Numbers may not add due to rounding.

Table 1

Operating Costs Summary - Regulated Hydroelectric ($M)

Line No.	Cost Item	2005 Actual	2006 Actual	2007 Actual	2008 Plan	2009 Plan
		(a)	(b)	(c)	(d)	(e)
	OM&A:					
1	**Base OM&A**	47.3	47.8	78.6	56.1	57.9
2	**Project OM&A**	6.6	9.4	7.0	12.9	12.1
3	**Allocation of Corporate Costs**	27.6	38.6	38.0	47.5	46.8
4	**Asset Service Fee**	1.2	2.5	2.3	2.5	2.1
5	**Total OM&A**	82.7	98.2	125.9	119.0	119.0
6	**Gross Revenue Charge**	251.2	245.5	242.0	228.2	244.1
	Other Operating Cost Items:					
7	**Depreciation**	67.1	66.2	68.5	62.7	63.2
8	**Income Tax**	7.0	0.0	0.0	0.0	0.0
9	**Capital Tax**	12.0	11.9	8.8	8.7	8.7
10	**Property Tax**	0.0	0.0	0.0	0.0	0.0
11	**Total Operating Costs**	419.9	421.7	445.2	418.6	435.0

BASE OM&A - REGULATED HYDROELECTRIC

1.0 PURPOSE

This section provides a description of the base OM&A costs for the regulated hydroelectric facilities. Base OM&A costs represent the resources required to fund routine day-to-day operations and maintenance-related activities in support of the production of electricity from OPG's regulated hydroelectric generating units, along with associated administration and Hydroelectric Central Support Group costs.

2.0 REGULATED HYDROELECTRIC BASE OM&A

The regulated hydroelectric OM&A budget is established through the annual business planning process (see Ex. A2-T2-S1). Base OM&A expenditures for OPG's regulated hydroelectric facilities are attributed on a work program basis, consistent with how costs are incurred. Base OM&A budgets are attributed to each of the plant groups based on the following work programs: operations, maintenance, and administration support.

Operations costs include all direct costs to operate the generating facilities for the purpose of generating electricity or producing other related products (e.g., ancillary services required by the electricity system). These costs include costs for control room operators, water management activities including dam operations, waterway patrol, water flow monitoring/snow surveys, ice breaking, and log operations. These costs also include OPG's portion of all joint works operations costs, shared with the New York Power Authority ("NYPA") pursuant to Joint Works Agreements that are further described in Ex. A1-T4-S2.

Maintenance includes all costs associated with the direct maintenance of the facilities to ensure their normal, safe, and environmentally sound operation. Base maintenance activities are programmed by the type of work: preventive (to reduce the need for corrective maintenance), corrective (i.e., to address breakdowns), and emergent (condition based maintenance, resulting from inspections). Work is also categorized by the following objectives: regulatory (e.g., health and safety, dam safety, and environment) and contractual obligations (e.g., joint works), and maintain condition/sustaining (e.g., production, asset protection, and non-production). Maintenance plans are established in a maintenance management system. The plans are used to prioritize work execution (i.e., 100 percent of regulatory work must be completed, etc.) and used to support budget requirements. As indicated in Ex. A1-T4-S2, investment in hydroelectric facilities (including base OM&A funding) is determined using a structured portfolio approach, and streamlined reliability-centred maintenance principles. The maintenance work program also includes OPG's portion of the maintenance costs for joint works, which are shared with NYPA.

Administration costs within the plant groups include all common support costs incurred for the production facilities that are not directly related to the production of electricity. This typically includes the following functional areas: Asset Management and Technical Support Services, Project Management, Human Resources and other Support Services, Finance, and the Plant Manager's Office.

Excluding the extraordinary expense related to a past grievance settlement with a First Nation, base OM&A expenditures for the regulated hydroelectric facilities are expected to remain relatively steady over the period from 2005 to 2009, with the exception of a 9 percent increase in 2008. As further discussed in Ex. F1-T2-S2 (Comparison of Regulated Hydroelectric Base OM&A), the 2008 increase is a result of the anticipated hiring of additional staff for both the Hydroelectric Central Support Groups and the regulated facilities, the timing of certain projects and initiatives, and other unforeseen events. In addition, all years are affected by increases in labour rates (per collective agreements) and changes in payroll burdens as discussed in Ex. F3-T4-S1 (Compensation and Benefits). Exhibit F1-T2-S1 Tables 1 and 2 provide a summary of base OM&A over the 2005 - 2009 period.

