the previous rate proceeding EB-2006-0501 ("Attachment B" of Exhibit J, Tab 1, Schedule 93). As noted in that Attachment, the project comprises: (i) the Unbundling of Circuits component (which provides benefits associated with reducing congestion and improving reliability), and (ii) the Refurbishment and Operation Flexibility component which is being carried out simultaneously with the unbundling component in order to take advantage of synergies.

Based on a recent update of the estimate, the total project cost is expected to be $107 million, out of which $80.5 million is for the "Unbundling of Circuits" component, which can be considered discretionary work, and $26.5 million is for the Refurbishment and Operation Flexibility component, which is classified non-discretionary. The project is now forecast to be in-service in December 2010 – a delay of one year, compared to the information filed in Proceeding EB-2006-0501, as a result of complexities in procuring high voltage equipment for the project.

An analysis by the IESO provided as part of proceeding EB-2006-0501 indicated that the congestion and reliability related benefits of the unbundling of the Cherrywood TS x Claireville TS circuits are estimated to be between $4 million and $5 million annually, including an estimated $200,000 in benefits for reliability. Assuming a project life of 45 years, and assuming that these benefits remain constant, the Net Present Value ("NPV") of the benefits is estimated to be between $83 and $104 million based on a real (social) discount rate of 4% that is used in the OPA's Integrated Power System Plan. When discounting unescalated, non-utility cash flows such as congestion and reliability penalties, use of a real social discount rate is more appropriate rather than a utility-specific, nominal, after-tax discount rate. Thus, the NPV of the benefits exceeds the $80.5 million cost of the discretionary work for unbundling the circuits. Hydro One Transmission believes that the annual benefits of reductions in congestion are likely to be even higher over the life time of the project since there will likely be an increase in power flow eastbound from Cherrywood TS because of several new resource developments (which were included in the benefit analysis) such as the committed in-service of the 197.8MW Wolfe Island Wind generation project; the proposed replacement of the Lennox GS units with gas-fired units, as per the IPSP; and the proposed Darlington "B" GS. The increase in eastbound power flows due to these developments will be larger than the potential reduction in power flow if Pickering "B" GS were retired.

Project D6: ***Installation of Static Var Compensator at Lakehead TS***

This project comprises the installation of a replacement 230kV static var compensator ("SVC") at Lakehead TS to avoid difficulties in voltage control and operation of the northwestern Ontario transmission system, in order to restore the transfer capability of the system. The project addresses equipment loading or voltage/short circuit stresses that have exceeded their rated capacities. The project is classified as a Category 2 project as the in-service date is within the test years.

A significant revision in the project cost estimate has been required since Proceeding EB-2006-0501. The primary reason for this change is that the conceptual level estimates included in the earlier filing were developed late during the Hydro One Transmission's business planning work in mid 2006 using the best available data at that time, without the benefit of site-specific assessment of work required. The project has now been completely scoped and fully released and a major "turn-key" contract has now been awarded based on competitive bids. Detailed engineering and procurement is well underway. The revised cost estimates take into account more detailed up-to-date information.

Project D7, D8: ***Northeast Transmission Reinforcement: Installation of Static Var Compensators at Porcupine TS and Kirkland Lake TS, and Installation of Series Capacitors at Nobel SS***

These projects comprise the installation of two 750MVar Series Capacitors on the 500kV lines between Sudbury and Toronto and the installation of two SVCs north of Sudbury (one 230kV 300MVar at Porcupine TS and one 115kV 200MVar at Kirkland Lake TS) to enhance the transfer capability to incorporate the new hydroelectric and wind generation that is planned in northern Ontario. The projects are required to incorporate new renewable generation to satisfy government directives and recommendations by the OPA. Both projects are classified as Category 2 as the in-service dates are within the test years.

A significant revision in the project cost estimate has been required since Proceeding EB-2006-0501. The primary reason for this change is that the conceptual level estimates included in the earlier filing were developed late in Hydro One's business planning process during 2006. Hence they did not have the benefit of a site-specific assessment of work requirements; instead, the earlier estimates relied on budgetary prices for the major turn-key contracts received from prospective vendors based on limited project information available at that time. Also, typically, the turn-key component of a project comprises, at most, only about 75% to 80% of the total direct costs of the project and, therefore, additional costs have to be added to budgetary estimate received from the vendors. The project has now been completely scoped and fully released and the major turn-key contracts have now been finalized based on competitive bids. At this time, even the cost of the turn-key portion of the project, in itself, is nearly twice as much as the budgetary prices based on vendor information in 2006.

To-date, experience with Series Capacitor banks and SVCs is limited in Ontario. Nobel SS is the first series capacitor bank installation in Ontario and the Porcupine and Kirkland Lake SVC's are only the second such installations in the province. The first SVC project, relatively smaller in size and complexity, is presently in its early stages of installation at Lakehead TS.

