RATE BASE

1.0 PURPOSE

This evidence presents a summary of the rate base for the regulated hydroelectric and nuclear facilities. In addition, this schedule provides a description of each of the components of the rate base and the methodology by which these components are determined.

2.0 OVERVIEW

OPG's rate base forecast is established from a forecast of net fixed assets and working capital. The rate base forecast for the regulated hydroelectric facilities is $3,885.5M in 2008 and $3,869.9M in 2009 (see Ex. B1-T1-S1 Table 1). The rate base forecast for OPG's nuclear facilities is $3,509.4M in 2008 and $3,460.5M in 2009 (see Ex. B1-T1-S1 Table 2).

OPG's forecast of net fixed asset in-service values is established from the property, plant, and equipment values in OPG's 2007 audited consolidated financial statements. These values were rolled forward based on forecast fixed asset additions, retirements, and depreciation on these assets to determine forecasts for 2008, and 2009. The determination of net fixed assets was performed separately for the regulated hydroelectric facilities and the nuclear facilities. The reconciliation of the net fixed asset in-service values presented in this exhibit to information provided in the 2007 audited consolidated financial statements is shown in Chart 1.

Exhibits D1-T1-S1, D2-T1-S1, and D3-T1-S1 present the capital expenditure forecasts for the regulated hydroelectric facilities, nuclear facilities, and corporate groups (for projects relating to the prescribed facilities) respectively. These forecasts are used to estimate the net fixed asset additions.

The depreciation forecasts for 2008 and 2009 were determined from the forecast net fixed asset values for the regulated hydroelectric facilities and the nuclear facilities and expected remaining life. The depreciation values for the regulated hydroelectric facilities and the nuclear facilities are presented in Ex. F3-T2-S1 Table 1 and Ex. F3-T2-S1 Table 4 respectively.

The net fixed asset portion of rate base is determined using a mid-year average methodology. In-service additions are considered to occur at mid-year, essentially assuming these expenditures are incurred evenly throughout the year. This is consistent with the "Filing Guidelines for Ontario Power Generation, Setting Payment Amounts for Prescribed Generation Assets" issued by the OEB on July 27, 2007. For large projects coming into service during the test period where the capital expenditure is forecast to exceed $50M, the expected in-service month is used instead of a mid-year average to improve accuracy. There are, however, no capital projects with forecast expenditures greater than $50M coming into service during the test period.

OPG's working capital consists of cash working capital, fuel inventory, and materials and supplies. Details on the calculation of these items are provided in section 3.2 of this schedule.

3.0 COMPONENTS OF RATE BASE

OPG's rate base consists of fixed assets and working capital associated with its prescribed generating facilities. These are described in the sections below.

Details regarding fixed asset net book values are provided in the tables in Ex. B2-T1-S1 and Ex. B2-T4-S1 (Regulated Hydroelectric) and Ex. B3-T1-S1 and Ex. B3-T4-S1 (Nuclear). Continuity of property, plant and equipment is presented in the tables in Ex. B2-T3-S1 (Regulated Hydroelectric) and Ex. B3-T3-S1 (Nuclear).

3.1 Fixed Assets

The value of fixed assets in the rate base (net plant) is the average of the opening and closing balances of the net book value of fixed assets in-service during the period. The net plant for the regulated hydroelectric facilities is $3,863.1M in 2008 and $3,847.5M in 2009. For OPG's regulated nuclear facilities net plant is $2,794.0M in 2008 and $2,696.0M in 2009.

Fixed assets under construction are excluded from the rate base until declared in-service. The value of fixed assets in-service is reduced by accumulated depreciation, retirements and asset impairments to arrive at the net book value of fixed assets in-service.

The nuclear information in the Exhibit B tables is presented for Darlington, Pickering, Nuclear Support Divisions, and Inspection and Maintenance Services. The nuclear organizational units are described in Exhibit F2. The regulated hydroelectric information is presented for Niagara Plant Group and R.H. Saunders. The regulated hydroelectric organizational units are described in Exhibit F1. Fixed assets used by both the regulated and unregulated generation business units are held centrally. These assets are not included in rate base. Instead, the regulated business units are charged a service fee for the use of these assets, as discussed in Ex. F3-T3-S1.

3.1.1 Capitalization of Expenditures

Expenditures that are capital in nature are recorded by OPG as fixed assets. OPG's capitalization policy is discussed in detail in Ex. A2-T2-S1.

3.1.2 Other Costs

In accordance with Generally Accepted Accounting Principles, the nuclear fixed assets balance includes an amount related to the nuclear liabilities, which is the present value of the committed costs for decommissioning of nuclear stations and nuclear waste management programs as discussed in Ex. H1-T1-S2. The gross plant rate base amount for 2006 is based on a 2006 closing balance that excludes the increase in the nuclear liabilities that occurred on December 31, 2006, as shown in Ex. B3-T3-S1 Table 1. The increase in the nuclear liabilities is described in Ex. H1-T1-S1, and the relationship between nuclear liabilities and fixed asset values is discussed in Ex. H1-T1-S2.

3.1.3 Accumulated Depreciation

Depreciation of an asset commences once it is declared in-service. The accumulated depreciation rate base amount is calculated as the average of the opening and closing balances for the year. Details on continuity of accumulated depreciation are provided in the tables in Ex. B2-T5-S1 (Regulated Hydroelectric) and Ex. B3-T5-S1 (Nuclear). OPG's depreciation methodology is discussed in Ex. F3-T2-S1.

3.1.4 Net Book Value

The net book value of fixed assets in the rate base is gross plant at cost less accumulated depreciation, as shown in the tables in Ex. B2-T1-S1 (Regulated Hydroelectric) and Ex. B3-T1-S1 (Nuclear). For 2005, 2006 and 2007, gross plant at cost is the average of the opening and closing balances of the gross plant for the period, as shown in Ex. B2-T3-S1 Table 1 (Regulated Hydroelectric) and Ex. B3-T3-S1 Table 1 (Nuclear). For 2008 and 2009, gross plant at cost is gross plant opening balance plus mid-year in-service additions less mid-year retirements and transfers, as shown in Ex. B2-T4-S1 Table 1 (Regulated Hydroelectric) and Ex. B3-T4-S1 Table 1 (Nuclear). As described in section 2.0 of this schedule, for large projects in excess of $50M coming into service during the test period, the expected in-service month is used rather than a mid-year average.

3.1.5 Retirements

Ordinarily, when an asset within a class is retired, the remaining net book value of the asset, if any, continues to be depreciated over the assigned life of the asset class. An exception to this treatment is applied if an asset is retired significantly in advance of the end of the life of its asset class, in which case the remaining net book value is charged to depreciation. This approach is part of OPG's group depreciation method, which is used widely by regulated utilities, as discussed in Ex. F3-T2-S1.

3.2 Working Capital

OPG's working capital consists of cash working capital and fuel inventory as well as materials and supplies. Working capital for the regulated hydroelectric facilities is forecast to be $22.4M in 2008 and in 2009. For OPG's regulated nuclear facilities working capital is forecast to be $715.5M in 2008 and $764.5M in 2009. Details regarding working capital as discussed below are provided in Ex. B2-T6-S1 Table 1 (Regulated Hydroelectric) and Ex. B3-T6-S1 Table 1 (Nuclear).

3.2.1 Cash Working Capital

The cash working capital reflects the average amount of capital provided by investors above and beyond investments in plant and other separately identified rate base items, including other components of working capital (e.g., materials and inventory), that bridges the gap between the time expenditures are made to provide service and the time payment is received for that service.

For regulatory purposes, cash working capital is calculated using net lag days, which is the difference between when revenue is received by OPG and when expenses are paid. The revenue lag is compared to expense lead and the net lag is applied to each of OPG's expenses to determine the cash working capital amount.

OPG conducted a lead/lag study using 2006 data to determine cash working capital requirements for the regulated hydroelectric and nuclear businesses (see Lead/Lag Study in Ex. B4-T1-S1). The results from this study were used to calculate cash working capital for the period 2005 - 2007. These are presented in Ex. B4-T1-S1. For simplicity, the 2007 cash working capital is used for the test period (2008 and 2009) as well, given the similar level and types of expenses in these years.

OPG reviewed the lead/lag methods used by a number of utilities (including Hydro One's 2005 Navigant Study and the 1993 Union Gas study) and concluded that the assessment techniques to determine revenue lags and expense leads utilized by OPG are comparable to the other companies.

3.2.2 Fuel Inventory

The hydroelectric generating stations do not require any fuel inventory.

Nuclear generating stations maintain a nuclear fuel inventory as well as an inventory of fuel oil for standby generators.