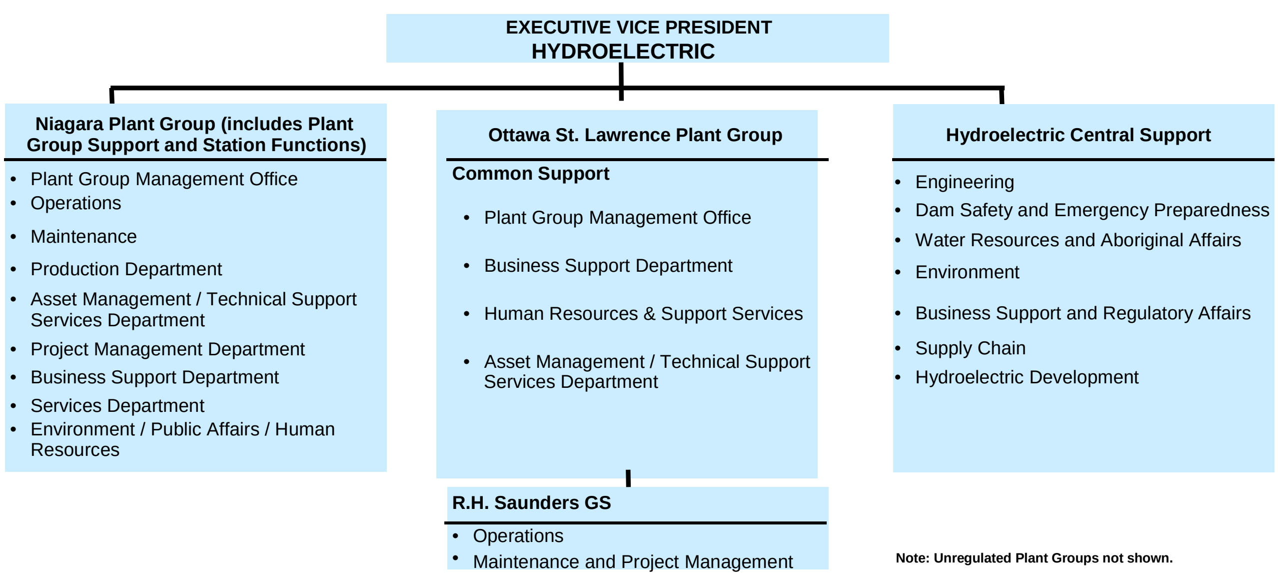
Detailed descriptions of the OM&A costs for the Niagara Plant Group and R.H. Saunders are provided below in sections 2.1, 2.2, and 2.3. Section 2.3 also describes the Ottawa - St. Lawrence Plant Group common support costs and the methodology for allocating these to R.H. Saunders. This level of allocation exists only for R.H. Saunders, as a result of it being the only regulated facility within the Ottawa - St. Lawrence Plant Group. Since the Niagara

Plant Group is comprised entirely of regulated facilities, no such allocation is necessary for Niagara.

In addition to those costs incurred within the plant groups, certain other costs incurred to support the regulated hydroelectric facilities are provided on a centralized basis. Hydroelectric Central Support Groups costs include functions and activities not provided within the plant groups such as specialized Engineering Services, Business Support and Regulatory Affairs, Water Resources and Aboriginal Affairs, Dam Safety and Emergency Preparedness, Environment, Hydroelectric Development, and Supply Chain. Section 2.4 includes a description of these Hydroelectric Central Support Groups and the methodology for allocating their costs to the Niagara Plant Group and R.H. Saunders.

The allocation of corporate support costs to the regulated hydroelectric facilities is detailed in Ex. F3-T1-S1.

Hydroelectric Organization



2.1 Niagara Plant Group Costs

The following Niagara Plant Group departments operate under the direction, leadership, management, and administrative support of the Niagara Plant Group management office:

- Human Resources Department
- Business Support Department
- Production Department
- Asset Management and Technical Support Serviced Department
- Project Management Department
- Services Department

2.1.1 <u>Human Resources Department</u>

The Human Resources Department provides plant group support in the areas of employee services, labour relations, vacancy management, health and safety, disability management, compensation, and pay services. The staff associated with these functions form part of OPG's Corporate Human Resources Department and the costs associated with supporting the Niagara Plant Group are allocated through the cost allocation process described in Ex. F3-T1-S1. In addition, also reporting to the Manager of the Human Resources Department are seven full time staff directly funded by the Niagara Plant Group providing support for public affairs, stakeholder relations, community relations services, and environmental services functions within the Niagara Plant Group. Their costs are budgeted, collected, and reported in the Niagara Plant Group administrative costs rather than allocated through the cost allocation process described in Ex. F3-T1-S1.

2.1.2 <u>Business Support Department</u>

The Business Support Department, managed by the Site Controller, provides financial management and material management support to the Niagara Plant Group. This department is responsible for coordinating the budgeting process, performing financial assessments on all business cases related to the Niagara Plant Group and its facilities, and monitoring for adherence to corporate policies with respect to business expenses, procurement, and internal control. The department also provides general services in areas such as administrative support, accounts receivable, accounts payable and material management. The Business Support Department prepares and reports on all financial performance results for projects, departments, stations and the plant group as a whole, including targets, current expenditures, forecasting and variance analysis. The staff associated with these functions are part of OPG's Corporate Finance Group and the costs related to supporting the Niagara Plant Group are allocated through the cost allocation process described in Ex. F3-T1-S1. In addition, also reporting to the Site Controller are three full time staff directly funded by the Niagara Plant Group providing support for material management by operating the plant group's stores function, including purchasing material and performing all shipping and receiving functions. Their costs are part of the plant groups staff complement, and, as such, are included as part of the plant group direct costs.