Project D9, D10, D11: *Installation of Shunt Capacitor Bank at Algoma TS, and Installation of Static Var Compensator and 2 Shunt Capacitor Banks at Mississagi TS*

These projects comprise the installation of a 230kV 300MVar SVC and two 230kV 75MVar shunt capacitor banks at Mississagi TS and installation of a 230kV shunt capacitor bank at Algoma TS to provide voltage support in northern Ontario. These projects will be committed only if the OPA recommends them, in order to accommodate new renewable generation in northern Ontario to satisfy government directive(s). The shunt capacitor projects are classified as Category 2 as the in-service date is within the test years. The SVC project is classified as Category 3 as the in-service dates are beyond the test years although significant funding is required within the test years.

Project D12: ***Installation of 2 Shunt Capacitor Banks at Porcupine TS***

This project comprises the installation of two 230kV 125MVar shunt capacitor banks at Porcupine TS to provide voltage support in northern Ontario. The project is required to incorporate new renewable generation to satisfy government directive(s) and recommendations by the OPA. The project is classified as a Category 3 project as the in-service dates are beyond the test years although significant funding is required within the test years.

Projects D13, D14: ***Installation of Static Var Compensators at Detweiler TS and Nanticoke TS***

These projects comprise the installation of two SVCs (one 500kV 350MVar at Nanticoke TS and one 230kV 350MVar at Detweiler TS) to provide voltage support and to provide for near-term measures to reinforce transmission capability from the Bruce Area. The projects were referenced during Proceeding EB-2007-0050 on the Bruce x Milton Reinforcement Project. The projects are classified as Category 3 as the in-service dates are beyond the test years although significant funding is required within the test years.

The primary reason for the increase in cost estimate over the cost submitted in the Proceeding EB-2006-0501 is attributable to scope change – i.e. from two 200Mvar installations to two, much larger, 350Mvar units, which contributes to about 40 % increase in costs; and the location at two different stations (at Nanticoke TS and one at Detweiler TS) instead of at one station (Nanticoke TS), which causes an additional cost increase of about 5% to 10%. Further, the budgetary unit cost ("per Mvar") provided by prospective vendors has increased over time and it is now about 35% more than estimates the estimates received in 2006. In addition, there is an increment of about 10% in cost as a result of escalation due to the changed in service date from 2009 to 2011.

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.

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 on the interconnected power system.

Funding levels for 2009 and 2010 for Local Area Supply Adequacy projects, along with the spending levels for the bridge and historic years, are provided in Table 3. Projects with gross total funding requirements in excess of $3 million in either of the test years are separately identified in Table 3 at the end of this exhibit. Customer capital contributions, where applicable, were determined in accordance with the TSC and Hydro One Transmission's Connection Procedures approved by the Board.

The primary drivers for the increase in overall spending on Local area Supply projects, compared to historical levels, are the two projects to reinforce transmission in GTA West, namely, "Hurontario Station and Transmission Line Reinforcement" project and the "Transmission Reinforcement for Supply to Jim Yarrow TS" project. The start of major construction work for both of these projects has been deferred from 2008 to 2009 as a result of complexities related to obtaining approvals associated with archeological surveys. The start of major construction for the Woodstock Area Transmission Reinforcement Project has also been deferred from 2008 to 2009 because of difficulties associated with acquisition of property rights.

The delayed expenditures on these three projects contribute to the increased spending requirements in 2009 and 2010, and illustrate the difficulties and complexities, resulting from external circumstances, in the construction of transmission projects.

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 D15: ***Southern Georgian Bay Transmission Reinforcement***

This project is planned to provide reliable supply capacity and transformation capacity for load growth in the Southern Georgian Bay and Simcoe County areas. There is a need to improve reliability since the existing transmission is inadequate to meet the local area supply requirements. The project was approved by the Board under its Proceeding EB-2006-0242 and is classified as Category 1.

Project D16, D17: ***Hurontario Station and Transmission Line Reinforcement, and Transmission Reinforcement for the Supply to Jim Yarrow TS***

These projects will address the bulk transmission needs by reliably accommodating load growth in the Western GTA as well as address related concerns about overloading on the circuits which transfer power into the Toronto area from the west and which supply most of Brampton and north Mississauga. These projects were approved by the Board under Proceedings EB-2006-0215 and EB-2007-0013 respectively, and are classified as Category 1.

Project D18: ***Woodstock Area Transmission Reinforcement***

This project is planned to provide reliable supply capacity to accommodate for load growth in the Woodstock area. There is a need to improve reliability since the existing 115kV transmission supply to Woodstock is expected to be overloaded by Spring 2010 should there be a contingency involving the outage of one circuit supplying the Woodstock area. The project was approved by the Board under its Proceeding EB-2007-0027 and is classified as Category 1.

Project D19, D20: ***Replacement of Twelve 115kV Circuit Breakers at Burlington TS, and Replacement of Switchgear and Main Bus in 115kV switchyard at Burlington TS***

This project will address the replacement of various components (including breakers, switches, buses) at Burlington TS where the short circuit levels exceed the equipment capability, thereby exposing customers to load shedding due to the operating measures implemented to manage the situation. The project is classified as a Category 3 project as the in-service dates are beyond the test years although significant funding is required within the test years. This project is for safety and reliability of the transmission system and hence no capital contributions are required.