The nuclear fuel inventory includes the following:

- Uranium concentrate
- Uranium dioxide
- Manufactured fuel bundles

As described in Ex. F2-T5-S1, the nuclear fuel supply chain consists of the purchase of uranium concentrate, the purchase of services to convert the uranium concentrate into uranium dioxide and the purchase of services to manufacture fuel bundles that contain the uranium dioxide. OPG maintains inventories at each stage of the nuclear fuel supply chain and maintains ownership of the work-in-process throughout the supply chain. A discussion on the levels and rationale for the various components of the nuclear fuel inventory supply chain can be found at Ex. F2-T5-S1.

Fuel inventory is valued using the weighted average costing method. The rate base inventory value is the average of the opening and closing inventory balances during the period.

3.2.3 <u>Materials and Supplies</u>

Materials and supplies consist of consumable supplies and spare parts. The rate base material and supplies value, which is net of a provision for accumulated obsolescence, is the average of the opening and closing balances during the period. OPG's inventory management system records materials and supplies inventory based on orders, receipts, issuances and returns using an average costing basis. The total cost of materials and supplies is calculated based on the average cost of each item.

OPG's audited financial statements include both a current materials and supplies inventory and a long-term materials and supplies inventory. In accordance with Generally Accepted Accounting Principles, materials and supplies are valued at the lower of average cost and net realizable value. The determination of net realizable value of the materials and supplies takes into account various factors including technological obsolescence, the remaining life of the related facilities in which the materials and supplies are expected to be used, and adjustments required as a result of performing physical inventory counts. Charges incurred as a result of valuing nuclear materials and supplies at the lower of cost and net realizable value are reflected in the inventory adjustments recorded in Nuclear OM&A, as discussed in Ex. F2-T2-S1, and reduce the inventory balance in rate base.

Materials and supplies could be consumed in the production process or utilized as part of OM&A or capital projects. Materials and supplies consumed in the production process or utilized in OM&A projects are included in OM&A expense as incurred. Materials and supplies utilized in capital projects that meet the capitalization criteria outlined in Ex. A2-T2-S1 are included either in construction-in-progress or in-service fixed assets depending on whether the related asset has been declared in-service.

4.0 RATE BASE TREND

Nuclear rate base increased at the end of 2006 due to an increase in the nuclear liabilities associated with an approved reference plan under the Ontario Nuclear Funds Agreement, as discussed in Ex. H1-T1-S1. Small changes in the nuclear rate base later in the 2005 - 2009 period and in the regulated hydroelectric rate base throughout the 2005 - 2009 period are the result of a combination of continued depreciation of in-service fixed assets and additions of new in-service assets. The increase in nuclear fuel inventory during 2007 and continuing through 2008 and 2009 is mainly due to increased market prices for uranium. Additional detail regarding in-service additions and retirements is provided in Exhibit D (Capital Projects).

Chart 1

Reconciliation of Net Plant In Service to Audited Financial Statements

As of December 31, 2007

Line No.	Reconciliation Item	Regulated Hydroelectric	Nuclear
		(a)	(b)
1	**Segmented Assets Net Plant in Service from Note 18 in 2007 OPG Audited Financial Statements**	3,871	4030
Calculation of Net Plant in Service from Schedules Provided in the Application			
2	**2007 Closing Balance of Property, Plant and Equipment** - from Ex. B2-T3-S1 Table 1 (Regulated Hydroelectric) and Ex. B3-T3-S1 Table 1 (Nuclear)	4,410	4,419
3	**Less: 2007 Closing Balance of Accumulated Depreciation** - from Ex. B2-T5-S1 Table 1 (Regulated Hydroelectric) and Ex. B3-T5-S1 Table 1 (Nuclear)	539	1,593
4	**Plus: Bruce Net Fixed Assets Closing Book Value** - from Ex. G2-T2-S1 Table 2	N/A	1,195
5	**Plus: Other Adjustments**	0	9
6	**Net Plant In-Service**	3,871	4,030
Note: Minor differences are due to rounding			

Numbers may not add due to rounding.

Table 1

Prescribed Facility Rate Base - Regulated Hydroelectric ($M)

Line No.	Rate Base Item	2005 Actual	2006 Actual	2007 Actual	2008 Plan	2009 Plan
		(a)	(b)	(c)	(d)	(e)
1	**Gross Plant at Cost**	4,362.4	4,380.4	4,396.5	4,433.2	4,480.6
2	**Accumulated Depreciation**	384.0	446.5	507.8	570.2	633.1
3	**Net Plant**	3,978.4	3,933.9	3,888.7	3,863.1	3,847.5
4	**Cash Working Capital**	22.4	22.8	21.8	21.8	21.8
5	**Fuel Inventory**	0.0	0.0	0.0	0.0	0.0
6	**Materials & Supplies**	0.5	0.6	0.6	0.6	0.6
7	**Total**	4,001.3	3,957.3	3,911.1	3,885.5	3,869.9

Numbers may not add due to rounding.

Table 2

Prescribed Facility Rate Base - Nuclear ($M)

Line No.	Rate Base Item	2005 Actual	2006 Actual	2007 Actual	2008 Plan	2009 Plan
		(a)	(b)	(c)	(d)	(e)
1	**Gross Plant at Cost**	3,357.7	3,643.9	4,321.1	4,531.7	4,733.2
2	**Accumulated Depreciation**	1,001.6	1,189.6	1,446.1	1,737.8	2,037.1
3	**Net Plant**	2,356.1	2,454.4	2,875.0	2,794.0	2,696.0
4	**Cash Working Capital**	5.5	18.2	16.0	16.0	16.0
5	**Fuel Inventory**	156.8	172.0	208.7	281.1	330.1
6	**Materials & Supplies**	347.1	361.2	400.4	424.4	441.7
7	**Total**	2,865.5	3,005.7	3,500.1	3,515.4	3,483.8

Numbers may not add due to rounding.

Table 1
Prescribed Facility Rate Base - Regulated Hydroelectric ($M)
Calendar Years Ending December 31, 2008 and December 31, 2009

Line No.	Prescribed Facility	2008 Gross Plant at Cost	2008 Less: Accumulated Depreciation	2008 Net Plant	2009 Gross Plant at Cost	2009 Less: Accumulated Depreciation	2009 Net Plant
		(a)	(b)	(c)	(d)	(e)	(f)
1	**Niagara Plant Group**	2,910.2	377.0	2,533.1	2,947.7	419.1	2,528.6
2	**Saunders GS**	1,523.1	193.1	1,329.9	1,532.9	214.0	1,318.9
3	**Total**	4,433.2	570.2	3,863.1	4,480.6	633.1	3,847.5
4	**Cash Working Capital**			21.8			21.8
5	**Fuel Inventory**			0.0			0.0
6	**Materials & Supplies**			0.6			0.6
7	**Total Rate Base**			3,885.5			3,869.9

Numbers may not add due to rounding.

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Exhibit B2
Tab 1
Schedule 1
Table 2

Table 2
Prescribed Facility Rate Base - Regulated Hydroelectric ($M)
Actual - Calendar Years Ending December 31, 2005, 2006 and 2007

Line No.	Prescribed Facility	2005 Gross Plant at Cost	2005 Less: Accumulated Depreciation	2005 Net Plant	2006 Gross Plant at Cost	2006 Less: Accumulated Depreciation	2006 Net Plant	2007 Gross Plant at Cost	2007 Less: Accumulated Depreciation	2007 Net Plant
		(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)
1	**Niagara Plant Group**	2,848.9	252.5	2,596.4	2,865.8	294.3	2,571.5	2,880.5	335.3	2,545.2
2	**Saunders GS**	1,513.5	131.5	1,382.0	1,514.6	152.2	1,362.4	1,516.0	172.5	1,343.5
3	**Total**	4,362.4	384.0	3,978.4	4,380.4	446.5	3,933.9	4,396.5	507.8	3,888.7
4	**Cash Working Capital**			22.4			22.8			21.8
5	**Fuel Inventory**			0.0			0.0			0.0
6	**Materials & Supplies**			0.5			0.6			0.6
7	**Total Rate Base**			4,001.3			3,957.3			3,911.1

Numbers may not add due to rounding.

Table 3
Prescribed Facility Rate Base - Regulated Hydroelectric ($M)
Actual - Calendar Years Ending December 31, 2005 and December 31, 2006

Line No.	Prescribed Facility	2005 Gross Plant at Cost	2005 Less: Accumulated Depreciation	2005 Net Plant	2006 Gross Plant at Cost	2006 Less: Accumulated Depreciation	2006 Net Plant
		(a)	(b)	(c)	(d)	(e)	(f)
1	**Niagara Plant Group**	2,848.9	252.5	2,596.4	2,865.8	294.3	2,571.5
2	**Saunders GS**	1,513.5	131.5	1,382.0	1,514.6	152.2	1,362.4
3	**Total**	4,362.4	384.0	3,978.4	4,380.4	446.5	3,933.9
4	**Cash Working Capital**			22.4			22.8
5	**Fuel Inventory**			0.0			0.0
6	**Materials & Supplies**			0.5			0.6
7	**Total Rate Base**			4,001.3			3,957.3

Numbers may not add due to rounding.

