HYDRO ONE NETWORKS INC.
TRANSMISSION
Statement of Utility Rate Base
Forecast Years (2011 and 2012)
Year Ending December 31
($ Millions)

Line No.	Particulars		2011 (a)		2012 (b)
	Electric Utility Plant				
1	Gross plant at cost	$	12,297.3	$	13,509.5
2	Less: accumulated depreciation		(4,429.1)		(4,690.6)
3	Net plant in service	$	7,868.2	$	8,818.9
4	Construction work in progress		485.8		289.0
5	Net utility plant	$	8,354.0	$	9,107.9
	Working Capital				
4	Cash working capital	$	7.1	$	5.0
5	Materials and Supplies Inventory		17.4		21.7
6	Total working capital	$	24.5	$	26.7
7	Total rate base	$	8,378.5	$	9,134.6

1 # COMPARISON OF NET CAPITAL EXPENSE BY MAJOR
2 # CATEGORY

3

	Historic			Bridge	Test	
	2007	2008	2009	2010	2011	2012
Transmission Capital ($ millions)						
Sustaining						
Transmission Stations						
Circuit Breakers	0.6	11.6	16.6	30.8	23.6	24.9
Station Reinvestment	48.9	71.1	34.6	16.8	84.0	84.7
Power Transformers	18.7	40.7	48.7	71.3	63.5	65.7
Other Power Equipment	11.5	9.0	13.1	15.4	19.6	21.2
Ancillary Systems	8.9	9.9	6.0	9.1	18.0	18.1
Stations Environment	5.9	6.2	3.0	2.8	8.4	8.5
Protection, Control, Monitoring, and Telecommunications	44.1	55.2	82.0	72.5	93.8	107.5
Transmission Site Facilities and Infrastructure	4.0	20.3	20.1	23.1	26.5	26.4
Total Transmission Stations Capital	142.7	223.9	224.1	241.8	337.3	357.0
Transmission Lines						
Overhead Lines Refurbishment and Component Replacement	46.4	44.0	56.8	54.9	55.6	57.6
Transmission Lines Reinvestment	6.2	7.3	15.2	9.8	8.9	7.3
Underground Lines Cable Refurbishment & Replacement	14.6	5.3	4.1	1.9	22.2	21.6
Total Transmission Lines Capital	67.2	56.5	76.0	66.6	86.7	86.5
Total Sustaining Capital	210.0	280.4	300.1	308.3	424.0	443.4

	Historic			Bridge	Test	
	2007	**2008**	**2009**	**2010**	**2011**	**2012**
Development						
Inter Area Network Transfer Capability	80.5	152.6	343.1	424.5	307.9	139.3
Local Area Supply Adequacy	97.4	91.0	93.7	61.9	150.5	101.4
Load Customer Connection	53.7	46.8	54.4	31.9	81.8	84.7
Generator Customer Connection	38.4	17.6	4.5	0.0	0.0	0.0
Performance Enhancement & Risk Mitigation	2.5	2.9	19.2	17.5	24.0	7.2
TS Upgrades to Facilities Distribution Generation	0.0	0.0	0.2	0.0	33.8	81.4
P&C Enablement for Generation Connections	0.0	0.0	0.9	0.6	11.4	36.0
Smart Grid	0.0	0.0	0.4	1.4	7.8	6.8
Total Development	272.6	310.9	516.2	537.9	617.2	456.8
Operations						
Grid Operating and Control Facilities	2.0	16.8	11.3	8.8	22.6	18.5
Operating Infrastructure	2.7	6.3	8.7	1.4	21.7	38.9
Total "Operations"	4.7	23.1	20.0	10.1	44.3	57.4
Shared Services and Other Costs						
Transport, Work & Service Equipment	13.3	17.5	14.0	19.8	21.6	17.0
Information Technology	13.3	9.2	9.2	17.0	18.9	14.4
Cornerstone	35.2	59.1	50.9	11.1	2.0	0.2
Facilities & Real Estate	3.2	3.5	6.3	25.8	23.9	19.1
Other	7.1	0.5	1.1	0.0	0.0	0.0
Total Shared Services & Other Costs	72.2	89.8	81.5	73.6	66.3	50.6
Total Transmission Capital	**559.5**	**704.2**	**917.8**	**930.0**	**1,151.8**	**1,008.3**

LIST OF CAPITAL INVESTMENT PROGRAMS OR PROJECTS REQUIRING IN EXCESS OF $3 MILLION IN TEST YEAR 2011 OR 2012 ($ MILLIONS)

1.0 SUSTAINING CAPITAL (EXHIBIT D1, TAB 3, SCHEDULE 2)

1.1 Stations

		2011	2012
S1	2011/2012 Oil Circuit Breaker Replacement Program	6.9	7.9
S2	2011/2012 SF6 Breakers Type SP Replacements	13.2	13.4
S3	2011/2012 Metalclad Circuit Breakers Replacement - GTA	10.5	10.7
S4	Beck #1 SS: Air Blast Circuit Breaker (ABCB) Re-Investment	25.5	20.6
S5	Abitibi Canyon Switching Station (SS) and Pinard Transformer Station (TS) - Replace EOL Components	10.3	10.3
S6	Nanticoke TS: Air Blast Circuit Breaker (ABCB) Re-Investment	4.3	0
S7	Orangeville TS: Air Blast Circuit Breaker (ABCB) Re-Investment	10.3	10.6
S8	Richview TS 230 kV Switchyard: Air Blast Circuit Breaker (ABCB) Re-Investment	5.1	10.3
S9	Hanmer TS 500 kV ABCB Replacement	8.4	8.5
S10	Pickering A switchyard : Air Blast Circuit Breaker (ABCB) Re-Investment	3.2	3.3
S11	Merival GIS ITE Bus Replacement	6.3	6.4
S12	N.R.C Transmission Station	0	4.0
S13	Richview TS - Replace EOL Transformers T7/T8	6.4	2.8
S14	Replace EOL CGE Transformers	31.8	34.4
S15	Leaside TS - Replace EOL Transformers T19, T20 and T21	4.9	6.5
S16	Purchase Spare Transformers	13.2	13.3
S17	2011/2012 Station HV Disconnect replacement Program	5.1	5.2
S18	Capacitor Bank Replacement	3.1	3.3
S19	2011/2012 Station Service Upgrades	11.6	11.8
S20	2011/2012 Spill Containment Refurbishment - Major	8.4	8.5
S21	BSPS Replacement of End-of-Life Equipment	7.6	11.1

S22	ITC - Line Protections Replacements	4.8	4.9
S23	NYPA Tie Lines - Beck Line Protections Replacements	3.2	3.5
S24	2011 - 2012 Station P&C Replacement	22.0	22.2
S25	2011-2012 Protection Replacements	8.1	11.8
S26	2011-2012 RTU Replacement	5.0	5.5
S27	DC Signaling (Remote Trip) Replacements	7.0	6.4
S28	DC Signaling Replacements (Toronto North & East)	3.3	8.1
S29	NPCC Regulated Lines - Tone Equipment Replacements	5.6	8.2
S30	PLC Replacement Program	3.2	2.2
S31	TDCN Cyber Security	5.3	5.1
S32	2011/2012 Spill - Major Drainage	4.3	4.4
S33	Station Security Infrastructure	8.3	8.5

1.2 Lines

		2011	**2012**
S34	2011/2012 Transmission Wood Pole Replacement Program	30.8	31.3
S35	2011/2012 Steel Structure Coating Program	5.5	6.5
S36	2011/2012 Shieldwire Replacement Program	4.2	4.3
S37	2011/2012 Transmission Lines Emergency Restoration	6.6	6.6
S38	Circuit A6P - Reserve Jct. to Port Arthur TS Transmission Line Refurbishment	7.1	6.2
S39	H2JK / K6J Cable Replacement (Riverside Jct. x Strachan TS)	20.6	20.0

Summary – Sustainment	**2011**	**2012**
Total Sustaining Projects & Programs Listed Above	**351.0**	**368.4**
Sustaining Projects & Programs Less than $3 M	**73.0**	**75.0**
Total Sustaining Capital (per Exhibit D1-3-2)	**424.0**	**443.4**

2.0 DEVELOPMENT CAPITAL (EXHIBIT D1, TAB 3, SCHEDULE 3)

2.1 Inter-Area Network Transfer Capability

		2011	2012
D1	New 500 kV Bruce to Milton Double Circuit Transmission Line4	184.4	94.3
D2	Northeast Transmission Reinforcement: Install SVC's at Porcupine TS & Kirkland Lake TS	33.1	0
D3	Nanticoke TS - Install 500 kV, 350 MVar Static Var Compensator	22.1	0
D4	Detweiler TS - Install 230 kV, 350 MVar Static Var Compensator	34.9	0
D5	Essa TS - Install 250 MVar Shunt Capacitor Bank	5.9	0
D6	Porcupine TS - Install two100 MVar Shunt Capacitor Banks	10.3	0.2
D7	Hanmer TS - Install 149 MVar Shunt Capacitor Bank	7.9	0.1
D8	Dryden TS - Install a Shunt Capacitor Bank	0.1	10.3

2.2 Local Area Supply Adequacy

		2011	2012
D9	Woodstock Area Transmission Reinforcement	20.7	0
D10	Rebuild Burlington TS 115kV Switchyard	30.4	1.4
D11	Toronto Area Station Upgrades for Short Circuit Capability: Rebuild Hearn SS	54.6	27.0
D12	Toronto Area Station Upgrades for Short Circuit Capability: Leaside TS Equipment Uprate	13.5	21.9
D13	Toronto Area Station Upgrades for Short Circuit Capability: Manby TS Equipment Uprate	9.0	9.2
D14	Midtown Transmission Reinforcement Plan	31.0	36.7
D15	Guelph Area Transmission Reinforcement	1.0	4.1

2.3 Load Customer Connection

		2011	2012
D16	Commerce Way TS: Build new TS and Line Connection (formerly Woodstock East TS)	27.1	6.5
D17	Kirkland Lake TS: Reconnect Idle K4 Line	13.3	0.2

D18	South Halton Tremaine TS: Build New Transformer Station	20.9	5.5
D19	Ancaster TS: Build new Transformer Station and Line Connection	3.4	17.0
D20	East Ottawa TS: Build new Transformer Station	3.6	21.3
D21	Leamington TS: New 230/27.6 kV DESN and Line Connection	15.4	33.8
D22	New 230/28 kV Transformer Station in Northern Mississauga & Line Connection	0.1	7.4
D23	Enfield TS: Build 230/44 kV DESN and Line Connection (formally Oshawa Area TS)	0	4.9
D24	Long Lac TS: Replace End-of-Life 115-44 kV Transformers	5.3	0
D25	North Bay TS: Upgrade to a 115-44 kV Transformer Station	18.3	8.4
D26	Barwick TS: Build new Transformer Station	8.8	6.2
D27	Duart TS: Build new Transformer Station and Line Connection (formerly Rodney TS)	12.1	12.6

2.4 Generation Customer Connection

		2011	**2012**
D28	500 MW Renewables III RFP (Talbot Wind Farm)	23.0	0
D29	350 MW Peaking Generation in Northern York Region	4.5	0
D30	Chatham Wind Generation Connection (260MW)	0.1	4.1
D31	Lower Mattagami Generation Connections	2.0	4.0

2.5 Enabling Facilities (Government Instruction)

		2011	**2012**
D32	Enabling 230/44kV TS #1 and Short (<2km) Tap	0.05	8.4
D33	Enabling 115/44kV TS #1 and Short (<2km) Tap	0.05	8.4

2.6 Bulk & Regional Transmission (Government Instruction)

		2011	**2012**
D34	Algoma x Sudbury Transmission Expansion	0	5.7
D35	Northwest Transmission Reinforcement	4.5	16.9

2.7 Station Equipment Upgrades & Additions to Facilitate Renewables (Government Instruction)

		2011	**2012**
D36	Static Var Compensator #1 at Existing Station in South Western	0.4	32.9

	Ontario		
D37	In-Line Circuit Breakers #1	13.4	6.9
D38	In-Line Circuit Breakers #2	13.4	6.9
D39	In-Line Circuit Breakers #3	3.2	7.2
D40	In-Line Circuit Breakers #4	3.2	7.2
D41	In-Line Circuit Breakers #5	0	1.2
D42	In-Line Circuit Breakers #6	0	1.2

2.8 Protection and Control for Enablement of Distribution Connected Generation (Government Instruction)

		2011	2012
D43	Station Protection Upgrades for Distributed Generation	5.3	15.8
D44	Transfer Trip Facilities	4.7	14.0

2.9 Smart Grid

		2011	2012
D45	End-to End Testing of Interoperable Bus Architecture at Owen Sound and Meaford Transformer Stations	5.5	5.5

2.10 Performance Enhancement

		2011	2012
D46	Various lines and TSs outliers-inliers	4.0	4.0

2.11 Risk Mitigation

		2011	2012
D47	Mitigate Reliability Problems of HV Shunt Capacitor Installations	16.8	0.0

Summary – Development	**2011**	**2012**
Total Development Projects & Programs Listed Above	**701.7**	**490.4**
Development Projects & Programs Less than $3 M	**21.5**	**44.3**
Less Capital Contribution	**(106.1)**	**(77.9)**
Total Development Capital (per Exhibit D1-3-3)	**617.2**	**456.8**

3.0 OPERATIONS CAPITAL (EXHIBIT D1, TAB 3, SCHEDULE 4)

3.1 Grid Operations Control Facilities

		2011	2012
O1	Network Operations Buildings	12.1	11.0
O2	NMS Upgrade & Enhancements	3.8	4.0
O3	Tx Operating Facilities Sustainment	6.5	3.5

3.2 Operating Infrastructure

		2011	2012
O4	Hub Site Management Program	2.9	4.3
O5	Telemetry Expansion	3.4	3.5
O6	Wide Area Network	11.0	26.1

Summary – Operations	2011	2012
Total Operations Projects & Programs Listed Above	**39.7**	**52.4**
Operations Projects & Programs Less than $3 M	**4.6**	**5.0**
Total Operations Capital (per Exhibit D1-3-4)	**44.3**	**57.4**

4.0 SHARED SERVICES AND OTHER CAPITAL (EXHIBIT D1, TAB 3, SCHEDULE 5)

4.1 Information Technology

		2011	2012
IT1	Cornerstone Phase 2	-	-
IT2	Cornerstone Phase 3	20.8	29.3
IT3	Mobile IT Platform	3.0	2.0
IT4	GIS Implementation	6.0	4.9
IT5	MFA PC and Printer Hardware	6.2	4.2
IT6	Software Refresh & Maintenance - Enterprise Application Software	3.2	3.6
IT7	MFA UNIX Servers	4.1	4.2
IT8	MFA Windows Servers	3.5	1.9

4.2 Other

		2011	2012
C1	Real Estate Facilities Capital for 2011 and 2012	25.8	19.6
C2	Real Estate Head Office and GTA Facilities Capital for 2011 and 2012	19.0	15.6
C3	Shared Services Capital – Service Equipment	8.8	5.9
C4	Shared Services Capital – Transport & Work Equipment	74.1	60.2

Summary - Shared Services and Other Capital	**2011**	**2012**
Total Shared Services, Other Projects & Programs listed above	**174.5**	**151.4**
Shared Services, Other Projects & Programs less than $3 M	**11.9**	**8.3**
Less Cornerstone Savings	**(13.9)**	**(22.1)**
Total Shared Services & Other Capital (per Exhibit D1-3-5)	**172.5**	**137.6**
Transmission allocation of Shared Services & Other Capital (per Exhibit D1, Tab 3)	**66.3**	**50.6**

INVESTMENT SUMMARY FOR PROGRAMS/PROJECTS IN EXCESS OF $3 MILLION

Sustaining Capital	S1 to S39
Development Capital	D1 to D47
Operations Capital	O1 to O6
Shared Services and Other Capital	IT1 to IT8
	C1 to C4

Hydro One Networks – Investment Summary Document

Investment Category: Sustaining Capital – Stations - Circuit Breakers

Reference #	Investment Name	Gross Cost	In-Service Date
S1	2011/2012 Oil Circuit Breaker Replacements	$16.5 M	Late 2012

Please see Exhibit D1, Tab 3, Schedule 2 for cash flows and other details about the investment.

Need:

This investment is required to address end of life issues of the aging population of oil circuit breakers (OCBs) by proactively replacing those that represent the highest risk to system security and customer connection reliability.

Implications of not proactively managing this population of breakers include overall decline of health of the OCB population and employee safety. Inaction will result in a trend of equipment unavailability, inadequate equipment fault ratings, an increase in probability of failure and equipment outages (both customer and network connected) and an increased risk to Hydro One's Safety & Environment business values.

Summary:

Hydro One currently owns and manages over 4,400 circuit breakers of which oil circuit breakers account for 2003 of the total population. These bulk oil circuit breakers, which utilize organic insulating fluids for extinguishing arc produced during opening sequences, are no longer commercially available and are being replaced with new SF6 Circuit Breaker (CB) technology. Historically, OCBs have provided excellent in-service performance but a portion of the entire population reaches end of life each year. 25 % of the total population is over 50 years old and over 50 % of the total population is over 40 years old. Based on various studies conducted since 1990 to assess the condition of OCBs, both refurbishment and replacement programs had been developed. As a result, an overall replacement strategy was developed by Hydro One to address the condition and ratings of OCBs on a prioritized basis. The strategy was developed based on several criteria, including age, physical condition, parts obsolescence and equipment ratings. These criteria are used to assess the replacement candidates, and to put into motion the recommendations of the strategy.

Current performance measures have steadily improved from thirteen catastrophic failures during 1992-1996 to only three during 1997- 2004 since the onset of annual replacement and refurbishment programs. As a result of program success, future overall performance trends are expected to remain at the current levels. The OCB replacement program as of 2009 will have addressed a total of 919 end of life oil circuit breakers throughout the province.

In summary, the strategy identifies candidates for replacement based on assessed conditions and switching duty-cycle requirements, equipment health reports, equipment defects reports and other localized special studies. Prioritization is based on risk as it relates to the HONI Business Values. The transmission system development and transmission load connections departments have reviewed the replacement candidates included in this investment for integration opportunities, and have concurred with the program prioritization.

Results:

This plan will replace 34 OCBs in 2011 and 2012 to address end-of-life equipment and maintain customer reliability.

Project Classification per OEB Filing Guidelines:

Project Class:	Sustaining
Project Need:	Non-Discretionary

Hydro One Networks – Investment Summary Document

Investment Category: Sustaining Capital – Stations - Circuit Breakers

Reference #	Investment Name	Gross Cost	In-Service Date
S2	2011/2012 SF6 Breaker Replacements	$29.5 M	Late 2012

Please see Exhibit D1, Tab 3, Schedule 2 for cash flows and other details about the investment.

Need:

This investment is required to address end of life issues of the population of SF6 breakers, Manufacturer Model Type SP, HPL, PA, FC4, FG4 and GA, by proactively replacing those that represent the highest risk to system security and customer connection reliability.

Implications of not proactively managing this population of breakers include overall decline of health of the SF6 breaker population and employee safety. Inaction will result in a trend of equipment unavailability, inadequate equipment fault ratings, an increase in probability of failure and equipment outages (both customer and network connected) and an increased risk to Hydro One's Safety & Environment business values.

Summary:

Hydro One currently owns and manages over 1,263 SF6 circuit breakers. The breaker types in this investment, which utilize SF6 gas for arc extinguishing, are no longer commercially available and are being replaced with new SF6 Circuit Breaker technology at end of life. Each of these breaker types are the original designed low voltage SF6 breakers built in early 1980’s and have several major design flaws which include poor interrupters (nozzles/contacts) that require frequent replacement, pneumatic mechanisms have leak issues, control valve issues and internal air storage tank rust/corrosion deterioration.

There is clear evidence from an increasing trend in forced outages and increasing maintenance costs, of deteriorating performance of the early vintage SF6 breakers over the last 5 years. About 44% of the worst performing HV breakers (based on forced outage frequency) are SF6 CBs.

A large proportion (about 30%) of the SF6 breaker population is applied for the most onerous, special purpose duties, such as reactor and capacitor bank switching, some involving several hundred operations per year thus accelerating the mechanical and electrical wear out of the breaker. The complex control and operating mechanisms installed in almost all of these early vintage breakers resulted in increased operating problems and significant maintenance and refurbishment expenditures. Most of these very poor performing breakers have reached or surpassed their mechanical design life of 2000 switching operations.

In summary, candidates for replacement are based on age, assessed condition and switching duty-cycle requirements, performance statistics, equipment health reports, equipment defects reports and other localized special studies. Prioritization is based on risk as it relates to the HONI Business Values. The transmission system development and transmission load connections departments have reviewed the replacement candidates included in this investment for integration opportunities, and have concurred with the program prioritization.

Results:

This plan will replace 68 SF6, circuit breakers in 2011 and 2012 to address end-of-life equipment and maintain customer reliability.

Project Classification per OEB Filing Guidelines:

Project Class:	Sustaining
Project Need:	Non-Discretionary

Hydro One Networks – Investment Summary Document

Investment Category: Sustaining Capital – Stations - Circuit Breakers

Reference #	Investment Name	Gross Cost	In-Service Date
S3	2011/2012 Metalclad Circuit Breakers Replacement - GTA	$23.5 M	Late 2012

Please see Exhibit D1, Tab 3, Schedule 2, Table 4 for cash flows and other details about the investment.

Need:

This investment is required to address the end of life (“EOL”) condition of the low-voltage metalclad switchgear in the Greater Toronto Area (“GTA”) and the lack of arc proofing on these units.

The implications of not proactively replacing EOL metalclad equipment are:

- A reliability reduction to Toronto Hydro (“THESL”) and its customers resulting in a negative impact on reputation
- Increased maintenance expenditures and difficulty in obtaining or fabricating technically obsolete spare parts
- GTA metalclads are not arc proofed which creates a safety risk

Summary:

Thirty one of the 100 metalclad line-ups in the GTA are currently exceeding manufacturer's life expectancy of 40 years. Eight metalclad line-ups have been replaced since 1992. THESL and Hydro One (HONI) have recently identified four locations in the GTA for replacement over the next two years. They are at EOL based on age, parts availability, reliability and safety considerations. The supporting information is obtained from consultations with THESL, asset condition assessment, data registries, routine diagnostics, inspection results, system analysis and outage logs.

This existing switchgear is not built to present day arc proof type C standards which results in safety and reliability concerns. HONl has experienced, on average, two major faults per year with inadequate metalclad arc proofing design. This can result in damages to the adjacent feeders and a potentially hazardous situation for personnel. The switchgear includes feeder breakers that are owned by THESL and bank breakers that are owned by HONI. THESL and HONl are coordinating replacements of end of life metalclad breakers at four transmission stations within the GTA. The replacement program includes the new metalclad circuit breakers along with new protections and the 15 kV cables that supply the switchgear.

Results:

- Reduce the life cycle cost and maintain customer reliability
- Facilitate recognized practices with the addition of a modern design and safety interlocks
- Upgrade breakers to current safety standards by the addition of arc proofing

Project Classification per OEB Filing Guidelines:

Project Class:	Sustaining
Project Need:	Non-Discretionary

Hydro One Networks – Investment Summary Document

Investment Category: Sustaining Capital - Stations - System Re-Investment

Reference #	Investment Name	Gross Cost	In-Service Date
S4	Beck #1 SS: Air Blast Circuit Breaker (ABCB) Re-Investment	$47.4 M	Late 2012

Please see Exhibit D1, Tab 3, Schedule 2, Table 4 for cash flows and other details about the investment

Need:

This investment is required to:

- Eliminate end of life obsolete Air Blast Circuit Breakers (“ABCB’s”) through replacement of ABCB’s and other equipment that is approaching end of life,
- De-merge Hydro One assets from the Ontario Power Generation (“OPG”) powerhouse.

If this work is not completed, there will be a continued decline in the health and reliability of the ABCB population and associated end of life (“EOL”) components, and reduced system reliability and customer reliability in the area.

Summary:

Originally built in the 1920’s, Beck #1 SS facilitates bulk power transfers on the 115 kV network, and connects 563 MW of hydroelectric generation at Beck #1 GS. In addition to providing a major network path, the 115 kV circuits supply several load stations and large customers including Allanburg TS, Niagara TS, Gage TS, Stanley TS, Murray TS, Decew Falls SS, Beamsville TS and Niagara on the Lake Hydro. There are twelve 115 kV circuits connected at Beck #1 SS including two circuits to USA Niagara Mohawk. Seven of the circuits operate at 60 Hz and the remaining five at 25 Hz.

There are ten 115 kV breakers that are owned by Hydro One. Six are 115 kV ABCBs manufactured by English Electric (“EE”) type OBN8G / OBN9G; in which five were built in 1950 and one built in 1954. The remaining 4 breakers are SF6 breakers. The original ABCB manufacturer is no longer in business. Technical support and spare parts are no longer available. Air blast circuit breakers employ high pressure air as an interrupting and insulating medium. At this point the o-rings and seals have deteriorated to such an extent that the breakers are unable to contain the insulating air properly resulting in an increased risk of failure. Two of the EE breakers are out of service at this time due to air system capacity issues.

In 2006, a site assessment identified all six of these 115 kV ABCB's to be replaced with new SF6 breakers, as well as replacement of 32 high voltage switches, two high voltage ground switches, and twelve high voltage instrument transformers. This investment will address these replacements with the establishment of the new 115 kV switchyard located on lands west of the existing power house and re-routing of the existing circuits. When this work is completed, there will be connections for the existing USA inter connections and space for two more diameters and a DESN station. This investment will also enable a staged de-merger from the common systems including high-pressure air systems that are shared with OPG.

Results:

- Reduce operational risks, minimize life cycle costs, and improve system reliability.
- De-merger of Hydro One assets from the OPG powerhouse and resulting reduction in business liability.

Project Classification per OEB Filing Guidelines:

Project Class:	Sustaining
Project Need:	Non-Discretionary

Hydro One Networks – Investment Summary Document

Investment Category: Sustaining Capital - Stations - System Re-Investment

Reference #	Investment Name	Gross Cost	In-Service Date
S5	Abitibi Canyon SS and Pinard TS - Replace Oil Circuit Breakers (OCB) and other EOL Components	$21.7 M	Late 2012

Please see Exhibit D1, Tab 3, Schedule 2, Table 4 for cash flows and other details about the investment.

Need:

This investment is required to replace Oil Circuit Breakers (OCB's) and other equipment that is reaching end of life at these stations to minimize life cycle costs and to de-merge Hydro One assets from Ontario Power Generation's (OPG) powerhouse.

If this work is not completed, there is significant risk of a system decline in the health and reliability of the OCB population and other EOL components, a reduction in system reliability and a decrease in customer reliability.

Summary:

Originally built in the early 1930's, Abitibi Canyon SS facilitates 350 MW of hydraulic generation and bulk power flows on the 230 kV and 115 kV networks. There is 230 kV and three 115 kV circuits connected at Abitibi Canyon SS. The 115 kV oil circuit breakers are used for both ring bus switching and generation unit synchronization. Hydro One's 115 kV ring bus arrangement is situated on the OPG owned powerhouse dam. All the ancillary services and protection and control systems are within the powerhouse dam.

The 115 kV breakers at Abitibi Canyon SS are 62 years old and rank amongst the top 30 worst breakers in the Hydro One system. Furthermore, the sole provider of spare parts for these breakers has indicated that they no longer support the breaker type. In addition to the breakers, the insulation systems, switches, protection and control facilities, foundations and ancillary systems have all reached end of life.

An asset condition and risk assessment has determined that the five 115 kV OCB's at Abitibi Canyon SS have reached end of life and have been prioritized for replacement with new SF6 breakers. The investments contained in this proposal primarily focus on the end of life 115 kV power equipment and the required 115 kV system reconfigurations which includes the construction of a new ring bus at Pinard TS and the reconfiguration of several circuits. In addition, investments are required to fully de-merge the integrated control, metering, relaying, annunciation and ancillary systems for both the 230 kV and 115 kV systems.