Project D21: ***Leaside TS x Birch Junction Transmission Reinforcement***

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 and loading under the contingency condition where there is a loss of one circuit. Although spending on this project in the test years is less than $3 million, an Investment Summary Document for this project is provided in Exhibit D2, Tab 2, Schedule 3 in recognition of the fact that the need for this project was approved by the Board, per its Decision with Reasons in Proceeding EB-2006-0501. The project is classified as a Category 4 project since further approvals from the Board in the form of Section 92 application will be required.

Project D22: ***Supply to Essex County***

This project is planned to provide reliable supply capacity and transformation capacity for load growth in Essex County. This project is required to accommodate load since the existing transmission is inadequate to meet the local area supply requirements. The project is classified as a Category 4 project as further approvals from the Board in the form of Section 92 application will be required.

A significant reduction (about 20%) in the project cost estimates, compared to that filed for Proceeding EB-2006-0501, is the result of reduction in project scope.

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. Because these types of projects are 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 2009 and 2010 for Load Customer Connection projects, along with the spending levels for the bridge and historic years, are provided in Table 4. Projects with gross total funding requirements in excess of $3 million are separately identified in Table 4.

The increase in overall spending on Load Connection projects, compared to historical levels, reflects the commencement of construction of several new customer-driven projects as a result of the Connection and Cost Recovery Agreement having been signed by the customer and, in the case of Holland TS, Environmental Assessment approvals having been obtained.

3.3.2 Summary of Load Customer Connection Projects

The following is a summary listing of the load customer transformation connection projects for which cash flow details are provided in Table 4 at the end of this exhibit. All of these projects are non-discretionary and customer driven. They are either in Category 2 (in service in the test years) or Category 3 (in-service beyond the test years but with significant expenditures within the test years) and they do not require Section 92 approval, except for Woodstock East TS (Category 4) that requires a Section 92 approval for the line connection component of the work.

Category 2 Projects	**Category 3 Projects**	**Category 4 Projects**
D23: Kingston Gardiner TS	D30: Hanlon TS	D37: Woodstock East TS
D24: Holland TS	D31: Crowland TS	
D25: Goreway TS	D32: New Northern Mississauga TS[1]	
D26: Vansickle TS	D33: Enfield TS	
D27: Churchill Meadow TS	D34: Bracebridge TS	
D28: Glendale TS	D35: Long Lac TS	
D29: Dunnville TS	D36: Rodney TS	

These projects are fully funded by customers through a combination of future rate revenues and a capital contribution, where required, as determined in accordance with the

[1] New Northern Mississauga TS may require a line connection longer than 2 km, in which case it would become a Category 4 project.

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.

For loads connection projects, equipment procurement is the area of most significant cost increase over the last five years. Global market forces have driven the prices of major electrical equipment up significantly, especially for power transformers for which costs have increased in the order of 75%. The procurement of equipment, materials & services comprise 60% to 70% of the direct cost of a typical load connection project, and the power transformers often make up 35% to 55% of this amount. Overall, these transformer price increases can alone drive project costs up by 20% to 25%. Other cost components, such as labour and other materials, are also experiencing escalation.

3.4 Generation Customer Connection

3.4.1 Description of Generator Customer Connection Investments

Generation customer connections are addressed by a radial connection; however in some cases other improvements and/or modifications may be required to Hydro One's local area connection facilities in order to incorporate the generation into the system.

Since the middle of 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 three renewable Request for Proposals ("RFPs"), one clean generation RFP, a combined heat and power RFP, a GTA West RFP, and individual project procurements. While the projects that received the first renewable RFP contracts required minimal modifications or upgrades to the transmission system, many subsequent RFP contracts require significant transmission modifications and upgrades.

The consequences of not proceeding with these investments include:

- Failure to connect generators which have been contracted by the 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
- Increased risk to the Province's supply adequacy
- Contravention of Hydro One Transmission's obligation to connect new generators under its Transmission License and the TSC.

Funding levels for 2009 and 2010 for Generation Customer Connection projects, along with the spending levels for the bridge and historic years, are provided in the attached Table 5 at the end of 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 increase in spending level in 2010, compared to historical levels, is primarily due to work associated with the Lower Mattagami Extension that is driven by the generator customer that is planning development of existing hydroelectric stations.

3.4.2 Summary of Generator Customer Connection Projects

In relation to the current application by Hydro One Transmission, the following lists the pertinent new generators that have been either contracted by the Ontario Government or the OPA, or that are considered substantially advanced (in terms of negotiations and/or implementation), so that they require allocation of funding for transmission upgrades within the test year periods:

- Lower Mattagami Extensions (450MW)
- Greenfield South (280MW)

- TCE Halton Hills (683MW)
- Kingsbridge II Wind (158.7MW)
- Northland Thorold (236MW)
- Beck #1 G7 Conversion

These projects are categorized as “Customer Driven” because they are requested by the customer to accommodate new generation and are fully funded by the customer. In some 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.