Table 1
Comparison of Prescribed Facility Rate Base - Regulated Hydroelectric ($M)

Line No.	Business Unit	2005 Actual	(c)-(a) Change	2006 Actual	(e)-(c) Change	2007 Actual	(g)-(e) Change	2008 Plan	(i)-(g) Change	2009 Plan
		(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)
1	**Regulated Hydroelectric**	4,001.3	(44.0)	3,957.3	(46.2)	3,911.1	(25.6)	3,885.5	(15.6)	3,869.9

Numbers may not add due to rounding.

Table 1
Continuity of Property, Plant and Equipment - Regulated Hydroelectric ($M)
Calendar Years Ending December 31, 2005, 2006 and 2007

Line No.	Prescribed Facility	Gross Plant Opening Balance	In-Service Additions	Retirements, Transfers & Adjustments	(b)+(c) Net Change	(a)+(d) Closing Balance	(a+e)/2 Gross Plant Rate Base Amount
		(a)	(b)	(c)	(d)	(e)	(f)
	2005:						
1	**Niagara Plant Group**	2,833.6	37.8	(7.3)	30.5	2,864.1	2,848.9
2	**Saunders GS**	1,513.1	0.7	0.0	0.7	1,513.8	1,513.5
3	**Total**	4,346.7	38.5	(7.3)	31.2	4,377.9	4,362.4
	2006:						
4	**Niagara Plant Group**	2,864.1	6.9	(3.6)	3.3	2,867.4	2,865.8
5	**Saunders GS**	1,513.8	2.9	(1.3)	1.6	1,515.4	1,514.6
6	**Total**	4,377.9	9.8	(4.9)	4.9	4,382.8	4,380.4
	2007:						
7	**Niagara Plant Group**	2,867.4	27.4	(1.2)	26.2	2,893.6	2,880.5
8	**Saunders GS**	1,515.4	1.5	(0.4)	1.1	1,516.5	1,516.0
9	**Total**	4,382.8	28.9	(1.6)	27.3	4,410.1	4,396.5

Numbers may not add due to rounding.

Table 2
Continuity of Property, Plant and Equipment - Regulated Hydroelectric ($M)
Calendar Years Ending December 31, 2008 and December 31, 2009

Line No.	Prescribed Facility	Gross Plant Opening Balance	In-Service Additions	Retirements, Transfers & Adjustments	(b)+(c) Net Change	(a)+(d) Gross Plant Closing Balance
		(a)	(b)	(c)	(d)	(e)
	2008:					
1	**Niagara Plant Group**	2,893.6	33.1	0.0	33.1	2,926.7
2	**Saunders GS**	1,516.5	13.1	0.0	13.1	1,529.6
3	**Total**	4,410.1	46.2	0.0	46.2	4,456.3
	2009:					
4	**Niagara Plant Group**	2,926.7	41.9	0.0	41.9	2,968.7
5	**Saunders GS**	1,529.6	6.6	0.0	6.6	1,536.2
6	**Total**	4,456.3	48.5	0.0	48.5	4,504.9

Numbers may not add due to rounding.

Table 1
Net Plant Rate Base - Regulated Hydroelectric ($M)
Calendar Years Ending December 31, 2008 and December 31, 2009

Line No.	Prescribed Facility	Gross Plant Opening Balance	Mid-Year In-Service Additions	Mid-Year Retirements, Transfers & Adjustments	Rate Base Values		
					(a)+(b)+(c) Gross Plant	Accumulated Depreciation	(d)-(e) Net Plant
		(a)	(b)	(c)	(d)	(e)	(f)
	2008:						
1	**Niagara Plant Group**	2,893.6	16.6	0.0	2,910.2	377.0	2,533.1
2	**Saunders GS**	1,516.5	6.6	0.0	1,523.1	193.1	1,329.9
3	**Total**	4,410.1	23.1	0.0	4,433.2	570.2	3,863.1
	2009:						
4	**Niagara Plant Group**	2,926.7	21.0	0.0	2,947.7	419.1	2,528.6
5	**Saunders GS**	1,529.6	3.3	0.0	1,532.9	214.0	1,318.9
6	**Total**	4,456.3	24.3	0.0	4,480.6	633.1	3,847.5

Numbers may not add due to rounding.

Table 1
Continuity of Accumulated Depreciation - Regulated Hydroelectric ($M)
Calendar Years Ending December 31, 2005, 2006 and 2007

Line No.	Prescribed Facility	Opening Balance	Depreciation	Retirements, Transfers & Adjustments	(a)+(b)+(c) Closing Balance	(a+d)/2 Accumulated Depreciation Rate Base Amount
		(a)	(b)	(c)	(d)	(e)
	2005:					
1	**Niagara Plant Group**	231.0	47.1	(4.1)	274.0	252.5
2	**Saunders GS**	120.9	21.1	0.0	142.0	131.5
3	**Total**	351.9	68.2	(4.1)	416.0	384.0
	2006:					
4	**Niagara Plant Group**	274.0	41.5	(1.0)	314.5	294.3
5	**Saunders GS**	142.0	20.8	(0.5)	162.3	152.2
6	**Total**	416.0	62.3	(1.5)	476.8	446.5
	2007:					
7	**Niagara Plant Group**	314.5	41.9	(0.3)	356.1	335.3
8	**Saunders GS**	162.3	20.8	(0.4)	182.7	172.5
9	**Total**	476.8	62.7	(0.7)	538.8	507.8

Numbers may not add due to rounding.

Table 2
Continuity of Accumulated Depreciation - Regulated Hydroelectric ($M)
Calendar Years Ending December 31, 2008 and December 31, 2009

Line No.	Prescribed Facility	Opening Balance	Depreciation on Opening Balance	Depreciation on In-Service Additions	Retirements, Transfers & Adjustments	(a)+(b)+(c)+(d) Closing Balance	(a+e)/2 Accumulated Depreciation Rate Base Amount
		(a)	(b)	(c)	(d)	(e)	(f)
	2008:						
1	**Niagara Plant Group**	356.1	41.7	0.2	0.0	398.0	377.0
2	**Saunders GS**	182.7	20.8	0.1	0.0	203.6	193.1
3	**Total**	538.8	62.4	0.3	0.0	601.5	570.2
	2009:						
4	**Niagara Plant Group**	398.0	42.0	0.3	0.0	440.2	419.1
5	**Saunders GS**	203.6	20.9	0.0	0.0	224.5	214.0
6	**Total**	601.5	62.9	0.3	0.0	664.7	633.1

Numbers may not add due to rounding.

Table 3
Continuity of Accumulated Depreciation - Regulated Hydroelectric ($M)
Calendar Years Ending December 31, 2008 and December 31, 2009

Line No.	Prescribed Facility	Opening Balance	Depreciation on Opening Balance	Depreciation on In-Service Additions	Retirements, Transfers & Adjustments	(a)+(b)+(c)+(d) Closing Balance	(a+e)/2 Accumulated Depreciation Rate Base Amount
		(a)	(b)	(c)	(d)	(e)	(f)
	2008:						
1	**Niagara Plant Group**	356.0	41.1	0.5	0.0	397.6	376.8
2	**Saunders GS**	183.1	20.7	0.1	0.0	204.0	193.5
3	**Total**	539.1	61.8	0.6	0.0	601.5	570.3
	2009:						
4	**Niagara Plant Group**	397.6	40.9	0.7	0.0	439.2	418.4
5	**Saunders GS**	204.0	20.7	0.2	0.0	224.8	214.4
6	**Total**	601.5	61.6	0.9	0.0	664.0	632.7

Numbers may not add due to rounding.

Table 1
Working Capital Summary - Regulated Hydroelectric ($M)
Calendar Years Ending December 31, 2005, 2006, 2007, 2008, 2009

Line No.	Working Capital Item	Opening Balance	Closing Balance	(a+b)/2 Rate Base Value
		(a)	(b)	(c)
	2005:			
1	**Cash Working Capital**	N/A	N/A	22.4
2	**Fuel Inventory**	0.0	0.0	0.0
3	**Materials & Supplies**	0.4	0.6	0.5
4	**Total**			22.9
	2006:			
5	**Cash Working Capital**	N/A	N/A	22.8
6	**Fuel Inventory**	0.0	0.0	0.0
7	**Materials & Supplies**	0.6	0.6	0.6
8	**Total**			23.4
	2007:			
9	**Cash Working Capital**	N/A	N/A	21.8
10	**Fuel Inventory**	0.0	0.0	0.0
11	**Materials & Supplies**	0.6	0.6	0.6
12	**Total**			22.4
	2008:			
13	**Cash Working Capital**	N/A	N/A	21.8
14	**Fuel Inventory**	0.0	0.0	0.0
15	**Materials & Supplies**	0.6	0.6	0.6
16	**Total**			22.4
	2009:			
17	**Cash Working Capital**	N/A	N/A	21.8
18	**Fuel Inventory**	0.0	0.0	0.0
19	**Materials & Supplies**	0.6	0.6	0.6
20	**Total**			22.4

Numbers may not add due to rounding.