Results:

- Reduce the operational risks, minimize life cycle costs, eliminate safety and environmental issues, and improve the bulk system equipment reliability.
- De-merger of Hydro One assets from the OPG powerhouse and the resulting reduction in business liability.

Project Classification per OEB Filing Guidelines:

Project Class:	Sustaining
Project Need:	Non-Discretionary

Hydro One Networks – Investment Summary Document

Investment Category: Sustaining Capital - Stations - System Re-Investment

Reference #	Investment Name	Gross Cost	In-Service Date
S6	Nanticoke TS: Air Blast Circuit Breaker (ABCB) Re-Investment	$4.9 M	Mid 2011

Please see Exhibit D1, Tab 3, Schedule 2, Table 4 for cash flows and other details about the investment

Need:
This investment is required to replace end of life (“EOL”) Air Blast Circuit Breakers (“ABCB's”) and other EOL station components, and de-merge Hydro One assets from the Ontario Power Generation (“OPG”) facilities.

If this work is not completed, there is significant risk of the decline in the health and reliability of the ABCB population and associated EOL components, and reduced system reliability and customer reliability in the area. This cash flow is used to complete a project started in 2008.

Summary:
Originally built in the early 1970’s, Nanticoke TS is a station that facilitates bulk power transfers on the 500 kV and 230 kV network, and connects 4000 MW of coal-fired generation at Nanticoke GS. There are three 500 kV and six 230kV circuits connected at Nanticoke TS. The 230 kV breakers at Nanticoke TS are approximately 35 years old, partially rebuilt in the mid-1990’s. The high-pressure air system was also partially refurbished to support the ABCB population. The sole provider of spare parts for these ABCB breakers has indicated that they no longer support this breaker type. The 230 kV breakers at Nanticoke TS are unique within Hydro One in so far as the parts are not interchangeable with any other ABCB on the system.

In addition to providing a major network path, the 230 kV circuits supply several load stations including Jarvis TS, Caledonia TS and large customers. As part of the Ontario Government’s coal replacement initiative, Nanticoke GS is planned to be shutdown in phases during the 2011 to 2014 period. Even without the Nanticoke generation, the transmission facilities at Nanticoke TS are required for ongoing system and customer load security.

This investment will replace fourteen 230 kV ABCB’s at Nanticoke TS, which are at end of life, with new SF6 breakers. In addition to the breaker replacement, other EOL components within the 230 kV switchyard have been identified for replacement. These components include 34 High Voltage Switches, 27 High Voltage Instrument Transformers and the main station service. The 230 kV yard perimeter fence will also be replaced in order to address site security and safety issues. This investment will enable a staged demerger from the common systems including station service and high-pressure air systems that are shared with OPG (230 kV only, as 500kV systems remain integrated with OPG).

Results:
- Reduce the operational risks, minimize life cycle costs, and satisfy regulatory requirements.
- The de-merger of the Hydro One assets from the OPG powerhouse will also be accomplished thereby reducing business liability and risk.

Project Classification per OEB Filing Guidelines:

Project Class:	Sustaining
Project Need:	Non-Discretionary

Hydro One Networks – Investment Summary Document

Investment Category: Sustaining Capital - Stations - System Re-Investment

Reference #	Investment Name	Gross Cost	In-Service Date
S7	Orangeville TS: Air Blast Circuit Breaker (ABCB) Re-Investment	$23.0 M	2013

Please see Exhibit D1, Tab 3, Schedule 2, Table 4 for cash flows and other details about the investment.

Need:

This investment is required to replace end of life ("EOL") Air Blast Circuit Breakers ("ABCB's") and other EOL station components and reduce regulatory maintenance requirements from the Technical Standards and Safety Authority ("TSSA").

If this work is not completed, there is significant risk of the decline in the health and reliability of the ABCB population and associated EOL components, and reduced system reliability and customer load security impacts.

Summary:

Originally built in the 1960's, Orangeville TS facilitates bulk power transfers on the 230 kV network between Bruce NGS, Detweiler TS and Essa TS. In addition to providing a major network path, the 230 kV circuits supply several load stations and large customers including Alliston TS, Hanover TS, Fergus TS, Campbell TS, Detweiler TS, Amaranth CTS / Melancthon Grey Wind NUG, Waterloo North MTS and Scheifelle MTS. There are six 230 kV circuits connected at Orangeville TS.

The 230kV ABCBs at Orangeville TS were built in 1968 and 1969 and were originally installed at Beck #2 TS. These breakers are at EOL based on their condition, performance and availability of spare parts. The interrupter contacts have been a source of problems since the breakers were installed at Orangeville in 1983. The contact fingers develop cracks after 1200 breaker operations, a major design flaw. Other major problems include premature mechanical and electrical wear to the stationary and moving contact fingers. Forced outage rates for ABCBs have been increasing and are 2.6 times worse than the all-Canada average for 230 KV breakers The sole provider of spare parts for these breakers has indicated that they no longer support this type of breaker.

In 2006, a site assessment to identify EOL components within the 230 kV switchyard, with the intention of bundling the work into a single efficient work package. The identified work within this investment includes replacement of six 230 kV ABCB's with new SF6 breakers and associated replacement of twenty high voltage switches, six high voltage line ground switches, four High Voltage Instrument Transformers and the main station service.

Results:

- Reduce operational risks and life cycle costs and regulatory maintenance requirements (TSSA).
- Improve the bulk system equipment availability indices and the reliability of supply to area customers.

Project Classification per OEB Filing Guidelines:

Project Class:	Sustaining
Project Need:	Non-Discretionary

Hydro One Networks – Investment Summary Document

Investment Category: Sustaining Capital - Stations - System Re-Investment

Reference #	Investment Name	Gross Cost	In-Service Date
S8	Richview TS 230kV Switchyard : Air Blast Circuit Breaker (ABCB) Re-Investment	$ 17.1	2012

Please see Exhibit D1, Tab 3, Schedule 2 for cash flows and other details about the investment.

Need:

This investment is required to replace end of life ("EOL") Air Blast Circuit Breakers ("ABCB's") and other EOL station components.

If this work is not completed, there is significant risk of the decline in the health and reliability of the ABCB population, associated EOL components, and ultimately the reliability of the system and customers in the area.

Summary:

The Richview 230kV switchyard was placed in service in1965 and consists of eight, 3-breaker diameters (diameter being the terminal of two line circuits into the station bus arrangement). The switchyard is divided into 2 yards (East and West) separated by two bus-tie breakers, consisting of 4 main buses. Richview TS is a critical network station that facilitates bulk transfers on the 230kV network. Richview TS connects to other major facilities which include: Trafalgar TS, Cherrywood TS, Claireville TS, Manby TS, and Cooksville TS.

There are currently twenty-five ABCBs, manufactured by ABB model type 'DMVF', in the 230kV yard that range from 38-45 years old with the average age being 43 years. Condition assessments have identified EOL issues with these ABB type 'DMVF' ABCBs, high pressure air system, high voltage instrument transformers, insulators, and disconnect switches. At this point the o-rings and seals have deteriorated to such an extent that the breakers will not contain the air properly resulting in an increased risk of failure. The breakers have a long history of problems with their contacts and parts are no longer available. The original equipment manufacturer support level is very limited for the breakers and will cease to continue by 2013. Hydro One has no spare breakers and parts are also limited. The 5-year average forced outage frequency for Hydro One 230kV ABCBs is 2.6 times the all-Canada average for 230 kV breakers.

The identified work within this investment includes replacement of twenty-five 230 kV ABCB's with new SF6 breakers and the replacement of associated equipment such as: insulators, disconnect switches, high voltage instrument transformers and Control, Metering, Relaying & Annunciation systems.

Results:

- Reduce the operational risks, minimize life cycle costs, and satisfy regulatory requirements.

Project Classification per OEB Filing Guidelines:

Project Class:	Sustaining
Project Need:	Non-Discretionary

Hydro One Networks – Investment Summary Document

Investment Category: Sustaining Capital - Stations - System Re-Investment

Reference #	Investment Name	Gross Cost	In-Service Date
S9	Hanmer TS : Air Blast Circuit Breaker (ABCB) Re-Investment	$ 18.8 M	Late 2012

Please see Exhibit D1, Tab 3, Schedule 2 for cash flows.

Need:

This investment is required to replace end of life ("EOL") Air Blast Circuit Breakers ("ABCB's") and other EOL station components.

If this work is not completed, there is significant risk of the decline in the health and reliability of the ABCB population, associated EOL components, and ultimately the reliability of the system and customers in the area.

Summary:

Hanmer TS is a critical network station just west of Sudbury. It facilitates the transfer of power between Northern and Southern Ontario. The 500kV switchyard consists of three breaker diameters (diameter being the terminal of two line circuits into the station bus arrangement). The switchyard also has two 750 MVA and two 360 MVA auto transformers which provide a connection point to the 230 kV system. There are three 500 kV circuits at Hanmer. One circuit connects the 500 kV system to Porcupine TS in the north with two circuits going to Claireville TS in the south.

There are currently three 500 kV ABCBs manufacturer type 'DLVF' and two 28 kV ABCBs manufacturer type 'DCVF' at Hanmer TS ranging in age from 33 to 44 years of age. The 500 kV breakers were rebuilt in 1993 and the 28 kV breakers have never been rebuilt. Condition assessments have identified EOL issues with both ABCB types the 'DLVF' and 'DCVF', high pressure air system, high voltage instrument transformers, insulators, and disconnect switches. There are no spare breakers or interrupters for these types of breakers and other spare parts are very limited. Manufacturer support will be discontinued as of 2013. Breaker fail protections on two of the breakers have also been identified as being sub standard by NPCC standards.

The identified work within this investment includes replacement of three 500 kV and two 28 kV ABCB's with new SF6 breakers , and the replacement of associated equipment such as: insulators, switches, high voltage instrument transformers , Control, Metering, Relay & Annunciation systems and breaker failure protections.

Results:

- Reduce the operational risks, minimize life cycle costs, and satisfy regulatory requirements.

Project Classification per OEB Filing Guidelines:

Project Class:	Sustaining
Project Need:	Non-Discretionary

Hydro One Networks – Investment Summary Document

Investment Category: Sustaining Capital - Stations - System Re-Investment

Reference #	Investment Name	Gross Cost	In-Service Date
S10	Pickering A switchyard : Air Blast Circuit Breaker (ABCB) Re-Investment	$7.3 M	Late 2012

Please see Exhibit D1, Tab 3, Schedule 2 for cash flows.

Need:

This investment is required to replace end of life ("EOL") Air Blast Circuit Breakers ("ABCB's") and other EOL station components, and de-merge Hydro One assets from the Ontario Power Generation ("OPG") facilities.

If this work is not completed, there is significant risk of the decline in the health and reliability of the ABCB population, associated EOL components, and ultimately the reliability of the system and customers in the area.

Summary:

Pickering 'A' was constructed in the late 1960's. The 230 kV switchyard consists of four 3-breaker diameters (diameter being the terminal of a line circuit into the station bus arrangement) incorporating four circuits, connection facilities for four unit generators and station service transformers. Each diameter has a combination of SF6 Circuit Breakers, Oil Circuit Breakers and ABCBs. The switchyard is divided into 2 yards (East and West), consisting of four main buses all configured to align with OPG's four unit generators. Detailed condition assessments identified EOL issues with the ABB manufacturer type 'DMVF' ABCBs, high pressure air system, "free-standing" current transformers, insulators, and disconnect switches.

In 2003, one of the four 3-breaker diameters was addressed through the replacement of the ABCBs, insulators, and refurbishment of the disconnect switches. As the ABCB'S continues to deteriorate, the need and requirement to replace the remaining EOL equipment is becoming more critical. This investment will address the remaining three 3-breaker diameters. This will include: replacing four ABCBs type 'DMVF' with SF6 breakers, bypassing and removal of the two ABCBs associated with Pickering A Generators #2 & 3, as these two units will never be returned to service by OPG, replacing insulators, and refurbishing the disconnect switches. This investment will enable a staged demerger from the common systems including station service and high-pressure air systems that are shared with OPG.

Results:

- Reduce the operational risks, minimize life cycle costs, and satisfy regulatory requirements.
- The de-merger of the Hydro One assets from the OPG powerhouse will also be accomplished thereby reducing business liability and risk.

Project Classification per OEB Filing Guidelines:

Project Class:	Sustaining
Project Need:	Non-Discretionary

Hydro One Networks – Investment Summary Document

Investment Category: Sustaining Capital - Stations - System Re-Investment

Reference #	Investment Name	Gross Cost	In-Service Date
S11	Merivale TS - GIS 'ITE' Bus Replacement	$14.1 M	Late 2012

Please see Exhibit D1, Tab 3, Schedule 2 for cash flows and other details about the investment

Need:

This investment is required to replace End of Life ("EOL") ITE Bus Duct and associated EOL components at Merivale TS.

Merivale TS is a critical switching station supporting Bulk System power flow into the Ottawa area and the implication of not completing this work includes reduced reliability in the Ottawa area and ongoing environmental concerns with the escape of SF6 gas.

Summary:

Merivale TS 230 kV gas insulated switchgear ("GIS") was placed in service in 1979. The GIS consists of six bus duct exits (bus duct exits are comprised of gas insulated bus duct, air to gas bushings, switch gear adapters, and gas density monitors) incorporating connection facilities for four circuits, two transformers; as well as, connection to the switchgear.

In 2006, an asset condition assessment and third party review was performed. This assessment indicated that the Merivale TS GIS equipment, manufacturer type 'ITE' was among the poorest performers in the Hydro One GIS fleet second only to the recently replaced Claireville equipment which was replaced in 2009. EOL for GIS switchgear is typically in the range of 40-50 years but the ITE GIS has proven to be an inferior design. ITE bus duct exits have accounted for 8 of the 19 outages across the entire population of all GIS bus duct exits in the last 5 years. Outages of the Merivale TS 'ITE' bus duct exits are 20 times that of the provincial population on an annual basis.

Two of the six bus duct exits at Merivale TS were replaced in the mid 80s with bus duct from Westinghouse. The four remaining bus ducts were refurbished and modified at that time. There have been no major failures as a result of partial discharge since that time. This refurbishment work however has not adequately addressed the unacceptably high SF6 gas leakage issues and resultant outage issues that occur at all interface bushings, pipes and fittings. This is an environmental concern since SF6 is a greenhouse gas. In addition the original manufacturer is no longer in business, making spare parts and support a significant issue.

This investment will address the remaining four bus ducts by replacing the bus duct exits, air to gas bushings, gas density monitors and bus duct exit adapters.

Results:

- Reduce operational risks, minimize life cycle costs, and reduce the escape of Greenhouse SF6 gas.

Project Classification per OEB Filing Guidelines:

Project Class:	Sustaining
Project Need:	Non-Discretionary

Hydro One Networks – Investment Summary Document

Investment Category: Sustaining Capital - Stations - System Re-Investment

Reference #	Investment Name	Gross Cost	In-Service Date
S12	National Research (N.R.C) TS	$4.5 M	2013

Please see Exhibit D1, Tab 3, Schedule 2, Table 4 for cash flows and other details about the project.

Need:

This investment is required to replace the non-standard 115 kV and 14 kV switchyards portion of National Research Council (N.R.C.) TS and other station components to address several issues associated with EOL equipment that affect the operability and reliability of this station.

If this work is not completed there is significant risk of the decline in the operability and reliability of the station which will impact the customer directly supplied from this station.

Summary:

Originally built in 1953, N.R.C. TS directly supplies the National Research Council of Canada. This station no longer meets Hydro One's current transmission standards and as such the station operates with restrictions that result in the interruption of power supply to customers and delay Hydro One's response to equipment failures at the station.

Both transformers are supplied off the same bus with only one disconnect switch for isolation. When the protection system opens the primary T1-A switch, both transformers are taken out of service which results in an outage to the customer. Service can not be resumed until the faulted equipment is physically isolated and the T1-A closed in again.

The 14 kV switchyard equipment clearances no longer meets today's requirements for working close to live equipment; this imposes safety concerns at the station. Most maintenance work at the station can only be performed during complete station outage on weekends. In addition, a generator (customer owned) is connected to the 14 kV, raising the fault level above the interrupting capability of the oil circuit breakers. These breakers operate with an exclusion zone that limits access to the station.

The transformer oil spill containment does not meet the standard and has deteriorated to the point that it would not contain the oil in the event of a major transformer failure.

This investment will address operating constraints, reduce safety & environmental risks at the station, and improve reliability of supply to the customer.

Results:

- Remove operating restrictions.
- Eliminate environmental concerns associated with the spill containment.
- Improve the reliability of supply to the customer.

Project Classification per OEB Filing Guidelines:

Project Class:	Sustaining
Project Need:	Non-Discretionary

Hydro One Networks – Investment Summary Document

Investment Category: Sustaining Capital - Stations – Power Transformers

Reference #	Investment Name	Gross Cost	In-Service Date
S13	Richview TS - Replace EOL Transformers T7/T8	$10.1M	Late 2012

Please see Exhibit D1, Tab 3, Schedule 2, Table 5 for cash flows and other details about the project.

Need:

This investment is required to replace end-of-life ("EOL") equipment at Richview TS including transformers T7 and T8.

If this work is not completed, there is significant risk of transformer failure that may cause load interruptions, high corrective costs, increased operational constraints and adverse environmental effects.

Summary:

There are three DESN stations on the Richview TS site: T1/T2 125 MVA 230/28/28 kV built in 1969, T5/T6 125 MVA 230/28/28 kV built in 1989 and T7/T8 83 MVA 230/28 kV built in the late '50s. Transformer T7 was built in 1956, transformer T8 in 1959. Both transformer units are leaking oil and they are not equipped with spill containment. While T7 was undergoing refurbishment work, cracked pressure plates were found on all three phases. It appeared that these cracks were not recent. Replacing the cracked pressure plates cannot be done in the field. The refurbishment work was scaled back in anticipation of the replacement of this transformer unit. The transformer unit was returned to service with an on-line monitor connected to observe the gas in oil levels on a continuous basis until replacement of T7 could be undertaken. T8 has a cracked headboard that is also not field repairable.

This investment will result in the replacement of these two transformer units (T7 and T8), replacement of associated EOL equipment, and installation of spill containment on T7 and T8.

Results:

- Reduce operational risks and life cycle costs.
- Improve equipment availability and the reliability of supply to area customers.

Project Classification per OEB Filing Guidelines:

Project Class:	Sustaining
Project Need:	Non-Discretionary

Hydro One Networks – Investment Summary Document

Investment Category: Sustaining Capital - Stations – Power Transformers

Reference #	Investment Name	Gross Cost	In-Service Date
S14	Replace End-of-Life CGE Transformers	$73.5 M	Late 2012

Please see Exhibit D1, Tab 3, Schedule 2 for cash flows.

Need:

This investment is required to replace end-of-life ("EOL") Canadian General Electric ("CGE") transformers.

If this work is not completed, there is significant risk of equipment unavailability, increased operational constraints, and increased risk of customer interruptions.

Summary:

In 2008, twenty-two CGE designed transformers were identified with design flaws that can cause severe internal overheating of the low voltage leads and result in dielectric breakdown. Three of these twenty-two units have already failed due to this design flaw and the remaining nineteen units have been identified as high risk. Oil analysis has corroborated the risk. The nineteen remaining CGE units are still in service at a total of eleven stations throughout Southern Ontario, but are presently de-rated to minimize the effects of over heating. Eight of the eleven affected sites utilize sister-paired defective units and are heavily loaded. The nineteen transformers are located at the following transformer stations Bramalea TS, Brantford TS, Cumberland TS, Ellesmere TS, Finch TS, Galt TS, Ingersoll TS, Leslie TS, Malden TS, Modeland TS and Oakville TS.

Temporary measures such as cancellation of non-critical outages, de- rating, load transfers and pre-cooling have already been implemented to help reduce aging rates and to mitigate the risk of failure. Lead time for procurement of replacement transformers is approximately 18 months and replacement installations will begin in 2010, with the replacement of 2 transformers.

This proposed investment will address the replacement of twelve units during the 2011/2012 period. The replacement priority for units has been based upon oil analysis, loading and customer impact.

Results:

- Reduce operational risks and life cycle costs.
- Improve equipment availability and the reliability of supply to area customers.

Project Classification per OEB Filing Guidelines:

Project Class:	Sustaining
Project Need:	Non-Discretionary

Hydro One Networks – Investment Summary Document

Investment Category: Sustaining Capital - Stations – Power Transformers

Reference #	Investment Name	Gross Cost	In-Service Date
S15	Leaside TS - Replace EOL Transformers T19, T20 and T21	$12.0 M	Early 2012

Please see Exhibit D1, Tab 3, Schedule 2, Table 5 for cash flows and other details about the project.

Need:

This investment is required to address replace end-of-life ("EOL") equipment at Leaside TS including T19, T20 and T21 transformers, associated transformer protections and all cap and pin insulators in the transformer zone.

If this work is not completed, there is significant risk of transformer failure that may cause: (1) increased risk of customer impact, (2) potential high cost corrective action after a catastrophic failure, (3) reduced availability and increased operational constraints.

Summary:

Leaside TS is located in the city of Toronto. T19/T20/T21 operate in parallel and are unique, non-standard, 83 MVA 230/128/114 kV units which supply Toronto Hydro Electric System Limited ("THESL"). In the summer of 2007, an on line monitor on T21 indicated an increasing trend in the build up of internal fault gasses. An internal inspection confirmed that T21 should be replaced and off-loaded. T21 is presently available for emergency use only.

Life expectancy of power transformers is typically between 40 to 60 years. TI9 and T20 are 51 years old and T21 is 48 years old. T19 and T20 are both showing insulation deterioration through Dissolved Gas Analysis. Transformer population demographics coupled with condition assessments indicate that failure rates are expected to increase among all transformer groups due to natural insulation degradation found on both failed sister units.

This plan will address the replacement of these three transformers (T19, T20, T21), it also includes the replacement of associated transformer protections and all cap and pin insulators in the transformer zone.

Results:

- Reduce operational risks and life cycle costs.
- Improve equipment availability and the reliability of supply to area customers.

Project Classification per OEB Filing Guidelines:

Project Class:	Sustaining
Project Need:	Non-Discretionary

Hydro One Networks – Investment Summary Document

Investment Category: Sustaining Capital - Stations – Power Transformers

Reference #	Investment Name	Gross Cost	In-Service Date
S16	Purchase Spare Transformers	$26.4 M	Late 2012

Please see Exhibit D1, Tab 3, Schedule 2, Table 5 for cash flows and other details about the project.

Need:

To provide adequate spare coverage for timely replacement in the event of a severe failure within several 230 KV and 115 KV transformer groups and station service transformers. This investment will bring the inventory of spares in this group to the optimum level as determined by risk analysis.

Not proceeding with this investment will increase risks to customer supply reliability and system security.

Summary:

The purpose of this investment is to purchase two 125 MVA (230 KV), two 115 MVA (115 KV), three 75 MVA (230 KV), one 78 MVA (115 KV) and one 42 MVA (115 KV) transformers as operating spares in 2011 and 2012 as well as 12 station service transformers.

Transformers purchased under this investment will support a total of 395 transformers in 7 different transformer groups, as well as station service transformers.

A probabilistic cost/risk analysis model, consistent with industry standards, has been used to determine the optimum number of spares required for each group. This analysis takes into consideration several factors such as demographics, failure rate and repair/replacement time.

Results:

To provide adequate spare group coverage and level of customer service in the event of a transformer failure.

Project Classification per OEB Filing Guidelines:

Project Class:	Sustaining
Project Need:	Non-Discretionary

Hydro One Networks – Investment Summary Document

Investment Category: Sustaining Capital - Stations – Other Power Equipment

Reference #	Investment Name	Gross Cost	In-Service Date
S17	2011/2012 Station HV Disconnect replacement Program	$11.4 M	Late 2012

Please see Exhibit D1, Tab 3, Schedule 2 for cash flows.

Need:

This investment is required to address the condition of high voltage disconnect switches at end-of-life, by way of replacement of those that represent the highest risk to system reliability.

Not proceeding with this investment would allow increased risk to customer supply reliability, increased safety hazards to personnel and an increased inability to complete scheduled work as a result of switch failures during isolation procedures.

Summary:

High voltage disconnect switches perform essential roles in the power system. They facilitate the electrical isolation and connection of system components such as high voltage lines, transformers and breakers. They are both manual and motor driven. There are over 5600 high voltage disconnect switches in the system. Normal end of life for switches is typically 40 years.

Switch performance has degraded from an average of 38 failures per year during the period 2000 to 2005 to an average of 66 or a 73% increase during the 2006 to 2008 period. The upward trend is due to the fact that we have a large number of switches at or near end of life. There are 1675 switches that are currently over 40 years old. Older switches have no manufacturer's support and do not meet current system design. The older switches also do not have replaceable current carrying parts due to their design.

Hydro One's replacement/refurbishment program has focused on managing switches in the poorest condition. Replacement criteria is based upon age, condition assessments, performance, reliability, saftey, consequences of failure, spare parts and customer needs.

This investment will result in the replacement of 83 high voltage disconnect switches.

Results:

- To improve reliability and system performance.
- To improve ability to effectively maintain equipment

Project Classification per OEB Filing Guidelines:

Project Class:	Sustaining
Project Need:	Non-Discretionary

Hydro One Networks – Investment Summary Document

Investment Category: Sustaining Capital - Stations – Other Power Equipment

Reference #	Investment Name	Gross Cost	In-Service Date
S18	2011/2012 Capacitor Bank Replacements	$7.1 M	Late 2012

Please see Exhibit D1, Tab 3, Schedule 2 for cash flows.

Need:

This investment is required to address the deteriorating condition of capacitor banks at end of lifethrough replacement of those that present a high risk to system security and reliability.

Failure to proactively manage this population will result in reduced system voltage support, increased transmission losses, customer power quality issues and an increase in the potential for an environmental and /or safety impact in the event of a failure.

Summary:

Capacitor banks are static devices that provide reactive power to the transmission system, which results in an improved power factor and allows for more efficient power transmission. A capacitor bank is made up of several capacitor units connected in an appropriate series-parallel arrangement, which can range from 9 to 216 capacitor units depending on rating and design of the capacitor bank. Each capacitor unit consists of two conductive plates with a dielectric material in between, where the distance between plates and the type of dielectric material determines the amount of capacitance produced.

There are a total of 57 high-voltage capacitor banks in-service at voltages of 115kV and 230kV ranging from 15 MVAR to 410 MVAR, and 297 low-voltage capacitor banks in-service at voltages from 4.16kV to 44kV ranging from 4.6 to 33 MVAR throughout the transmission system.

The need to replace capacitor banks is based on asset condition, reliability and criticality to the system. Asset condition information used to assist in determining end-of-life includes the deterioration of individual capacitor units or by general deterioration of structure, insulators, fuses and capacitor units.

This investment will result in the replacement of two high-voltage capacitors and six low-voltage capacitors.

Results:

- Improve reliability of the capacitor bank population by replacing end-of-life capacitor banks.
- Reduce operational constraints and environmental risks associated with capacitor bank failures.

Project Classification per OEB Filing Guidelines:

Project Class:	Sustaining
Project Need:	Non-Discretionary

Hydro One Networks – Investment Summary Document

Investment Category: Sustaining Capital - Stations - Ancillary Systems

Reference #	Investment Name	Gross Cost	In-Service Date
S19	2011/2012 Station Service Upgrades – Network Stations	$25.9 M	Late 2012

Please see Exhibit D1, Tab 3, Schedule 2 for cash flows.

Need:

This investment is required to address the condition of the aging population of station service transfer schemes through replacement of those that present a high risk to system security and reliability.

Failure to proactively manage this population will result in the inability to operate station equipment as a result of loss of AC or DC power.

Summary:

Station service systems comprise all equipment necessary to provide AC or DC power to station facilities. 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 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 transfer system is designed to enable the transfer of loads over to the second station service supply. If the transfer fails, transmission elements at the station could be forced out of service or de-rated.