From the above list of generation connections, only one project – the Lower Mattagami Extension – requires significant spending by Hydro One Transmission (gross costs exceeding $3 million) within the test years. Additional details for the Lower Mattagami Extension project are provided in the Investment Summary Documents in Exhibit D2, Tab 2, Schedule 3.

3.5 Performance Enhancement and Risk Mitigation Programs

The program investments in this category are grouped into two categories:

3.5.1 Delivery Point Performance and Power Quality

Delivery Point Performance and Power Quality (“PQ”) investments are initiated to improve the performance of either group or individual customer’s performance 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.

There are two types of investments undertaken to address ODPs. The first are investments associated with the regular maintenance program and the second are investments to address a specific problem or implementing a corrective solution. For the ODPs identified in 2007, remedial actions, covering maintenance program or development investments, have been completed at 38 ODPs and another 26 ODPs are currently under assessment and/or execution. The development spending level for 2007 was lower because analysis, assessment and mitigation measures could not be conducted in advance due to the 2005 labor dispute. The level of funding in 2009 and 2010 is based on the goal to manage and contain ODPs to less than 10% of the total number of delivery points, on an annual basis.

PQ issues are complex and generally mitigation measures are unique to customer operations. Hydro One Transmission has been proactive in the installation of PQ monitors to collect and assess PQ data to understand the issues, system and/or customer contributions that adversely affect PQ and work with individual customers to address their issue. To date, 34 PQ monitors have been installed at critical sites to capture this information and the plan is to install additional monitors at critical locations, as required. In addition, the pilot system to collect and analyze the information is being replaced in 2009 with a permanent system.

3.5.2 Compliance/Mitigate High-Risk

Work to ensure compliance to mandatory standards (such as NERC, NPCC) are 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 normally not planned on a priority basis considering legislative, regulatory, environmental, and safety requirements. Accordingly, the funding levels under this program can vary based on issue(s) and 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. For example, in 2007 a capacitor bank remediation plan to address system security and safety for various stations was developed due to a catastrophic event at Richview TS. During 2008, detailed studies were required to identify more specialized mitigation measures to be implemented at some stations (because of their unique characteristics); as a result, there was no significant funding of capital projects during that year. The stations requiring specialized mitigation have now been identified and the required funding for the work to be carried out has been allocated in 2009 and 2010.

Funding levels for 2009 and 2010 for Performance Enhancement and Risk Mitigation projects, along with the spending levels for the bridge and historic years, are provided in the attached Table 6 at the end of this exhibit.

3.6 Smart Grid

The Hydro One Transmission Smart Grid Program has been developed to support Hydro One Transmission’s continued commitment to improving system reliability, performance and customer satisfaction levels in view of recent increases in number of renewable energy generators which are being connected to the grid.

Renewable energy generation (i.e. wind mills, solar panels, etc.) incentives by the regulatory environment have prompted the need to study and understand the dynamics involved with connections to the electrical network by utilities, research agencies and the industry. Currently there are no fully established, tested and validated approaches and models for the equipment offered by power system vendors of renewable generators.

Findings on impacts of renewable generation connections to Hydro One Transmission require new planning tools, standards and facilities to operate, monitor and control these generators. Upgrades to equipment, devices, telecommunication links, controls and automation are also required.

Planned spending of $3.5 million and $3.4 million in test years 2009 and 2010 respectively will provide funding for various initiatives to study and analyze potential impacts on the transmission grid and to implement pilot projects prior to full deployment for connection of renewable generators to the grid. All planned initiatives will test and verify the best technical and cost effective solutions for enabling better use of existing infrastructure or for upgrading the infrastructure where needed.

4.0 UPDATE ON "CATEGORY 2" PROJECTS FROM PROCEEDING EB-2006-0501

In its Decision on Hydro One Transmission's application under Proceeding EB-2006-0501 the Board directed Hydro One Transmission to provide updates and progress reports in its next Transmission application on the six "Category 2" projects identified in Exhibit L2.1 of that proceeding. In Proceeding EB-2006-0501 "Category 2" projects were those that had capital spending in the test years, but only went in-service beyond the test year period.[2] The status and progress on the six projects noted by the Board is provided below.

[2] In the current application, such projects are classified as Category 3.

Circuit Re-terminations at Richview TS: This project is still on schedule for in-service in 2009 with forecasted capital expenditures less than the estimated $8.0M in the previous application. The current projection for the total cost of this project is $6.4M, which is captured under “Other Projects” in Table 2 - Inter-Area Network Transfer Capability.

Allanburg TS Upgrades: The project is not being pursued at this time based on a further review of the project need. It has been determined that the anticipated load growth is not transpiring as planned. In addition, Ontario Power Generation is planning to increase the generation connected to the 115kV transmission system by December 2008, which will further alleviate the constraints at Allanburg TS.