Updated: 2008-03-14
EB-2007-0905
Exhibit B3
Tab 1
Schedule 1
Table 1

Table 1
Prescribed Facility Rate Base - Nuclear ($M)
Calendar Years Ending December 31, 2008 and December 31, 2009

Line No.	Prescribed Facility	2008 Gross Plant at Cost	2008 Less: Accumulated Depreciation	2008 Net Plant	2009 Gross Plant at Cost	2009 Less: Accumulated Depreciation	2009 Net Plant
		(a)	(b)	(c)	(d)	(e)	(f)
1	**Darlington NGS**	1,844.4	763.9	1,080.5	1,926.7	866.4	1,060.3
2	**Pickering NGS**	2,153.0	687.1	1,465.9	2,201.5	846.7	1,354.8
3	**Nuclear Support Divisions**	437.4	243.9	193.5	499.7	270.9	228.8
4	**IMS**	97.0	42.9	54.1	105.3	53.2	52.1
5	**Total**	4,531.7	1,737.8	2,794.0	4,733.2	2,037.1	2,696.0
6	**Cash Working Capital**			16.0			16.0
7	**Fuel Inventory**			281.1			330.1
8	**Materials & Supplies**			424.4			441.7
9	**Total Rate Base**			3,515.4			3,483.8

Numbers may not add due to rounding.

Table 2
Prescribed Facility Rate Base - Nuclear ($M)
Actual - Calendar Years Ending December 31, 2005, 2006 and 2007

Line No.	Prescribed Facility	2005 Gross Plant at Cost	2005 Less: Accumulated Depreciation	2005 Net Plant	2006 Gross Plant at Cost	2006 Less: Accumulated Depreciation	2006 Net Plant	2007 Gross Plant at Cost	2007 Less: Accumulated Depreciation	2007 Net Plant
		(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)
1	**Darlington NGS**	1,563.2	458.2	1,105.0	1,632.1	551.0	1,081.2	1,795.8	657.4	1,138.4
2	**Pickering NGS**	1,317.9	327.6	990.3	1,565.5	421.3	1,144.3	2,049.9	538.3	1,511.6
3	**Nuclear Support Divisions**	404.0	192.9	211.1	370.7	193.0	177.7	388.3	217.2	171.1
4	**IMS**	72.6	22.9	49.7	75.6	24.4	51.3	87.1	33.2	53.9
5	**Total**	3,357.7	1,001.6	2,356.1	3,643.9	1,189.6	2,454.4	4,321.1	1,446.1	2,875.0
6	**Cash Working Capital**			5.5			18.2			16.0
7	**Fuel Inventory**			156.8			172.0			208.7
8	**Materials & Supplies**			347.1			361.2			400.4
9	**Total Rate Base**			2,865.5			3,005.7			3,500.1

Numbers may not add due to rounding.

Table 3
Prescribed Facility Rate Base - Nuclear ($M)
Actual - Calendar Years Ending December 31, 2005 and December 31, 2006

Line No.	Prescribed Facility	2005 Gross Plant at Cost	2005 Less: Accumulated Depreciation	2005 Net Plant	2006 Gross Plant at Cost	2006 Less: Accumulated Depreciation	2006 Net Plant
					(a)	(b)	(c)
1	**Darlington NGS**	1,563.2	458.2	1,105.0	1,632.0	551.0	1,081.1
2	**Pickering NGS**	1,317.9	327.6	990.3	1,565.9	421.3	1,144.7
3	**Nuclear Support Divisions**	404.0	192.9	211.1	370.7	193.0	177.7
4	**IMS**	72.6	22.9	49.7	75.6	24.4	51.3
5	**Total**	3,357.7	1,001.6	2,356.1	3,644.2	1,189.6	2,454.7
6	**Cash Working Capital**			5.5			18.1
7	**Fuel Inventory**			156.8			172.0
8	**Materials & Supplies**			347.1			361.2
9	**Total Rate Base**			2,865.5			3,005.9

Numbers may not add due to rounding.

Table 1

Comparison of Prescribed Facility Rate Base - Nuclear ($M)

Line No.	Business Unit	2005 Actual	(c)-(a) Change	2006 Actual	(e)-(c) Change	2007 Actual	(g)-(e) Change	2008 Plan	(i)-(g) Change	2009 Plan
		(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)
1	**Nuclear**	2865.45	140.3	3005.7	494.4	3,500.1	15.3	3,515.4	(31.5)	3,483.8

Numbers may not add due to rounding.

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Schedule 1
Table 1

Table 1
Continuity of Property, Plant and Equipment - Nuclear ($M)
Calendar Years Ending December 31, 2005, 2006 and 2007

Line No.	Prescribed Facility	Gross Plant Opening Balance	In-Service Additions	Retirements, Transfers & Adjustments	(b)+(c) Net Change	(a)+(d) Closing Balance	(a+e)/2 Gross Plant Rate Base Amount
		(a)	(b)	(c)	(d)	(e)	(f)
	2005:						
1	**Darlington NGS**	1,530.6	71.0	(5.8)	65.2	1,595.8	1,563.2
2	**Pickering NGS**	1,098.3	449.3	(10.1)	439.2	1,537.5	1,317.9
3	**Nuclear Support Divisions**	438.1	9.3	(77.6)	(68.3)	369.8	404.0
4	**IMS**	75.4	6.4	(12.1)	(5.7)	69.7	72.6
5	**Total**	3,142.4	536.0	(105.6)	430.4	3,572.8	3,357.7
	2006:						
6	**Darlington NGS**[1]	1,595.8	73.9	117.5	191.4	1,787.2	1,632.1
7	**Pickering NGS**[1]	1,537.5	55.3	390.5	445.8	1,983.3	1,565.5
8	**Nuclear Support Divisions**	369.8	8.3	(6.6)	1.7	371.5	370.7
9	**IMS**	69.7	12.1	(0.4)	11.7	81.4	75.6
10	**Total**	3,572.8	149.6	501.0	650.6	4,223.4	3,643.9
	2007:						
11	**Darlington NGS**[1]	1,787.2	17.7	(0.5)	17.2	1,804.4	1,795.8
12	**Pickering NGS**[1]	1,983.3	133.1	0.1	133.2	2,116.5	2,049.9
13	**Nuclear Support Divisions**	371.5	17.2	16.4	33.6	405.1	388.3
14	**IMS**	81.4	11.4	0.0	11.4	92.8	87.1
15	**Total**	4,223.4	179.4	16.0	195.4	4,418.8	4,321.1

1 Retirements, Transfers & Adjustments include an increase recorded at the end of the year related to the Nuclear Liabilities. An adjustment was made to exclude this increase from the Gross Plant Rate Base Amount for 2006, since the rate base represents an average balance for the year and the increase was recorded on December 31, 2006. The Gross Plant Rate Base Amount for 2007 includes the impact of this increase related to the Nuclear Liabilities.

Numbers may not add due to rounding.

Table 2
Continuity of Property, Plant and Equipment - Nuclear ($M)
Calendar Years Ending December 31, 2008 and December 31, 2009

Line No.	Prescribed Facility	Gross Plant Opening Balance	In-Service Additions	Retirements, Transfers & Adjustments	(b)+(c) Net Change	(a)+(d) Gross Plant Closing Balance
		(a)	(b)	(c)	(d)	(e)
	2008:					
1	**Darlington NGS**	1,804.4	79.9	0.0	79.9	1,884.3
2	**Pickering NGS**	2,116.5	73.0	0.0	73.0	2,189.5
3	**Nuclear Support Divisions**	405.1	64.6	0.0	64.6	469.7
4	**IMS**	92.8	8.3	0.0	8.3	101.1
5	**Total**	4,418.8	225.8	0.0	225.8	4,644.6
	2009:					
6	**Darlington NGS**	1,884.3	84.7	0.0	84.7	1,969.0
7	**Pickering NGS**	2,189.5	23.9	0.0	23.9	2,213.4
8	**Nuclear Support Divisions**	469.7	60.1	0.0	60.1	529.8
9	**IMS**	101.1	8.3	0.0	8.3	109.4
10	**Total**	4,644.6	177.1	0.0	177.1	4,821.7

Numbers may not add due to rounding.