2.1.3 <u>Production Department</u>

The Production Department's function is to operate and maintain the regulated generation assets to produce electrical capacity and energy and energy-related products and services at targeted performance levels. The scope of required work includes: operation and maintenance of the Sir Adam Beck I, Sir Adam Beck II, and Sir Adam Beck Pump Generating Station, and DeCew Falls I, Decew Falls II and all associated water conveyance structures in accordance with approved plans and applicable policies, contracts, and legal requirements. The department is managed by a Production Manager. All costs associated with the Production Department are budgeted, collected and reported in the Niagara Plant Group OM&A budget. There are 111 staff supporting the functional requirements of the Production Department.

2.1.4 <u>Asset Management and Technical Support Services Department</u>

The Asset Management and Technical Support Services Department provides specialist expertise in the area of business strategy, planning, programming, asset portfolio management, decision support, business effectiveness, due diligence, and engineering governance. The department also assists in ensuring the Niagara Plant Group meets its targets for electrical capacity and energy, including energy-related products and services, as well as providing staff specialist expertise in the area of generation asset management consistent with Hydroelectric strategies, policies and programs. The department is managed by the Asset Management and Technical Services Manager and has two sub-departments, the Technical Services Department and the System Support Department. The Technical Services Department provides electrical, mechanical and civil engineering services, as well as technical services (separate and distinct from the services provided by the central Engineering Services group that will be discussed below in section 2.3), dam safety management, management systems coordination (including registration for International Organization for Standardization), compliance with market rules, as well as providing liaison services between the plant group and Hydro Central Engineering Services. The System Support Department provides drafting, clerical, administrative, records management, and information technology processes and services to the plant group. All costs associated with the department are budgeted, collected and reported in the Niagara Plant Group OM&A and capital budgets. There are 27 staff supporting the functions of the Asset Management and Technical Support Services Department.

2.1.5 Project Management Department

The Project Management Department is responsible for delivering projects at targeted levels of performance and results. The scope of the assigned work includes project management, pre-project planning, and concept studies in support of the Asset Manager. The group also supports labour assignment processes. The department is responsible for the execution of all Niagara Plant Group controlled capital and non-standard projects and includes a Site Project Group, Engineering Management Group, and a Rehabilitation Crew. There are 25 staff executing the responsibilities of the Project Management Department and the costs associated with their services are budgeted, collected, and reported against the Niagara Plant Group capital and OM&A budgets. In the event there should be a lower amount of project work, labour costs not associated with project work are recorded as base OM&A.

2.1.6 Services Department

The Services Department is responsible for an annual work program which supports the needs of the Niagara Plant Group that are not part of the direct production operations and maintenance. This includes items such as outside maintenance, snow removal, ice breaker operations, and property maintenance related to generating facilities. The department is also responsible for the joint works program as agreed with New York Power Authority, which includes joint works operations and the International Control Dam, as well as the cost recoveries from New York Power Authority under the Joint Works Agreement. The department is managed by the Services Manager and has three sections: River Control Operations (i.e., Niagara International Control Works), Field Services, and Shop Services. These are described in the following paragraphs.

The River Control Operations section is responsible for managing the Niagara River water flows through the operation of the Niagara International Control Works, in accordance with the International Boundary Waters Treaty, described at Ex. A1-T4-S2. The costs associated with this function are budgeted, collected, and reported against the Niagara Plant Group operations budget and shared with New York Power Authority pursuant to the Joint Works Agreement, as described in Ex. A1-T4-S2. There are ten staff associated with the River Control Operations section.

The Field Services section performs site services work, such as general transport and work equipment management, river control maintenance under the joint works program, operation and maintenance of the Niagara Queen ice breaker, management and performance of regulatory maintenance on such systems as heating, ventilation and air conditioning, elevators, fire systems, and public safety systems. There are 27 staff associated with the Field Services section.

The Shop Services section provides specialized machine shop services and welding shop services to the Niagara Plant Group. A small amount of work is done for other OPG non-regulated facilities. The cost of such work is charged directly to the non-regulated facility at incurred cost. There are 19 staff associated with the Shop Services section.

All costs associated with the joint works program are budgeted, collected, and reported in accordance with the Joint Works Agreements as described in Ex. A1-T4-S2. All costs associated with the Niagara Plant Group regulated facilities and structures are budgeted, collected and reported in the Niagara Plant Group OM&A budget. There are a total of 56 staff carrying out the responsibilities of the Services Department.

2.2 R.H. Saunders Generating Station Costs

The R.H. Saunders Production Department manages the station to produce electrical capacity and energy and energy-related products and services at targeted performance levels. The scope of required work includes: operation and maintenance of R.H. Saunders Generating Station in accordance with approved plans and applicable policies, contracts, and legal requirements. Almost all of the OM&A budget for R.H. Saunders is comprised of maintenance and operations expenses. Starting in 2008, the R.H. Saunders Production Department assumed responsibility for project execution. The new Production/Project Department is responsible for managing their assigned resources and assets. All other services are provided to R.H. Saunders from either the Ottawa - St. Lawrence Plant Group or by Hydroelectric Central Support Groups, both of which are discussed in subsequent sections of this exhibit. The R.H. Saunders Production/Project Department staff complement has remained relatively stable around the planned number of 68 staff. Similarly, the OM&A budget has also remained relatively stable.

Operations expenses include control room operations, which have a total staff of 15 and various water management activities such as dam operations, waterway patrol, water flow monitoring, and ice management, and all joint works operations expenses shared with NYPA.