Claireville TS x Cherrywood TS Unbundle 500kV Circuits: A detailed status of this project is provided in Section 3.1 and Table 2 of this Exhibit. The in-service date for this project has been deferred by a year as a result of material procurement complexities. However, the current projection for the total cost of this project remains in line with the amount estimated in the previous application.

Churchill Meadows TS *(formerly NW Mississauga TS)*: Details for this project are provided in Exhibit D2, Tab 2, Schedule 3 and the projected cash flows are provided in Table 4 of this Exhibit. The in-service date for this project has been deferred by a year as a result of delays in the approval process and property issues. The total gross cost of this project has increased by $5.4M from the amount estimated in the previous application due to property acquisition requirements and increases in scope and material costs (e.g. power transformers).

Enfield (Oshawa) TS: Details for this project are provided in Exhibit D2, Tab 2, Schedule 3 and the projected cash flows are provided in Table 4 of this Exhibit. The in-service date for this project has been deferred by a year as a result of delays in the approval process. The total gross cost of this project has increased by $7.0 from the amount estimated in the previous application due to additional transmission line work and access road requirements, as well as due to increases in material costs.

Vansickle TS: Details for this project are provided in Exhibit D2, Tab 2, Schedule 3 and the projected cash flows are provided in Table 4 of this Exhibit. The in-service date for this project has been deferred by a year as a result of delays in negotiations with the customer. The total gross cost of this project has increased by $2.5M from the amount estimated in the previous application due to increases in project scope (e.g. sound enclosures, spill containment) and higher material costs.

Table 2
Inter-Area Network Transfer Capability: Summary of Development Capital Projects in Excess of $3 Million

Item#	Investment Description	Classification as per OEB Filing Guidelines	Capital Project Category	IPSP Category[1]	EA Status	Section 92 Status	Gross Cash Flow ($ Millions) Historical			Bridge	Test	Test	Gross Total Cost[2]	Capital Contribution[3]	Net Total Cost[4]	In-Service Year
							2005	2006	2007	2008	2009	2010				
D1	Hydro One - Hydro Québec: 1250MW Interconnection	Development, Discretionary	Category 1	Non-IPSP	Completed	Completed	-	2.6	72.6	35.7	11.9	0.0	122.8	0.0	122.8	Mid 2009
D2	New 500kV Bruce to Milton Double Circuit Transmission Line	Development, Non-Discretionary	Category 1	Pre-IPSP	In Progress	Completed	-	1.2	6.6	30.9	170.3	263.1	619.8	0.0	619.8	Mid 2010 / Late 2011
D3	Installation of Seven 230kV Capacitor Banks in Southwestern Ontario	Development, Non-Discretionary	Category 2	Pre-IPSP	Not Required	Not Required	-	-	-	22.3	34.2	0.0	56.5	0.0	56.5	Late 2009
D4	Bruce Special Protection System Modifications for Bruce Area	Development, Non-Discretionary	Category 2	Pre-IPSP	Not Required	Not Required	-	-	0.1	0.0	4.0	1.7	5.8	0.0	5.8	Mid 2010
D5	Cherrywood TS x Claireville TS: Unbundle 500kV Circuits	Development, Partial Discretionary	Category 2	Non-IPSP	Not Required	Not Required	-	0.2	0.3	19.5	40.4	46.9	107.3	0.0	107.3	Late 2010
D6	Installation of Static Var Compensator at Lakehead TS	Development, Non-Discretionary	Category 2	Non-IPSP	Not Required	Not Required	-	-	0.5	6.5	10.1	5.4	22.5	0.0	22.5	Late 2010
D7	Northeast Transmission Reinforcement: Installation of Static Var Compensators at Porcupine TS & Kirkland Lake TS	Development, Non-Discretionary	Category 2	Pre-IPSP	Not Required	Not Required	-	-	0.3	5.0	48.5	54.8	108.6	0.0	108.6	Late 2010
D8	Installation of Series Capacitors at Nobel SS	Development, Non-Discretionary	Category 2	Pre-IPSP	Completed	Not Required	-	0.1	0.4	5.3	34.2	7.2	47.2	0.0	47.2	Late 2010
D9	Installation of 100MVar Shunt Capacitor Bank at Algoma TS	Development, Non-Discretionary	Category 2	Pre-IPSP	Not Required	Not Required	-	-	-	-	4.6	5.1	9.7	0.0	9.7	Late 2010
D10	Installation of two 75MVar Shunt Capacitor Banks at Mississagi TS	Development, Non-Discretionary	Category 2	Pre-IPSP	Not Required	Not Required	-	-	-	-	2.9	7.4	10.3	0.0	10.3	Late 2010
D11	Installation of +300/-100MVar Static Var Compensator at Mississagi TS	Development, Non-Discretionary	Category 3	Pre-IPSP	Not Required	Not Required	-	-	-	-	0.8	20.9	31.9	0.0	31.9	Late 2011
D12	Installation of two 125MVar Shunt Capacitor Bank at Porcupine TS	Development, Non-Discretionary	Category 3	Pre-IPSP	Not Required	Not Required	-	-	-	-	0.0	5.5	14.6	0.0	14.6	Late 2011
D13	Installation of 350MVar Static Var Compensator & two 27kV, 150MVar Reactors at Nanticoke TS	Development, Non-Discretionary	Category 3	Pre-IPSP	Not Required	Not Required	-	-	-	-	15.2	44.4	80.0	0.0	80.0	Mid 2011
D14	Installation of 350MVar Static Var Compensator at Detweiler TS	Development, Non-Discretionary	Category 3	Pre-IPSP	Not Required	Not Required	-	-	-	-	13.1	38.5	69.2	0.0	69.2	Mid 2011
	Other Capital Projects (<$3M) with 2009-10 Cashflows[5]						-	0.1	1.1	5.2	6.4	8.6	28.3	0.0	28.3	
	Other Historical Projects (pre-2009)[6]						37.3	63.8	(0.3)	0.0	-	-	100.8	2.0	98.8	
	Total						**37.3**	**68.0**	**81.6**	**130.4**	**396.5**	**509.6**	1435.3	**2.0**	1433.3	