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Tab 4
Schedule 1
Table 1

Table 1
Net Plant Rate Base - Nuclear ($M)
Calendar Years Ending December 31, 2008 and December 31, 2009

Line No.	Prescribed Facility	Gross Plant Opening Balance	Mid-Year In-Service Additions	Mid-Year Retirements, Transfers & Adjustments	Rate Base Values (a)+(b)+(c) Gross Plant	Accumulated Depreciation	(d)-(e) Net Plant
		(a)	(b)	(c)	(d)	(e)	(f)
	2008:						
1	**Darlington NGS**	1,804.4	40.0	0.0	1,844.4	763.9	1,080.5
2	**Pickering NGS**	2,116.5	36.5	0.0	2,153.0	687.1	1,465.9
3	**Nuclear Support Divisions**	405.1	32.3	0.0	437.4	243.9	193.5
4	**IMS**	92.8	4.2	0.0	97.0	42.9	54.1
5	**Total**	4,418.8	112.9	0.0	4,531.7	1,737.8	2,794.0
	2009:						
6	**Darlington NGS**	1,884.3	42.3	0.0	1,926.7	866.4	1,060.3
7	**Pickering NGS**	2,189.5	12.0	0.0	2,201.5	846.7	1,354.8
8	**Nuclear Support Divisions**	469.7	30.1	0.0	499.7	270.9	228.8
9	**IMS**	101.1	4.2	0.0	105.3	53.2	52.1
10	**Total**	4,644.6	88.5	0.0	4,733.2	2,037.1	2,696.0

Numbers may not add due to rounding.

Table 1
Continuity of Accumulated Depreciation - Nuclear ($M)
Calendar Years Ending December 31, 2005, 2006 and 2007

Line No.	Prescribed Facility	Opening Balance	Depreciation	Retirements, Transfers & Adjustments	(a)+(b)+(c) Closing Balance	(a+d)/2 Accumulated Depreciation Rate Base Amount
		(a)	(b)	(c)	(d)	(e)
	2005:					
1	**Darlington NGS**	414.6	93.2	(6.1)	501.7	458.2
2	**Pickering NGS**	280.5	118.3	(24.1)	374.7	327.6
3	**Nuclear Support Divisions**	202.4	29.9	(48.9)	183.4	192.9
4	**IMS**	25.4	6.9	(12.0)	20.3	22.9
5	**Total**	922.9	248.3	(91.1)	1,080.1	1,001.6
	2006:					
6	**Darlington NGS**	501.7	99.4	(0.9)	600.2	551.0
7	**Pickering NGS**	374.7	96.9	(3.8)	467.8	421.3
8	**Nuclear Support Divisions**	183.4	23.3	(4.1)	202.6	193.0
9	**IMS**	20.3	8.1	0.0	28.4	24.4
10	**Total**	1,080.1	227.7	(8.8)	1,299.0	1,189.6
	2007:					
11	**Darlington NGS**[1]	600.2	114.5	(0.1)	714.6	657.4
12	**Pickering NGS**[1]	467.8	141.0	0.0	608.8	538.3
13	**Nuclear Support Divisions**	202.6	23.8	5.4	231.8	217.2
14	**IMS**	28.4	9.6	0.0	38.0	33.2
15	**Total**	1,299.0	288.9	5.3	1,593.2	1,446.1

1 The Accumulated Depreciation Rate Base Amount for 2007 includes the impact of an increase related to the Nuclear Liabilities recorded on December 31, 2006.

Numbers may not add due to rounding.

Table 2
Continuity of Accumulated Depreciation - Nuclear ($M)
Calendar Years Ending December 31, 2008 and December 31, 2009

Line No.	Prescribed Facility	Opening Balance	Depreciation on Opening Balance	Depreciation on In-Service Additions	Retirements, Transfers & Adjustments	(a)+(b)+(c)+(d) Closing Balance	(a+e)/2 Accumulated Depreciation Rate Base Amount
		(a)	(b)	(c)	(d)	(e)	(f)
	2008:						
1	**Darlington NGS**	714.6	94.9	3.7	0.0	813.2	763.9
2	**Pickering NGS**	608.8	152.9	3.7	0.0	765.4	687.1
3	**Nuclear Support Divisions**	231.8	21.0	3.1	0.0	255.9	243.9
4	**IMS**	38.0	8.6	1.1	0.0	47.8	42.9
5	**Total**	1,593.2	277.5	11.6	0.0	1,882.3	1,737.8
	2009:						
6	**Darlington NGS**	813.2	101.9	4.4	0.0	919.5	866.4
7	**Pickering NGS**	765.4	160.6	1.9	0.0	927.9	846.7
8	**Nuclear Support Divisions**	255.9	26.5	3.5	0.0	285.9	270.9
9	**IMS**	47.8	9.6	1.2	0.0	58.6	53.2
10	**Total**	1,882.3	298.6	11.0	0.0	2,192.0	2,037.1

Numbers may not add due to rounding.

Table 3
Continuity of Accumulated Depreciation - Nuclear ($M)
Calendar Years Ending December 31, 2008 and December 31, 2009

Line No.	Prescribed Facility	Opening Balance	Depreciation on Opening Balance	Depreciation on In-Service Additions	Retirements, Transfers & Adjustments	(a)+(b)+(c)+(d) Closing Balance	(a+e)/2 Accumulated Depreciation Rate Base Amount
		(a)	(b)	(c)	(d)	(e)	(f)
	2008:						
1	**Darlington NGS**	700.9	108.0	5.3	0.0	814.2	757.6
2	**Pickering NGS**	572.7	140.4	1.6	0.0	714.7	643.7
3	**Nuclear Support Divisions**	227.0	23.8	9.7	0.0	260.4	243.7
4	**IMS**	40.7	16.5	1.7	0.0	58.9	49.8
5	**Total**	1,541.3	288.6	18.3	0.0	1,848.2	1,694.8
	2009:						
6	**Darlington NGS**	814.2	115.6	6.0	0.0	935.8	875.0
7	**Pickering NGS**	714.7	143.6	2.1	0.0	860.4	787.5
8	**Nuclear Support Divisions**	260.4	46.9	1.0	0.0	308.3	284.4
9	**IMS**	58.9	19.8	3.4	0.0	82.1	70.5
10	**Total**	1,848.2	325.9	12.5	0.0	2,186.6	2,017.4

Numbers may not add due to rounding.

Table 1
Working Capital Summary - Nuclear ($M)
Calendar Years Ending December 31, 2005, 2006, 2007, 2008, 2009

Line No.	Working Capital Item	Opening Balance	Closing Balance	(a+b)/2 Rate Base Value
		(a)	(b)	(c)
	2005:			
1	**Cash Working Capital**	N/A	N/A	5.5
2	**Fuel Inventory**	153.8	159.7	156.8
3	**Materials & Supplies**	354.3	339.9	347.1
4	**Total**			509.4
	2006:			
5	**Cash Working Capital**	N/A	N/A	18.2
6	**Fuel Inventory**	159.7	184.3	172.0
7	**Materials & Supplies**	339.9	382.4	361.2
8	**Total**			551.4
	2007:			
9	**Cash Working Capital**	N/A	N/A	16.0
10	**Fuel Inventory**	184.3	233.0	208.7
11	**Materials & Supplies**	382.4	418.4	400.4
12	**Total**			625.1
	2008:			
13	**Cash Working Capital**	N/A	N/A	16.0
14	**Fuel Inventory**	233.0	329.1	281.1
15	**Materials & Supplies**	418.4	430.3	424.4
16	**Total**			721.4
	2009:			
17	**Cash Working Capital**	N/A	N/A	16.0
18	**Fuel Inventory**	329.1	331.1	330.1
19	**Materials & Supplies**	430.3	453.1	441.7
20	**Total**			787.8

LEAD/LAG STUDY

1.0 INTRODUCTION

The purpose of a lead/lag study is to provide a measure of the amount of investor funds used in sustaining utility operations from the time expenditures are made until the time payment is received.

Generally a utility provides service prior to receipt of payment from ratepayers, and there is also a delay in payment for goods and services acquired by the utility. A lead/lag study is used to analyze transactions throughout the year to determine the number of days between the time services are rendered and payment is received (revenue lag), and the number of days between the time expenditures are incurred and payment is made for such services (expense or payment lead). In some instances, revenue may be received prior to payment for the related expense (i.e., a net lead or alternatively a negative net lag).

The revenue lag is compared to the expense lead and the net lag is applied to each category of operating expenses to determine the cash working capital requirements.

This document is laid out as follows:

1. Introduction
2. Methodology
3. Calculation of lead/lag days and 2006 cash working capital for generation sales
4. Calculation of lead/lag days and 2006 cash working capital for Bruce Lease revenue
5. Calculation of lead/lag days and 2006 cash working capital for other revenue
6. Calculation of lead/lag days and 2006 cash working capital for sales tax ("GST")

2.0 METHODOLOGY

OPG performed a lead/lag study based on 2006 financial information to determine the cash working capital requirements for its nuclear and regulated hydroelectric operations. This evidence outlines the methodology used by OPG to calculate lead/lag days. These lead/lag days were then applied to operations in other years to estimate cash working capital for those years.