Maintenance plans have been developed for R.H. Saunders based on streamlined reliability-centred maintenance practices (see Ex. A1-T4-S2). Base maintenance activities are categorized by these objectives: regulatory, maintain condition, contractual (i.e., New York Power Authority joint works), dam safety, environmental, policy, and health and safety. There are 53 staff that support the maintenance programs and project execution as of 2008 including the production/project manager, two first line managers for the electrical and mechanical trades and engineering support, and two clerical and three dedicated to supply chain activities.

2.3 Ottawa - St. Lawrence Plant Group Common Costs

This section describes the common functions in the Ottawa - St. Lawrence Plant Group central departments and explains the methodology for allocating a portion of the costs for these functions to R.H. Saunders.

There are four departments in the Ottawa - St. Lawrence Plant Group that provide common support services to R.H. Saunders. Effective 2008 the Project Management Department was amalgamated with the Production Departments in the Plant Group. This has resulted in the project management resources becoming a direct base OM&A expense, replacing the allocation.

The Plant Group Management Department leads, manages, and supports the provision of common services. The Human Resource and Support Services Department provides a range of common environmental services and expertise, and supplies public affairs, stakeholder relations, and community relations services. The Business Support Department provides general administrative support, fleet management administration, accounts receivables and payables, procurement support for project execution, and the administration of project management enterprise systems. The total cost of these three groups is allocated to R.H. Saunders based on its proportion of the total budgeted base OM&A within the Ottawa - St. Lawrence Plant Group. Base OM&A is generally linked to the size of the station and its generation and therefore provides a reasonable basis for allocating common services costs.

The Asset Management and Technical Support Services Department provides specialist expertise in the area of business strategy, planning, programming, asset portfolio management, decision support, business effectiveness, due diligence, and engineering governance. The department also provides electrical, mechanical, and civil engineering services (separate and distinct from the more specialized services provided by the Central Engineering Services Group discussed below), information and records management services, and is responsible for business programming and performance reporting functions. R.H. Saunders is already resourced to provide the vast majority of asset management and engineering support so the level of support provided from Asset Management and Technical Support Services Department is fairly modest. In addition, R.H. Saunders is resourced to provide all of its own information and records management functions. As such, based on management's time estimates, 15 percent of the asset management and engineering services costs and none of the information and records management function costs from this department are allocated to R.H. Saunders.

The Project Management Department is responsible for the execution of all capital and non-standard projects and includes two project crews at Chats Falls and Otto Holden Generating Stations, both within Ottawa - St. Lawrence Plant Group. Only costs associated with the project manager and the project engineers are considered common support costs and are allocated based on the relative percentage of budgeted Base OM&A. The rationale for this methodology is similar to that discussed above. The remaining project management expenditures are attributed to the non-regulated hydroelectric stations in the Plant Group as they are assigned to specific non-regulated stations. As discussed in sections 2.2 and 2.3, the Project Management Department has been disbanded effective 2008 as a result of restructuring. The project execution accountabilities and resources to support investment management at Saunders have been amalgamated with the previous R.H. Saunders Production Department. This eliminates the minor allocation associated with this common support department and replaces it with a reduced direct base OM&A expense. The Project Management Department is not shown in the organizational chart included earlier in this exhibit.

2.4 Hydroelectric Central Support Groups Descriptions and Cost Allocation Methodology

As mentioned previously, the Hydroelectric Central Support Groups provide common or specialized services to all of OPG's hydroelectric plant groups, both regulated and non-regulated. This section provides a brief description of the functions and key activities of each central support group and describes the methodology used to allocate costs to the regulated and non-regulated facilities.

The Hydroelectric business unit consists of the office of the Executive Vice President ("EVP"), five plant groups, and six support groups that provide common or specialized services to the plants and provide oversight for the EVP, as well as for the Hydroelectric Development Group which studies and undertakes new hydroelectric development projects.

The following Hydroelectric Central Support Groups' costs are allocated in part to the regulated facilities:

- Engineering
- Dam Safety and Emergency Preparedness
- Water Resources and Aboriginal Affairs
- Business Support and Regulatory Affairs
- Environment
- Hydroelectric Development
- Supply Chain
- Executive Vice President's Office

A brief description of the accountabilities of each central support group and allocation methodology is provided below.

2.4.1 Engineering Services

The Engineering Services Division provides specialized civil, mechanical, and electrical engineering support to plant groups. It includes three main departments - Civil, Mechanical, and Electrical Engineering.

The Civil Engineering Department provides expertise in the following areas:

- Structural
- Geotechnical

- Instrumentation
- Hydrotechnical (hydraulics and hydrology)
- Specialized inspection and maintenance support
- Owner's engineer and advice for projects
- Dam safety engineering
- Dam performance monitoring, instrumentation, assessment, data management, and reporting
- Dam safety emergency response support

The Mechanical Engineering Department provides expertise in the following areas:

- Hydraulic turbines
- Sluice and head gates
- Cranes
- Piping
- Non-destructive examinations

The Electrical Engineering department provides expertise in the following areas:

- Hydro generators
- Power transformers
- Breakers
- Rotating exciters
- Grounding
- Protections
- Static exciters / voltage regulators
- Metering
- Governor controls
- Market compliance

The Engineering Division has 47 staff, consisting of engineers, technicians, and clerks.