Note 1: **IPSP Category:** in relation to the Integrated Power System Plan ("IPSP") indicating whether the project is Pre-IPSP, IPSP, or Non-IPSP.
Note 2: **Gross Total Cost:** of the plan cost, including the sum of the cash flows in the years before 2009 and after 2010 and the amount of customer contribution where applicable.
Note 3: Customer Contribution: the sum of the cash flows that is paid by the customer (where applicable). The capital contribution amounts indicated herein are considered preliminary, since they are yet to be finalized, based on the signed CCRA and the actual project cost.
Note 4: Net Total Cost: Gross Total Cost minus Customer Contribution.
Note 5: The cash flows shown in **"Other Capital Projects"** comprise accumulated gross cash flows for projects that require non-zero expenditures of less than $3 million in either 2009 or 2010
Note 6: The cash flows shown in **"Other Historical Projects"** comprise accumulated gross cash flows in Historical and Bridge years for projects that do not have any expenditure in 2009 or 2010.

Table 3
Local Area Supply Adequacy: Summary of Development Capital Projects in Excess of $3 Million

Item#	Investment Description	Classification as per OEB Filing Guidelines	Capital Project Category	IPSP Category[1]	EA Status	Section 92 Status	Cash Flow ($ Millions)									In-Service Year
							Historical			Bridge	Test	Test	Gross Total Cost[2]	Capital Contribution[3]	Net Total Cost[4]	
							2005	2006	2007	2008	2009	2010				
D15	Southern Georgian Bay Transmission Reinforcement	Development, Non-Discretionary	Category 1	Pre-IPSP	Completed	Completed	0.6	0.6	34.7	41.1	11.0	0.0	88.0	0.0	88.0	Mid 2009
D16	Hurontario Station and Transmission Line Reinforcement	Development, Non-Discretionary	Category 1	Pre-IPSP	Completed	Completed	-	0.5	2.6	15.9	15.9	8.6	43.5	0.0	43.5	Mid 2010
D17	Transmission Reinforcement for the Supply to Jim Yarrow TS	Development, Non-Discretionary	Category 1	Pre-IPSP	Completed	Completed	-	-	0.4	1.8	30.3	8.9	49.1	0.0	49.1	Mid 2011
D18	Woodstock Area Transmission Reinforcement	Development, Non-Discretionary	Category 1	Pre-IPSP	Completed	Completed	-	0.1	0.7	2.1	32.3	17.2	69.8	0.0	69.8	Mid 2011
D19	Replacement of Switchgear & Main Bus in 115kV Switchyard at Burlington TS	Development, Non-Discretionary	Category 3	Non-IPSP	Not Required	Not Required	-	-	0.1	0.8	2.5	3.4	11.8	0.0	11.8	Mid 2011
D20	Replacement of Twelve 115kV Circuit Breakers at Burlington TS	Development, Non-Discretionary	Category 3	Non-IPSP	Not Required	Not Required	-	-	-	-	3.0	5.9	14.1	0.0	14.1	Late 2011
D21	Leaside TS x Birch Junction Transmission Reinforcement	Development, Non-Discretionary	Category 4	Pre-IPSP	Required	Required	-	0.2	0.1	-	-	0.6	56.6	39.6	17.0	Mid 2012
D22	Supply to Essex County	Development, Non-Discretionary	Category 4	Pre-IPSP	Required	Required	-	-	0.2	0.1	0.0	3.0	43.9	0.0	43.9	Late 2012
	Other Capital Projects (<$3M) with 2009-10 Cashflows[5]						-	0.1	1.5	5.9	6.3	3.2	63.2	0.0	63.2	
	Other Historical Projects (pre-2009)[6]						65.7	33.3	65.2	5.8	-	-	170.1	15.6	155.7	
	Total						**66.3**	**34.8**	**105.5**	**73.4**	**101.3**	**50.8**	**610.1**	**55.2**	**556.1**	