OPG's lead/lag study was based on an analysis of transactions during 2006, which was the first full year of rate regulation for OPG and the most recent year for which financial information was available when the study was conducted. Except where noted, the analysis focused on transactions during the first six months of the year (January to June 2006), as it was felt that the timing for delivery of services and payment for most expenses would not change over the course of the year, and the additional effort of examining transactions throughout the year would not make a material difference to the results. For transactions that take place on a periodic basis, such as monthly, quarterly, or annually, OPG analyzed transactions for the entire year. The transactions that were included in this study were selected based on their dollar value, and sampling was utilized to balance accuracy of results with the cost to perform the study.

Materials, supplies, and inventory are excluded from cash working capital as they are included as separate components of total overall working capital.

OPG's regulated business earns three types of revenues: (1) generation sales, (2) Bruce Lease revenues, and (3) other revenues. Each of these revenue types has its own cash receipt cycle. Therefore, three individual cash working capital components are analyzed in order to more accurately reflect total working capital requirements. Each component of working capital consists of revenue lags for each type of revenue and specific expense leads that relate to each type of revenue. In addition to separate working capital calculations for the three revenue streams, OPG calculated cash working capital requirements for the GST separately and included it as a fourth component of cash working capital.

Results are summarized in Chart 1:

Chart 1

Summary of Results – 2006 Cash Working Capital ($M) Types

Line No.	Item	Regulated Hydroelectric	Nuclear	Total
		(a)	(b)	(c)
	Cash Working Capital:			
1	**Generation**	28.0	36.6	64.6
2	**Bruce**		1.5	1.5
3	**Other Revenue**		(0.4)	(0.4)
4	**GST**	(5.2)	(19.5)	(24.8)
5	**Total**	22.8	18.2	40.9

3.0 GENERATION SALES

The largest component of revenue is generation sales, which consists of electricity sales and the provision of ancillary services to the IESO. The revenue lag associated with generation sales and the associated expense leads are described in the sections below, and the detailed cash working capital calculations are provided in Chart 4 (for nuclear generation) and Chart 5 (for regulated hydroelectric generation).

3.1 Revenue Lag - Generation

As described in section 2.0, the revenue lag is the difference between the time OPG provides a service and the date when revenue in the form of cash is received. When a service is continuous, such as generation sales, the mid-point of the service period is considered the service date. For example, the service period for generation revenue earned on an hourly basis in the month of June would be June 15th. This approach is consistent with the approach used by other regulated companies in Ontario. OPG receives generation revenue from the IESO 14 business days after the end of the month, or approximately on the 20th of the following month.

OPG reviewed the IESO payment dates in 2006 and determined the number of lag days for each calendar month. This information was used to calculate a simple average for the year and resulted in a generation revenue lag of 35.7 days.

Note that some companies split revenue lags into different components such as service lag, billing lag, and collection lag. Because OPG provides service on a continuous basis and the services provided are essentially billed on a real time basis, only a collection lag is required.

3.2 Expense Lead - Generation

As described in section 2.0, the expense lead is the difference between the time a service is provided and the date that OPG pays for the service. Expense leads can vary by supplier and/or by type of expense. The following expenses are associated with generation revenue: fuel, OM&A, and other costs (e.g., property tax, capital taxes, etc.).

3.2.1 Expense Lead - Generation Fuel

Nuclear fuel expenses are excluded from cash working capital as they are reflected in fuel inventory working capital (as described in Ex. B1-T1-S1).

Regulated hydroelectric “fuel” expense consists of; gross revenue charges (“GRC”) which are paid mid-month to the Ontario Electricity Financial Corporation (“OEFC”) and to the Ministry of Finance, and payments to the St. Lawrence Seaway Management Corporation which are paid annually, at mid-year. OPG examined all GRC payments from January through June 2006 and the GRC expense lead was determined to be 1.1 days.

3.2.2 Expense Lead - OM&A Labour

The most significant OM&A expense is labour. Labour expense includes salaries, wages, and payroll burdens, including benefits. Payroll burdens include the costs of pensions, health, dental, life insurance benefits, statutory deductions for OPG’s share of Canada pension plan and employment insurance, other post employment benefits (“OPEB”), Workplace Safety and Insurance Board payments, fees to benefit carriers, and other costs. For additional details regarding payroll, benefits, burden rates, etc., see Ex. F3-T4-S1.

OPG has two types of payrolls for its employees:

- Biweekly - Most employees (approximately 90 percent) are paid on a bi-weekly basis. The pay period is for two weeks ending on a Wednesday and OPG makes the payment two weeks later on a Thursday.
- Monthly - The remaining ten percent of employees are paid on a monthly basis and these employees are paid mid month.

A sample of payments to employees, benefit carriers, Receiver General, pension funds, etc., were examined and the OM&A labour expense lead was determined to be 20.9 days. The individual expense lead days are detailed in Chart 2 below. This rate was used for both regulated hydroelectric and nuclear as the service period and payment dates are the same for both business units.

Chart 2

Payment Lead Days for Labour Expenses

Line No.	Item	Bi-weekly Days (a)	Monthly Days (b)	Burden Factor (c)	Bi-weekly Days (d)=(a)*(c)	Monthly Days (e)=(b)*(c)	Total Days
1	**Pay**				22.0		
2	**Burdens:**						
3	**Health/Dental/Life**	7.0	8.3	30.8%	2.2	2.6	
4	**Carrier fees**	14.6	36.6	1.5%	0.2	0.5	
5	**Pension**	(15.5)	6.5	19.9%	(3.1)	1.3	
6	**EI/CPP**	7.0	8.3	5.4%	0.4	0.4	
7	**OPEB**	8.0	30.0	7.3%	0.6	2.2	
8	**WSIB**	19.0	41.0	0.5%	0.1	0.2	
9	**Total Days**				22.4	7.2	
10	**Weighting**				90%	10%	
11	**Total**				**20.2**	**0.7**	**20.9**

In addition to the bi-weekly and monthly payrolls, OPG maintains a weekly payroll for trade staff that are part of Electrical Power Systems Construction Association ("EPSCA"). The difference between the time the service is provided and pay dates for the EPSCA payroll produces a labour expense lead of 12.0 days.

3.2.3 Expense Lead - OM&A Other Expenses

Other OM&A expenses include costs for consultants, augmented staff, outsourced services, and other costs such as utilities and travel. For a complete description of OM&A expenses see Exhibit F1 for regulated hydroelectric and Exhibit F2 for nuclear.

Listings of all payments made relating to large expenses (those with balances > $1M as at December 31, 2005) were generated. A sample of invoices was then selected from these listings and used to determine the expense lead (date service performed compared to date

OPG paid the supplier). The sample values comprise about ten percent to 100 percent of the total value of the populations of each cost category.

3.2.4 Expense Lead - OM&A Centrally Held Costs

In addition to the OM&A expenses incurred directly by each business unit, certain corporate costs are allocated to business units' OM&A (see Exhibit F3). While the specific expenses in this account vary from year to year, the most significant items (OPEB, pension, incentives, and the Gregorian adjustment) exist every year. The expenses in the 2006 study are as follows:

- OPEB/Pension: This OPEB/pension expense relates to past services and is in addition to current OPEB/pension cost discussed in section 3.2.2. The expense lead days for OPEB/pension was determined to be 17.1 days.
- Incentives: The corporate cash incentives are paid out annually in February for the previous year resulting in an expense lead of 240.0 days.
- Health Tax: The health tax is the amount that OPG is required to pay Power Workers' Union ("PWU") members. The 2006 liability is expected to be paid in February 2007 - expense lead of 240.0 days.
- Ontario Nuclear Funds Agreement ("ONFA") Fee: OPG is required to pay the Province of Ontario a fee for their guarantee to the Canadian Nuclear Safety Commission ("CNSC"). As required, OPG paid 11 months in advance - expense lead of (151.5) days.
- Ontario Electricity Financial Corporation Fee: Indemnity fee paid six months in advance - expense lead of (91.3) days. Beginning in 2007 this fee has been eliminated and is not included in future lead/lag calculations.
- Wellness (flu vaccine): OPG offers a flu vaccine to employees annually. This expense was paid on the service date (i.e., when the flu vaccine was administered), and therefore there is an expense lead of 0.0 days.
- Gregorian Adjustment: This adjustment is made annually to adjust the fiscal year to the calendar year (see Ex. F3-T1-S1 for details). Although OPG's fiscal year-end is December 31, financial systems are closed on the last Wednesday of December, which will not necessarily be December 31. Since most of the adjustment relates to labour costs, the OM&A labour expense lead of 20.9 days is used for the Gregorian adjustment.