There are 96 – 600V AC and 179- 208V AC station service transfer schemes and 61 - 125/250 V DC station service transfer schemes in-service. The average age of the 600 V AC and 125/250 V DC systems are 33 and 34 years respectively with end of life (EOL) typically in the 30 year range. The average age of the 208 V AC system is 23 years with EOL typically at 20 years. The deterioration of the transfer schemes has been evident for several years. Restoring reliability to these systems through increased maintenance continues to be a challenge due to the lack of spare parts and inability to obtain replacement parts from the manufacturer. Further compounding the reliability issues, the AC transfer schemes are housed within poorly insulated outdoor cubicles and are deteriorating due to corrosion.

The Cherrywood TS, Hanover TS, Richview TS and St. Lawrence TS transfer schemes have exceeded the manufacturers intended life expectancy of 30 years, and have experienced difficulties with the transfer capability both with switchgear and control.

The upgrade will include the replacement of the station service transfer schemes at Cherrywood TS (both 500kV yard & 230kV yard AC), Hanover TS (AC), Richview TS (AC) and St. Lawrence TS (AC&DC). The equipment associated with the transfer schemes (LV fuses, cables, enclosures, and distribution panels) will also be addressed at these locations. Also included will be the replacement of ten 208V transfer schemes at 10 smaller DESN type stations.

Results:

- Improved reliability of the station service transfer schemes by replacing end-of-life station service equipment.

Project Classification per OEB Filing Guidelines:

Project Class:	Sustaining
Project Need:	Non-Discretionary

Hydro One Networks – Investment Summary Document

Investment Category: Sustaining Capital – Stations – Stations Environment

Reference #	Investment Name	Gross Cost	In-Service Date
S20	2011/2012 Spill Containment Refurbishment - Major	$17.8 M	Late 2012

Please see Exhibit D1, Tab 3, Schedule 2 for cash flows.

Need:

This investment is required to address the risk of releasing oil off site at various TS sites. This risk is present because the transformer oil spill containment system is at end of life and no longer provides adequate protection.

Not proceeding with this investment will not address an unacceptable risk of releasing transformer oil into the environment, leading to negative environmental impact and potential regulatory action by the Ministry of Environment (MOE) under the powers of the Environmental Protection Act R.S.O. 1990, c. E. 19.

Summary:

Transformers contain large volumes (up to 240,000L) of insulating oil (PCBs are within allowable Environment Canada Standards). Periodically, transformers leak and or fail catastrophically releasing large volumes of oil. Spill containment systems are designed to capture the oil contained within one transformer on site. They also are designed to take into account significant accumulations or rain in the event of a severe rain storm. Oil water separators (OWS) are used to prevent spilled oil from leaving the station while allowing rainwater to drain offsite.

The combination of leaking spill containment pits and severe transformer oil leaks present a serious environmental concern. Oil spill containment systems with chronic oil leaks have been identified within this project. The amount of oil that has leaked from the subject transformers is tracked using oil volume top-up records. Problems with traces of oil leaching into the drainage ditch are typically identified. It is suspected this is caused by a lack of integrity of the original plastic containment unit liners. Due to the inability of the containment pits to prevent oil from seeping into the soil below the containment units, oil can migrate from the failed pits into the station storm water drainage system and migrate off site. In some locations temporary control measures such as berms are required to prevent oil from migrating off site and potentially into adjacent waterways. These are not long term solutions, and as such containment must be restored as planned with this investment.

This investment covers the installation of a passive oil water separator as well as refurbishment of the existing containment pits. Refurbishing the spill containment system mitigates the risk of releasing oil to the environment and reduces resources required to operate the oil water separation units by eliminating the need to manually pump out the containment units of rain and melt water. Investment plans for 2011 include refurbishment of 14 systems (spill containment and or OWS) at 7 stations and 2012 work includes 16 systems at 11 different stations.

Results:

- Reduce the risk of off-site pollutant migration and subsequent impacts to the environment.
- Minimize the potential for punitive action by the MOE as a result of oil spills and leaks to the environment.

Project Classification per OEB Filing Guidelines:

Project Class:	Sustaining
Project Need:	Non-Discretionary

Hydro One Networks – Investment Summary Document

Investment Category: Sustaining Capital – Protection & Control, Telecom and Metering

Reference #	Investment Name	Gross Cost	In-Service Date
S21	Bruce Special Protection Scheme (BSPS) Replacement of End-of-Life Equipment	$19.1 M	Late 2012

Need:

This investment is required at this time to:

1. Provide Special Protection Scheme coverage for breaker outages at Bruce A, Bruce B, Milton, Claireville, Longwood, Middleport, Nanticoke, Detweiler, Orangeville, Buchanan and Chatham for the grid configuration that will exist following the completion of the new Bruce to Milton line. Without this coverage, outages required to carry out Hydro One's sustainment and development programs will cause curtailment of energy out of the Bruce Area at a cost of $4.2M per year. In addition, the scheduling complexity of outages at those stations will increase significantly. The present scheme does not have the functionality to accommodate these breaker outages.
2. Provide expansion capacity for future generation connections in the Bruce Area.
3. Address the pending end of life and obsolescence issue with the existing BSPS

Summary:

The existing BSPS went into service in 1991 and is near end of life (EOL). The existing scheme was designed and built in its entirety by Ontario Hydro. There is no vendor support. The existing BSPS is being expanded to its capacity limits to provide outputs to support generation in this area. The Protection Scheme (BSPS) will be replaced with a new system based on modern protection technology provided by numerous vendors. The new system will have the capability to handle breaker outages at stations throughout southern Ontario and will have capacity for additional generation connecting in the Bruce Area.

Results:

- Provide functionality to support planned outages.
- Restore protection and control reliability in the Bruce area.
- Provide protection and control facilities that will allow for added generation in the Bruce area.

Project Classification per OEB Filing Guidelines:

Project Class: Sustaining
Project Need: Non-Discretionary

Hydro One Networks – Investment Summary Document

Investment Category: Sustaining Capital – Protection & Control, Telecom and Metering

Reference #	Investment Name	Gross Cost	In-Service Date
S22	International Transmission Company (ITC) – Line Protections Replacements	$9.9 M	Late 2012

Please see Exhibit D1, Tab 3, Schedule 2 for cash flows.

Need:

The line protection and associated communication systems on the interconnection circuits between Michigan and Ontario have been assessed to be at end of life (EOL). The technology employed in these systems has a mean service life expectancy of 35 years and these systems have now been in service for over forty years. Further delay to the replacement of these protections is expected to result in increased outages to these transmission circuits due to protection failures.

Summary:

The interconnection facility to Michigan in Sarnia/Windsor area consists of four transmission circuits crossing the St Clair River: B3N, J5D, L4D, and L51D. This investment will replace the remaining end of life line protection equipment on the transmission lines which form the interconnection to Michigan. This will be done in accordance with agreements with ITC Holdings Inc., the transmission asset owner of the Michigan terminals of these interconnection facilities.

Replacement of line protections and communication for circuit B3N was initiated by ITC in 2009. This project will replace line protections and associated communication system of the remaining three Michigan lines with modern protection and communication equipment. The interconnection circuits are classified as Bulk Power System facilities subject to the standards established by NPCC and NERC. Hydro One is required under the Market Rules to comply with these standards which are more stringent than those applied to the existing designs.

Results:

- Restore protection and control reliability for this interconnection.
- Interconnection facilities will be brought up to the standards required by NERC and NPCC.

Project Classification per OEB Filing Guidelines:

Project Class:	Sustaining
Project Need:	Non-Discretionary

Hydro One Networks – Investment Summary Document

Investment Category: Sustaining Capital – Protection & Control, Telecom and Metering

Reference #	Investment Name	Gross Cost	In-Service Date
S23	NYPA Tie Lines – Beck Line Protections Replacements	$6.8 M	Late 2012

Please see Exhibit D1, Tab 3, Schedule 2 for cash flows.

Need:

The line protection and associated communication systems on the New York State interconnections circuits have been assessed by both the New York Power Authority (NYPA) and Hydro One as at or near their end of life (EOL). The technology employed in these systems has a mean service life expectancy of 35 years and these systems have now been in service for over forty years. Further delay to the replacement of these protections is expected to result in increased outages to these transmission circuits due to protection failures.

Summary:

The interconnection facility to NYPA consists of two transmission lines in the Cornwall area crossing the St. Lawrence River and three in the Niagara Falls area crossing the Niagara gorge. This investment will replace the remaining end of life line protection equipment on the transmission lines which form the interconnection to NYPA. This will be done in accordance to agreements with NYPA.

Replacements of line protections for the two lines near Cornwall (L33P and L34P) were initiated jointly with NYPA in 2007 following an event in which the protections on this interface failed to operate correctly resulting in 3000MW load loss in New York State and a major investigation by NERC. This project will replace line protections and associated communication systems of the remaining three NYPA lines at Niagara with modern protection and communication equipment. The interconnection circuits are classified as Bulk Power System facilities subject to the standards established by NPCC and NERC. Hydro One is required under the Market Rules to comply with these standards which are more stringent than those applied to the existing scheme designs.

Results:

- Restore protection and control reliability for this interconnection.
- Interconnection facilities will be brought up to the standards required by NERC and NPCC.

Project Classification per OEB Filing Guidelines:

Project Class:	Sustaining
Project Need:	Non-Discretionary

Hydro One Networks – Investment Summary Document

Investment Category: Sustaining Capital – Protection & Control, Telecom and Metering

Reference #	Investment Name	Gross Cost	In-Service Date
S24	2011/2012 Station P&C Replacement	$46.6 M	Late 2012

Please see Exhibit D1, Tab 3, Schedule 2 for cash flows.

Need:

Hydro One has identified 10 load supply stations at which most of the protection systems as well as RTU have reached end of life as determined by the Health Indices and need to be replaced during 2011 and 2012 to maintain reliability.

Summary:

The optimum approach for addressing the protection replacement need at these 10 stations is to the replace the entire relay building. Between 2006 and 2008 Hydro One developed a standardized packaged design solution for replacing the entire relay building at load supply stations. Unlike the protection replacement program (see ISD S-25) and the RTU replacement program (see ISD S-26), in which protection schemes or RTU's are replaced individually, this standardized packaged design solution has all protections and the RTUs installed on racks in a prefabricated building and wired according to Hydro One specification by the vendor in the factory. This approach is cost effective. As well, it is an effective means for best utilization of P&C resources. All protection and control systems for load supply stations are generally housed in a single building. For cases where most of the components of the protection systems are at end of life, it is more cost effective and simpler from the perspectives both of design and staging into service to replace the entire relay building using this standard design rather than replace individual components. Replacements using standard PCT building design will result in savings of about 15% when compared to replacements of individual components of protection and control systems.

Results:

- Restore reliability of protections and controls at 10 transmission stations..
- Cost effective replacement base on modular designs with effective utilization of scarce resources.

Project Classification per OEB Filing Guidelines:

Project Class:	Sustaining
Project Need:	Non-Discretionary

Hydro One Networks – Investment Summary Document

Investment Category: Sustaining Capital – Protection & Control, Telecom and Metering

Reference #	Investment Name	Gross Cost	In-Service Date
S25	2011/2012 Protection Replacements	$20.3M	Late 2012

Please see Exhibit D1, Tab 3, Schedule 2 for cash flows.

Need:

Protection systems are essential to the operation of every element (circuit, transformer, bus, breaker, etc.) of the grid. The failure of a protection system to operate promptly when required will have serious consequences including one or more of: equipment damage, injury to people, and wide spread power outage. An element for which the protection systems are known to be non-functional or un-reliable, must be removed from service. It can take 3 months or longer to replace a protection scheme. Consequently, Hydro One plans replacement of protection schemes before they are likely to fail. A Health Index methodology is used to determine the schemes requiring replacement.

Demographics of protective relays are such that the large populations of electromechanical and solid-state relays are beginning to enter end-of-life with inherent increased failure rates within the next 3 to 5 years. In response, this program will increase replacement rates from 40 systems in 2010 to 50 systems in 2011, and 83 systems in 2012 giving priority to those protection schemes which have the lowest Health Index and for which failure will have the largest consequences. The majority of the protection replacements planned in 2011 and 2012 are those schemes that use Programmable Auxiliary Logic Controllers (PALCs). PALCs are based on solid state technology that has a 20 year life expectancy. Hydro One has 350 PALCs performing critical functions the bulk of which were installed between 1989 and 1993. The Health Index for PALCs has deteriorated dramatically over the past 6 years. There were 9 PALC related failures in 2004, 13 in 2005, 14 in 2006, 16 in 2007, 34 in 2008, and 59 in 2009. PALC programming stations required to maintain these systems use obsolete technology with 8" floppy discs. Of the three programming stations owned by Hydro One, only one is still working.

Summary:

The extremely severe consequences of protection systems becoming un-reliable, or failing to operate, requires a preventative sustainment strategy in which aging protections are replaced before the onset of end of life effects. Protection systems are complex components of the grid and their design and maintenance requires highly specialized expertise which is in global short supply. This, combined with the fact that protection systems exist in very large numbers (more than 12,000 in Hydro One), adds another critical risk dimension to the management of protection sustainment: the planning must ensure a program that is feasible in terms of the available expert resources required to execute it. Consequently, Hydro One must increase protection replacements in order to address this aging class of assets.

The program gives priority to the highest risk protections: those with highest likelihood of failure and largest consequences to the reliability of the grid. 133 protection systems are planned to be replaced in 2011 and 2012. Sustainability modeling of protective relaying population demographics with known end of life failure rates has shown that, in order to keep ahead of accelerating failure rates and avoid engineering and maintenance resources being overwhelmed by failures, replacements should ramp up to 200 systems per year within a few years.

Results:

- Restore reliability of protections on the Hydro One system, specifically PALCS
- Secure the operability of the system to function as required based on regulations and system demands.

Project Classification per OEB Filing Guidelines:

Project Class:	Sustaining
Project Need:	Non-Discretionary

Hydro One Networks – Investment Summary Document

Investment Category: Sustaining Capital – Protection & Control, Telecom and Metering

Reference #	Investment Name	Gross Cost	In-Service Date
S26	2011-2012 RTU Replacement	$10.7M	Late 2012

Need:

There is a need to address this aging class of assets that are end of life to ensure control functionality at transmission stations in order to operate the system remotely.

Not proceeding with this work will expose Hydro One to concurrent failures that would overwhelm available expert maintenance resources. The direct result would be serious reduction in the reliability of the assets, negative customer impacts, reduced operability, and breaches of Market Rules. It will also result in higher costs to carry out development and other sustainment programs.

Summary:

Remote Terminal Units (RTUs) are essential components for the central operation of the transmission network. The RTU provides remote monitoring and operational control of all transmission stations to the Ontario Grid Control Centre (OGCC). The RTUs are also used to provide telemetry to the Independent Electricity System Operator (the IESO) and transmission-connected customers in accordance with the obligations of the Market Rules and the Transmission System Code respectively. The Market Rules provide specific performance levels for data accuracy, update time, and restoration upon failure. Hydro One has a population of about 600 RTUs of various type and vintage.

A population of over 100 RTUs has reached a Poor or Very Poor health index rating and is at end-of-life as validated by the Health Index methodology. Under that methodology RTUs are scheduled for replacement either when the reliability has failed to meet the Hydro One and Market Rule requirements and/or there is no vendor support or supply of spare parts for these RTU's and/or the RTUs are also at or near the point of functional obsolescence. Functional obsolescence means such things as the RTU cannot be expanded to accommodate planned station expansion or perform required additional control function and replacing is the lowest cost option. Failure of an RTU results in complete loss of monitoring and control of a station. The consequences of this include delayed or no response to equipment alarms, delayed restoration of customer outages, delayed switching for planned work, and bottling of generation.

The program is focused on the RTU's that are assessed to be at end of life. 28 RTU's will be replaced in the years 2011 and 2012 with accelerated rates of accomplishment in subsequent years. The Station P&C Replacement Program described in S24 will replace another 10 end of life RTUs in this period for a total of 38.

Results:

- Maintain the required functionality and reliability of monitoring and control of the grid.
- Ensure compliance with IESO Market Rules.

Project Classification per OEB Filing Guidelines:

Project Class:	Sustaining
Project Need:	Non-Discretionary

Hydro One Networks – Investment Summary Document

Investment Category: Sustaining Capital – Protection & Control, Telecom and Metering

Reference #	Investment Name	Gross Cost	In-Service Date
S27	DC Signaling (Remote Trip) Replacements	$13.7 M	Late 2012

Please see Exhibit D1, Tab 3, Schedule 2 for cash flows.

Need:

Restore the reliability of Direct Current (DC) signaling to ensure customer supply remains intact and provide adequate redundancy to maintain transformer stations at acceptable levels..

Summary:

Direct Current signaling is still used in the protection systems of many of Hydro One transmission circuits which have tapped load supply stations. The reliability of DC signaling is essential to the reliability of load supply at all such tapped stations. DC signaling relies on transmission of DC voltages over dedicated and continuous metallic telephone wires between stations, and uses DC based relaying to transmit/receive and monitor the DC communications channels. If the DC signaling for a transmission circuit is degraded or unavailable, the redundant supply capability of the tapped stations is lost and the load is vulnerable to single contingency events or, in some cases, transformers will be removed from service exposing load to curtailment for the resulting capacity restriction. These required actions compromise load supply reliability and increase cost. 11,000MW of load is supplied from stations that use DC signaling and is therefore exposed to this risk.

DC signaling facilities are at end of life. Both HONI owned and Telco owned metallic cables are typically as old as the stations (over 40 years old) and at the end of life due to increasing breaks in the old cable insulation sheaths that require repairs as well as constant operation and frequent failures of compressor equipment required for the operation of these cables. Over 10-years ago Telcos have provided letters stating that new DC signaling is no longer offered and maintenance of existing DC circuits will be reduced to best effort basis. Average restoration times per event over the last two years has gone from 85 hours in 2007 to over 140 hrs in 2009. DC relaying equipment in the stations is also at end of life. The manufacture of this equipment was discontinued in the mid 1980's, spares and repairs are limited by the ability to re-claim spare components from old relays and this relaying equipment has failure rates above acceptable levels..

Results:

Restore DC signaling to acceptable levels to maintain a level of equipment redundancy so as not to jeopardize customer supply and restore the ability to maintain station equipment to acceptable levels.

Project Classification per OEB Filing Guidelines:

Project Class:	Sustaining
Project Need:	Non-Discretionary

Hydro One Networks – Investment Summary Document
Investment Category: Sustaining Capital – Protection & Control, Telecom and Metering

Reference #	Investment Name	Gross Cost	In-Service Date
S28	DC Signaling Replacements (Toronto North & East)	$11.6 M	Late 2023

Please see Exhibit D1, Tab 3, Schedule 2 for cash flows.

Need:

Direct Current (DC) signaling is still used in the protection systems of many of Hydro One transmission circuits which have tapped load supply stations. As such, the reliability of DC signaling is essential to the reliability of load supply at all such tapped stations. This project will eliminate DC signalling teleprotections on 13 transmission lines and 14 transformer stations supplying the North-Eastern part of the Greater Toronto Area (GTA) that have become unreliable and are end of life. Specifically, the following stations are affected by this project: Richview TS, Finch TS, Bathurst TS, Fairchild TS, Leslie TS, Agincourt TS, Malvern TS, Cherrywood TS, Sheppard TS, Ellesmere TS, Scarborough TS, Bermondsay TS, Warden TS, and Leaside TS.

Summary:

DC signaling relies on transmission of DC voltages over dedicated and continuous metallic telephone wires between stations, and uses DC based relaying to transmit/receive and monitor the DC communications channels. If the DC signaling for a transmission circuit is degraded or unavailable, the redundant supply capability of the tapped stations is lost and the load is vulnerable to single contingency events or, in some cases, transformers will be removed from service exposing load to curtailment for the resulting capacity restriction. These required actions compromise load supply reliability and increase cost.

DC signaling facilities are at end of life. Both HONI owned and Telco owned metallic cables are typically as old as the stations (over 40 years old) and at the end of life due to increasing breaks in the old cable insulation sheaths that require repairs as well as constant operation and frequent failures of compressor equipment required for the operation of these cables. Over 10-years ago Telcos have provided letters stating that new DC signaling is no longer offered and maintenance of existing DC circuits will be reduced to best effort basis. DC relaying equipment in the stations is also at end of life. The manufacture of this equipment was discontinued in the mid 1980's, spares and repairs are limited by the ability to re-claim spare components from old relays, and this relaying equipment has failure rates above acceptable levels.

Results:

Restore DC signaling to acceptable levels to maintain a level of equipment redundancy so as not to jeopardize customer supply and to restore the ability to maintain station equipment to acceptable levels.

Project Classification per OEB Filing Guidelines:

Project Class:	Sustaining
Project Need:	Non-Discretionary

Hydro One Networks – Investment Summary Document

Investment Category: Sustaining Capital – Protection & Control, Telecom and Metering

Reference #	Investment Name	Gross Cost	In-Service Date
S29	NPCC Regulated Lines – Tone Equipment Replacements	$14.0 M	Late 2012

Please see Exhibit D1, Tab 3, Schedule 2 for cash flows.

Need:

Restore reliable communications for line protections between terminals to ensure protections operate as mandated by NERC/NPCC.

Summary:

Line protection systems use telecommunications to transfer the protection signals between terminals of high voltage transmission lines. One of the early technologies developed for this signalled by means of a change in the pitch of a tone. These are referred to a tone channels. The end devices used in tone channels which were deployed from the late 1960's and through the 1970's have been reaching end of life since 2001. Hydro One has had a program to replace them since 2002. Due to intricate interconnectivity between communication devices and protective relays it is most efficient to replace tone equipment at the same time as protection replacement. Consequently, the program to replace tone equipment has always been coordinated with that for protection replacement. This investment will continue to coordinate with the protection replacement program and will conclude the replacement of all remaining end of life tone channel end devices from the protection systems of all lines designated as part of the Bulk Power System. Hydro One has assigned highest priority to sustaining the reliability of those protections as they are subject to NPCC and NERC Reliability Standards and consequences of failures can be most severe.

This investment will replace remaining end of life tone channel equipment from protection systems on high voltage transmission lines governed by NERC and NPCC reliability standards.

Results:

Cost effectively eliminate major risks to reliability on the grid and ensure NERC/NPCC compliance.

Project Classification per OEB Filing Guidelines:

Project Class:	Sustaining
Project Need:	Non-Discretionary

Hydro One Networks – Investment Summary Document

Investment Category: Sustaining Capital – Protection & Control, Telecom and Metering

Reference #	Investment Name	Gross Cost	In-Service Date
S30	Power Line Carrier (PLC) Replacement Program	$5.5 M	Late 2012

Please see Exhibit D1, Tab 3, Schedule 2 for cash flows.

Need:

Replace unreliable end of life PLC equipment to ensure protections operate as required for the circuits in Eastern and Northeastern Ontario.

Summary:

Power Line Carrier (PLC) facilities associated with 3 HV lines (M80B, M81B; W71D) have reached the end of life and need to be replaced. This investment will replace PLCs and auxiliary devices (such as line traps, PLC coupling equipment) which suffered failures, and upgrade the PLC teleprotections of 5 HV lines (D1M, D2M, D3M, D4M, and D5H) connected to generation stations in North Eastern Ontario (Des Joachims and Otto Holden). The upgrade will provide standard redundant teleprotection which will avoid HV line outages and possible loss of load/generation if the existing single PLC teleprotection fail.

Hydro One's PLC systems provide highly reliable high-speed communication for the protection of the transmission lines (primarily in Eastern and Northern Ontario). The sparseness of HV Lines at these remote areas makes PLC the preferred telecom medium compared with fiber or microwave whose high cost is typically only justified where the telecom circuits serve a large number of power lines. PLC systems may also carry critical data traffic for the monitoring and control of the power system.

The majority of the PLC replacement program is now complete. However, a small number of PLC systems remain and this investment will address the majority of the outstanding replacements. Those older than 30 years old, have increasing failure rates, and are considered at, or approaching, the end of life. The systems are obsolete and are no longer supported by the manufacturer. Interconnected utilities (Hydro Quebec and Manitoba Hydro) are also replacing PLCs of the same vintage. Purchasing of spare parts is not possible and spare parts gleaned from decommissioned old PLC systems are marginal in performance, as a result these systems need to be replaced.

Results:

Reduce the likelihood of forced outages and ensure protections function as required to operate the system in Eastern and Northeastern Ontario.

Project Classification per OEB Filing Guidelines:

Project Class:	Sustaining
Project Need:	Non-Discretionary

Hydro One Networks – Investment Summary Document

Investment Category: Sustaining Capital – Cyber Security

Reference #	Investment Name	Gross Cost	In-Service Date
S31	Telecom Device Control Network Cyber Security	$10.4M	Late 2012

Please see Exhibit D1, Tab 3, Schedule 2 for cash flows.

Need:
This investment is required to ensure an appropriate level of security on critical telecommunication facilities as required to meet the requirements of NPCC Directory 4, Appendix A, Section 3. This Directory came into force Dec 1, 2009.

Summary:

The Telecom Device Control Network (TDCN) Cyber Security Project will address certain security issues associated with the telecom network that is used for the protection and control of the grid.

Results:

- Security risks affecting the operation of the grid will be addressed.
- Comply with NPCC/NERC regulatory cyber security requirements.

Project Classification per OEB Filing Guidelines:

Project Class:	Sustaining
Project Need:	Non-Discretionary

Hydro One Networks – Investment Summary Document

Investment Category: Sustaining Capital – Stations – Stations Environment

Reference #	Investment Name	Gross Cost	In-Service Date
S32	2011/2012 Spill - Major Drainage	$9.1 M	Late 2012

Please see Exhibit D1, Tab 3, Schedule 2 for cash flows.

Need:

This investment is required to address the deteriorating condition of station drainage systems at various Hydro One Transmission Stations. End of Life (EOL) and deteriorated drainage systems increase the risk of standing water within the yard, flooding of below-grade electrical equipment rooms, instability of equipment footings and access/service roads, and increased risk of non-compliant storm water effluent quality.

This Investment demonstrates effective stewardship of Hydro One’s assets by proactively managing this critical infrastructure through to End of Life (EOL). Not proceeding with this Investment will result in further deterioration of the station drainage systems resulting in an increased risk to employee safety, equipment failure and system reliability, reduced vehicular access to station equipment; and potential for Ministry of the Environment (MOE) punitive action.

Summary:

Transformer and Switching Stations require functional drainage systems. Functioning drainage systems ensure dry ground conditions to minimize employee safety hazards due to step voltage potential, provide stable access roadways for maintenance vehicles and personnel, prevent flooding of below-grade electrical equipment rooms, ensure stable conditions for footing/foundations and structural supports for major electrical equipment, and reduce the potential for site contaminants to impact storm water quality and/or migrate off-site.

More than 60% of Hydro One’s transmission station drainage systems are greater than 35 years old and approximately 26% are older than 50 years. Asset condition information obtained from drainage system inspections, site geotechnical assessments, and staff-identified deficiencies is used to identify and prioritize required station drainage projects. Priority work is driven primarily by safety, regulatory and reliability criteria.

The scope of drainage system refurbishment work is station-specific, depending upon the layout of the drainage system and its functional components, site-specific geotechnical conditions, and condition of the various system components. Typically drainage system projects involve the replacement of underground drainage in all or portions of the station yard, and repairs and/or replacement of sections of main drainage pipes and associated catch basins/manholes.

Results:

- The replacement/refurbishment of the station drainage systems reaching end of life
- Reduce the likelihood of equipment room flooding, ensuring equipment structural stability, provide safe and accessible service roadways for equipment maintenance

Project Classification per OEB Filing Guidelines:

Project Class:	Sustaining
Project Need:	Non-Discretionary

Hydro One Networks – Investment Summary Document

Investment Category: Sustaining Capital - Stations – Security Infrastructure

Reference #	Investment Name	Gross Cost	In-Service Date
S33	Security Infrastructure	$17.3 M	Late 2012

Please see Exhibit D1, Tab 3, Schedule 2 for cash flows.