Note 1: **IPSP Category:** in relation to the Integrated Power System Plan ("IPSP") indicating whether the project is Pre-IPSP, IPSP, or Non-IPSP.
Note 2: **Gross Total Cost:** of the plan cost, including the sum of the cash flows in the years before 2009 and after 2010 and the amount of customer contribution where applicable.
Note 3: Customer Contribution: the sum of the cash flows that is paid by the customer (where applicable). The capital contribution amounts indicated herein are considered preliminary, since they are yet to be finalized, based on the signed CCRA and the actual project cost.
Note 4: Net Total Cost: Gross Total Cost minus Customer Contribution.
Note 5: The cash flows shown in **"Other Capital Projects"** comprise accumulated gross cash flows for projects that require non-zero expenditures of less than $3 million in either 2009 or 2010
Note 6: The cash flows shown in **"Other Historical Projects"** comprise accumulated gross cash flows in Historical and Bridge years for projects that do not have any expenditure in 2009 or 2010.

Table 4
Load Customer Connection: Summary of Development Capital Projects in Excess of $3 Million

Item#	Investment Description	Classification as per OEB Filing Guidelines	Capital Project Category	IPSP Category (Note 1)	EA Status	Section 92 Status	Cash Flow ($ Millions) (Note 2)									In-Service Year
							Historical			Bridge	Test	Test	Gross Total Cost	Capital Contribution	Net Total Cost	
							2005	2006	2007	2008	2009	2010				
D23	Kingston Gardiner TS: Add Transformation Capacity	Connection, Customer Driven	Category 2	Non-IPSP	Not Required	Not Required	-	-	2.2	6.1	6.0	0.0	14.3	5.8	8.5	Late 2008 / Mid 2009
D24	Holland TS: Build new 230/44kV TS & Line Connection	Connection, Customer Driven	Category 2	Non-IPSP	Completed	Not Required	-	1.2	6.6	12.3	6.1	0.0	26.2	0.0	26.2	Mid 2009
D25	Goreway TS: Build and Connect second 230/27.6 kV DESN	Connection, Customer Driven	Category 2	Non-IPSP	Not Required	Not Required	-	-	0.2	3.2	14.9	6.3	24.6	9.8	14.8	Mid 2010
D26	Vansickle TS: Increase capacity to supply new load	Connection, Customer Driven	Category 2	Non-IPSP	Not Required	Not Required	-	-	-	-	10.4	5.9	16.3	11.6	4.7	Mid 2010
D27	Churchill Meadow TS: Build new 230/44kV TS & Line Connection	Connection, Customer Driven	Category 2	Non-IPSP	Required	Not Required	-	0.1	(0.1)	1.1	12.4	10.5	24.0	2.7	21.3	Late 2010
D28	Glendale TS: Increase capacity to supply new load	Connection, Customer Driven	Category 2	Non-IPSP	Not Required	Not Required	-	-	-	-	1.0	12.2	13.2	10.0	3.2	Late 2010
D29	Dunnville TS: Increase capacity to supply new load	Connection, Customer Driven	Category 2	Non-IPSP	Not Required	Not Required	-	-	-	-	0.4	8.1	8.6	7.8	0.8	Late 2010
D30	Hanlon TS: Build new TS & Line Connection	Connection, Customer Driven	Category 3	Non-IPSP	Not Required	Not Required	-	-	-	0.1	0.9	21.3	28.3	27.2	1.1	Mid 2009 / Mid 2011
D31	Crowland TS: Build and Connect second 115/27.6 kV DESN	Connection, Customer Driven	Category 3	Non-IPSP	Not Required	Not Required	-	-	-	-	0.2	12.7	21.9	19.4	2.5	Mid 2011
D32	Build New 230/28 kV TS & Line Connection in Northern Mississauga	Connection, Customer Driven	Category 3	Non-IPSP	Required	Maybe Required	-	-	-	-	2.0	25.7	36.1	29.1	7.0	Mid 2011
D33	Enfield TS: Add Transformation Capacity	Connection, Customer Driven	Category 3	Non-IPSP	Required	Not Required	-	0.3	0.3	0.3	0.4	18.3	25.6	13.6	12.0	Mid 2011
D34	Bracebridge TS: Station Expansion	Connection, Customer Driven	Category 3	Non-IPSP	Not Required	Not Required	-	-	0.2	0.0	0.4	14.4	19.5	17.1	2.4	Mid 2011
D35	Long Lac TS: Replace End-of-Life 115/44kV Transformers	Connection, Non-Discretionary	Category 3	Non-IPSP	Not Required	Not Required	0.2	-	0.1	0.1	1.0	4.7	14.6	0.0	14.6	Mid 2011
D36	Rodney TS: Build new TS & Line Connection	Connection, Non-Discretionary	Category 3	Non-IPSP	Required	Not Required	-	-	0.2	0.0	3.0	8.5	18.9	0.0	18.9	Late 2011
D37	Woodstock East TS: Build new TS & Line Connection	Connection,	Category 4	Non-IPSP	Required	Required	-	-	-	0.1	0.2	17.2	30.6	17.7	12.9	Mid 2011
	Other Capital Projects (<$3M) with 2009-10 Cashflows[5]						0.1	0.0	0.1	0.0	7.5	5.6	104.0	86.0	18.0	
	Other Historical Projects (pre-2009)[6]						36.9	51.2	53.9	10.3	-	-	152.3	26.4	128.9	
	Total						**37.2**	**52.8**	**63.7**	**33.6**	**66.9**	**171.6**	**579.0**	**284.2**	**297.8**	