Expense Lead - Other Costs

Other costs consist of property tax, capital tax, large corporations tax, income tax, and insurance expense.

- Property Tax: Property tax consists of: 1) proxy property tax paid mid-month to the OEFC and, 2) four (quarterly) payments to municipalities for the nuclear stations. This produces an expense lead of 1.9 days.
- Capital Tax: Proxy Ontario tax instalments made at month end to the OEFC, producing an expense lead of 15.1 days.
- Large Corporations Tax: The proxy federal tax on large corporations was eliminated as of January 1, 2006.
- Income Tax: Proxy Ontario and federal income taxes instalments made at month end to the OEFC, producing an expense lead of 15.1 days.
- Insurance: The January through June corporate insurance payments were reviewed and the expense lead was determined to be (103.7) days.

3.2.5 Expenses/Revenues Not Included

Consistent with regulatory practices in Ontario, corporate interest, return on equity and certain non-cash items were excluded from the lead/lag study. The non-cash items include future income taxes, accretion expense, and depreciation. OPG earns income on its segregated nuclear funds, which is excluded from the revenue lag analysis since it is a non-cash item. The following chart summarizes current industry practices with respect to the treatment of non-cash items:

Chart 3

Comparison of Other Costs Expense Leads

Line No.	Company	Interest	Depreciation	Cash Income Taxes	Future income Taxes	Return on Equity
		(a)	(b)	(c)	(d)	(e)
1	OPG	no	no	yes	no	no
2	Hydro One	no	no	yes	no	no
3	Union Gas	no	no	no	no	no
4	Enbridge	no	no	no	no	no
5	Alberta	yes	yes	yes	no	yes
6	Nova Scotia	no	no	yes	no	no

4.0 BRUCE LEASE

The second distinct component of cash working capital is for the Bruce Lease. This relates to the lease of the Bruce A and B Generating Stations, which are owned by OPG, and leased to Bruce Power L.P. ("Bruce Power").

4.1 Bruce Revenue Lag

OPG receives rent from Bruce Power as part of the Bruce Lease. The terms of the lease stipulate that Bruce Power pay OPG 30 days after the end of each month. OPG also earns revenue from Bruce Power through the provision of services such as engineering and waste management services to Bruce Power. These services are invoiced on the 20th day of the month following when services were delivered and are due net 30 days. Therefore, payment is received 50 days after the end of the service month. The combination of these two receipts for rent and services produces a revenue lag of 47.1 days.

4.2 Expense Lead

The expense lead days associated with the Bruce Lease were calculated on the same basis as that used for expenses associated with generation revenue. This is because the staff that provide services to Bruce Power are OPG employees that are paid on the same basis as other employees of the company, and other expenses are also incurred on the same basis. See section 3.2.2 for a discussion of labour and section 3.2.3 for a discussion of other expenses.

5.0 OTHER REVENUE

The third distinct component of cash working capital is for other revenue. Other revenue consists of isotope sales, heavy water sales, and engineering services.

5.1 Revenue Lag

Isotope and heavy water sales are invoiced on the date the service is performed, and payment is due within 30 days. Engineering services are invoiced on the 20th day of the following month and payment is due within 30 days. The combination of these two receipt types produces a revenue lag of 31.7 days.

5.2 Expense Lead

The expense lead days for costs associated with other revenue were determined as described in section 3.2.3 for other expenses. The primary cost associated with the other revenue is consultants.

6.0 GOODS AND SERVICES TAX

OPG pays GST to suppliers for the purchase of goods and services and remits GST that is collected on revenue to the Federal Government. The GST lag is the time between the GST payment date (to the supplier or to the Receiver General) and the date the Federal Government either refunds the GST to OPG or when OPG receives the input tax credit. OPG also collects GST from the IESO before making the remittance to the Receiver General. OPG collects significantly more GST than it pays to suppliers. A GST cash working capital amount is calculated for each of the three types of revenue. See Chart 8 for the relevant calculations.

6.1 Goods and Services Tax for Generation - Nuclear and Regulated Hydroelectric

- Collections: OPG remits GST after the IESO pays for the previous month's power. The remittance is made at the end of the next fiscal month. For example, if the IESO pays OPG GST for June's power production on July 17, OPG reports it on the July GST remittance, which is paid on September 5.
  - On average OPG retains the GST for a net period of 38.1 days.
  - The amount of regulated GST = total GST collected from the IESO x the regulated station's share of total generation sales.

- Payments: OPG generally pays GST on all purchases and then claims an input tax credit on its monthly GST remittance. For example, the goods received in June are included in the June GST remittance paid on July 28.
  - On average, OPG paid GST 30.0 days before receiving the GST credits.

6.2 GST for Bruce and Other Revenue

- Collections: OPG remits GST when services are invoiced (not when paid). For example, GST associated with Bruce rent for June is collected on July 31 and is remitted to the Receiver General on July 28, whereas GST associated with June engineering services is collected on August 20 but remitted on July 28.
  - On average, OPG remits the GST 5.9 days before the revenues have been received.

- Payments: OPG generally pays GST on all non-internal labour costs and then claims an input tax credit on its monthly GST remittance. The cash working capital requirement resulting from GST payments associated with Bruce and the Other Revenue is already included in the GST for generation via cost of goods sold.

6.3 Provincial Sales Tax ("PST")

OPG collects PST and then remits it to the provincial government. Since electricity sales are not subject to PST, any collection lag relating to the regulated facilities is insignificant or zero.

The subsequent sections of this document provide tables with cash working capital requirements associated with OPG's generation business, Bruce Lease, other revenue, and sales tax.

The 2006 nuclear generation cash working capital is calculated as shown in Chart 4 using the methodology described in section 2.0. Consistent with other jurisdictions, the cash working capital is calculated as: annual expenses x (revenue lag days - expense lead days)/365 days.

Chart 4

Cash Working Capital - Generation Nuclear

2006

Line No.	Expense Category	Expense Amount ($M) (a)	Revenue Lag Days (b)	Expense Lead Days (c)	Net Lead / Lag Days (d)=(b)-(c)	2006 CWC ($M) (e)=(a)*(d) /365
1	OM&A - Labour	1,106.7	35.7	20.9	14.8	44.9
2	OM&A - EPSCA Labour	14.6	35.7	12.0	23.7	1.0
3	**Sub total**	**1,121.3**			**38.5**	**45.9**
	OM&A - Other expenses:					
4	Consultants - Nuclear	219.1	35.7	71.3	(35.6)	(21.4)
5	Consultants - Corporate	15.7	35.7	40.4	(4.7)	(0.2)
6	Augmented staff - Nuclear	62.3	35.7	44.4	(8.7)	(1.5)
7	Augmented staff - Corporate	2.4	35.7	61.4	(25.7)	(0.2)
8	Outsourced Services	71.7	35.7	6.2	29.5	5.8
9	Operating Licenses	15.3	35.7	-	35.7	1.4
10	All other cash OM&A expenses	60.6	35.7	25.0	10.7	1.7
11	**Sub total**	**447.1**			**1.2**	**(14.4)**
	OM&A - Centrally Held Costs:					
12	OPEB/Pensions	158.0	35.7	17.1	18.6	8.1
13	Incentives	26.6	35.7	240.0	(204.3)	(14.9)
14	PWU EHT	3.0	35.7	240.0	(204.3)	(1.7)
15	ONFA fee	7.6	35.7	(151.5)	187.2	3.9
16	OEFC indemnity fee	1.2	35.7	(91.3)	127.0	0.4
17	Corporate wellness	1.6	35.7	-	35.7	0.2
18	Gregorian Adjustment	(15.6)	35.7	20.9	14.8	(0.6)
19	Insurance	17.2	35.7	(103.7)	139.4	6.6
20	**Sub total**	**199.6**			**114.1**	**2.0**
21	**Total OM&A**	**1,768.0**			**153.8**	**33.5**
22	Other Costs:					
23	Property Tax	25.6	35.7	1.9	33.8	2.4
24	Capital Tax (Ontario)	12.8	35.7	15.1	20.6	0.7
25	Income Taxes	-	35.7	15.1	20.6	-
26	**Sub total**	**38.4**			**75.0**	**3.1**
27	**Total Nuclear Cash Working Capital**	**1,806.4**			**228.8**	**36.6**

The 2006 regulated hydroelectric generation cash working capital is calculated as shown in Chart 5 using the methodology described in section 2.0.