Need:

- Since 2004, more than 647 security incidents have been reported at Hydro One TSs, including trespassing, theft, vandalism and suspicious activity.
- Significant risks occur when station perimeters are breached including the potential for severe injury or fatality to the intruders.
- Copper thieves steal fence grounds, underground grid, live grounds off transformer neutrals as well as station equipment.
- There are heightened safety concerns for employees and first responders where tampering with electrically live equipment has occurred.
- The reliability and integrity of the power system is undermined, which could affect the operation of other equipment or those of customers.
- Recent examples of security incidents include Stations such as Scarborough TS which has have had more than 26 cuts along the perimeter fence; Warden TS had 150 metres of chain link fence replaced in mid-2008 due to repeated break-ins along one section of the perimeter. Burlington TS recorded more that 30 security incidents since 2004, including trespassing, theft, vandalism, metal theft and suspicious activity.

Summary:

- Security Infrastructure is designed to effectively deter, delay, detect and respond to security threats that target Transmission stations.
- These threats can include copper theft, criminal activity, domestic extremism and terrorism.
- Investments are required in order to maintain system reliability, and promote greater safety within the station environment.
- The program follows a risk based approach using Threat & Risk Assessments (TRA) to determine station criticality, exposure threats and the resulting impacts on reliability and safety.
- An additional and enhanced suite of security equipment and systems has been developed to provide a range of protection options at stations. This suite includes items like reinforced fencing (both razor mesh and anti-tamper), intrusion and tamper detection, security cameras, horns, strobe lights and other sensors. The appropriate level of deployment is based on the Threat & Risk Assessments conducted for sites.
- Not implementing the appropriate level of security means the risk to stations will continue to occur with likelihood of severe injury or fatality from the intrusions, risk of outages and emergency maintenance.

Results:

- The program includes security upgrades at 10 TSs during 2011 and 2012.
- The program's security objectives are to deter, delay, detect and respond to intruders breaching the station perimeter.
- By investing in Security Infrastructure, Hydro One seeks to protect its TS assets as well as enhance reliability and public & employee safety.

Project Classification per OEB Filing Guidelines:

Project Class:	Sustaining
Project Need:	Non-Discretionary

Hydro One Networks – Investment Summary Document

Investment Category: Sustaining Capital - Lines - O/H Lines Component Refurbishment and Replacement

Reference #	Investment Name	Gross Cost	In-Service Date
S34	2011/2012 Transmission Wood Pole Replacement Program	$ 69.0 M	Late 2012

Please see Exhibit D1, Tab 3, Schedule 2 for cash flows.

Need:

This investment is required to address end-of-life components of transmission wood pole line structures in order to maintain their reliability and safety in a cost-effective manner.

If this work is not completed, there is significant risk of structure failure during adverse weather conditions with associated risks to public safety and transmission system reliability. Since the majority of wood pole lines are single supply, component failures on these lines usually cause supply interruptions to customers.

Summary:

Approximately 21,000 route kilometers (or 29,000 circuit km) of overhead transmission lines have been built in the province over the past 100 years. The transmission line system includes approximately 88,000 steel and wood structures. The wood structure lines consist of about 7,000 route km which includes 41,900 wood pole structures. The majority of the wood pole structure population is located in Northern Ontario, typically in remote locations with difficult access.

Wood structures deteriorate over time; the rate of deterioration depends on age, 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 components are replaced when their condition has deteriorated to a point where there is a significant risk of failure under adverse weather conditions. When component replacement work is carried out on wood structures, the crossarms, poles, hardware, insulators and guy wires are repaired or replaced as necessary.
Replacement candidates are based on on-going condition assessment programs. Asset condition assessment work includes detailed helicopter inspection (DHI) and ground line inspection. DHI assesses the upper area of wood structures and ground line inspection assesses the lower part of wood structures.

Condition assessment work has identified 1,710 structures for replacement and refurbishment work in 2011 and 2012.

Results:

- Maintain transmission system security and customer delivery reliability.
- Reduce the risk of a major interruption of supply to customers.
- Reduce safety hazards to the public from potential component failure.
- Replace 1710 sub-standard structures that have reached end of life.

Project Classification per OEB Filing Guidelines:

Project Class:	Sustaining
Project Need:	Non-Discretionary

Hydro One Networks – Investment Summary Document

Investment Category: Sustaining Capital - Lines - O/H Lines Component Refurbishment and Replacement

Reference #	Investment Name	Gross Cost	In-Service Date
S35	2011/2012 Steel Structure Coating Program	$12.0 M	Late 2012

Please see Exhibit D1, Tab 3, Schedule 2 for cash flows.

Need:

This investment addresses the need to restore identified steel lattice towers to their original design requirements and to extend their service lives. Tower coating is used to cost effectively manage the life cycle of these structures.

Not proceeding with this investment will result in further deterioration of the steel towers and eventually lead to advancing the replacement of towers at a substantially greater cost.

Summary:

Hydro One's transmission system consists of about 21,000 route kilometers (about 29,000 circuit kilometers) of overhead transmission lines. The system is almost exclusively made up of overhead lines and a large part of the system is supported by approximately 47,000 steel structures.

Hydro One's steel towers are manufactured with a zinc-based galvanized coating which 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. Once the galvanizing has depleted, bare metal is exposed to the atmosphere and the steel will corrode at a rate up to 25 times faster than the galvanized coating. The accelerated corrosion of the base metal increases the risk of structural damage to tower members, which will eventually need to be replaced if left unchecked

Asset condition assessment is carried out on an annual basis with a focus on line sections with in-service dates greater than 30 years that are located in highly corrosive areas and in locations where known problems exist.. The assessments determine the amount of galvanizing that remains on the tower members, or in the case where the coating is depleted, the amount of metal loss that has occurred. Recent condition assessments have shown that 320 structures on several line sections have, to a large part, lost their galvanized coating and need to have the corrosion protection re-instated.

Tower asset condition assessment is an ongoing program that requires field inspections with follow-up analysis to determine if any structural damage has taken place. Current detailed condition information and further analysis suggests that within the next 10 years, about 2,000 towers will need to have their corrosion protection re-instated in order to stem the deterioration of Hydro One's steel towers. As such, tower coating is an ongoing annual program which will coat 100 to 200 structures a year. The proposed 320 towers over two years are aligned with the annual requirements.

Results:

- Apply the protective coating on the identified steel towers to extend their life..
- Optimize the life-cycle costs of these 320 steel transmission towers.

Project Classification per OEB Filing Guidelines:

Project Class:	Sustaining
Project Need:	Non-Discretionary

Hydro One Networks – Investment Summary Document

Investment Category: Sustaining Capital - Lines - O/H Lines Component Refurbishment and Replacement

Reference #	Investment Name	Gross Cost	In-Service Date
S36	2011/2012 Shieldwire Replacement Program	$9.5 M	Late 2012

Please see Exhibit D1, Tab 3, Schedule 2 for cash flows.

Need:

This investment is required to replace shieldwire that has reached end-of-life.

Not proceeding with this investment will jeopardize system reliability, cause an increased number of customer interruptions, and will increase public and employee safety risks.

Summary:

Hydro One's transmission system consists of about 21,000 route kilometres (about 29,000 circuit kilometres) of overhead transmission lines. Almost all of these lines have shieldwire strung above the conductor to protect against lightning strikes and provide grounding continuity. The majority of shieldwire in Hydro One's system is made of galvanized steel wire, whose protective zinc coating deteriorates over time. When the galvanizing corrosion protection has depleted, the underlying steel begins to corrode resulting in loss of metal, reduction in strength, and eventual failure of the shieldwire. When failure does occur, the broken shieldwire usually makes contact with the conductors before falling to the ground.

To mitigate the risk of shieldwire failure, Hydro One has implemented an annual shieldwire-testing program which selects samples from line sections situated in corrosive environments that exhibit signs of deterioration and/or have a history of forced outages due to failed shieldwire. Shieldwire samples are removed and sent to a laboratory for ductility and tensile strength testing to gather additional data on its condition. If the test data for a particular shieldwire meets end-of-life criteria, then that shieldwire is replaced. Hydro One has established end-of-life criteria for shieldwire that considers Canadian Standards Association tensile strength requirements and Hydro One ductility requirements.

Testing has established that about 200 km on four line sections will need to be replaced during 2011 and 2012...

Results:

- Eliminate 200 km of the identified shieldwire that has reached end-of-life.
- Maintain system security and customer delivery reliability.
- Eliminate worker and public safety risks associated with shieldwire failures.

Project Classification per OEB Filing Guidelines:

Project Class:	Sustaining
Project Need:	Non-Discretionary

Hydro One Networks – Investment Summary Document

Investment Category: Sustaining Capital - Lines - O/H Lines Component Refurbishment and Replacement

Reference #	Investment Name	Gross Cost	In-Service Date
S37	2011/2012 Transmission Lines Emergency Restoration	$14.4 M	End 2012

Please see Exhibit D1, Tab 3, Schedule 2 for cash flows.

Need:

These investments are required to maintain the reliability of the transmission lines system and ensure public and employee safety.

Not proceeding with these investments would result in a significant reduction in reliability and increased reputation and regulatory risks, as well as an increase in public and employee safety risks.

Summary:

A number of transmission line components fail each year due to adverse weather, component deterioration, vandalism, or through accidents caused by public activity. These failures can cause unsafe conditions and create disruptions to the power system. A prompt response is required to restore the system to its normal state including restoration of customer load and eliminating unsafe conditions.

This is a demand program 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 condition assessment. This investment is essential to the operation of the transmission business through expedient response to failures and elimination of public and employee safety issues.

Emergency work under this release includes the replacement of failed or defective transmission line components such as wood structures, wood crossarms, towers, foundations, insulators, conductor, shieldwire and hardware. Funding allocation is based on recent historic costs and it is estimated that $14.5 million will be required to address emergency work during 2011 and 2012.

Results:

- Maintain system and customer reliability by responding to transmission line emergency repair work in an expedient manner.
- Maintain public and worker safety by responding to unsafe conditions in a timely manner.

Project Classification per OEB Filing Guidelines:

Project Class:	Sustaining
Project Need:	Non-Discretionary

Hydro One Networks – Investment Summary Document

Investment Category: Sustaining Capital - Lines - Transmission Lines Re-Investment

Reference #	Investment Name	Gross Cost	In-Service Date
S38	Circuit A6P – Reserve Jct. to Port Arthur TS Transmission Line Refurbishment	$14.0 M	Late 2012

Please see Exhibit D1, Tab 3, Schedule 2 for cash flows.

Need:

This investment is required to address the condition of the conductors and associated components on the 115kV circuit A6P from Reserve Jct. to Port Arthur TS (73.7 km). The conductor has deteriorated to the point where the strength and ductility characteristics are below established criteria determining end-of-life.

Failure to proceed with this investment will increase the probability of future line failures that will adversely impact the supply reliability to a number of industrial and residential customers in Thunder Bay, Nipigon, and Dorion Regions. Conductor failures will also create a risk to public safety.

Summary:

This program is driven by end-of-life conductors which is based on the accumulative degradation in tensile, ductility and surface condition given to its operating environment (i.e. conductor tension, geographic weather zone and vibration). To mitigate the risk of conductor failure, Hydro One has implemented a conductor testing program. Approximately 20 samples are removed from our lines each year and sent to an external laboratory for testing and analysis. The results of these tests drive the requirements for this program. Should replacement of the conductor be required then all other transmission line components on that line that are near or have reached end of life are replaced under the same project.

A6P is a 115 kV single-circuit wood pole transmission line that was built in 1920. This circuit extends between Alexander SS and Port Arthur TS in Northern Ontario. This section of line includes 560 wood pole structures and associated components. The conductor on A6P is 90 years old and conductor tests reveal that the tensile strength and ductility has deteriorated to the extent that it is now at end-of-life. The circuit currently contains a variety of non standard conductor sizes ranging from 211 kcmil ACSR to 477 kcmil ACSR and it is planned to replace these with a new 477 kcmil ACSR conductor. The 477 kcmil ACSR conductor is a standard conductor size that is broadly available

The proposed line refurbishment project will replace the conductor along with insulators, hardware, and shieldwire to bring the line to near new condition. Furthermore, approximately 55% of the existing wood poles have been assessed as being at end-of- life and will also be replaced.

Results:

- Reduce safety hazards to the public from potential component failures of the transmission line.
- Maintain and improve customer delivery reliability and voltage performance.
- Improve energy efficiency by reducing line losses.

Project Classification per OEB Filing Guidelines:

Project Class:	Sustaining
Project Need:	Non-Discretionary

Investment Category: Sustaining Capital - Lines - UG Cables Component Refurbishment and Replacement

Reference #	Investment Name	Gross Cost	In-Service Date
S39	H2JK / K6J Cable Replacement (Riverside Jct. x Strachan TS)	$ 45.1 M	Early 2013

Please see Exhibit D1, Tab 3, Schedule 2 for cash flows.

Need:

To replace two end of life 115 kV underground transmission circuits totaling 11.2 circuit km that run from Strachan TS to Riverside Jct. along Toronto's waterfront.

Failure to proceed with this investment will lead to reliability and supply issues to the downtown Toronto area.

Summary:

These buried cables were installed in 1957 and are constructed of a copper conductor surrounded with paper insulation and pressurized with oil from pre- pressurized tanks at the terminal ends of the circuit. They are contained within a lead sheath to hermetically seal the cable insulation which is covered with a protective jacket to insulate and help provide corrosion protection to the sheath. The low pressure oil system plays an essential part of the insulation system by saturating and maintaining the dielectric strength of the lapped paper insulating tapes over the core of the cable. The cable route length is 5.6 km and the majority of the circuit length runs parallel to lakeshore blvd west along the Toronto waterfront.

These circuits have been electrically reliable throughout their life, but have been plagued with multiple oil leaks during the last 7 years which have become progressively worse. System alarms monitor the cable circuits for oil loss and each leak that was detected in the past, was located, and assessed, repaired and the contaminated soil was recovered and remediated. In all cases the defect in the lead sheath demonstrated a reasonable cause for the leak (i.e. workmanship or isolated flaw). However in 2009, two large leaks that occurred were uncovered and subsequent failure analysis discovered widespread corrosion of the lead sheath on both K6J cable and H2JK cable which signals end of life for a cable system.

Continuing to feed, locate oil leaks then repair the cables and remediate the contaminated surrounding soil is very time consuming and expensive. Each event typically costs between $250 k and $500 k. These circuits are critical to maintain adequate supply to the downtown Toronto load. Should oil leak rates increase to a level that is unsustainable a decision would have to be made to shut off the oil supply and remove the circuits from service which would pose serious supply issues to the downtown core. The time period required to carry out replacement these cable circuits is a minimum of 2 to 3 years.

Results:

- Maintain system and customer reliability.
- Prevent public safety incidents by maintaining a reliable supply to the downtown core
- To address environmental risks by replacing leaking cables

Project Classification per OEB Filing Guidelines:

Project Class:	Sustaining
Project Need:	Non-Discretionary

Hydro One Networks – Investment Summary Document

Investment Type: Inter-Area Network Transfer Capability

Reference #	Investment Name	Gross Cost	In-Service Date
D1	New 500kV Bruce to Milton Double Circuit Transmission Line	$695.5M	Late 2012

Please see Exhibit D1, Tab 3, Schedule 3, Appendix A, Table 2 for cash flow and other details about this project.

Need:
To construct a new double-circuit 500kV line between Bruce and Milton in accordance with the Ontario Power Authority recommendation; to address the inadequate transmission capacity to transmit committed renewable and baseload generation in Bruce Area to the load in southern Ontario (as per deliberations during Proceeding EB-2007-0050 for the Bruce to Milton 500kV project). Not proceeding with this investment would result in the constraint of nuclear and renewable generation in the Bruce Area.

Summary:
The existing transmission in southern Ontario cannot accommodate the generation expected to come into service in the Bruce area over the next few years. This includes:

- 1500MW from upgrades of existing facilities and rehabilitation and restart of Bruce A units G1 and G2, for which Ontario Power Authority has assumed a contract between the Ministry of Energy and Bruce Power Inc.
- 1700MW from new wind generation in the Bruce area, including an aggregate of 723MW for which the Ontario Power Authority has entered into contracts with wind developers, through the Ministry of Energy's Request For Proposals.

To incorporate the above generation into the transmission system, additional transmission capability is required. The Ontario Power Authority has determined that the preferred solution to increase the transfer capability of Hydro One's 500kV system is to build 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 and the committed and potential wind generation.

The need for this project was identified in the IESO's December 2007 Ontario Reliability Outlook and an IESO System Impact Assessment Report (CAA ID 2006-250) has been completed for this project. The Ontario Government has also, in its announcement of "A Balanced Plan for Ontario's Electricity Future", reiterated the need for "expanding the transmission capacity from Bruce County and surrounding area to facilitate the transmission of electricity from several new wind farms and the Bruce facility".

The project will entail building a new 176km 500kV double circuit line adjacent to the existing 500kV line B560V/B561M utilizing an expanded transmission corridor. One of the 500kV circuits will connect at Bruce A TS, and the other at Bruce B SS. Both circuits will terminate at Milton SS. Addition of new equipment at the existing switchyards will be undertaken to accommodate the connection of the new circuits.

The Ontario Energy Board granted Hydro One 'Leave to Construct' approval in September 2008 (Proceeding EB-2007-0050) and an Order-In-Council granting Environmental Assessment approval was received in December 2009. The project construction will be staged to take advantage of the availability of transmission outages as a result of planned outages at Bruce GS.

The cost estimate of $695.5 million assumes the "Accelerated Cost Recovery of CWIP" mechanism as explained in Exhibit A, Tab 11, Schedule 5.

Results:
Provide sufficient transmission capacity to reliably transmit the output of the Bruce GS and 1700MW of wind generation in Bruce and surrounding counties in accordance with Northeast Power Coordinating Council criteria.

Project Classification per OEB Filing Guidelines:

Project Class:	Development
Project Need:	Non-Discretionary: The project is required to satisfy the recommendations outlined by the OPA to accommodate new generation.

Hydro One Networks – Investment Summary Document

Investment Type: Inter-Area Network Transfer Capability

Reference #	Investment Name	Gross Cost	In-Service Date
D2	Northeast Transmission Reinforcement: Installation of Static Var Compensators at Porcupine TS and Kirkland Lake TS	$121.6M	Late 2011

Please see Exhibit D1, Tab 3, Schedule 3, Appendix A, Table 2 for cash flow and other details about this project.

Need:

- Allow the Ontario Power Authority to successfully procure approximately 500 MW of hydroelectric generation north of Timmins from four specific projects that were directed by the Minister of Energy detailed in a letter dated May 20th, 2008.
- Promote the use and generation of electricity from renewable energy resources in a manner consistent with the policies of the Government of Ontario by providing timely reinforcement of the transmission system necessary to accommodate the renewable generation to be procured in Northern Ontario

Summary:

The existing north and south electricity systems in Ontario are interconnected by two, 278 km long, 500 kV single-circuit lines between Hanmer TS and Essa TS and one 91 km long, 230 kV single-circuit line between the Otto Holden GS and Des Joachims TS. These circuits comprise the North-South (N-S) Interface, which allows transfer of generation that is surplus in northern Ontario to southern Ontario during peak load conditions.

In the past few years, addition of new generation resources and reduction of load in northern Ontario have increased the level of southbound flow. Further, The Ontario Power Authority forecasts another 900 MW of new resources, mainly renewable, to be in-service in northern Ontario by 2014. The enactment of the Green Energy and Green Economy Act and the subsequent Feed-in Tariff program is expected to further increase the southbound flows on the N-S tie, which currently operates near its capability of about 1,300 MW without post contingency generation rejection (GR) or 1,400MW with GR. In order to enable renewable generation in the north, Ontario Power Authority has recommended, via its letter dated May 20, 2008, several near term measures to enhance the transfer capability of the N-S Interface by late 2010/2011. These near term measures were reconfirmed by the Ontario Power Authority in its supplemental supporting evidence (EB-2008-0272) dated August 21, 2009 and on December 16, 2009 the Ontario Energy Board approved the cost recovery for the Static Var Compensators projects (Project D7) and the Series Capacitors at Nobel SS (Project D8) from the 2009-2010 Transmission rates.

The two series capacitor banks at Nobel SS increase the transfer capability to 1740MW assuming GR. With the installation of one +300/-100MVar static var compensator at Porcupine TS and one +200/-100MVar static var compensator at Kirkland Lake TS this will further increase the N-S transfer capability by 410MW to 2,150MW assuming GR.

Results:

- The increased transfer capabilities along the transmission corridors north and south of Sudbury through the installation of the static var compensators, (along with the Nobel series capacitor) will allow the Ontario Power Authority to successfully procure approximately 500 MW of renewable generation.
- Address concerns about the risk of supply reliability in northeastern Ontario due to increasing renewable generation development.

Project Classification per OEB Filing Guidelines:

Project Class:	Development
Project Need:	Non-Discretionary: The projects are required to incorporate new renewable generation in northern Ontario to satisfy government directive(s), and to support the OPA's recommendation

Hydro One Networks – Investment Summary Document

Investment Type: Inter-Area Network Transfer Capability

Reference #	Investment Name	Gross Cost	In-Service Date
D3	Installation of Static Var Compensator at Nanticoke TS	$84.6M	Mid 2011
D4	Installation of Static Var Compensator at Detweiler TS	$80.3M	Mid 2011

Please see Exhibit D1, Tab 3, Schedule 3, Appendix A, Table 2 for cash flow and other details about these projects.

Need:
To provide increased transmission capacity to support 1500MW of increased generation at the Bruce complex plus 1700MW of committed and potential wind generation in the Bruce Area both as a near-term measure and long term solution to increased transfer capability out of the Bruce Area following the decommissioning of the Nanticoke coal-fired plant in 2014 (as per deliberations during Proceeding EB-2007-0050 for the Bruce to Milton 500kV project). Not proceeding with this investment would result in constraining nuclear and renewable generation in the Bruce Area.

Summary:
The existing transmission out of the Bruce complex comprising 4 x 500kV circuits and 6 x 230kV circuits transmit power from the Bruce nuclear plants and the wind generation in the Bruce Area. Two Bruce 230kV nuclear generating units are currently being refurbished and are planned to return to service in 2011. Two new Bruce x Milton 500kV circuits, planned to be incorporated in 2012, are intended to support the resulting 1500MW of increased generation plus 1700MW of committed and potential wind generation in the Bruce Area. In the interim period, additional reactive support will be required to support the large transfers out of the Bruce Area. Over the longer term, reduction in generation at Nanticoke and the eventual decommissioning of the coal-fired plant, by 2014, will require the availability of reactive support to permit large transfers out of the Bruce complex. This reactive support requirement will be met by the installation of two 350MVar Static Var Compensators; one at Nanticoke TS (at 500kV) and the other at Detweiler TS (at 230kV).

These projects were identified in the IESO's December 2007 Ontario Reliability Outlook and the IESO System Impact Assessment Report (CAA ID 2008-346) have been completed for these projects.

Result:
Increase transfer capability out of the Bruce Area by 250MW to support increased generation in the area and reduce the risk of generation congestion.

Project Classification per OEB Filing Guidelines:

Project Class:	Development
Project Need:	Non-Discretionary: The project is needed to satisfy the recommendations outlined by the OPA to accommodate phasing out of coal-fired generation and to incorporate new generation in southwestern Ontario.

Hydro One Networks – Investment Summary Document

Investment Type: Inter-Area Network Transfer Capability

Reference #	Investment Name	Gross Cost	In-Service Date
D5	Installation of 1 Shunt Capacitor Bank at Essa TS	$6.3M	Late 2011
D6	Installation of 2 Shunt Capacitor Banks at Porcupine TS	$11.7M	Late 2011
D7	Installation of 1 Shunt Capacitor Bank at Hanmer TS	$8.5M	Late 2011

Please see Exhibit D1, Tab 3, Schedule 3, Appendix A, Table 2 for cash flow and other details about these projects.

Need:

- Allow the Ontario Power Authority to successfully procure approximately 500 MW of hydroelectric generation north of Porcupine TS from four specific projects that were directed by the Minister of Energy, detailed in a letter dated May 20th, 2008.
- Promote the use and generation of electricity from renewable energy resources in a manner consistent with the policies of the Government of Ontario by providing for the timely reinforcement of the transmission system which is necessary to accommodate the connection of up to 400MW in addition to the 500 MW of hydroelectric generation to be procured in Northern Ontario.

Summary:

The existing north and south electricity systems in Ontario are interconnected by two, 278 km long, 500 kV single-circuit lines between Hanmer TS and Essa TS and one 91 km long, 230 kV single-circuit line between the Otto Holden GS and Des Joachims TS. These circuits comprise the North-South (N-S) Interface, which allows transfer of generation that is surplus in northern Ontario to southern Ontario during peak load conditions.

In the past few years, addition of new generation resources and reduction of load in northern Ontario have increased the level of southbound flow. Further, The Ontario Power Authority forecasts another 900 MW of new resources, mainly renewable, to be in-service in northern Ontario by 2014. The enactment of the Green Energy and Green Economy Act and the subsequent Feed-in Tariff program is expected to further increase the southbound flows on the N-S tie, which currently operates near its capability of about 1,300 MW without post contingency generation rejection (GR) or 1,400MW with GR. In order to enable renewable generation in the north, Ontario Power Authority has recommended, via its letter dated May 20, 2008, several near term measures to enhance the transfer capability of the N-S Interface by late 2010/2011. The near term measures include: the series capacitors at Nobel SS and static var compensators at Porcupine TS and Kirkland Lake TS (as outlined in Project D2), as well as the installation of four shunt capacitor banks, one 245MVar capacitor bank at Essa TS, two 100MVar capacitor banks at Porcupine TS, and one 192MVar capacitor bank at Hanmer TS. These near term measures were reconfirmed by the Ontario Power Authority in its supplemental supporting evidence (EB-2008-0272) dated August 21, 2009.

As discussed in Project D2, the addition of series capacitors at Nobel SS and static var compensators at Porcupine TS and Kirkland Lake TS increase N-S transfer capability to 2,150MW assuming GR. With the installation of the four shunt capacitor banks this will further increase the N-S transfer capability by 200MW to 2,350MW assuming GR.

Results:

- The increased transfer capabilities along the (north and south of Sudbury) transmission corridors, through the installation of the four shunt capacitor banks will allow the Ontario Power Authority to successfully procure renewable generation.

Project Classification per OEB Filing Guidelines:

Project Class:	Development
Project Need:	Non-Discretionary: The projects are required to incorporate new renewable generation in northern Ontario to satisfy government directive(s), and to support the OPA's recommendation

Hydro One Networks – Investment Summary Document

Investment Type: Inter-Area Network Transfer Capability

Reference #	Investment Name	Gross Cost	In-Service Date
D8	Installation of Shunt Capacitor Bank at Dryden TS	$10.7M	Late 2013

Please see Exhibit D1, Tab 3, Schedule 3, Appendix A, Table 2 for cash flow and other details about this project.

Need:

- To improve the transmission capability that currently restricts the grid connection of new renewable energy resources in the west of Atikokan area (the "Orange Zone").This would facilitate the development of renewable energy resources in a manner consistent with the policies of the Government of Ontario as prescribed by the Minister of Energy's September 17, 2008 directive to Ontario Power Authority and the Green Energy and Green Economy Act.
- To maintain acceptable voltage performance after the retirement of Aitkokan GS and also to comply with the Market Rules.

Summary:

The total generation in the area is approximately 340 MW with limited dispatching ability. The recent area demand has declined due to economic downturn in the forestry sector. During low demand (around 200MW) periods there is a surplus of generation of approximately 140 MW. This surplus can be as high as 465 MW with maximum import from Manitoba and Minnesota. There has been interest in developing renewable resources in the area, some of which have been expressed through the Feed-in-Tariff program. The development of these renewable resources will further increase the surplus.