2.4.2 Dam Safety and Emergency Preparedness

The Dam Safety and Emergency Preparedness Group, which has four staff, provides oversight, guidance, and advice for OPG's Dam Safety and Hydro's Emergency Preparedness Program at all of OPG's dams. Key elements of the program include oversight of dam-related comprehensive inspections, assessments, design reviews, monitoring, safety upgrades, and personnel training as follows:

- Develop and maintain a managed system for the dam safety, waterways public safety and emergency preparedness programs, including establishing program objectives, scope, accountabilities, assessment and reporting.
- Develop and maintain the hydroelectric standards for emergency preparedness, provide oversight on tests, drills and exercises, and coordinate participation with corporate emergency preparedness as required.
- Develop and maintain dam safety governance documents and technical standards that are aligned with regulations, corporate policy and industry best practices.
- Assess compliance with regulations, corporate dam safety policy and programs for waterways public safety and emergency preparedness, provide advice to meet/maintain compliance.
- Report annually to the OPG Board of Directors on the results of the dam and waterways public safety program and regular updates on emerging dam and public safety issues.

2.4.3 Water Resources and Aboriginal Affairs

The Water Resources and Aboriginal Affairs Group, which has 12 staff, provides business level expertise and services for the management of water resources and Aboriginal relations including:

- Water management policy and planning (negotiating, establishing, and maintaining relationships with regulatory agencies and boards).
- Energy forecasting.
- Administration of agreements (e.g., water power leases, licenses of occupation, crown leases, Parks Canada, Quebec, and water conveyance).
- Day-ahead coordination of hydroelectric resources.

- Integration of capacity and energy forecasts submitted by plant groups.
- Aboriginal relations.
- Provide expertise and lead OPG in past grievance negotiations with First Nations and administer payments associated with settled past grievances.

2.4.4 Business Support and Regulatory Affairs

The Business Support and Regulatory Affairs Division, which has nine staff, provides business related oversight/support for the EVP-Hydroelectric and support to the plant groups in the following areas:

- Business planning and budgeting (five year time horizon).
- Performance reporting.
- Production support and integration (e.g., Maintenance Module for Streamlined Reliability-Centred Maintenance).
- Benchmarking.
- Market operations support.
- Asset management oversight in areas such as project prioritization and life cycle planning.
- Annual incentive plan development and monitoring for Hydroelectric management.
- Interface with corporate support groups as required.
- Regulatory support for the preparation of Hydroelectric portions of OPG's rate filing.
- Centralized document management support for the hydroelectric business.

2.4.5 Environment

The Environment Division which has seven staff (environmental specialists), provides environmental oversight for the EVP-Hydroelectric. In addition, this division supports the business by providing expertise and services in a wide range of environmental subject areas including:

- ISO 14001 Environmental Management Systems.
- Legislative monitoring and compliance.
- Aquatic and terrestrial biology.

- Environmental assessments.
- Environmental approvals.
- Land, water, and waste management
- Environmental risk management

2.4.6 Hydroelectric Development

Hydroelectric Development's role is to expand and redevelop OPG's existing sites as well as to develop new capacity in new locations where feasible. This group identifies, studies, plans, and oversees the design and execution of hydroelectric redevelopment and new development projects (e.g., Niagara Tunnel project). The group includes the Vice President of Hydroelectric Development, project managers, project engineers, and project specialists. The work program is primarily capital in nature. However, before a project is approved and released, costs incurred for concept and preliminary engineering studies are classified as OM&A expenses. There are also general OM&A expenses incurred by this group that must be allocated to the Plant Groups. These include costs to maintain a Hydroelectric Developments database, develop and provide information to the Ontario Power Authority's Integrated Power System Plan process, and interface with the various government ministries (Ministry of Natural Resources, Ministry of the Environment, and Ministry of Finance) with respect to hydroelectric developments.

2.4.7 Hydroelectric Supply Chain

The Supply Chain Division, which has 11 staff, provides procurement support activities and materials management activities for the hydroelectric plant groups and Hydroelectric Development.

2.4.8 Executive Vice President's Office

The costs budgeted in this category include various expenses incurred by the EVP-Hydroelectric, including travel, administrative support and membership costs in various hydroelectric associations, such as the International Hydropower Association and Canadian Hydropower Association. The EVP budget also includes a small contingency for any unforeseen work that may emerge in any given year and cannot be deferred to a subsequent year (e.g., safety work and environmental work). This is held at the EVP level and is only used if the unforeseen project cannot be funded through the normal OM&A base or project budgets for the year. The total amount kept for contingency is less than 0.5 percent of the total Hydroelectric OM&A budget (i.e., less than $1M per year which is allocated for the purposes of this application to each plant group using the allocation methodology for the EVP costs indicated below).

2.4.9 Allocation Methodology for Hydroelectric Central Support Groups Costs

The method for allocating Hydroelectric Central Support Group Costs has evolved since 2005. The methodology was reviewed by R.J. Rudden Associates in 2006 as part of an OPG-wide review (see Ex. F4-T1-S1) and its recommendations were incorporated for 2006 through 2009, where practical. R.J. Rudden also reviewed the allocation of Ottawa - St. Lawrence common costs to R.H. Saunders Generating Station and its recommendations were adopted (see allocation methodology section 2.3 above).