Chart 5

Cash Working Capital - Generation Regulated Hydroelectric

2006

Line No.	**Expense Category**	**Expense Amount ($M)** (a)	**Revenue Lag Days** (b)	**Expense Lead Days** (c)	**Net Lead / Lag Days** (d)=(b)-(c)	**2006 CWC ($M)** (e)=(a)*(d) /365
1	GRC	245.4	35.7	(1.1)	36.8	24.7
2	OM&A - Labour	51.1	35.7	20.9	14.8	2.1
3	OM&A - Other expenses:					
4	Consultants - Hydroelectric	8.1	35.7	66.0	(30.3)	(0.7)
5	Consultants - Corporate	1.5	35.7	40.4	(4.7)	-
6	Augmented staff - Corporate	0.2	35.7	61.4	(25.7)	-
7	Outsourced Services	7.4	35.7	6.2	29.5	0.6
8	All other cash OM&A expenses	6.0	35.7	17.0	18.7	0.3
9	**Sub Total**	**23.2**			**(12.5)**	**0.2**
	OM&A - Centrally Held Costs:					
10	OPEB/Pensions	7.7	35.7	17.1	18.6	0.4
11	Incentives	2.1	35.7	240.0	(204.3)	(1.1)
12	PWU EHT	0.3	35.7	240.0	(204.3)	(0.1)
13	OEFC indemnity fee	0.1	35.7	(91.3)	127.0	-
14	Corporate wellness	0.1	35.7	-	35.7	-
15	Gregorian Adjustment	(1.3)	35.7	20.9	14.8	(0.1)
16	Insurance	1.6	35.7	(103.7)	139.4	0.6
17	**Sub Total**	**10.6**			**(73.1)**	**(0.3)**
18	**Total OM&A**	**84.9**			**(70.8)**	**1.9**
	Other Costs					
19	Property Tax	0.1	35.7	1.9	33.8	-
20	Capital Tax (Ontario)	18.3	35.7	15.1	20.6	1.0
21	Income Taxes	4.8	35.7	15.1	20.6	0.3
22	**Sub Total**	**23.2**			**75.0**	**1.3**
23	**Total Hydro Cash Working Capital**	**353.5**			**41.0**	**28.0**

The 2006 Bruce cash working capital is calculated as shown in Chart 6 using the methodology described in section 2.0.

Chart 6
Cash Working Capital – Bruce
2006

Line No.	Expense Category	Expense Amount ($M)	Revenue Lag Days	Expense Lead Days	Net Lead / Lag Days	2006 CWC ($M)
		(a)	(b)	(c)	(d)	(e)
1	**Labour**	15.3	47.1	20.9	26.2	1.1
2	**Consultants**	3.2	47.1	71.3	(24.2)	(0.2)
3	**Augmented staff**	5.6	47.1	44.4	2.7	-
4	**Property tax**	5.9	47.1	1.9	45.2	0.5
5	**Capital tax**	1.1	47.1	15.1	32.0	0.1
6	**Total**					**1.5**

The 2006 Other Revenue cash working capital is calculated as shown in Chart 7 using the methodology described in section 2.0. The cost associated with other revenue comprise of cobalt, tritium and heavy water consultants and other engineering amount.

Chart 7
Cash Working Capital - Other Revenue
2006

Line No.	Category	Amount ($M)	Revenue Lag Days	Expense Lead Days	Net lead Lag Days	2006 CWC ($M)
1	**Consultants**	3.1	31.7	71.3	(39.6)	(0.4)
2	**Total**					**(0.4)**

The 2006 GST cash working capital is calculated as shown in Chart 8 using the methodology described in section 6.0.

Chart 8
Cash Working Capital – GST
2006

Line No.	Expense Type	Regulated Hydroelectric ($M)	Nuclear ($M)	Total ($M)
		(a)	(b)	(c)
1	**Generation Revenue**	(5.4)	(22.9)	(28.4)
2	**Bruce & Other Revenue**	N/A	.3	.3
3	**Payments - Regulated**	.2	3.1	3.3
4	**Total**	(5.2)	(19.5)	(24.8)

The 2007 nuclear generation cash working capital is calculated as $33.2M as shown in Chart 9 using the methodology described in section 2.0. Including the $1.5M Bruce, -$0.4 other revenue and -$18.3M GST results in 2007 Nuclear cash working capital of $16.0M.

Chart 9

Cash Working Capital – Generation Nuclear

2007

Line No.	**Expense Category**	**Expense Amount ($M)** (a)	**Revenue Lag Days** (b)	**Expense Lead Days** (c)	**Net Lead/ Lag Days** (d)=(b)-(c)	**2007 CWC ($M)** (e)=(a)*(d) /365
1	OM&A - Labour	1,186.9	35.7	20.9	14.8	48.1
2	OM&A - EPSCA Labour	11.5	35.7	12.0	23.7	0.7
3	**Sub total**	**1,198.4**				**48.8**
	OM&A - Other expenses:					
4	Consultants - Nuclear	235.8	35.7	71.3	(35.6)	(23.0)
5	Consultants - Corporate	12.0	35.7	40.4	(4.7)	1.2
6	Augmented staff - Nuclear	58.3	35.7	44.4	(8.7)	(1.4)
7	Augmented staff - Corporate	5.4	35.7	61.4	(25.7)	(0.4)
8	Outsourced Services	65.9	35.7	6.2	29.5	5.3
9	Operating Licenses	16.9	35.7	2.8	32.9	1.5
10	Computer maintenance	5.2	35.7	30.0	5.7	0.1
11	Computer sofware licences	2.1	35.7	(23.1)	58.8	0.3
12	All other cash OM&A expense	46.8	35.7	34.9	0.8	0.1
13	**Sub total**	**448.4**				**(16.3)**
	OM&A - Centrally Held Costs:					
14	OPEB/Pensions	134.8	35.7	17.1	18.6	6.9
15	Incentives	29.0	35.7	240.0	(204.3)	(16.1)
16	PWU EHT	3.3	35.7	240.0	(204.3)	(1.8)
17	ONFA fee	7.5	35.7	(151.5)	187.2	3.8
18	OEFC indemnity fee	0.0	35.7	(91.3)	127.0	0.0
19	Corporate wellness	0.0	35.7	0	35.7	0.0
20	Gregorian Adjustment	3.1	35.7	20.9	14.8	0.1
21	Insurance	15.0	35.7	(103.7)	139.4	5.7
22	**Sub total**	**192.7**				**(1.4)**
23	Total OM&A	**1,839.5**				**31.1**
24	Other Costs:					
25	Property Tax	17.4	35.7	1.9	33.8	1.6
26	Capital Tax (Ontario)	9.0	35.7	15.1	20.6	0.5
27	Income Taxes	0.0	35.7	15.1	20.6	0.0
28	**Sub total**	**26.4**				**2.1**
29	**Total Nuclear Generation Cash Working Capital**	**1,865.9**				**33.2**

The 2007 regulated hydroelectric generation cash working capital is calculated as $26.6M as shown in Chart 10 using the methodology described in section 2.0. Including the 2007 GST component of the cash working capital (-$4.8M) results in total 2007 Regulated Hydroelectric cash working capital of $21.8M.

Chart 10

Cash Working Capital – Generation Regulated Hydroelectric

2007

Line No.	Expense Category	Expense Amount ($M) (a)	Revenue Lag Days (b)	Expense Lead Days (c)	Net Lead/ Lag Days (d)=(b)-(c)	2007 CWC ($M) (e)=(a)*(d) /365
1	GRC	244	35.7	-1.1	36.8	24.6
2	OM&A - Labour	53.2	35.7	20.9	14.8	2.1
	OM&A - Other expenses:					
3	Consultants - Hydroelectric	12	35.7	66	-30.3	-1
4	Consultants - Corporate	2.7	35.7	40.4	-4.7	0
5	Augmented staff - Corporate	0.5	35.7	61.4	-25.7	0
6	Outsourced Services	6.5	35.7	6.2	29.5	0.5
7	All other cash OM&A expenses	5.6	35.7	30	5.7	0.1
8	**Sub total**	**80.5**				**1.7**
	OM&A - Centrally Held Costs:					
9	OPEB/Pensions	6.1	35.7	17.1	18.6	0.3
10	Incentives	2.1	35.7	240	-204.3	-1.1
11	PWU EHT	0.3	35.7	240	-204.3	-0.1
12	OEFC indemnity fee	0	35.7	-91.3	127	0
13	Corporate wellness	0	35.7	0	35.7	0
14	Gregorian Adjustment	0.3	35.7	20.9	14.8	0
15	Insurance	1.5	35.7	-103.7	139.4	0.6
16	**Sub total**	**10.3**				**-0.3**
17	Total OM&A	**90.8**				**1.4**
18	Other Costs:					
19	Property Tax	0.2	35.7	1.9	33.8	0
20	Capital Tax (Ontario)	11.2	35.7	15.1	20.6	0.6
21	Income Taxes	0	35.7	15.1	20.6	0
22	**Sub total**	**11.4**				**0.6**
23	**Total Regulated Hydroelectric Generation Cash Working Capital**	**346.2**				**26.6**