The transmission system West of Atikokan is very sparse and long, and it is also in the direct path of Manitoba/Minnesota import. The power transfers are restricted by voltage and thermal limitations. These limitations are associated with the single circuit contingencies west of Mackenzie TS. Other contingencies, such as those at Kenora, can cause local thermal overload. These contingencies show there is no room to connect additional generation and for that reason the West of Atikokan area was declared an Orange Zone by the OPA. There are also inter-area transfer limitations, such as the interfaces Transfer East of Mackenzie and East-West Tie.

To improve the transmission capability to achieve the Government's goal; a first stage of transmission improvement in the near term would be to install two 230 kV shunt capacitor banks at Dryden TS together with the deployment of a Generation Rejection scheme to reject new generation facilities. This near term investment will adequately maintain the present transfer capability in the area and allow up to 50 MW of additional new generation to be connected. In addition, the need for the new Dryden TS capacitor banks in preparation for the retirement of Atikokan GS is confirmed by the System Impact Assessment dated May 31, 2009. In the longer term, dynamic reactive power support or other measures may be required if transfers are increased beyond present levels as the result of reduced load west of Atikokan and/or increased transfers from Manitoba or Minnesota. This project will be committed only if the Ontario Power Authority recommends it, based on its assessment of technical characteristics currently being finalized.

Results:

This investment will provide transmission improvement in the near term to allow the procurement of renewable generation of approximately 50 MW in the West of Atikokan area and provide adequate reactive power resources when Atikokan GS is not operating or is no longer in-service (after-retirement).

Project Classification per OEB Filing Guidelines:

Project Class:	Development
Project Need:	Non-Discretionary: The project is required to incorporate new renewable generation in northern Ontario to satisfy government objective(s) and to support the OPA's recommendation

Hydro One Networks – Investment Summary Document

Investment Type: Local Area Supply Adequacy

Reference #	Investment Name	Gross Cost	In-Service Date
D9	Woodstock Area Transmission Reinforcement	$70.9M	Mid 2011

Please see Exhibit D1, Tab 3, Schedule 3, Appendix A, Table 3 for cash flow and other details about the project.

Need:
Customer load supplied in the Woodstock Area at 115kV has exceeded the reliable transmission capacity. Not proceeding with this investment would result in the inability to reliably supply customers in the Woodstock Area.

Summary:
Driving the increased electricity demand in the Woodstock Area is the fact that Toyota Canada Inc. has built a new manufacturing plant that opened in 2008. The new Toyota plant has resulted in economic growth in the Woodstock Area in the form of industrial load ancillary to the Toyota plant such as parts fabrication as well as increased residential and commercial load. As a result the total load supplied at 115kV in the Woodstock area is expected to grow over the next 18 years at an average of 3.5% per year including the impact of Conservation and Demand Management.

On February 13, 2007, Hydro One issued a report entitled "Woodstock Area Study" in response to inquires from Woodstock Hydro and Hydro One Distribution who were concerned about the capability of the existing 115kV transmission network to supply the growing load in the Woodstock area. The Woodstock Area Study found that the existing Woodstock area loads exceed the current reliable transmission capacity of 96MW for a loss of one of the existing 115kV circuits that supplies Woodstock TS. The Woodstock Area Study recommended that major transmission reinforcement be provided by 2010 to increase the transmission capacity so that this load can be supplied reliably. Project delays have resulted in the in-service being delayed to 2011.

The proposed facilities of this investment include 11km of new 230kV double-circuit line on the existing 115kV right-of-way (ROW) between Ingersoll TS and a new station called Karn TS and 3km of new 230kV double-circuit line, initially operated at 115kV[1], on the existing 115kV ROW between Karn TS and Woodstock TS. The project also includes construction of the new Karn TS which consists of two 250MVA 230/115kV autotransformers with three 115kV circuit breakers at a location 3km west of Woodstock TS. These projects will increase the transmission capacity in the Woodstock Area to 290MW in preparation for future growth.

This project is highlighted in the IESO's December 2007 Ontario Reliability Outlook and the IESO System Impact Assessment Report (CAA ID 2006-253) has been completed for this project. This project received Ontario Energy Board 'Leave to Construct' Approval on October 11, 2007 (Proceeding EB-2007-0027) and the final Environmental Study Report was filed with the Ministry of the Environment on September 12, 2007.

Results:
Increase reliable transmission capacity in the Woodstock Area.

Project Classification per OEB Filing Guidelines:

Project Class:	Development
Project Need:	Non-Discretionary: The project is required to increase reliable transmission capacity in the Woodstock Area to supply new load customers, and it is endorsed by OPA.

[1] The new line between Karn TS to Woodstock TS will be built to 230kV in order to cater for possible future 230kV conversion

Hydro One Networks – Investment Summary Document

Investment Type: Local Area Supply Adequacy

Reference #	Investment Name	Gross Cost	In-Service Date
D10	Rebuild Burlington TS 115kV Switchyard	$56.4M	Mid 2012

Please see Exhibit D1, Tab 3, Schedule 3, Appendix A, Table 3 for cash flow and other details about the project.

Need:

Major components in the Burlington TS 115 kV switchyard are under-rated with respect to short circuit withstand rating and/or ampacity. The emergency ratings of the four 230/115 kV transformers cannot be utilized when required due to limiting station components in the 115 kV switchyard. Failure to proceed with this investment will result in the continued exposure of customers to post-contingency load interruptions in contravention of the security criteria contained within the IESO's Ontario Resource and Transmission Assessment Criteria.

Summary:

Under-rated equipment is limiting the operation and reliable supply of customers from Burlington TS. During planned maintenance outages of certain breakers at Burlington TS, or when the bus is split to control fault levels, the emergency ratings of the existing 230/115kV autotransformers cannot be utilized due to substandard busses. An automatic load rejection scheme is used at Burlington TS to reduce the transformer loadings to within their limits following critical contingencies.

Network changes including new generation to be incorporated in the area including Halton Hills CGS and Northland Thorold CGS has resulted in the short circuit rating of all 115 kV Burlington breakers to be exceeded. In April 2008 the fault level exceeded the capabilities of the 115 kV breakers. The 115 kV bus at Burlington TS was opened to reduce the fault level to within the interrupting capabilities of the existing breakers. Split bus operation further reduced the load carrying capacity of North and South switchyards, limited the customer load that Burlington TS could supply during summer of 2008 and resulted in two major customer load interruptions.

During preliminary engineering work to replace the 115 kV breakers it was determined that after considering the complexities of construction and outage requirements, it is more appropriate to merge all Burlington related projects into one by constructing an entirely new 115 kV Burlington TS switchyard at the existing station. The proposed switchyard layout of the integrated plan is according to modern design standards versus the layout used 60-years ago and results in a more maintainable station and improved customer reliability.

The Independent Electricity System Operator has completed the System Impact Assessment Report (CAA ID 2007-299) for this project, which concludes that the proposed changes will not result in a material adverse effect on the reliability of the IESO-controlled grid.

Results:

Improve load supply reliability of the 115kV customer load supplied from Burlington TS and restore reliable overload meeting capability at Burlington TS. This overload capability combined with the 1000 MVA total transformation capacity at Burlington TS will provide sufficient load supply for at least the next 15-20 years.

Project Classification per OEB Filing Guidelines:

Project Class:	Development
Project Need:	Non-Discretionary: The project is required to meet compliance and reliability requirements; and increase the reliability of supplying the 115kV customer load at Burlington TS.

Hydro One Networks – Investment Summary Document

Investment Type: Local Area Supply Adequacy

Reference #	Investment Name	Gross Cost	In-Service Date
D11	Toronto Area Station Upgrades for Short Circuit Capability: Rebuild Hearn SS	$84.9M	Late 2012

Please see Exhibit D1, Tab 3, Schedule 3, Appendix A, Table 3 for cash flow and other details about the project.

Need:
To replace aging facilities at Hearn SS, and improve short circuit ratings as per the Transmission System Code.

Not proceeding with this investment would result in risk of poor reliability to customers and an inability to connect new generation in the Toronto 115kV area.

Summary:
The Hearn SS facility consists of a 115kV switchyard with lines connecting to Leaside TS, Esplanade TS, John TS and the new Portlands Generating Station. The station is a critical element of the supply to the City of Toronto.

The station was built in the early 1950's to connect the old Hearn Generating Station. The need for rebuilding the station has been identified as most components: breakers, buses and insulators are at the end of useful life. In addition, the 115kV breakers at the station are rated at 37.5kA and do not meet the Transmission System Code requirement and need to be replaced to allow new distributed generation to be connected in the City of Toronto.

It is proposed to rebuild the Hearn 115kV switchyard using gas insulated switchgear. The new GIS switchyard will be built adjacent to the existing Hearn switchyard on lands to be acquired from Ontario Power Generation. The additional property is required to be acquired from Ontario Power Generation by September 2010.

Project development work is currently under way to obtain release estimates for the work. Hydro One expects to release the project by October 2010 assuming all approvals have been obtained. The current planned in-service date for the new station is end of December 2012.

Results:
Improve system reliability and enable connection of new generation in the City of Toronto.

Project Classification per OEB Filing Guidelines:

Project Class:	Development
Project Need:	Non-Discretionary: The project is required to meet compliance and reliability requirements and to address end-of-life equipment at Hearn SS.

Hydro One Networks – Investment Summary Document

Investment Type: Local Area Supply Adequacy

Reference #	Investment Name	Gross Cost	In-Service Date
D12	Toronto Area Station Upgrades for Short Circuit Capability: Leaside TS Equipment Uprate	$37.4M	Late 2012
D13	Toronto Area Station Upgrades for Short Circuit Capability: Manby TS Equipment Uprate	$30.4M	Late 2013

Please see Exhibit D1, Tab 3, Schedule 3, Appendix A, Table 3 for cash flow and other details about the projects.

Need:
To replace aging 115kV breakers and associated 115kV switchyard facilities at Leaside TS and Manby TS, and to improve short circuit ratings at these stations to comply with the Transmission System Code.

Not proceeding with this investment would result in risk of poor reliability to customers and an inability to connect new generation in the Toronto 115kV area.

Summary:
Both Leaside TS and Manby TS are 230/115kV autotransformer stations supplying the City of Toronto; Leaside TS supplies the eastern section of the central area of the City and Manby TS supplies the western section of the central area of the City.

Both stations 115kV switchyards are equipped with 115kV oil breakers with an asymmetrical current rating of 45.5A. It is planned to uprate the station fault current withstand capability to 50kA as per the Transmission System Code. This will permit incorporation of up to 300MVA of new generation in the Leaside TS 115kV area and up to 300MVA of new generation in the Manby 115kV area respectively.

At Leaside TS, the uprating work requires that 28 existing oil breakers in the 115kV switchyard be replaced and sections of the station strain bus uprated. The average age of these oil breakers is 46 years and the breakers are approaching end of life. Similarly at Manby TS, the uprating work requires that 16 existing oil breakers in the 115kV switchyard be replaced and sections of the station strain bus uprated. The average age of these oil breakers is 49 years and the breakers are approaching end of life. Three oil breakers associated with decommissioned circuits K7B and K8B are to be removed.

A number of additional components such as 115kV instrument transformers and insulators have also been identified as end of life and due for replacement. It is therefore proposed to take advantage of 115kV outages to replace all end-of-life components in the Leaside TS 115kV switchyard and Manby TS 115kV switchyard respectively.

It is proposed to release the Leaside TS project by December 2010 and have the work completed by December 2012. The Manby TS project will follow and it is proposed to release the project by December 2010 and have the work completed by December 2013.

Results:
Replace aging equipment and allow incorporation of distributed generation in the City of Toronto.

Project Classification per OEB Filing Guidelines:

Project Class:	Development
Project Need:	Non-Discretionary: The project is required to meet compliance and reliability requirements and address end-of-life equipment at Leaside TS and Manby TS.

Hydro One Networks – Investment Summary Document

Investment Type: Local Area Supply Adequacy

Reference #	Investment Name	Gross Cost	In-Service Date
D14	Midtown Transmission Reinforcement Plan	$107.3M	Mid 2013

Please see Exhibit D1, Tab 3, Schedule 3, Appendix A, Table 3 for cash flow and other details about the project.

Need:
To replace aging facilities and provide adequate supply capacity to meet future load growth; and to adhere to applicable reliability criteria that specify load customers are not to be rejected upon a first contingency. Not proceeding with this investment would result in increased risk of customer interruptions affecting supply reliability for customers.

Summary:
The existing facilities between Leaside TS and Wiltshire TS consist of three 115kV circuits L13W, L14W and L15W. These circuits supply Bridgman TS and Dufferin TS and provide load transfer capability between the Leaside TS and Manby TS 230/115kV autotransformer stations.

There is a need to refurbish/replace the existing underground cable section of 115kV circuit L14W between Birch Jct. and Bayview Jct. This section of cable is 55 years old and has been identified as requiring replacement by 2011. There is also a need to provide additional transmission capacity to relieve the overloading under single contingency and meet load growth at Bridgman TS and Dufferin TS. It is planned to do the installation of the new circuit at the same time as the cable replacement so as to minimize costs and avoid unnecessary disruption to the community.

The IESO has completed the System Impact Assessment Report (CAA ID 2006-238) for this project; which concludes that the proposed plan will alleviate thermal overloading of the Leaside to Wiltshire circuits under contingency conditions. This project will also provide operational flexibility to Hydro One and the customer with respect to load transfers, maintenance and outage scheduling.

The project cost that is allocated to the development component of the project (i.e. after subtracting cost allocated to replacement of the cable) will be recoverable through incremental revenue from the appropriate rate pool and capital contributions from the customers, as indicated in Table 3 of Exhibit D1, Tab 3, Schedule 3. The capital contribution amounts indicated therein are considered preliminary as they are only finalized when the Capital Cost Recovery Agreement is signed and when the project is placed in-service. The capital contributions are determined as per Hydro One's Transmission Customer Contribution Policy in accordance with the Transmission System Code.

A Section 92 "Leave to Construct" proceeding is underway for the project (Proceeding EB-2009-0425). The application was filed with the Ontario Energy Board on December 23, 2009. The Environmental Assessment process is also underway and the draft Environmental Study Report was issued for public review on March 8, 2010.

The planned in-service date is now April 2013, a delay of about 4 years compared to the date identified in 2009, in order to allow for required development work, consultations, approvals, design, and construction. The impact of the delay has been somewhat mitigated by the effect of the economic recession as load growth has been slower than previously forecast. However, load continues to exceed capability and if expeditious approvals are obtained, Hydro One will attempt to have the facilities completed earlier.

Results:
Improve load meeting capability and transmission reliability for customers in the City of Toronto mid-town area.

Project Classification per OEB Filing Guidelines:

Project Class:	Development
Project Need:	Non-Discretionary: The project is required to reliably serve customers in the City of Toronto.

Hydro One Networks – Investment Summary Document

Investment Type: Local Area Supply Adequacy

Reference #	Investment Name	Gross Cost	In-Service Date
D15	Guelph Area Transmission Reinforcement	$50.7M	Mid 2014

Please see Exhibit D1, Tab 3, Schedule 3, Appendix A, Table 3 for cash flow and other details about the project.

Need:

- To transfer load from the 115 kV system to the 230 kV system in the Guelph Area and provide adequate capacity on the 115 kV double-circuit line B5G/B6G to accommodate future 115 kV load growth in the Hanlon area.
- To eliminate the exposure of customers in the Guelph area to automatic load loss for first contingency during summer peak load conditions.

Summary:

The Guelph transmission system to South-Central Guelph consisting of 115 kV circuits B5G and B6G supplied from Burlington TS requires upgrades to increase its capacity from the 105 MW that the Guelph area load reached in 2008 to 130-150 MW that Guelph area is expected to require in 2015-2020. Loading limits on the Burlington TS autotransformers require that load must be transferred to alternate sources during the summer months. Load growth, operating restrictions on the autotransformers and short circuit values at Burlington TS all contribute to this requirement. During past summers load normally supplied from Burlington TS on circuits B5G and B6G was transferred to the Detweiler TS and Preston TS. With the B5G/B6G circuits transferred to Detweiler TS and Preston TS, control actions were in place requiring open bus tie breakers at Hanlon TS, Cedar TS and at other customer load locations. This action contributed to frequent load losses (13 forced outages with load losses in summer of 2009 alone).

The overall investment will require Ontario Energy Board "Leave to Construct" approval under Section 92 and Environmental Assessment Approval by the Ministry of Environment. The Leave to Construct application will include assessment of the project's alternatives. In early 2009 a Class Environmental Assessment study commenced for the Guelph Area Transmission Reinforcement project. This project will be committed only if the Ontario Power Authority recommends it, based on its assessment of project needs, and once all required approvals have been obtained.

Result:

A second supply from the 230 kV system at Campbell TS to B5G and B6G normally supplied from Burlington TS. This will provide a capacity relief to Burlington TS that is exceeding its full capacity during summer peak load conditions.

Project Classification per OEB Filing Guidelines:

Project Class:	Development
Project Need:	Non-Discretionary: The project is required to increase reliable transmission capacity in the Guelph Area to supply new load customers.

Hydro One Networks – Investment Summary Document

Investment Type: Load Customer Connection

Reference #	Investment Name	Gross Cost	In-Service Date
D16	Commerce Way TS: Build new 115/27.6kV Transformer Station & Line Connection (formerly Woodstock East TS)	$45.8M	Early 2012

Please see Exhibit D1, Tab 3, Schedule 3, Appendix A, Table 4 for cash flow and other details about the project.

Need:
To provide relief for the existing Woodstock TS that has exceeded its capacity. Woodstock Hydro and Hydro One Distribution are forecasting an additional 30MW growth in the area by 2010. This growth is fuelled by spin-off industries around the new Toyota Woodstock plant.

In the short term, increases in load have been met by transferring loads to Ingersoll TS. Beyond this load transfer, there will be a need to reject load upon contingency scenarios when peak load levels exceed the Woodstock TS capacity limit. Implications of not proceeding with this investment include: insufficient supply capacity and a decrease in supply reliability.

Summary:
In April 7, 2007, Woodstock Hydro Services Inc and Hydro One Distribution gave Hydro One the go-ahead to build a pool funded transformer station (Commerce Way TS) to meet future demand in the area. The in-service date for the station is targeted for Summer 2011. However, the Ontario Energy Board approved Woodstock Area Transmission Facilities must be in-service before Commerce Way TS can be reliably connected to the network.

The proposed Commerce Way TS will consist of two 115/27.6kV, 50/83MVA transformers. In order to accommodate the new TS, the existing 115kV single circuit (B8W) has to be rebuilt to a double circuit line from Woodstock TS to the tapping point of the new Commerce Way TS. The line would be operated at 115kV, but would be built to 230kV standards for possible future use at 230kV.

Construction of the new double circuit line will occur on existing right-of-ways. Property acquisition is required for the construction of the new transformer station. The Ontario Energy Board granted "Leave to Construct" approval on November 6, 2009 under Proceeding EB-2009-0079 for the project. The entire project is subject to the provincial Environmental Assessment Act approval in accordance with the Class EA for minor Transmission Facilities. Environmental Assessment approval was received in April, 2009.

The project cost will be recoverable through incremental revenue for the appropriate rate pool and capital contributions from the customers, as indicated in Table 4 of Exhibit D1, Tab 3, Schedule 3. The capital contribution amounts are considered preliminary as they are only finalized when the Capital Cost Recovery Agreement is signed and when the project is placed in-service. The capital contributions are determined as per Hydro One's Transmission Customer Contribution Policy in accordance with the Transmission System Code.

Results:
Ensure availability of electricity supply and maintain required quality of supply to customers in the Woodstock area.

Project Classification per OEB Filing Guidelines:

Project Class:	Connection
Project Need:	Customer Driven: This project is required to supply customers' future load growth.

Hydro One Networks – Investment Summary Document

Investment Type: Load Customer Connection

Reference #	Investment Name	Gross Cost	In-Service Date
D17	Kirkland Lake TS: Reconnect Idle K4 Line	$13.7M	Mid 2011

Please see Exhibit D1, Tab 3, Schedule 3, Appendix A, Table 4 for cash flow and other details about the project.

Need:
To rebuild the idle 115 kV circuit, K4, from Kirkland Lake TS to supply Northgate Minerals Corporation new mine facilities.

Summary:
Hydro One Networks is obligated as per the Transmission System Code to meet customer connection needs. Northgate Minerals Corporation is proposing to develop a gold mine near Matachewan, Ontario. The mine facility will require Hydro One to rebuild 47 km of idle 115kV transmission line (between Macassa #3 Jct and Matachewan Jct) originating from Kirkland Lake TS. The customer will build an additional 7 km of new transmission line to the mine site substation. Ownership of the 7 km line segment will then be transferred to Hydro One upon completion.

All Environmental Assessment work has been completed though an Environmental Assessment services agreement. The project cost will be fully recoverable through capital contributions from the customers, as indicated in Table 4 of Exhibit D1, Tab 3, Schedule 3. The Connection and Cost Recovery Agreement is scheduled for signature by Northgate Minerals Corporation by end of Q1 2010. The capital contribution amounts are considered preliminary as they are only finalized when the Capital Cost Recovery Agreement is signed and when the project is placed in-service. The capital contributions are determined as per Hydro One’s Transmission Customer Contribution Policy in accordance with the Transmission System Code.

Results:
Rebuilding the idle 115kV circuit, K4, will allow Northgate Minerals Corporation to supply the mine site substation by the planned in-service date.

Project Classification per OEB Filing Guidelines:

Project Class:	Connection
Project Need:	Customer Driven: This project is required to provide the power supply requirements of Northgate Minerals Corporation’s new mine in a timely manner.

Hydro One Networks – Investment Summary Document

Investment Type: Load Customer Connection

Reference #	Investment Name	Gross Cost	In-Service Date
D18	South Halton Tremaine TS: Build new Transformer Station	$28.5M	Mid 2012

Please see Exhibit D1, Tab 3, Schedule 3, Appendix A, Table 4 for cash flow and other details about the project.

Need:
To add new transformation capacity to alleviate overloading and address future load growth in the Palermo TS supply area. Not proceeding with this investment would impair the customers' ability to supply its load. Hydro One is obliged under the Transmission System Code to meet customer supply needs, when requested by the area customers.

Summary:
Palermo TS, located in the Town of Oakville, supplies Burlington Hydro, Milton Hydro and Oakville Hydro. The station load has reached its capacity. The peak loading on this station has exceeded capacity by about 130%. Additionally, the loading on other stations supplying these local distribution companies is approaching capacity and load is forecast to continue to grow in this part of Halton Region by 2-3% per year over the next five to ten years. The local distribution Companies have requested Hydro One to provide a proposal for the new capacity to alleviate overloading and to supply new loads in the Palermo TS supply area. The most suitable location for the new transformer station would be near Tremaine Road and also near the right-of-way through which T36B, T37B, T38B and T39B circuits pass. The in-service date of the new station "Tremaine TS" is June 1, 2012.

A new facility such as the one proposed requires Environmental Assessment approval from the Ministry of Environment in accordance with the provincial Environmental Assessment Act (Class EA for minor Transmission Facilities).

The project cost will be recoverable through incremental revenue for the appropriate rate pool and capital contributions from the customers, as indicated in Table 4 of Exhibit D1, Tab 3, Schedule 3. The capital contribution amounts are considered preliminary as they are only finalized when the Capital Cost Recovery Agreement is signed and when the project is placed in-service. The capital contributions are determined as per Hydro One's Transmission Customer Contribution Policy in accordance with the Transmission System Code.

Results:
Increase transformation capacity to alleviate overloading and meet the future load requirements.

Project Classification per OEB Filing Guidelines:

Project Class:	Connection
Project Need:	Customer Driven: This project is required to supply customers' future load growth.

Hydro One Networks – Investment Summary Document

Investment Type: Load Customer Connection

Reference #	Investment Name	Gross Cost	In-Service Date
D19	Ancaster TS: Build new Transformer Station & Line Connection	$24.1M	Mid 2013

Please see Exhibit D1, Tab 3, Schedule 3, Appendix A, Table 4 for cash flow and other details about the project.

Need:
To provide relief for existing Nebo TS that has approached its capacity. Hydro One Distribution has received requests for new customer connections in the Ancaster area. There is not sufficient capacity to supply these new loads, as such a new station will be required to accommodate the additional load.

Not proceeding with this investment would impair the customers' ability to supply its load and a decrease in supply reliability. Hydro One is obligated under the Transmission System Code to meet customer supply needs, when requested by the area customers.

Summary:
Hydro One Distribution has received several requests for new load connections in the Ancaster area. The existing Nebo TS 27.6 kV capacity has been exhausted. Hydro One Distribution has requested Hydro One Transmission to build a pool funded transformer station ("Ancaster TS") to supply new loads in the area. The proposed Ancaster TS will consists of two 230/27.6 kV, 25/41MVA transformers and is expected in-service in mid 2013. A new facility such as the one proposed requires Environmental Assessment approval from the Ministry of Environment in accordance with the provincial Environmental Assessment Act (Class EA for minor Transmission Facilities).

The project cost will be recoverable through incremental revenue for the appropriate rate pool and capital contributions from the customers, as indicated in Table 4 of Exhibit D1, Tab 3, Schedule 3. The capital contribution amounts are considered preliminary as they are only finalized when the Capital Cost Recovery Agreement is signed and when the project is placed in-service. The capital contributions are determined as per Hydro One's Transmission Customer Contribution Policy in accordance with the Transmission System Code.

Results:
Ensure availability of electricity supply and maintain required quality of supply to customers in the Ancaster area.

Project Classification per OEB Filing Guidelines:

Project Class:	Connection
Project Need:	Customer Driven: This project is required to supply customers' future load growth.

Hydro One Networks – Investment Summary Document

Investment Type: Load Customer Connection

Reference #	Investment Name	Gross Cost	In-Service Date
D20	East Ottawa TS: Build new Transformer Station	$33.4M	Mid 2013

Please see Exhibit D1, Tab 3, Schedule 3, Appendix A, Table 4 for cash flow and other details about the project.

Need:
Hydro One Distribution has requested Hydro One to add transformation capacity in the Orleans Area (in East Ottawa) to improve supply reliability and meet future load growth.

Not proceeding with this investment would impair the customers' ability to reliably supply its load. Hydro One is obligated under the Transmission System Code to meet customer supply needs, when requested by the area customers.

Summary:
The City of Orleans and the surrounding area are served by Hydro One Distribution from the existing Wilhaven DS, Navan DS and Bilberry Creek TS. The loading at Bilberry Creek has been at its limit for the past ten years and new load growth has been supplied from Wilhaven DS and/or Navan DS.

Both Wilhaven DS and Navan DS are supplied from a single 115kV circuit H9A and have experienced several outages over the past few years. Hydro One Distribution has therefore requested building a new dual supply station to serve customer load in the area so as to improve load supply reliability.

It is proposed to build the new station in the Orleans Area east of Ottawa which will be connected to 230kV circuit D5A and 115kV circuit H9A. The new transformer station will provide improved reliability for Hydro One Distribution customers. A new facility such as the one proposed requires Environmental Assessment approval from the Ministry of Environment in accordance with the provincial Environmental Assessment Act (Class EA for minor Transmission Facilities).

The project cost will be recoverable through incremental revenue from the appropriate rate pool and capital contributions from the customers, as indicated in Table 4 of Exhibit D1, Tab 3, Schedule 3. The capital contribution amounts are considered preliminary as they are only finalized when the Capital Cost Recovery Agreement is signed and when the project is placed in-service. The capital contributions are determined as per Hydro One's Transmission Customer Contribution Policy in accordance with the Transmission System Code.

Results:
Increase transformation capacity to the Orleans Area, thereby providing for future load growth and improving supply reliability.

Project Classification per OEB Filing Guidelines / IPSP Status:

Project Class:	Connection
Project Need:	Customer Driven: This project is required to supply customers' future load growth.