In 2005, the Hydroelectric Business Unit and Fossil Business Unit were part of the same organization known as Electricity Production. The Electricity Production central support organization consisted of an executive responsible for the Electricity Production business, and a number of Electricity Production central support groups. The costs for these central support groups were allocated using a full time equivalent (staff numbers) approach. The number of full time equivalent staff in a particular hydroelectric plant group or fossil plant was divided by the total staff in the plant groups plus fossil plants to determine the amount of central support costs to be allocated to the particular plant group. The only exceptions were the Water Resources and Dam Safety and Emergency Preparedness Groups which were specific to Hydroelectric and existed as separate groups under the old Electricity Production structure. These two groups were allocated using the staff in a particular plant group divided by the total staff in the plant groups.

After 2005, the Hydroelectric and Fossil organizations were separated (see Ex. A1-T4-S2), and the allocation approach changed based on the corporate-wide review and recommendations made by R.J. Rudden Associates. R.J. Rudden Associates recommended that as a general principle, direct assignment (i.e., time estimates or management estimates of full time equivalents dedicated to a particular group) should be used where practical and efficient, and base OM&A costs should be used to allocate all other central support group costs that cannot be directly assigned.

With respect to Hydroelectric, R.J. Rudden Associates recommended that plant group base OM&A costs should be used to allocate costs that cannot be directly assigned or where it is inefficient to perform direct assignment. This includes costs for the office of the EVP-Hydroelectric, Business Support and Regulatory Affairs, Water Resources and Aboriginal Affairs, Dam Safety and Emergency Preparedness and Environment. As such, the base OM&A approach is used to allocate planned and actual costs for each of these central support groups (after 2005).

2.4.10 Direct Assignment

A direct assignment type approach was used for Engineering Services, Hydroelectric Developments (except VP Office costs), and Supply Chain.

2.4.11 Engineering Services

The costs for Engineering Services are allocated as follows: estimates of engineering cost allocations for each year in the planning cycle are developed during the business planning/budgeting process. Each department in Engineering Services develops time estimates for each of the plant groups (or plants in the case of R.H. Saunders) based on a high level review of each Plant Group's future work plans/projects and anticipated support requirements, as well as a review of previous year's historical engineering support costs for each plant group. Total engineering hours are then allocated to each plant group based on these reviews. The total engineering budget for the year is allocated using the ratio of estimated hours for each plant group divided by the total engineering hours. The 2008 and 2009 planned engineering allocations to each plant group are achieved by applying the 2007 ratios (i.e., the ratios developed as part of the 2007 - 2011 business planning process) to forecast cost in 2008 and 2009, respectively.

2.4.12 Hydroelectric Development

Since the projects undertaken by the Hydroelectric Development group are generally known in advance, costs are assigned based on management's estimates of planned OM&A project expenditures. If a project is in pre-concept or concept phase, and is related to a regulated facility or site, then its costs are directly attributed to that site (e.g., the Lake Gibson site located upstream of DeCew Falls Generating Station). The costs associated with the office of the Vice President - Hydroelectric Development and the general OM&A expenses referred to above are allocated based on management estimates. The portion of these costs allocated to the regulated plants is typically seven percent of the total.

2.4.13 Supply Chain

The allocation of Supply Chain costs is based on management's time estimates. Approximately three staff are dedicated to procurement and material management activities related to the regulated operations. Therefore, less than 30 percent of the 11 person Supply Chain group's costs are allocated to the regulated operations. Allocation between the Niagara Plant Group and R.H. Saunders is based on further time estimates by management of the responsibilities assigned to staff. Two of the staff are assigned to the Niagara Plant Group and are physically located in Niagara, while the remaining staff person is dedicated to R.H. Saunders.

Numbers may not add due to rounding.

Updated: 2008-03-14
EB-2007-0905
Exhibit F1
Tab 2
Schedule 1
Table 1

Table 1
Base OM&A - Regulated Hydroelectric ($M)

Line No.	Item	2005 Actual	2006 Actual	2007 Actual	2008 Plan	2009 Plan
		(a)	(b)	(c)	(d)	(e)
	Base OM&A:					
1	**Niagara Plant Group**	34.6	35.3	38.3	41.7	43.1
2	**Saunders GS**	12.7	12.5	40.3	14.4	14.8
3	**Total Base OM&A**	47.3	47.8	78.6	56.1	57.9
	Labour[1]:					
4	**Niagara Plant Group**	23.1	25.0	26.7	29.0	30.3
5	**Saunders GS**	7.4	7.8	8.0	8.5	8.9
6	**Total Labour**	30.5	32.8	34.7	37.5	39.2
	Staff Levels (FTEs):					
7	**Niagara Plant Group**	230.2	223.4	228.8	236.2	233.0
8	**Saunders GS**	72.5	65.6	65.5	67.8	68.5
9	**Total Staff Level**	302.7	289.0	294.3	304.0	301.5

1 Labour expense is included in Base OM&A

Numbers may not add due to rounding.