Note 1: **IPSP Category:** in relation to the Integrated Power System Plan ("IPSP") indicating whether the project is Pre-IPSP, IPSP, or Non-IPSP.
Note 2: **Gross Total Cost:** of the plan cost, including the sum of the cash flows in the years before 2009 and after 2010 and the amount of customer contribution where applicable.
Note 3: Customer Contribution: the sum of the cash flows that is paid by the customer (where applicable). The capital contribution amounts indicated herein are considered preliminary, since they are yet to be finalized, based on the signed CCRA and the actual project cost.
Note 4: Net Total Cost: Gross Total Cost minus Customer Contribution.
Note 5: The cash flows shown in **"Other Capital Projects"** comprise accumulated gross cash flows for projects that require non-zero expenditures of less than $3 million in either 2009 or 2010
Note 6: The cash flows shown in **"Other Historical Projects"** comprise accumulated gross cash flows in Historical and Bridge years for projects that do not have any expenditure in 2009 or 2010.

Table 5
Generation Customer Connection: Summary of Development Capital Projects in Excess of $3 Million

Item#	Investment Description	Classification as per OEB Filing Guidelines	Capital Project Category	IPSP Category[1]	EA Status	Section 92 Status	Cash Flow ($ Millions)									In-Service Year
							Historical			Bridge	Test	Test	Gross Total Cost[2]	Capital Contribution[3]	Net Total Cost[4]	
							2005	2006	2007	2008	2009	2010				
D38	Lower Mattagami Extensions	Connection, Customer Driven	Category 4	Non-IPSP	Required	Required	-	-	0.3	(0.3)	6.9	16.4	32.8	13.8	19.0	Early 2012
	Future Generation Provision[7]	Connection, Customer Driven	Category 4	Non-IPSP	TBD	TBD	-	-	-	-	-	9.5	9.5	0.0	9.5	
	Other Capital Projects (<$3M) with 2009-10 Cashflows[5]						-	0.5	0.7	2.4	5.0	6.4	15.0	10.2	4.8	
	Other Historical Projects (pre-2009)[6]						3.4	37.0	54.8	23.9	-	-	119.1	42.6	76.5	
	Total						**3.4**	**37.5**	**55.8**	**26.0**	**11.9**	**32.3**	**176.4**	**66.6**	**109.8**	

Note 1: **IPSP Category:** in relation to the Integrated Power System Plan ("IPSP") indicating whether the project is Pre-IPSP, IPSP, or Non-IPSP.
Note 2: **Gross Total Cost:** of the plan cost, including the sum of the cash flows in the years before 2009 and after 2010 and the amount of customer contribution where applicable.
Note 3: Customer Contribution: the sum of the cash flows that is paid by the customer (where applicable). The capital contribution amounts indicated herein are considered preliminary, since they are yet to be finalized, based on the signed CCRA and the actual project cost.
Note 4: Net Total Cost: Gross Total Cost minus Customer Contribution.
Note 5: The cash flows shown in **"Other Capital Projects"** comprise accumulated gross cash flows for projects that require non-zero expenditures of less than $3 million in either 2009 or 2010
Note 6: The cash flows shown in **"Other Historical Projects"** comprise accumulated gross cash flows in Historical and Bridge years for projects that do not have any expenditure in 2009 or 2010.
Note 7: The 2010 cashflow for Future Generation Provision provides for potential generation connection work that may be required as a result of supply projects arising out of recent RFPs issued by the OPA.

Table 6
Performance Enhancement and Risk Mitigation: Summary of Development Capital Programs

Investment Description	Classification as per OEB Filing Guidelines	Gross Cash Flow ($ Millions)					
		Historical			Bridge	Test	Test
		2005	2006	2007	2008	2009	2010
Delivery Point Performance / Power Quality	Development, Non-Discretionary	0.7	2.0	1.0	3.6	4.2	3.0
Compliance / Mitigate High-Risk	Development, Non-Discretionary	2.8	10.4	1.5	0.1	3.0	11.2
Total		**3.5**	**12.4**	**2.5**	**3.7**	**7.2**	**14.2**