Hydro One Networks – Investment Summary Document

Investment Type: Load Customer Connection

Reference #	Investment Name	Gross Cost	In-Service Date
D21	Leamington TS: New 230/27.6kV DESN & Line Connection	$62.4M	Mid 2013

Please see Exhibit D1, Tab 3, Schedule 3, Appendix A, Table 4 for cash flow and other details about the project.

Need:
Transmission capacity in the Windsor – Essex area is inadequate to ensure supply security in the area to meet the requirements of loads supplied by transformers connected to the 115 kV network; and in particular, to meet the load requirements of Kingsville TS due to voltage and thermal concerns. Establishment of the Leamington TS and its associated 230kV double-circuit line is intended to address the Kingsville TS loading issues.

The total load in the area exceeded the loading of the station and the 115 kV circuits supplying the station are overloaded as well. The loading issues at Kingsville TS are currently managed with a Special Protection System and operating measures. Not proceeding with this investment would result in the continued exposure of customers in Kingsville and Leamington to post-contingency load-shedding.

Summary:
Two integrated solutions were developed to address the inadequacies in the Windsor-Essex area. One of these includes a new transformer station in the municipality of Leamington and a 230kV new double-circuit line to supply the transformer station, to provide relief for Kingsville TS. The second solution includes facilities in the Windsor-Essex area which will be brought forward in future proceedings.

This project's proposed facilities include: a new transformer station consisting of two 230/27.6kV 75/100/125 MVA step-down transformers and associated 27.6 kV switchgear and feeder positions; and a new 230 kV double-circuit 13 km line on a new right-of-way between the new transformer station and new taps on 230 kV circuits (C21J/C22J) between Chatham TS and Keith TS (near Sandwich Junction).

The IESO System Impact Assessment Report (CAA ID 2008-318) has been completed for this project. The project development is now underway; this project will require Ontario Energy Board "Leave to Construct" approval under Section 92 and Environmental Assessment Approval from the Ministry of Environment in accordance with the provincial Environmental Assessment Act (Class EA for minor Transmission Facilities). A draft Environmental Study Report has been filed. The scope of work and cost estimates are being reviewed and more details will be included in the Section 92 "Leave to Construct" application that is planned to be submitted for the project.

Results:
Ensure reliability of electricity supply to customers in the Kingsville – Leamington area, and contribute towards improving the reliability of supply in the general Windsor – Essex area.

Project Classification per OEB Filing Guidelines:

Project Class:	Connection
Project Need:	Customer Driven: This project is required to ensure reliability of supply.

Hydro One Networks – Investment Summary Document

Investment Type: Load Customer Connection

Reference #	Investment Name	Gross Cost	In-Service Date
D22	Build New 230/27.6kV Transformer Station & Line Connection in Northern Mississauga	$39.3M	Mid 2014

Please see Exhibit D1, Tab 3, Schedule 3, Appendix A, Table 4 for cash flow and other details about the project.

Need:
The 27.6kV supply facilities in northern Mississauga are reaching capacity. Enersource Hydro Mississauga has requested that Hydro One build a 230/27.6kV transformer station.

Not proceeding with this investment would impair the customers' ability to supply its load. Hydro One is obligated under the Transmission System Code to meet customer supply needs, when requested by the area customers.

Summary:
Hydro One undertook a West GTA planning study jointly with Hydro One Brampton, Enersource Hydro Mississauga, Halton Hills Hydro and Milton Hydro. The study identified the need for a number of upgrades to the Hydro One system in the area, including the need for a new 230/27.6kV, 75/125MVA transformer station to supply Enersource Hydro Mississauga in northern Mississauga. This station is required because the transformation capacity for 27.6kV supply within the City of Mississauga area bounded by Highways 401 and 407 is reaching capacity. The customer has requested that Hydro One build a new transformer station to meet future load growth in this area of Mississauga. A new facility such as the one proposed requires Environmental Assessment approval from the Ministry of Environment in accordance with the provincial Environmental Assessment Act (Class EA for minor Transmission Facilities).

The preferred location is in northern Mississauga, close to the greatest concentration of new load growth, near Highway 407 and Kennedy Road. Connection of this new transformer station will likely require construction of a new line connection, likely to be shorter than 2 kilometers. The project is in the preliminary planning stage and the new transformer station site has not yet been selected.

The project cost will be recoverable through incremental revenue for the appropriate rate pool and capital contributions from the customers, as indicated in Table 4 of Exhibit D1, Tab 3, Schedule 3. The capital contribution amounts are considered preliminary as they are only finalized when the Capital Cost Recovery Agreement is signed and when the project is placed in-service. The capital contributions are determined as per Hydro One's Transmission Customer Contribution Policy in accordance with the Transmission System Code.

Results:
Increase transformation capacity to Enersource Hydro Mississauga, thereby providing for future load growth.

Project Classification per OEB Filing Guidelines:

Project Class:	Connection
Project Need:	Customer Driven: This project is required to supply customers' future load growth.

Hydro One Networks – Investment Summary Document

Investment Type: Load Customer Connection

Reference #	Investment Name	Gross Cost	In-Service Date
D23	Enfield TS: Build new 230/44kV DESN and Line Connection (formally Oshawa Area TS)	$28.7M	Mid 2014

Please see Exhibit D1, Tab 3, Schedule 3, Appendix A, Table 4 for cash flow and other details about the project.

Need:
Oshawa Power & Utilities (OPUC) and Hydro One Distribution have requested Hydro One to add transformation capacity in the East Oshawa area to address load growth in the Durham Region.

Not proceeding with this investment would impair the customers' ability to supply its load. Hydro One is obliged under the Transmission System Code to meet customer supply needs, when requested by the area customers.

Summary:
Hydro One (Transmission and Distribution) and OPUC jointly assessed the future supply needs for the Durham Region. A joint study with the local distribution companies recommended that a new 230/44kV, 75/125MVA TS near the border of the two municipalities of Oshawa and Clarington be built to address present and future load growth.

It is proposed to build the new Enfield station at the Oshawa Area Junction Site to serve both OPUC and Hydro One Distribution customers. The new transformer station will provide load relief for existing stations - Oshawa Wilson TS and Oshawa Thornton TS.

The Environmental Study Report was filed with the Ministry of the Environment on August 25, 2008 in accordance with the provincial Environmental Assessment Act (Class EA for minor Transmission Facilities).

The project cost will be recoverable through incremental revenue for the appropriate rate pool and capital contributions from the customers, as indicated in Table 4 of Exhibit D1, Tab 3, Schedule 3. The capital contribution amounts are considered preliminary as they are only finalized when the Capital Cost Recovery Agreement is signed and when the project is placed in-service. The capital contributions are determined as per Hydro One's Transmission Customer Contribution Policy in accordance with the Transmission System Code.

Results:
Increase transformation capacity to meet the future load growth at OPUC and Hydro One Distribution.

Project Classification per OEB Filing Guidelines:

Project Class:	Connection
Project Need:	Customer Driven: The project is required to incorporate new loads and supply customers' future load growth.

Hydro One Networks – Investment Summary Document

Investment Type: Load Customer Connection

Reference #	Investment Name	Gross Cost	In-Service Date
D24	Long Lac TS: Replace End-of-Life 115/44kV Transformers	$19.8M	Mid 2011

Please see Exhibit D1, Tab 3, Schedule 3, Appendix A, Table 4 for cash flow and other details about the project.

Need:

- To replace the station's power transformers which are approaching or at end-of-life.
- To address the transformation capacity of the station supply.
- To address the safety and maintenance issues associated with the low voltage structure.

Implications of not proactively managing the end-of-life issues of transmission facilities include: an increase in customer complaints and a decline in reliability as well as an increased risk to employees' safety relating to known deficiencies associated with the low voltage structure.

Summary:

Long Lac TS is a 115/44kV transformer station located in the northwest district supplied from the 115kV circuit, AL4. The station has three single-phase transformers and one spare single-phase transformer each rated 115/44kV 5/6.67/8.33MVA. The transformers are more than 60 years old and tests on similar retired units have shown major insulation deterioration. The spare parts for these transformers are not available and transformer accessories e.g. bushings and controls have a high failure rate. The transformer insulation has no tensile strength and with any major disturbance the transformer can fail at any time. Recently one of the transformers failed that resulted in a 12 hour outage for the area. Hydro One received a number of service interruption complaints from the area customers. The installation of two larger, 25/42MVA transformers will address the existing loading situation and will provide for the future load growth as identified by Hydro One Distribution.

The proposed replacement is consistent with the current transformer Asset Management Strategy that looks to manage an aging population and also to manage spares effectively. No capital contribution is required from the customers since the primary driver for the plan is end-of-life replacement.

Results:

- Optimize the life cycle of the facility by reducing the Operating and Maintenance expenditures and outage requirements through an integrated replacement and refurbishment program.
- Eliminate the reliability, maintenance and safety concerns associated with the end-of-life components.
- Increase the transformation capacity of the station.

Project Classification per OEB Filing Guidelines:

Project Class:	Connection
Project Need:	Customer Driven: The project is required to replace end-of-life equipment and increase transformation capacity to supply future load growth.

Hydro One Networks – Investment Summary Document

Investment Type: Load Customer Connection

Reference #	Investment Name	Gross Cost	In-Service Date
D25	North Bay: Upgrade to a 115/44kV Transformer Station	$26.8M	Mid 2012

Please see Exhibit D1, Tab 3, Schedule 3, Appendix A, Table 4 for cash flow and other details about the project.

Need:

- To replace end-of-life equipment to ensure reliable supply.
- To upgrade North Bay TS to a 115/44kV station; converting the low voltage from 22kV to 44kV to address the customer request to improve distribution operations.
- To address the safety and maintenance issues associated with the low voltage structure.

Implications of not proactively managing the end-of-life issues of transmission facilities include: an increase in customer complaints and a decline in reliability as well as an increased risk to employees' safety relating to known deficiencies associated with the low voltage structure.

Summary:

North Bay Hydro is currently supplied from Trout Lake TS and North Bay TS. Trout Lake TS is a 230/44 kV transformer station located in the north east part of the city. North Bay TS is a non standard 115/22 kV transformer station located in the center of the city. Different low voltages and phase angles are causing operational issues for North Bay Hydro, and thus the utility has requested Hydro One to convert North Bay TS to a 115/44kV transformer station. This conversion will help alleviate the operational issues of two different sub-transmission voltages in the area.

In addition to the customer request, a 2006 Asset Condition Assessment report identified that many North Bay TS assets have approached end of life and are in need of replacement. Transformers T1 and T3 have been in service since 1954 and transformer T2 since 1957. Other assets in need of replacement are insulators, switches, surge arresters and the station service scheme.

Major station equipment upgrades will include two 115/44kV, 22/33/42MVA transformers, feeder breakers, and one 44kV 10MVar capacitor bank. A prefabricated protection & control building, new spill containment and grounding grid will also be installed.

This replacement of end-of-life equipment is required to maintain the reliability of North Bay TS. The proposed replacement is consistent with the current transformer Asset Management Strategy that looks to manage an aging population and also to manage spares effectively. No capital contribution is required from the customers since the primary driver for the plan is end-of-life replacement.

Results:

- Optimize the life cycle of the facility by reducing the Operating and Maintenance expenditures and outage requirements through an integrated replacement and refurbishment program.
- Eliminate the reliability, maintenance and safety concerns associated with the end-of-life assets at North Bay TS.
- Converting the low voltage from 22kV to 44kV to satisfy the customer request to improve distribution operations.

Project Classification per OEB Filing Guidelines:

Project Class:	Connection
Project Need:	Customer Driven: The project is required to replace end-of-life equipment and increase transformation capacity to supply future load growth.

Hydro One Networks – Investment Summary Document

Investment Type: Load Customer Connection

Reference #	Investment Name	Gross Cost	In-Service Date
D26	Barwick TS: Build new Transformer Station	$15.5M	Late 2012

Please see Exhibit D1, Tab 3, Schedule 3, Appendix A, Table 4 for cash flow and other details about the project.

Need:

- To build a new transformer station in place of an end-of-life Fort Frances TS.
- To address power quality and delivery point performance issues related to 98.4 km long 44 kV feeder.
- To address problems in supplying new loads in the Rainy River area.

Implications of not proactively managing the end-of-life issues of transmission facilities include an increase in customer complaints and a decline in reliability. Furthermore, Hydro One being the Transmitter/ Distributor is obligated to supply new loads in the area and improve supply to existing customers.

Summary:

The supply source to the Fort Frances – Rainy River area load is from the tertiary winding of an auto transformer located inside Fort Frances TS. The auto transformer is over 50 year old and based on an asset condition assessment the transformer is estimated to be at end-of-life within the next five years. The back up for the retail load is from a Hydro One Distribution transformer 13.8/44 kV step up transformer supplied from the tertiary winding of another 230/115 kV auto transformer. Due to this unique configuration of Fort Frances TS, a new transformer station would need to be built. Hydro One Transmission is recommending building the new transformer station near the town of Chapple and retiring Fort Francis TS. Hydro One purchased a 115 kV line from Ainsworth Engineering in 2008 for future supply to the proposed transformer station.

Distribution of power from Fort Frances TS to the Fort Frances – Rainy River area load is via a single 98 km long 44kV feeder which is difficult to protect and is the second worst feeder in supply reliability in the province. The new transformer station will be located almost in the middle of the load centre, near the town of Barwick. This will reduce the average feeder length by approximately 50 km and significantly improve the reliability of supply in the area. A new facility such as the one proposed requires Environmental Assessment approval from the Ministry of Environment in accordance with the provincial Environmental Assessment Act. Environmental Assessment work is underway for the project.

The proposed replacement is consistent with the current transformer Asset Management Strategy that looks to manage an aging population and also to manage spares effectively. No capital contribution is required from the customers since the primary driver for the plan is end-of-life replacement.

Results:

- Improve supply to the area by locating the transformer station in the middle of the load centre and reducing the customers affected by each outage.
- Increase the transformation capacity of the station.
- Address end-of-life components.

Project Classification per OEB Filing Guidelines:

Project Class:	Connection
Project Need:	Customer Driven: The project is required to replace end-of-life equipment and increase transformation capacity to supply future load growth.

Hydro One Networks – Investment Summary Document

Investment Type: Load Customer Connection

Reference #	Investment Name	Gross Cost	In-Service Date
D27	Duart TS: Build new Transformer Station & Line Connection (formerly Rodney TS)	$26.7M	Late 2012

Please see Exhibit D1, Tab 3, Schedule 3, Appendix A, Table 4 for cash flow and other details about the project.

Need:
To replace end-of-life St. Thomas TS and to resolve Hydro One Distribution's supply issues related to supplying load from St. Thomas TS and Kent TS. Implications of not proactively managing the end-of-life issues of transmission facilities include an increase in customer complaints and a decline in reliability.

Summary:
The 100 year old St. Thomas TS is forecasted to be end-of-life by 2010. This station currently supplies about 25 MW of Hydro One Distribution's load. Hydro One Distribution has also identified several issues related to supply from St. Thomas TS and Kent TS. The feeders out of St. Thomas TS and Kent TS are approximately 45km long and supply loads in the vicinity of Duart TS. The long feeders are subject to voltage problems and outages caused by lightning. To compound matters Kent TS load cannot be backed-up from St. Thomas TS because St. Thomas TS is a 3-wire station and Kent TS is a 4-wire station.

To resolve the transmission and distribution issues it was decided to build Duart TS for an in-service of late 2012. Duart TS will be located approximately mid-way between St. Thomas TS and Kent TS. A new facility such as the one proposed requires Environmental Assessment approval from the Ministry of Environment in accordance with the provincial Environmental Assessment Act. Environmental Assessment work is underway for the project.

The proposed replacement is consistent with the current transformer Asset Management Strategy that looks to manage an aging population and also to manage spares effectively. No capital contribution is required from the customers since the primary driver for the plan is end-of-life replacement.

Results:
Resolve current distribution supply issues and replace end-of-life St. Thomas TS.

Project Classification per OEB Filing Guidelines:

Project Class:	Connection
Project Need:	Customer Driven: The project is required to replace end-of-life equipment and resolve supply issues.

Hydro One Networks – Investment Summary Document

Investment Type: Generation Customer Connection

Reference #	Investment Name	Gross Cost	In-Service Date
D28	500MW Renewables III RFP: Talbot Wind Farm	$25.0M	Late 2011

Please see Exhibit D1, Tab 3, Schedule 3, Appendix A, Table 5 for cash flow and other details about the project.

Need:
To connect a 99 MW wind farm that was awarded a contract under the Ontario Power Authority's Renewable Energy Standard III procurement in January 2009 to the transmission network

Failure to proceed with the generation connection will not meet customer's requirement.

Summary:
The Talbot wind farm is to connect to the 230 kV Buchanan TS x Longwood TS x Chatham SS circuit, W45LC, about 23 km east of Chatham SS. The IESO in its System Impact Assessment report for this connection found that adequate line protections could not be provided unless the W45LC transmission circuit was sectionalized at the Talbot Wind Farm point of connection by the installation of two in-line 230 kV circuit breakers. This investment creates a new 230 kV switching station, "Talbot Wind Farm" SS so that Talbot Wind Farm can connect to the transmission network in a manner that satisfies IESO reliability requirements.

The addition of this new switching station as well as allowing this renewable resource to connect to the transmission network will also facilitate the connection of similar wind farms in between the new switching station and Chatham SS.

The project cost will be fully recoverable through capital contributions from the customers, as indicated in Table 5 of Exhibit D1, Tab 3, Schedule 3. The capital contribution amounts are considered preliminary as they are only finalized when the Capital Cost Recovery Agreement is signed and when the project is placed in-service. The capital contributions are determined as per Hydro One's Transmission Customer Contribution Policy in accordance with the Transmission System Code.

A Capital Cost Recovery Agreement will be prepared and signed before construction work is carried out by Hydro One. The expected in-service date of the station is late 2011.

Results:
The connection of a 99 MW wind farm that won a contract in an Ontario Power Authority administered procurement process to the transmission network in a manner that satisfies IESO requirements.

Project Classification per OEB Filing Guidelines:

Project Class:	Connection
Project Need:	Customer Driven: The project is required to incorporate new renewable generation that was contracted under the OPA's procurement process.

Hydro One Networks – Investment Summary Document

Investment Type: Generation Customer Connection

Reference #	Investment Name	Gross Cost	In-Service Date
D29	350MW Peaking Generation in Northern York Region	$4.9M	Late 2011

Please see Exhibit D1, Tab 3, Schedule 3, Appendix A, Table 5 for cash flow and other details about the project.

Need:
To connect new generation in Northern York region that was awarded under the Ontario Power Authority's Simple Clean Energy Contracts to the transmission network.

Failure to proceed with the generation connection will not meet the customer's requirement and impair ability to supply load in the area under contingency conditions.

Summary:
The York Energy Centre LP, a limited partnership between York Energy Centre Inc. and Pristine Power Inc., has a contract for a capacity of about 400 MW gas-fired peaking plant with the Ontario Power Authority. The generation contract was in response to a need to provide additional supply capability in a transmission constrained area and will improve supply reliability to area load customers in Aurora, Newmarket, East Gwillimbury, Bradford and surrounding areas.

The York Energy Centre is to connect to the 230kV Claireville TS x Brown Hill TS circuits, B82V and B83V about 1km northeast of Holland Marsh Junction. The project only requires the line connection into the generating facility; in which York Energy Centre has proposed to be located on a 4-acre property that fronts on Dufferin Street between Graham Sideroad to the north and Miller Sideroad to the south in the Township of King in Ontario.

The project cost will be fully recoverable through capital contributions from the customer, as indicated in Table 5 of Exhibit D1, Tab 3, Schedule 3. The cost estimates are preliminary and will be revised once detailed estimates are completed in early May 2010. The capital contribution amounts are also considered preliminary as they are only finalized when the Capital Cost Recovery Agreement is signed and when the project is placed in-service. The capital contributions are determined as per Hydro One's Transmission Customer Contribution Policy in accordance with the Transmission System Code.

A Capital Cost Recovery Agreement will be prepared and signed before construction work is carried out by Hydro One. The expected in-service date of the station is November 2011.

Results:
Connect new generation in northern York region and improve ability to supply load under contingency conditions.

Project Classification per OEB Filing Guidelines:

Project Class:	Connection
Project Need:	Customer Driven: The project is required to incorporate new generation that was contracted under the OPA's procurement process.

Hydro One Networks – Investment Summary Document

Investment Type: Generation Customer Connection

Reference #	Investment Name	Gross Cost	In-Service Date
D30	Chatham Wind Generation Connection (260MW)	$4.2M	Late 2012

Please see Exhibit D1, Tab 3, Schedule 3, Appendix A, Table 5 for cash flow and other details about the project.

Need:
To connect a 260 MW wind farm that was awarded a contract by the Ontario Government in January 2010 to the transmission network.

Failure to proceed with the generation connection will not meet customer's requirement.

Summary:
Samsung was awarded a contract to connect a 260 MW wind-farm directly into the Hydro One Chatham SS at 230 kV. A new switching position will be developed at Chatham SS. Two new 230 kV breakers will be required to terminate the customer owned 230 kV transmission circuit. It is expected that Samsung will develop a 230 kV transformer station less than 2 km south of Chatham SS and will construct a 230 kV single circuit line to Chatham SS.

The project cost will be fully recoverable through capital contributions from the customers, as indicated in Table 5 of Exhibit D1, Tab 3, Schedule 3. The capital contribution amounts are considered preliminary as they are only finalized when the Capital Cost Recovery Agreement is signed and when the project is placed in-service. The capital contributions are determined as per Hydro One's Transmission Customer Contribution Policy in accordance with the Transmission System Code.

A Capital Cost Recovery Agreement will be prepared and signed before construction work is carried out by Hydro One. The expected in-service date of the station is November 2012.

Results:
The connection of a 260 MW wind farm to the transmission network in a manner that satisfies IESO requirements.

Project Classification per OEB Filing Guidelines:

Project Class:	Connection
Project Need:	Customer Driven: The project is required to incorporate new renewable generation that was contracted by the Ontario Government.

Hydro One Networks – Investment Summary Document

Investment Type: Generation Customer Connection

Reference #	Investment Name	Gross Cost	In-Service Date
D31	Lower Mattagami Generation Connections	$8.3M	Late 2012

Please see Exhibit D1, Tab 3, Schedule 3, Appendix A, Table 5 for cash flow and other details about the project.

Need:
To connect new renewable generation in the Lower Mattagami River to the transmission network. Ontario Power Generation Inc. (OPGI) is proposing to upgrade their generating stations in the Lower Mattagami River, namely Little Long GS, Smoky Falls GS, Harmon GS and Kipling GS, to increase generation output by approximately 450MW. The Minster of Energy directed Ontario Power Authority to assume the responsibility of the Crown and negotiate a financial energy supply agreement with OPGI. The proposed investment is consistent with government direction and expectations.

Not proceeding with this investment would result in violation of Hydro One's Transmission License for failure to connect a generator proponent. As well, the Ontario government's directive for renewable energy would not be satisfied.

Summary:
The OPGI proposed redevelopment of the existing generating plants on the Lower Mattagami River involves installing a third generating unit at Little Long GS, Harmon GS and Kipling GS and replacing the existing four-unit Smoky Falls generating station with a new three-unit facility. The following investments are required to accommodate the additional output from the generating facilities on the Lower Mattagami River:

- Addition of a second 230kV circuit on the L20D corridor from Harmon GS to Kipling GS.
- Connection of a second tap point for each of the existing generating stations to the 230kV network.
- Uprating of the section of the 115kV circuits H6T and H7T between La Forest Junction and Timmins TS.

The project cost directly attributable to the generator will be recoverable through capital contributions from the generator, as indicated in Table 5 of Exhibit D1, Tab 3, Schedule 3. The capital contribution amounts are considered preliminary as they are only finalized when the Capital Cost Recovery Agreement is signed and when the project is placed in-service. The capital contributions are determined as per Hydro One's Transmission Customer Contribution Policy in accordance with the Transmission System Code.

The cost of the work for the construction of the line connection, approximately 4km of 230kV double circuit line from Smoky Falls GS to the existing H22D and L20D circuits, is included in the total cost of this project but may be contracted to a third party by OPGI.

Results:

- Provide adequate transmission facilities to allow the connection of OPGI Lower Mattagami plant expansions.
- Enable Ontario Power Authority to successfully procure approximately 450MW of renewable generation north of Sudbury.

Project Classification per OEB Filing Guidelines:

Project Class:	Connection
Project Need:	Customer Driven: The projects are required to incorporate new renewable generation in northern Ontario to satisfy government directive(s).

Hydro One Networks – Investment Summary Document

Investment Type: Enabling Facilities (Government Instruction)

Reference #	Investment Name	Gross Cost	In-Service Date
D32	Enabling 230/44kV TS #1 and Short (<2km) Tap	$33.8M	Late 2013
D33	Enabling 115/44kV TS #1 and Short (<2km) Tap	$33.8M	Late 2013

Please see Exhibit D1, Tab 3, Schedule 3, Appendix A, Table 6 for cash flow and other details about these projects.

Need:
To facilitate the development of renewable energy resources, specifically the addition of capacity to incorporate distributed generation into the transmission system, as outlined by the Ontario Government under the Green Energy and Green Economy Act (refer to Exhibit A, Tab 11, Schedule 4)

Not proceeding with this investment will limit the ability to connect new generation.

Summary:
Under the provincial "Feed In Tariff" program, a large number of renewable energy customers have applied to connect to the distribution system. Ontario Power Authority as part of the Feed-In-Tariff program is in the process of identifying locations where there is a significant potential for renewable generation (mainly wind) development within Ontario. However, in a number of areas, particularly south west Ontario, there is limited capability at the transformer station or on the distribution feeders to incorporate the proposed generation. As a result it may not be possible to connect all applicants that have applied for connection.

The "Enabling" Transmission Stations are intended to connect multi-proponent clusters of renewable generation resources to our transmission facilities. This will be accomplished through construction of either a 230/44kV Enabling Transmission Station or a 115/44kV Enabling Transmission Station and an associated 230kV or 115kV line tap to the generator connection site. A typical "Enabler" Transmission Station will accommodate about twenty four 10 MW distributed generation customers and will consist of two 75/125 MVA, 230/44 kV transformers and eight 44 kV dedicated feeders.

The Enabler Transmission Station will initially only accommodate distributed generation. This facility will need to be modified following completion if it were to accommodate load customers in the future.

The projects are initiated based on the customer requests for connection of renewable generators. None of the enabling facilities projects will be undertaken without obtaining all necessary project specific approval requirements under the Environmental Assessment Act or Section 92/95 of the Ontario Energy Board Act and a supporting letter of project need from the Ontario Power Authority.

As specific generators are identified, there may be capital contributions to the enabling transmission stations in accordance with the Board's Amendment to the Transmission System Code.

Results:
Allow the connection of distributed renewable generation to the transmission system throughout Ontario.

Project Classification per OEB Filing Guidelines:

Project Class:	Development:
Project Need:	Non-Discretionary: The projects are required to incorporate new renewable generation to satisfy government directive(s).

Hydro One Networks – Investment Summary Document

Investment Type: Bulk & Regional Transmission (Government Instruction)

Reference #	Investment Name	Gross Cost	In-Service Date
D34	Algoma x Sudbury Transmission Expansion	$431.6M	Late 2015

Please see Exhibit D1, Tab 3, Schedule 3, Appendix A, Table 7 for cash flow and other details about the project.

Need:
- To increase the transfer capability of the Mississagi Flow-East Interface to provide access to renewable generation in the area from Sudbury to eastern Lake Superior including Manitoulin Island ("Sault/Algoma area") and in North-western Ontario
- Promote the use and generation of electricity from renewable energy resources in a manner consistent with the policies of the Government of Ontario by providing timely reinforcement of the transmission system necessary to accommodate the renewable generation to be procured in Northern Ontario

Summary:
The transmission system between Wawa and Sudbury serves about 500MW of load and about 1,100MW of generation in the Sault/Algoma area. It provides the capability for transferring the generation surplus to the Sudbury area, as well transferring up to 325MW from northwestern Ontario to the east. The Mississagi Flow-East Interface comprises three 230kV circuits connecting Mississagi TS to Hanmer TS and Martindale TS in Sudbury area. The present eastbound transfer from Mississagi TS to Sudbury can potentially reach 1,000MW which would exceed the 670MW existing transfer limit.