Table 2
Base OM&A by Major Components - Regulated Hydroelectric ($M)

Line No.	Prescribed Facility	Labour	Materials	External Purchased Services	Other	Allocated Support Costs	Total Base OM&A	Staff (FTEs)
		(a)	(b)	(c)	(d)	(e)	(f)	(g)
	Budget - Calendar Year Ending December 31, 2005							
1	**Niagara Plant Group**	24.2	3.0	2.8	0.3	4.8	35.1	234.2
2	**Saunders GS**	7.9	0.7	1.4	(0.3)	2.9	12.7	74.7
3	**Total**	32.1	3.7	4.2	0.0	7.7	47.8	308.9
	Actual - Calendar Year Ending December 31, 2005							
4	**Niagara Plant Group**	23.1	2.3	4.9	(0.1)	4.3	34.6	230.2
5	**Saunders GS**	7.4	0.8	2.0	(0.4)	2.9	12.7	72.5
6	**Total**	30.5	3.1	6.9	(0.5)	7.3	47.3	302.7
	Budget - Calendar Year Ending December 31, 2006							
7	**Niagara Plant Group**	27.2	2.6	2.8	(0.2)	3.5	35.9	236.8
8	**Saunders GS**	8.2	0.8	1.4	(0.0)	2.2	12.6	70.2
9	**Total**	35.4	3.4	4.2	(0.2)	5.7	48.5	307.0
	Actual - Calendar Year Ending December 31, 2006							
10	**Niagara Plant Group**	25.0	2.1	4.3	0.3	3.4	35.3	223.4
11	**Saunders GS**	7.8	0.9	1.3	(0.1)	2.7	12.5	65.6
12	**Total**	32.8	3.0	5.6	0.2	6.1	47.8	289.0
	Budget - Calendar Year Ending December 31, 2007							
13	**Niagara Plant Group**	28.3	1.9	4.9	0.0	4.9	40.0	229.4
14	**Saunders GS**	8.0	1.0	1.7	1.1	2.8	14.6	64.1
15	**Total**	36.3	2.9	6.6	1.1	7.7	54.6	293.5
	Actual - Calendar Year Ending December 31, 2007							
16	**Niagara Plant Group**	26.7	3.5	6.0	(1.3)	3.4	38.3	228.8
17	**Saunders GS**	8.0	0.8	1.6	27.0	2.9	40.3	65.5
18	**Total**	34.7	4.3	7.6	25.7	6.3	78.6	294.3
	Plan - Calendar Year Ending December 31, 2008							
19	**Niagara Plant Group**	29.0	1.5	5.3	0.1	5.8	41.7	236.2
20	**Saunders GS**	8.5	1.0	1.7	0.5	2.7	14.4	67.8
21	**Total**	37.5	2.5	7.0	0.6	8.5	56.1	304.0
	Plan - Calendar Year Ending December 31, 2009							
22	**Niagara Plant Group**	30.3	1.4	5.4	0.1	5.9	43.1	233.0
23	**Saunders GS**	8.9	1.0	1.7	0.4	2.8	14.8	68.5
24	**Total**	39.2	2.5	7.0	0.5	8.7	57.9	301.5

COMPARISON OF REGULATED HYDROELECTRIC BASE OM&A BY ORGANIZATIONAL UNIT

1.0 PURPOSE

This evidence presents the base OM&A costs broken down by organizational unit for the regulated hydroelectric facilities along with a discussion of period-over-period changes.

2.0 PERIOD-OVER-PERIOD CHANGES – BRIDGE AND TEST PERIOD

Exhibit F1-T2-S2 Table 1 sets out the Hydroelectric Central Support Groups OM&A budgets by organizational or functional area for the bridge and test periods which are allocated to the Niagara Plant Group and R.H. Saunders, using the methodology described in Ex. F1-T2-S1. It does not include the corporate allocations which are discussed in Ex. F3-T1-S1.

Exhibit F1-T2-S2 Table 2b identifies the Hydroelectric base OM&A costs for the Niagara Plant Group for the bridge and test periods. It includes the portion of Hydroelectric Central Support Group OM&A expenses allocated to the Niagara Plant Group for the same period. It does not include the corporate allocations which are discussed in Ex. F3-T1-S1.

Exhibit F1-T2-S2 Table 3b sets out the Hydroelectric base OM&A costs for R.H. Saunders for the bridge and test periods. It includes a base OM&A allocation from the Ottawa - St. Lawrence Plant Group ("OSPG") support organizations and from the Hydroelectric Central Support Groups as per the methodology described in Ex. F1-T2-S1. It does not include the corporate allocations which are discussed in Ex. F3-T1-S1.

<u>2009 Plan versus 2008 Plan</u>

Cost changes from 2008 to 2009 for R.H. Saunders and allocations from the Hydroelectric Central Support Groups and the OSPG support organizations are under ten percent. As such, they are not explained as per section 2.5.1 of the OEB Filing Guidelines.

Administration costs for the Niagara Plant Group are planned to increase in 2009 to $4.7M from $4.3M in 2008. The increase is attributed to increases in labour rates and payroll burdens, and the planned hiring of three additional support staff to address reliability and health and safety issues during 2008 with the full annual budget impact appearing in 2009. Cost changes in Niagara Plant Group operations and maintenance are less than ten percent. As such, they are not explained as per section 2.5.1 of the OEB Filing Guidelines.