To meet this need it is proposed that a second Hanmer TS to Mississagi transmission line be built (approximately 210 km). This line would be built as 500 kV line and operated initially at 230 kV. This would provide an additional transfer capability of about 450 MW. When further capacity is required, to add renewable resources west of Sudbury, this line and the existing companion line could be converted to operation at 500 kV. This way the reinforcements can be coordinated to match resource developments in the Sault/Algoma area.

This plan is in accordance with the letter dated September 21, 2009, from the Minister of Energy and Infrastructure asking Hydro One to proceed with the planning, development and implementation of several transmission projects including the line from Sudbury Area to the Sault Ste. Marie/Algoma.

The cost estimate is based on Hydro One's intention to seek approval in the Section 92 Application for this project for the "Accelerated Cost Recovery of CWIP" mechanism as outlined in Exhibit A, Tab 11, Schedule 4. This project will be committed only if Ontario Power Authority recommends it, based on its assessment of technical characteristics, and once all required approvals have been obtained.

Results:
- Increase the transfer capability of Mississagi Flow-East Interface to allow development and use of renewable generation while maintaining the reliability of the network.
- Enable Ontario Power Authority to procure renewable generation west of Sudbury to meet the government's objectives.

Project Classification per OEB Filing Guidelines:

Project Class:	Development
Project Need:	Non-Discretionary: The project is required to incorporate new renewable generation in northern Ontario to satisfy government objectives and to support OPA's recommendation

Hydro One Networks – Investment Summary Document

Investment Type: Bulk & Regional Transmission (Government Instruction)

Reference #	Investment Name	Gross Cost	In-Service Date
D35	Northwest Transmission Reinforcement	$399.5M	Late 2014

Please see Exhibit D1, Tab 3, Schedule 3, Appendix A, Table 7 for cash flow and other details about each project.

Need:
To (a) provide sufficient capacity by the year 2014 to meet the increasing load in Patricia District, particularly the mining industry, (b) improve the reliability of supply to Pickle Lake, (c) enable development of renewable resources around Lake Nipigon, including wind resources and OPGI's proposed Little Jackfish (LJF) Generating Station, (d) provide opportunity for future connection of the First Nation communities to the grid, and (e) provide opportunity for future enhancements of the transmission network in Northwestern Ontario.

Not proceeding with this investment will result in curtailment of mining and other economic developments, as well as development of renewable generation in the region and persistence of sub-standard reliability of supply for the customers at Pickle Lake and Red Lake.

Summary:
This project involves building a new single-circuit 230 kV transmission line, from the Nipigon Area (northern shore of Lake Superior) to a new Transformer Station near the Town of Pickle Lake to connect to the end of existing 115 kV line. The route of this line will be on the east side of Lake Nipigon and will pass within 40 km (approximately) distance from the proposed Little Jackfish generation.

The Nipigon x LJF section of the proposed transmission line was recommended to enable development of renewable resources, including 85 MW (could go up to 130 MW) hydroelectric generation at LJF and up to 280 MW wind generation on the eastern shores of Lake Nipigon. The LJF x Pickle Lake section of the new line will improve the reliability for the Pickle Lake customers who are currently supplied by the long and aging 115 kV circuit E1C, which has one of the worst performance records in the system. It will also provide sufficient capacity for the increasing load in Patricia District, which according to the mining industry forecast, will soon exceed the capacity of the existing circuits. The new line will provide opportunities to connect First Nations and remote communities to the grid and allow future reinforcement for the whole East-West transmission network by allowing the upgrade of circuit E1C to 230 kV. The stakeholders in Patricia District have expressed their support for the proposed line.

The cost estimate is based on Hydro One's intention to seek approval in the Section 92 Application for this project for the "Accelerated Cost Recovery of CWIP" mechanism as outlined in Exhibit A, Tab 11, Schedule 4. This project will be committed only once all required approvals have been obtained.

Results:
- Enable Ontario Power Authority to procure renewable generation in the region to meet the government objectives.
- Provide capacity and improved reliability of supply for the increasing mining and other economic developments in the region.
- Support the First Nations attempts to connect their communities to the grid.

Project Classification per OEB Filing Guidelines:

Project Class:	Development:
Project Need:	Non-Discretionary: The project is needed to enable renewable generation, increase the supply capacity for the load customers and improve the reliability for the existing customers

Hydro One Networks – Investment Summary Document

Investment Type: Station Equipment Upgrades & Additions to Facilitate Renewables (Government Instruction)

Reference #	Investment Name	Gross Cost	In-Service Date
D36	Static Var Compensator #1 at Existing Station in South Western Ontario	$78.7M	Late 2013
D37	In-Line Circuit Breakers #1	$20.3M	Late 2012
D38	In-Line Circuit Breakers #2	$20.3M	Late 2012
D39	In-Line Circuit Breakers #3	$20.8M	Late 2013
D40	In-Line Circuit Breakers #4	$20.8M	Late 2013
D41	In-Line Circuit Breakers #5	$21.6M	Late 2014
D42	In-Line Circuit Breakers #6	$21.6M	Late 2014

Please see Exhibit D1, Tab 3, Schedule 3, Appendix A, Table 8 for cash flow and other details about these projects.

Need:
To facilitate the incorporation of new renewable generation into the Hydro One system, through the addition of switching facilities and reactive support, as outlined by the Ontario Government under the Green Energy and Green Economy Act (refer to Exhibit A, Tab 11, Schedule 4).

Not proceeding with this investment will limit the ability to connect new generation.

Summary:
Under the provincial "Feed In Tariff" program, a large number of renewable energy customers have applied to connect to the Hydro One system. The Ontario Power Authority manages the Feed-In-Tariff program and is in the process of identifying locations where there is a significant potential for renewable generation (mainly wind) development within Ontario.

However, in a number of areas, transmission station capacity constraints are limiting the amount of embedded generation that can be connected to the Hydro One system; hence the requirement for station equipment upgrades. There are two primary types of station upgrade projects, installation of static var compensators and installation of in-line circuit breakers.

The installation of static var compensators will assist in providing reactive support to intermittent renewable generation connected to the distribution system and to ensure that voltages on the transmission system remain within the limits specified in the Transmission System Code.

The installation of "in-line" breakers will address the limitation of the protection system as more and more generators are connected. By splitting the line into smaller sections by installing "in-line" breakers and additional protection relays, it is possible to allow more generation to connect to the transmission system.

The need for the investments will be reconfirmed by the Ontario Power Authority on a project by project basis before detailed design and construction is initiated. It has been assumed that these projects will be pool funded, based on the interpretation of Compliance Bulletin #200606 issued by the Ontario Energy Board on September 11, 2006.

Results:
Allow the connection of renewable generation to the transmission system throughout Ontario.

Project Classification per OEB Filing Guidelines:

Project Class:	Development:
Project Need:	Non-Discretionary: The project is required to incorporate new renewable generation to satisfy government objectives and to support the OPA's recommendation

Hydro One Networks – Investment Summary Document

Investment Type: Protection and Control for Enablement of Distribution Connected Generation (Government Instruction)

Reference #	Investment Name	2011 Gross Cost	2012 Gross Cost	In-Service Date
D43	Station Protection Upgrades for Distributed Generation	$5.3M	$15.8M	Annual

Please see Exhibit D1, Tab 3, Schedule 3, Appendix A, Table 9 for cash flow and other details about the project.

Need:

- Preserve the loading capability of the feeders
- Maintain proper protection for Transmission assets

Not proceeding with this investment will limit the ability to connect new generation.

Summary:
The connection of generation to the distribution system supplied from the Hydro One Transmission System requires a number of changes and additions to the protection and control facilities in transmission stations. These changes are required to meet requirements for Bulk Power System reliability, requirements of the Distribution System Code and to increase the amount of distributed generation that can be connected to the system.

One of the modifications required to the protection and control facilities in the transmission stations to enable distributed generation is the replacement of feeder protections. The existing feeder protections in Hydro One transmission stations are simple un-directioned overcurrent schemes. The connection of generation to the feeders requires these schemes to be replaced with directioned impedance protection schemes equipped for transfer trip signaling with the generators. Impedance protections with load blinding techniques are required to overcome the desensitizing effects of the infeeds from the generators and preserve the loadability of the feeders.

Depending on the configuration of a transformer station and the existing design of its protection systems, some modifications are required to ensure proper operation with fault energy coming from the distribution system. These can include modifications to bus protections, transformer protections and the addition of protections for faults on the transmission lines.

Results:
Allow the connection of renewable generation to the distribution systems throughout Ontario.

Project Classification per OEB Filing Guidelines:

Project Class:	Development:
Project Need:	Non-Discretionary: The project is required to incorporate new renewable generation to satisfy government objectives.

Hydro One Networks – Investment Summary Document

Investment Type: Protection and Control for Enablement of Distribution Connected Generation (Government Instruction)

Reference #	Investment Name	2011 Gross Cost	2012 Gross Cost	In-Service Date
D44	Transfer Trip Facilities	$4.7M	$14.0M	Annual

Please see Exhibit D1, Tab 3, Schedule 3, Appendix A, Table 9 for cash flow and other details about the project.

Need:

- To provide detection of islands due to transmission configurations and transfer trip signaling facilities to generators connected to distribution systems.

Not proceeding with this investment will limit the ability to connect new generation and will result in connected generators being frequently forced out of service during planned or un-planned transmission outages.

Summary:

The connection of generation to the distribution system supplied from the Hydro One Transmission System requires a number of changes and additions to the protection and control facilities in transmission stations. These changes are required to meet requirements for Bulk Power System reliability, requirements of the Distribution System Code and to increase the amount of distributed generation that can be connected to the system.

Generators connected to the distribution system cannot be allowed to be isolated from the main grid together with loads. To prevent this, such conditions need to be detected and a signal sent to trip all the generators that would be in the isolated (islanded) portion of the grid. The most common configuration at a transformer station which can cause this is the opening of the feeder breaker which results in all generators connected to the feeder being isolated with the loads. However, there are other configurations inside a transformer station that will also have the same effect. Systems need to be put in place in transformer stations to detect these and provided the telecommunication signaling required to trip the appropriate generators.

Results:

Allow the connection of renewable generation to the distribution system throughout Ontario.

Project Classification per OEB Filing Guidelines:

Project Class:	Development:
Project Need:	Non-Discretionary: The project is required to incorporate new renewable generation to satisfy government directives.

Hydro One Networks – Investment Summary Document

Investment Type: Smart Grid

Reference #	Investment Name	Gross Cost	In-Service Date
D45	End-to End Testing of Interoperable Bus Architecture at Owen Sound and Meaford Transformer Stations	$11M	Late 2012

Please see Exhibit D1, Tab 3, Schedule 3, Appendix A, Table 10 for cash flow and other details about the project.

Need:
Hydro One needs to facilitate a robust integration of distributed generation on its transmission system. This will require a well planned and interoperable architecture (IEC 61850 standards) at its transformer stations. International Electrotechnical Commission ("IEC") 61850 was created to be an internationally standardized method of communication and integration to support systems built from multivendor intelligent electronic devices ("IED"). End-to-end testing and evaluation of this new architecture is critical because integrated testing, evaluation, and validation of various smart devices including communication interfaces is needed prior to major deployment.

This initiative is required as part of the "Smart Zone" Pilot project carried out in Owen Sound, with the objective to test new technologies and systems which can be implemented to facilitate a robust integration of distributed generation on the transmission system. Failure to proceed with this end-to-end test could affect Hydro One's capability to effectively accommodate distributed generation resulting from the feed-in tariff program and other green initiatives advocated through the Ontario Government's GEGEA.

Summary:
Owen Sound and Meaford TS will be converted to have IEC61850 compliant protection and control equipment in order to facilitate implementation of an integrated scheme that will maximize the benefit of renewable generation. Working with experts as a part of the Smart Grid initiative Hydro One will develop a turnkey solution for station conversion at Owen Sound and Meaford. The solution will address the issues surrounding anti-islanding of distributed generation, maintaining generation output during maintenance contingencies, adaptive protection co-ordination and optimization of telecommunication facilities. Successful implementation will enable standardization and deployment throughout the province in the future.

The expected in-service date of this project is late 2012.

Results:
- Implementation, end-to-end testing and evaluation of the new architecture (IEC 61850) at Owen Sound TS and Meaford TS.
- The new architecture will allow Hydro One to facilitate a robust integration of distributed generation on its transmission system.

Project Classification per OEB Filing Guidelines:

Project Class:	Development:
Project Need:	Non-Discretionary: The project is required to incorporate new renewable generation to satisfy government objective(s).

Hydro One Networks – Investment Summary Document

Investment Type: Performance Enhancement

Reference #	Investment Name	2011 Gross Cost	2012 Gross Cost	In-Service Date
D46	Various lines and TSs outliers-inliers	$4.0M	$4.0M	Annual

Please see Exhibit D1, Tab 3, Schedule 3, Appendix A, Table 11 for cash flow and other details about the project.

Need:
Hydro One is required to improve the delivery point performance of Outliers as per the Customer Delivery Point Performance Standard (CDPPS) that has been approved by the Ontario Energy Board in April 2008 with a stated requirement to review the CDPPS and our performance in 2011.

Summary:
There will be capital investments to target chronic poor performance delivery points whether the cause is at the Station or initiated on the Line. Many station outages are due to Wildlife Intrusion and many stations will be targeted for bus cover-ups, cable tray doors and better gates. Other station problems are more equipment based and mitigation measures will be evaluated per station. Line related mitigation will target weather issues – wind, ice and lightning. The mitigation measures employed can be the replacement of old wood wishbone cross arms, replacement of old poles, replacement of insulators with new glass insulators with skirts or alternating diameters, phase spacers, surge arrestors and skywire replacement or upgrade. Also for consideration will be sectionalizing of long radial lines or circuits with many branches / laterals.

Results:
The anticipated results of these Mitigation investments will be to maintain the performance reliability of all Customer Delivery Points to their historical levels established in the 1990 to 2000 period as defined in the CDPPS.

Project Classification per OEB Filing Guidelines:

Project Class:	Development:
Project Need:	Non-Discretionary: This project is required to maintain the performance reliability as per the Customer Delivery Point Performance Standard.

Hydro One Networks – Investment Summary Document

Investment Type: Risk Mitigation

Reference #	Investment Name	Gross Cost	In-Service Date
D47	Mitigate Reliability Problems of HV Shunt Capacitor Installations	$48.1M	Late 2011

Please see Exhibit D1, Tab 3, Schedule 3, Appendix A, Table 12 for cash flow and other details about the project.

Need:
To address the reliability issues associated with the Hydro One high voltage shunt capacitor bank fleet of 35 units to limit the rate of rise of recovery voltage in the shunt capacitor breakers.

Summary:
On January 30, 2007 an explosive failure of a 230kV capacitor bank at Richview TS occurred 4 seconds after it was energized. In the course of the investigation that followed the incident it was determined that all HV capacitor banks that are equipped with series reactors must be furnished with surge capacitors in the form of capacitor voltage transformers to limit the rate of rise of recovery voltage in the shunt capacitor breakers.

To address the reliability issues with high voltage capacitor bank installations, a multi-staged approach was developed. The first phase entailed temporarily bypassing current limiting reactors, and the installation of surge capacitors which allowed restoration of 16 of the capacitor banks to service prior to the summer 2007 peak load season. The second phase will entail equipping the remaining 19 shunt capacitors with surge capacitors. Seven will have their breakers replaced with ones that can withstand the required rate of rise of recovery voltage duty. Five buses supported by only one insulator will be rebuilt to withstand the electromagnetic forces associated with high voltage short circuit currents. And the surge capacitors installed at the 16 shunt capacitors in Phase 1 will be retrofitted with voltage transformers to enable the monitoring of the surge capacitor condition.

Following the implementation of Phase 2, all Hydro One shunt capacitor installations will operate without restrictions and the temporary measures introduced in 2007 will no longer be required. The shunt capacitors will provide reactive power support to maintain acceptable voltage levels in the system at all times. Phase 2 will address all outstanding issues that were identified by the investigation that followed the explosive failure of Richview capacitor bank in January of 2007.

Results:
Mitigate the reliability risk associated with the 35 high voltage shunt capacitor bank fleet.

Project Classification per OEB Filing Guidelines:

Project Class:	Development:
Project Need:	Non-Discretionary: This project is required to address equipment reliability concerns.

Hydro One Networks – Investment Summary Document

Investment Category: Operating Capital: Grid Operations Control Facility

Reference #	Investment Name	Gross Cost	In-Service Date
O1	Network Operating Buildings Expansion	$23.1 M	2012

Please see Exhibit D1, Tab 3, Schedule 4 for cash flows.

Need:

Growing business requirements are driving increases in staff numbers and expansion of the operating facilities. All available office space at the OGCC is now fully occupied and additional space is required. Existing Backup Control Centre computer rooms are currently stretched beyond capacity in terms of physical space, power supplies and environmental controls and stop-gap measures have been deployed. Additional back-up centre computer room space is required.

Summary:

Growing business requirements in Operations are described in exhibit C1 Tab2 Schedule 5. They include increased outage management volumes and complexity due to the expanding capital and sustainment work programs and increases in customer and generator relations activity associated with the green generation. Space margins designed into the OGCC have been utilized for the hiring and training of junior staff in accordance with ongoing succession requirements.

As an alternative to expanding the OGCC building, consideration was given to moving staff to nearby “overflow” locations or decentralizing some departments. Analysis of these options revalidated the one-centre strategy that lead to the creation of the OGCC. In addition to being more costly due to lease costs and lost time due to travel, the effectiveness of operations would be diminished. The operations functions at the OGCC manage real time or near real time plans, actions and events and need to interact tightly, promptly and efficiently to do so. This can only be achieved if all staff are in one building. The best option is to enhance and expand the OGCC building facilities.

A review of options for the Back-up Control Centre (BUCC) is in progress considering total life-cycle cost, reliability, NERC requirements in addition to the current and future operating needs. Analysis is indicating that relocating to a new back-up centre with expansion capacity may be the best option.

Results:

The present and foreseeable accommodation needs of Operations are met at one centre where maximum efficiency and effectiveness can be realized. The present and foreseeable space needs at the Back up Centre are addressed at minimum total life cycle cost.

Project Classification per OEB Filing Guidelines:

Project Class:	Operations
Project Need:	Non-Discretionary

Hydro One Networks – Investment Summary Document

Investment Category: Operating Capital: Grid Operations Control Facility

Reference #	Investment Name	Gross Cost	In-Service Date
O2	NMS Enhancements	$7.8 M	2012

Please see Exhibit D1, Tab 3, Schedule 4 for cash flows.

Need:

This investment is required to maintain the capability and capacity of operators to continue performing tasks correctly and with required promptness and pace in the face of increasing operational complexities and work load.

Summary:

The workload in the OGCC Control Room and Outage Planning office is increasing due the increasing numbers and complexity of outages required to execute the growing sustainment and development work programs. Enhanced tools are needed to improve operator decision making, efficiencies and work flow while maintaining or improving the efficiency of the outage program, without impact on worker safety or the reliability of the Hydro One Transmission system.

During 2011 and 2012, new commercially available NMS applications will be implemented to provide better information on the status and condition of field equipment, better information on the power system and to automate routine tasks. As well, standard vendor supplied applications will replace custom applications thereby reducing ongoing support costs.

The specific NMS enhancements will include:

- GIS based displays that integrate the power system applications results and provide an improved “wide area” view of the power system. This will enhance operator awareness of power flows and generally improve situational awareness.
- automation of manual power flow calculations
- increased integration to operating and enterprise applications for improved work flow efficiency

Additionally, these funds make provision for additional tool enhancements which may be required as a result of incorporating green energy initiatives such as renewable and distributed generation, automated network systems and protection or equipment enhancements.

Results:

Operations staff at the OGCC will be equipped to manage increasing workload. Ongoing support costs for some tool functions will be reduced.

Project Classification per OEB Filing Guidelines:

Project Class:	Operations
Project Need:	Non-Discretionary

Hydro One Networks – Investment Summary Document

Investment Category: Operating Capital: Grid Operations Control Facility

Reference #	Investment Name	Gross Cost	In-Service Date
O3	Transmission Operating Facilities Sustainment	$10.0 M	2012

Please see Exhibit D1, Tab 3, Schedule 4 for cash flows

Need:

The computer tools and systems that support the Control Room and back office transmission operating functions at the OGCC and the back-up centres are mission critical 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 these tools and systems.

Many of the components of these systems have about a 5-year life and must be refreshed. Investment in these components is essential to maintain system reliability.

Summary:

This investment funds separate projects that provide replacement of the transmission operating facilities that are at the end of their normal life cycle and are subject to reduced reliability. For all of these components, replacements plans are based on end of life assessments and criticality to reliability and performance.

During 2011 and 2012, end of life replacements will include: the Control Room telephone system, NMS workstations and displays and, Control Room display wallboards.

Results:

Completion of this investment will result in the following accomplishments: (i) hardware upgrades for continued sustainability; (ii) better performance and reliability (iii) additional capacity for transmission growth and incorporation of distributed generation connections.

Project Classification per OEB Filing Guidelines:

Project Class:	Operations
Project Need:	Non-Discretionary

Hydro One Networks – Investment Summary Document

Investment Category: Operating Capital – Operating Infrastructure

Reference #	Investment Name	Gross Cost	In-Service Date
O4	Hub Site Management Program	$7.2M	Late 2012

Please see Exhibit D1, Tab 3, Schedule 4 for cash flows.

Need:

This investment is required to:

- provide capacity expansion for the monitoring and control of new or expanded transmission stations and new Generators,
- maintain the performance and reliability of monitoring and control of critical grid stations and facilities
- refresh end-of-life gateway systems

Summary:

A Hub Site is a location which comprises a number of gateway systems that connect the transmission stations in their geographic vicinity to the OGCC and back-up centre. There are 37 Hub Sites.

As new assets or generators are added to the grid, the gateways become fully loaded and more gateways need to be added. As the number of gateways at a hub site increases, the risk of loss of that single site exceeds thresholds for grid control reliability and the hub site needs to be split into two or more locations. Presently, there are 5 sites that exceed these thresholds.

Gateway systems are computer systems which are subject to software technology obsolescence after a period of about 6 years. This program also refreshes these systems in order to keep the fleet within range of vendor supported versions.

Additional gateways will be installed to provide capacity for the monitoring and control of new grid assets and connecting generators. Some new hub sites will be added and large hub sites split. Gateway obsolescence will be optimally managed.

Results:

Grid development projects and generation connections can proceed without impediment or delay and grid loss-of-control risks associated with loss of a hub site are contained to acceptable levels.

Project Classification per OEB Filing Guidelines:

Project Class:	Operating
Project Need:	Non Discretionary

Hydro One Networks – Investment Summary Document

Investment Category: Operating Capital – Telemetry Expansion

Reference #	Investment Name	Gross Cost	In-Service Date
O5	Telemetry Expansion	$6.9M	Late 2012

Please see Exhibit D1, Tab 3, Schedule 4 for cash flows.

Need:

Telemetry expansion is needed to eliminate unnecessary equipment outages and wasteful use of the time of field staff, to allow optimum utilization of assets and to better manage aging assets.

Summary:

The function of Ontario Grid Control Centre (OGCC) depends on voltages, power flow, statuses of switching devices, and alarms transmitted in real time from the transmission stations throughout the province. This information is called telemetry.

A legacy problem that exists in many Hydro One stations is the "bundling" of alarms. When older stations were built, limitations in equipment and telecommunication capacity required multiple alarm signals at a station to be wired together and transmitted back to the operator as a single alarm. About 2,000 of these require service personnel to be urgently dispatched to the station to determine the real cause. In the meantime, action must be taken based on the worst case interpretation of the bundled alarm and this sometimes requires removing equipment from service resulting in reduced reliability of supply, market congestion or, in some instances, immediate interruption of load. In most instances these actions prove unnecessary when alarm details become known. Each year about 280 such emergency callouts are made. These 2000 alarms and are high priority to have unbundled. The program prioritizes stations that have longer travel time and larger numbers of bundled alarms.

Modern protection and control equipment provides additional information from stations that will allow assets such as transformers to be utilized more effectively. Improved equipment limits facilitate allowing an outage to proceed.

Results:

Telemetry sets from 10 stations will be expanded to present-day standards.

Project Classification per OEB Filing Guidelines:

Project Class:	Operating
Project Need:	Discretionary

Hydro One Networks – Investment Summary Document

Investment Category: Operating Capital – Wide Are Network Project

Reference #	Investment Name	Gross Cost	In-Service Date
O6	Wide Area Network Project	$37.1M	Late 2011[1]

Please see Exhibit D1, Tab 3, Schedule 4 for cash flows.

Need:

Hydro One requires expanded telecommunication capacity into may of its transmission stations to support protection and control for new generation, video surveillance for security, smart grid, cyber security and enterprise systems. Depending on the rate of deployment of some new systems such as smart grid, video conferencing and improved enterprise systems, the requirement could range from a doubling of service capacity to a sevenfold increase over the next five years.

Summary:

Most of Hydro One's transmission stations are in remote locations that are not served by high bandwidth telecommunication providers. Hydro One has been using the fibre optic cables built onto transmission lines for the protection and control of the grid to service some of these telecommunication requirements. However, the existing terminal equipment does not make optimum use of the fibre capacity and there are some locations where capacity is already fully allocated. The needs for protection and control take precedence.

Not proceeding with this investment will result in immediate increases in telecom leased costs as services are displaced in order to release capacity for protection needs. This project will implement new network technology to make more efficient use of the existing fibre optic cables on transmission circuits. This technology, which is readily scalable, will provide the capacity to meet all telecom needs expected over the next five years and beyond and avoid large leased telecom services costs.

Results:

New network equipment will be deployed at transmission stations across the province to meet existing and future telecommunication needs and avoid ongoing leased telecom services costs. The expenditure is projected to pay back within 5 years in telecom lease cost savings.

Project Classification per OEB Filing Guidelines:

Project Class:	Operating
Project Need:	Discretionary

[1] First phase is in service in 2011. All phases will be in service by end of 2014.

Hydro One Networks – Investment Summary Document
Cornerstone Phase 2 – Finance/HR/Payroll

Reference #: IT1

Investment Name: Cornerstone Phase 2 – Finance/HR/Payroll **In-Service:** Late 2010

Need:

The current Hydro One version of PeopleSoft, installed in 1998 for Finance, Human Resources, and Payroll processing was last partially upgraded in 2002, and is at end-of-life and is no longer under vendor support. Significant investment is required or else process and technology solutions will not exist to support the achievement of business objectives. Moreover, significant business continuity risks would remain unaddressed if Cornerstone Phase Two did not proceed.

Investment Summary:

In 2006, Hydro One developed an IT strategy that called for replacement of core business systems (and associated bolt-ons) which had reached or were approaching end-of-life, with one or two off the shelf Enterprise Resource Planning (ERP) systems. In 2007, to commence implementation of this IT strategy, Hydro One initiated Cornerstone Phase I, an SAP Enterprise Asset Management solution; this project was successfully completed on June 30, 2008.

Cornerstone Phase 2 continues to expand Hydro One's SAP solution to replace PeopleSoft, eliminating the need for the temporary SAP-to-PeopleSoft interfaces and bringing a greater proportion of Hydro One's core business systems under vendor support. In addition, Cornerstone Phase 2 will replace the in-house application, Business, Regulatory Planning & Reporting (BRPR), which tracks the release of work from Asset Management to the field; this will be a first step in the deployment of SAP business planning and investment management functionality. Lastly, Cornerstone Phase 2 will replace legacy Data Warehouse applications and databases with a single SAP business warehouse and a reporting tool, to provide one source of reliable business data. The go-live date for Cornerstone Phase 2 was Q3 2009.

In addition to the defined project scope outlined above, Phase 2 also addresses currently anticipated International Financial Reporting Standards (IFRS) requirements to accommodate IFRS compliance by January 1, 2011. A parallel IFRS Project will be carried out to review Hydro One accounting policies/practices and recommend changes to meet IFRS compliance requirements. It is expected that many of these recommendations will be incorporated into the Phase 2 SAP solution while others will be addressed in subsequent releases of SAP, to address any late changes in IFRS requirements so as to provide full IFRS compliance before the January 1, 2011 deadline.

Similar to Cornerstone Phase I, the scope consists of and is restricted to doing what is required to turn on the SAP product and make it work as designed in the business, with no SAP software customizations or unnecessary enhancements.

Results:

Cornerstone Phase 2 will bring the following business benefits to Hydro One:
- Critical Finance & Payroll functions will be moved to a fully vendor-supported environment
- Hydro one will avoid prolonged reliance on temporary financial interfaces between SAP and PeopleSoft
- One integrated system of record for all asset and financial data

Costs:

	2010 ($M)	**Total** ($M)
Capital* and Minor Fixed Assets	12.7	12.7

*Includes overhead and Allowance for Funds Used During Construction at current rates

Hydro One Networks – Investment Summary Document
Cornerstone Phase 3 – Enhance Integrated Planning

Reference #: IT2

Investment Name: Cornerstone Phase 3 – Enhance Integrated Planning **In-Service:** 2012

Need:
Phase 3 will enhance integrated planning by expanding Hydro One's SAP solution and integrating key systems/technologies and specialized packaged point solutions to drive additional business value, improve end-to-end process efficiency and improve asset lifecycle management analytics/decisions. This investment is required to support the achievement of business objectives and to release significant business value. Not proceeding with this investment would eliminate the integrated tools and systems that are needed to further optimize asset lifecycle decisions and improve operational efficiency and productivity. It would also necessitate a continued reliance on existing end-user disparate systems/databases for this decision support.

Investment Summary:
In 2006, Hydro One developed an information technology (IT) strategy that called for replacement of core business systems (and associated bolt-ons) which had reached or were approaching end-of-life, with one or two off the shelf Enterprise Resource Planning (ERP) systems. In 2007, Hydro One embarked on this strategy by initiating Cornerstone Phase 1, an SAP Enterprise Asset Management (EAM) solution. This project was successfully completed in June 2008. Cornerstone Phase 2 is now underway to replace PeopleSoft Finance/Human Resources/Payroll Functionality that is integrated with the EAM solution installed in Phase 1 for service Q3 2009.

Hydro One business information consists of many different components that reside in many different sources even after completion of Phases 1 and 2. The key is to integrate these sources to allow asset and other business data to be captured once and used consistently throughout Hydro One to provide asset and asset work information from a variety of perspectives e.g. system performance, asset condition, labour, cost (historical and forecasted), work accomplishment, performance and work metrics, customer reliability, outage management, etc. This facilitates breaking down the information silos and driving enterprise integration and improvements via process, people and technology. An essential element of this vision is to provide seamless integration of data between the asset registry, work orders, scheduling/dispatch and GIS system using mobile technology.

Cornerstone Phase 3 will build on the success of Phases 1 and 2 and further enhance integrated planning by expanding Hydro One's SAP solution and integrating key systems/technologies and specialized packaged point solutions to drive additional business value, improve end-to-end process efficiency and improve asset lifecycle management analytics/decisions. This includes adding SAP functionality by turning on new SAP modules (including workflow for process control); integrating specialized software applications for reliability centred maintenance optimization (RCM) and scheduling/dispatch; interfacing key enterprise systems (i.e. graphical information system, operating, fleet, telecom, protection & control, etc); incorporating new assets into the asset registry (e.g. information technology assets, real estate assets, metering assets, etc); deploying enterprise mobile strategy across the province; and consolidating end-user databases. The proposed go-live date for Cornerstone Phase 3 is 2012.

Results:
Cornerstone Phase 3 will deliver the following business benefits

- Provide SAP integration to operating, scheduling/dispatch and GIS system using mobile technology
- Provide specialized RCM software application to monitor/analyze preventative maintenance results, validate asset models, and facilitate strategic/scenario planning that is focused on improving asset lifecycle management decisions
- Consolidate and eliminate duplicative end-user databases/applications
- Streamline processes and improve information transparency

Costs:

	2010 ($M)	**2011** ($M)	**2012 ($M)**	**Total** ($M)
Capital* and Minor Fixed Assets	22.2	20.8	29.3	72.3

*Includes overhead and Allowance for Funds Used During Construction at current rates

Hydro One Networks – Investment Summary Document
Mobile IT Platform

Reference #: IT3

Investment Name: Mobile IT Platform **In-Service:** Mid 2011

Need:
To support the mobile workforce, Hydro One has implemented 13+ point solutions which consist of a blend of Custom Developed, Commercial Off the Shelf (COTS) and customized COTS. The existing applications have evolved in a fragmented way, driven by independent LOB needs without assessing common processes and needs across the enterprise. The need for an enterprise wide Mobile IT Platform is to establish a common platform on which Hydro One can build and satisfy its provincial field force mobility and data automation needs now and into the future while capitalizing on investments such as SAP and GIS.

Not proceeding with this investment would result in decreased productivity as a result of duplication of work, increase associated costs with respects to future investment decisions and ongoing support, and would compromise the realization of Cornerstone benefits.

Investment Summary:

Two separate Mobile strategies commissioned by Hydro One recommended implementing a mobile IT platform to alleviate the fire-fighting approach that will inevitably occur once the existing mobile applications reach end of life. The platform will provide a common solution suite across the LOB's and will align with HONI's business and technology strategy to continue to move to 'off-the-shelf' applications with no customizations, while allowing Hydro One to benefit from the experience of industry leaders that include best practices embedded in their software.

Hydro One will select a mobile IT platform that will establish a mobile forms solution. The solution will provide a data automation platform that will facilitate the accurate collection of asset information. The platform will allow information to be exchanged between various back-end systems (SAP, GIS) and will be based on proven technology (cradle, LAN, wireless). The implementation has been broken down into two stages. Stage 1 will consist of a suite of asset maintenance results reporting forms with an interface to SAP. Stage 2 will address provincial field force mobile applications that have reached end of life. Stage 3 will provide asset master data updating capabilities with SAP and GIS. Future stages will address other mobility needs and may form a multi-year mobility program or specific individual projects.

Results:

- Robust and scalable Mobile IT Platform that meets business and technical requirements across all business units (Asset Management, Customer Operations, E&CS, Grid Operations)
- Reduction in the number of in-service applications, lowering the costs and business risks associated with the multitude of supported and unsupported legacy and custom solutions
- Provide consistent quality data into SAP which will contribute to the realization of Cornerstone's business case benefits
- Ability to utilize HONI's GIS system as the database of record for locating assets and their associated attributes
- Increased productivity as crews can collect and transfer data to corporate systems without further intervention

Costs:

	2011 ($M)	**2012** ($M)	**Total** ($M)
Capital* and Minor Fixed Assets (A)	3.0	2.0	5.0

*Includes overhead and Allowance for Funds Used During Construction at current rates

Hydro One Networks – Investment Summary Document
GIS Implementation

Reference #: IT4

Investment Name: GIS Implementation **In-Service:** 2014

Need:

This is a foundational investment required to support initiatives across the entire Hydro One organization. Geospatial technology is a key infrastructure that enables a variety of business processes including design, transmission and distribution planning, outage management, work management, real estate and others. Geospatial technology and the underlying connected network model is also a key component required to support the benefits achieved from smart metering and smart grid initiatives.

If this investment is not undertaken, there are a number of risks across Line of Businesses (LOBs). First and foremost, up-to-date geospatial information resources facilitate safety goals as crews have access to accurate and timely views of the network; thus there is a risk to crew safety. There is also a risk of sub-optimal crew routing for work, and for outage restoration, for sub-optimal planning, and for litigation due to improperly managed real estate. There is also a risk that the goals planned as part of the smart metering and smart grid initiatives will not be able to be fully realized.

Investment Summary:

Geospatial information and technology is a foundational infrastructure that enables LOBs across the Hydro One organization. Geospatial information is also a foundational requirement for smart metering and smart grid applications, as the benefits to these next-generation programs cannot be fully realized with inaccurate or out-of-date data. A single system of record comprising the location and connectivity of both transmission and distribution assets (and GIS is the only technology that fully supports both logical connectivity and physical location of assets), as well as properties and condition facilitates planning and outage management, supports mobile workforce management through intelligent crew routing and automated vehicle location (AVL), manages real estate records and Hydro One property, and provides the intelligent underpinnings of smart grid applications such as FLISR (fault location, isolation and service restoration, which minimizes the outage impact to customers) and VVO (volt var optimization, which provides a consistent quality of service while achieving efficiency through voltage reduction). At the present time, there is no single system of record; spatial data is managed in siloed databases and business processes across Hydro One; consumers of spatial data are required to maintain their own spatial repositories, which do not necessarily reflect the current state of the network. In addition, not all data is available in a GIS format, complicating the challenge of interoperability. There is no publically consumable data portal, and no integration to other critical business systems such as SAP.

The preferred plan is to create a consolidated system of record for spatial data, and to publish it to consumers as needed either via export for more sophisticated needs, such as distribution planning with CYME, outage management with ORMS, or next-generation DMS, or via a published web portal. This will entail completing the conversion of Dx data, reconciling the data and business processes with Nconns, DOMs, ORMS, CYME, etc., publishing a spatial data web portal, and completing integration with SAP and other enterprise applications. This investment provides for updates to GIS infrastructure, particularly software applications as well.

Results:

- *Improved Decision Quality:* Provide immediate access to more comprehensive and integrated spatial asset and connectivity data in corporate systems, contributing to consistency and timeliness in asset planning, maintenance and outage decisions.
- *Improved Safety:* Provide access to reliable, accurate and up-to-date data regarding the state of the network, which empowers work crews to work more safely.
- *Reduced Litigation:* Provide access to a single, seamless and up-to-date repository of records from which organization can avoid and defend against litigation for land usage.
- *Prevent Rework:* Provide a single, seamless repository of spatial records which are updated by appropriate LOBs to eliminate the need for each LOB to maintain its own spatial data.
- *Support Next Generation Applications:* Provide access to network properties and connectivity information to support next generation smart grid applications such as FLISR and VVO.

Costs:

	2011 ($M)	2012 ($M)	Total ($M)
Capital* and Minor Fixed Assets	6.0	4.9	21.0

*Includes overhead and Allowance for Funds Used During Construction at current rates

Hydro One Networks – Investment Justification

MFA PC and Printer Hardware

Reference #: IT5

Investment Name: MFA PC and Printer Hardware **In-Service:** 2011 & 2012

Need:

This investment driver funds the maintenance of the PC and printer hardware. This equipment includes desktop PCs, laptop PCs, tablet PCs, printers, and plotters. This equipment is used by Hydro One staff to perform their daily work such as accessing email, desktop applications (i.e. Microsoft Office), and enterprise applications and databases.

This investment is required to fund the replacement of existing PC and printer equipment that has reached the end of useful life, upgrade existing equipment to meet business needs, and purchase additional equipment to accommodate business growth. One major new driver for business growth in 2010 and 2011 is the increased work program in E&CS and Grid Ops planned for the Green Energy Act.

Not to proceed with this investment could negatively impact the delivery of all IT services to the business by using equipment that does not meet business needs or is past the end of it's useful life and is becoming unreliable.

Investment Summary:

In order to protect Hydro One's investment in PC and printer hardware and ensure that this equipment delivers the required level of reliability and service to the business funding is required replace old equipment, upgrade existing equipment, or add new equipment to accommodate business growth. Old equipment that is past the end of it's useful life becomes unreliable and negatively impacts the ability of the business to use PC and printer equipment to perform their day to day work. In addition existing equipment may need to be upgraded to meet the changing needs of the business.

Results:

The PC and printer hardware assets will provide timely and reliable services to the Hydro One business.

Costs:

	2011 ($M)	**2012 ($M)**	**Total ($M)**
Capital* and Minor Fixed Assets	6.2	4.2	10.4

Hydro One Networks – Investment Justification

Enterprise Application Software

Reference #: IT6
Investment Name: Enterprise Application Software **In Service:** 2011 & 2012

Need:

This investment driver funds the maintenance of existing enterprise application software. This software is accessed by end users to create or manipulate data in support of the operation of the business. Examples of such software include GIS (ARC FM), business intelligence (Cognos), supply chain management (SAP), and document management software.

This investment is required to fund upgrades to maintain software currency, accommodate organic business growth, and maintain regulatory compliance.

Not to proceed with this investment could impact the efficiency of business operations utilizing this software or increase the risk of regulatory non-compliance.

Investment Summary:

In order to protect Hydro One's investment in enterprise application software and ensure that this software delivers the intended benefits to the business, ongoing funding is required for replacement of obsolete software and major version upgrades. The investment will also ensure continued vendor support and reliable operation of the software.

Furthermore, funding is required for additional licenses to accommodate growth in the number of customers or business use.

Results:

The Enterprise Application software assets will provide reliable and efficient services to the Hydro One business.

Costs:

	2011 ($M)	2012 ($M)	Total ($M)
Capital and Minor Fixed Assets	3.2	3.6	6.8

Hydro One Networks – Investment Justification

MFA UNIX Servers

Reference #: IT7

Investment Name: MFA UNIX Servers

In Service: 2011 & 2012

Need:

This investment driver funds the maintenance of the existing UNIX Server equipment. This equipment is used to run enterprise applications, such as SAP, that are utilized across the Hydro One business.

This investment is required to fund the replacement of existing UNIX Server equipment that has reached the end of useful life, and purchase additional equipment to accommodate growth in business volumes.

Not to proceed with this investment could negatively impact the delivery of enterprise application services to the business by using UNIX Server equipment that does not meet business needs or is past the end of it's useful life and is becoming unreliable.

Investment Summary:

Old equipment that is past the end of it's useful life becomes unreliable and negatively impacts the ability to deliver enterprise application services that meet the needs of the Hydro One business. This investment will replace old UNIX Server equipment and accommodate growth in business volumes.

Results:

The UNIX Server assets will provide timely and reliable services to the Hydro One business.

Costs:

	2011 ($M)	**2012 ($M)**	**Total ($M)**
Capital and Minor Fixed Assets	4.1	4.2	8.3

Hydro One Networks – Investment Justification

MFA Windows Servers

Reference #: IT8

Investment Name: MFA Windows Servers

In Service: 2011 & 2012

Need:

This investment driver funds the maintenance of the existing Windows Server equipment. This equipment is used to run Exchange email, workgroup applications, and PC and Network management services that are utilized across the Hydro One business

This investment is required to fund the replacement of existing Windows Server equipment that has reached the end of useful life, and purchase additional equipment to accommodate growth in business volumes.

Not to proceed with this investment could negatively impact the delivery of email, workgroup application, and PC and Network management services to the business by using Windows Server equipment that does not meet business needs or is past the end of it's useful life and is becoming unreliable.

Investment Summary:

Old equipment that is past the end of it's useful life becomes unreliable and negatively impacts the ability to deliver services that meet the needs of the Hydro One business. In order to protect Hydro One's investment in Windows Server equipment and ensure that this equipment delivers the required level of reliability and accommodates growth in business volumes, it is required to replace old equipment and add new equipment using a cyclic approach.

Results:

The Windows Server assets will provide timely and reliable services to the Hydro One business.

Costs:

	2011 ($M)	2012 ($M)	Total ($M)
Capital and Minor Fixed Assets	3.5	1.9	5.4

Hydro One Networks – Investment Summary Document

Reference #	Investment Name	Gross Cost	In-Service Date
C1	Real Estate Field Facilities Capital for 2011	$25.8M	Late 2011
C1	Real Estate Field Facilities Capital for 2012	$19.6M	Late 2012

Need:

Facilities Capital Work Program addresses facilities portfolio accommodation needs in terms of facility improvements, building additions and new facilities in line with Company operational requirements. This program also focuses on ensuring critical facility structural and other building integrity improvements are made to administrative and service centres to ensure appropriate maintenance and operation of the asset in the longer term.

The Facilities Organization is responsible to ensure program delivery in terms of planned capital improvements and providing for Company accommodation needs. The funding requirements in 2011 and 2012 mainly reflects on the expanded facilities work program that primarily responds to current and future anticipated Company work space accommodation needs. The Company workload including recent Green Energy Act Project Initiatives continues to drive the need to provide for additional work space to accommodate additional staff levels in the field service centres.

The aging facilities asset base in conjunction with operational needs of the business units requires capital investment in order to continue to provide adequate accommodation space. Approximately 40% of administrative and service centres facilities infrastructure are estimated to be more than 40 years old. The program focuses on undertaking the critical component replacement work on a priority basis including provision of new buildings, buildings additions and facility renovations.

Summary:

Key program work activities include:

- Addressing Company accommodation requirements in terms of new buildings, buildings additions and major facility renovations;
- Replacement of major building components including roof structures, windows, heating, ventilating and air conditioning (HVAC) systems and other structural elements and building systems;
- Dealing with environmental issues that may arise such as mould;
- Water treatment upgrades to improve quality and reliability of water supply, including conversions to municipal supply.

Capital investment of $25.8M is required for 2011 and $19.6M is required for 2012 to provide for new accommodation solutions, address need for new buildings, buildings additions and provide for facilities improvements in order to continue to provide adequate accommodation space to support work programs.

Results:

- Secured necessary accommodation space in the field in line with work programs requirements.
- Improved Administrative and Service Centre facilities through replacement of roof structures, windows, HVAC systems and other structural elements.

Hydro One Networks – Investment Summary Document

Reference #	Investment Name	Gross Cost	In-Service Date
C2	Real Estate Head Office and GTA Facilities Capital for 2011	$19.0M	Late 2011
C2	Real Estate Head Office and GTA Facilities Capital for 2012	$15.6M	Late 2012

Need:

The Facilities Capital Work Program is responsible to ensure program delivery in terms of capital improvements and providing for Company accommodation needs.

Capital investment of $19.0 million is required in 2011 and $15.6 million is required in 2012. This investment is required to secure accommodation (including furniture systems) and address the need for tenant improvements for the required additional space within the GTA.

Hydro One Networks has completed an eleven year lease renewal for 483 Bay Street, Toronto effective February 1, 2010 to serve its ongoing head office requirements. The head office capital investment consists of both leasehold improvements and replacement furniture systems which will commence in the bridge year 2010 and are expected to continue throughout test years and end in 2013. In 2011 the gross leasehold improvements and the furniture systems funding requirements are estimated to be $13.0 million and $6.0 million respectively and in 2012 the gross leasehold improvements are estimated to be $13.0 million and the furniture systems funding requirements are estimated to be $2.6 million. The leasehold improvements are necessary as major head office building infrastructure elements are now at end of life and require replacement. Similarly, furniture systems were acquired from the previous tenant, refurbished and are also now considered to be at end of life. The planned tenant improvements are part of the newly negotiated lease agreement.

Summary:

Capital investment of $19.0 million is required for 2011 and $15.6 million in is required in 2012 to provide for head office accommodation improvements.

Results:

Secured necessary accommodation space for head office.

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Hydro One Networks – Investment Summary Document
Shared Services Capital – Service Equipment

Reference #: C3

Investment Name: Shared Services Capital – Service Equipment **In-Service:** Late 2011 and 2012

Need:

Minor fixed asset expenditures for service equipment in 2011 and 2012 are required: to support the growing levels of transmission and distribution capital and OM&A sustainment, development, and operations work programs which includes the initiatives of the GEGEA, to replace end of life and obsolete equipment, and staffing expansions.

Service equipment is used by field staff to carry out day-to-day work activities including specialized transportation equipment to and from the work site. This equipment must be maintained at appropriate levels such that work can be executed in a safe and cost effective manner. Inadequate investment will result in equipment breakdowns or increased labour time. Overall this would adversely impact job costs, outage duration, and work program accomplishments.

Investment Summary:

Minor fixed asset (MFA) spending for service equipment represents items > $2000 each exclusive of general computer MFA requirements, real estate MFA requirements and fleet MFA requirements, addressed elsewhere, which are necessary to replace end of life equipment used by field staff to execute the work program in a cost effective manner.
Purchases in this category include:

- Minor specialized transportation equipment such as snowmobiles, all terrain vehicles, boats, barges, and related accessories to transport crews to off-road work sites,
- Measuring and testing equipment to carry out a variety of work activities including trouble shooting, performance testing of equipment, wood pole density testing, battery testing, relay test systems, moisture analyzers, circuit breaker testers, resistance testers, etc.,
- Tools and a wide range of other miscellaneous equipment such as PCB waste bins, portable generators, cabling trailers and equipment, satellite equipment for mobile emergency preparedness, insulator power washing equipment, Automated External Defibrillators devices, conventional line tensioning puller ropes, Maintenance shop equipments to describe a few.
- Relatively large tanker units utilized in the service of transformers including SF6 gas carts, degassifiers used to remove impurities from insulating oil, heated oil tankers, oil filters, oil farm upgrades and dry air machines.

MFA service equipment requirements will vary year to year depending on a number of factors including the overall asset condition, the number of large cost "one-time" items that occur from year to year, the size of the work program and associated staffing levels projected in the business plan, random equipment failures, unanticipated system impacts, weather severity and trends which affect the intensity and use of certain types of equipment particularly related to storm and trouble call programs.

Spending in both 2011 and 2012 is focused on the level of equipment required to accomplished the growth in the overall transmission and distribution work programs, and end of life replacement of specific large equipment such as oil tankers, degassifiers and air supply equipment used to overhaul and maintain large power transformers and manage the related oil requirements. Such purchases are a part of long term replacement plans to replace end of life equipment that are expected to extend to 2012 and beyond.

Results:

- Maintain equipment and tool fleets at the required levels to accomplish the growing levels of capital and OM&A sustainment, development, and operations work programs in 2011 and 2012;
- This investment will result in reduced operating costs, increased efficiency, and reliability.

Costs:

	2011 ($M)	**2012** ($M)
Capital* and Minor Fixed Assets (Networks Only)	8.8	5.9

*Includes overhead and Allowance for Funds Used During Construction at current rates

Hydro One Networks – Investment Summary Document
Shared Services Capital – Transport & Work Equipment

Reference #: C4

Investment Name: Shared Services Capital – Transport & Work Equipment **In-Service:** Mid-Late 2011 & 2012

Need:

Transport and Work Equipment expenditures for 2011 and 2012 are required: to support the growing levels of transmission and distribution capital and OM&A sustainment, development, and operations work programs which includes the initiatives of the GEGEA, to replace end of life core Fleet and equipment, and staffing expansions resulting from Provincial Lines and Forestry Apprenticeship Programs.

Not proceeding, or delaying this investment would: lead to lower than required fleet and equipment levels, have an unfavorable impact on the appropriate mix of vehicles and equipment required, and may cause a shift to use of more expensive rental units. Extending the life of the vehicles past their optimum level of economic and reliable operations will also result in increased equipment and user operating costs, reduced reliability and unsafe operating conditions.

Investment Summary:

Hydro One controls and manages approximately 5,700 fleet units and other equipment which support the various lines of business (LOBs) including Provincial Lines, Stations, Forestry and Engineering and Construction Services (E&CS). Fleet vehicles must be maintained at an optimum level to comply with various regulations (Highway Traffic Act, CVOR regulations, etc.) and to maintain LOB productivity by minimizing downtime and travel time and taking advantage of opportunities resulting from improvements in technology.

Present replacement criteria are based on manufacturers' recommendations and repair history. Light vehicles are replaced after 6 years or 180,000 km, service trucks are replaced after 6 years or 200,000 km, and work equipment is replaced after 8 – 10 years or 330,000 km. This is used as a guideline and ultimately it is used in combination with break-even analysis, including replacement cost, depreciation, operating cost and potential life expectancy.

The key contributors to the 2011 and 2012 capital program include:

- the replacement of core fleet and equipment;
- additional vehicle and equipment requirements to support the Forestry Apprenticeship Program and additional staff;
- additional vehicle and equipment requirements to support the Provincial Lines Apprenticeship Program and additional staff;
- additional vehicle, light and heavy equipment required to support the growing levels of the transmission and distribution capital and OM&A sustainment, development and operations work programs, including the initiatives of the GEGEA.

Results:

- This investment will result in reduced operating costs, increased efficiency, and reliability.

Costs:

	2011 ($M)	**2012**($M)
Capital* and Minor Fixed Assets (Networks Only)	74.1	60.2

*Includes overhead and Allowance for Funds Used During Construction at current rates

HYDRO ONE NETWORKS INC.
TRANSMISSION
Continuity of Property, Plant and Equipment
Year Ending December 31
Historical (2007, 2008, 2009), Bridge (2010) & Test (2011, 2012) Years
Total - Gross Balances
($ Millions)

Fixed Assets

Line No.	Year	Opening Balance	Additions	Retirements	Sales	Transfers In/Out	Closing Balance	Average
		(a)	(b)	(c)	(d)	(e)	(f)	(g)
Historic								
1	2007	9,793.4	489.9	(167.3)	(6.8)	(5.4)	10,103.8	9,948.6
2	2008	10,103.8	408.5	(29.4)	(4.0)	2.5	10,481.4	10,292.6
3	2009	10,481.4	661.3	(34.3)		(27.1)	11,081.3	10,781.3
Bridge								
4	2010	11,081.3	798.2	(30.1)		24.2	11,873.6	11,477.5
Test								
5	2011	11,873.6	870.6	(39.3)		16.1	12,721.0	12,297.3
6	2012	12,721.0	1,618.8	(41.6)		(0.2)	14,298.0	13,509.5

HYDRO ONE NETWORKS INC.
TRANSMISSION
Continuity Accumulated Depreciation
Year Ending December 31
Historical (2007, 2008, 2009), Bridge (2010) & Test (2011, 2012) Years
Total - Accumulated Depreciation
($ Millions)

Fixed Assets

Line No.	Year	Opening Balance	Additions	Retirements	Sales	Transfers In/Out	Other	Closing Balance	Average
		(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)
Historic									
1	2007	3,627.2	214.3	(167.3)	(2.4)	(2.6)	-	3,669.2	3,648.2
2	2008	3,669.2	225.4	(29.4)	(3.5)	(0.3)	-	3,861.4	3,765.4
3	2009	3,861.4	246.6	(34.3)	-	(1.8)	-	4,071.9	3,966.7
Bridge									
4	2010	4,071.9	263.9	(30.1)	-	(0.1)	-	4,305.6	4,188.8
Test									
5	2011	4,305.6	286.3	(39.3)	-	-	-	4,552.7	4,429.1
6	2012	4,552.7	317.6	(41.6)	-	-	-	4,828.6	4,690.7

HYDRO ONE NETWORKS INC.
TRANSMISSION
Continuity of Property, Plant and Equipment - Construction Work in Progress
Year Ending December 31
Historical (2007, 2008, 2009), Bridge (2010) & Test (2011, 2012) Years
Total - Gross Balances
($ Millions)

Fixed Assets

Line No.	Year	Opening Balance	Capital Expenditures	Transfers to Plant	Closing Balance
		(a)	(b)	(c)	(d)
Historic					
1	2007	376.4	559.5	(488.0)	447.9
2	2008	447.9	704.2	(389.1)	763.0
3	2009	763.0	917.8	(664.4)	1,016.4
Bridge					
4	2010	1,016.4	930.0	(798.2)	1,148.1
Test					
5	2011	1,148.1	1,151.8	(870.6)	1,429.4
6	2012	1,429.4	1,008.3	(1,618.8)	818.9

HYDRO ONE NETWORKS INC.
TRANSMISSION
Statement of Working Capital
Annual Average
Forecast Years (2011 and 2012)
($ Millions)

Line No.	Particulars	2011 (a)	2012 (b)
1	Cash Working Capital	$ 7.1	$ 5.0
2	Materials and Supplies	17.4	21.7
3	Total	$ 24.5	$ 26.7