<u>2008 Plan versus 2007 Actual</u>

Cost changes from 2007 to 2008 for the Niagara Plant Group and the R.H. Saunders, including allocations from the Hydroelectric Central Support Groups and the OSPG support organizations are discussed below.

<u>Hydroelectric Central Support Groups</u>

Costs allocated from central support groups for 2008 are $2.5M higher than the actual costs in 2007 due to a number of factors:

- Addition of $0.5M in 2008 for definition phase work and implementation associated with the North American Electric Reliability Corporation (NERC) Cyber Security standards. OPG must be substantially compliant by the end of 2008 and fully compliant by the end of 2009.
- Under-spending in 2007 by all central support groups due to continuing attrition and lag in hiring during 2007 ($0.9M). Several projects were deferred from 2007 to subsequent years due to engineering staff shortfalls. An engineer-in-training program was initiated in 2007, and is evolving in 2008, to address existing staffing shortfalls and supplement existing engineers expected to retire in 2008 and 2009. This program will continue through to 2010 to mitigate the impact of demographics in the Engineering/Technical and other support areas, where the average age is over 48.
- Addition of support staff to assist in activities associated with new internal controls, audit activities, regulatory activities and other due diligence activities ($0.4 M).
- The small contingency in the Executive Vice President (EVP) budget (i.e., $0.3M per year) to address any unforeseen critical work for the regulated assets (e.g., safety work and environmental work) was not used in 2007, but has been kept in 2008.

- Transfer of the EVP salary from a central corporate payroll cost centre to Hydroelectric cost centre ($0.2 M).
- Increases in labour rates and payroll burdens.

<u>Niagara Plant Group</u>

Administration costs for 2008 are $2.1M over the 2007 actual of $2.2M. This cost increase is a result of lower than average administration costs for 2007, due to a one-time credit of $1.6M received from Hydro One in 2007 for OPG's operations and maintenance support of Hydro One equipment located inside the Sir Adam Beck I powerhouse for the period dating back to the demerger of Ontario Hydro in 1999. In addition, administration spending is planned to increase approximately $0.5M resulting from the planned hiring of three additional staff combined with changes to labour rates and payroll burdens. Cost changes in operations and maintenance are less than ten percent. As such, they are not explained as per section 2.5.1 of the OEB Filing Guidelines.

<u>R.H. Saunders Generating Station</u>

Excluding the extraordinary expense of $27.2M in 2007 related to past grievance settlement with a First Nation, total 2007 OM&A spending at R.H. Saunders was $1.5M lower than the 2008 budget of $11.7M.

Planned maintenance expenses for 2008 are $1.3M higher than 2007 actual expenditures but are $0.2M lower than the 2007 maintenance budget. The reasons for the lower maintenance spending in 2007 compared to the 2007 budget and 2008 plan are outlined in the 2007 actual versus budget discussion below.

Cost changes in operations are less than ten percent. As such, they are not explained as per section 2.5.1 of the OEB Filing Guidelines.

Ottawa/St. Lawrence Plant Group common costs are forecast to decrease by approximately $0.2M in 2008 versus the 2007 actual allocated costs. This is a result of the restructuring discussed in Ex. F1-T2-S1 section 2.3.

2007 Actual versus 2007 Budget

Hydroelectric Central Support Groups

Costs allocated from central support groups for 2007 were $1.4M under the 2007 budget due to the following factors:

- Staffing under-variance (three staff less compared to plan) due to staff departures and slower hiring ($0.5 M).
- EVP contingency was not required in 2007 ($0.3 M).
- Lower consulting costs ($0.2 M).
- Labour rate under-variance due to difference in demographic plan assumptions compared to actual demographics (i.e., actual staff mix starting to get younger, thereby reducing the average rate).

Niagara Plant Group

Total base OM&A spending in 2007 was $34.8M versus the budget of $35.2M. Spending in operations was $2.0M below plan resulting from contingency funds budgeted in operations being transferred to maintenance activities. As described in Ex. F1-T2-S1, the Production Department is responsible for both the operation and maintenance of the Niagara Plant Group facilities. Included in the operations budget of the Production Department is funding for unforeseen events that could impact the operational performance of the Niagara generating stations. Additional maintenance activities resulted in approximately $3.7M in additional costs. These activities included: unplanned maintenance activities necessary to maintain generators in operation, health and safety improvements, and additional field service work for snow removal, fence repair, and public safety signage.

Administration costs were approximately $2.1M below budget mainly due to the one time cost recovery from Hydro One of $1.6M described above in the 2008 Plan versus 2007 Actual discussion. In addition, a cost transfer from administration to maintenance of approximately $0.4M resulted from the shifting of project staff from the Projects Department to the Production Department. The transfer was a result of using contract labour for the Sir Adam Beck I G7 Frequency Conversion project. The administration budget held funding for the project staff to cover time not spent on projects such as training, and health and safety meetings.

R.H. Saunders Generating Station

Total base OM&A spending in 2007 was $37.4M versus the budget of $11.7M. This was the result of an extraordinary item ($27.2M) related to the settlement of a past grievance with a First Nation. Excluding that expense, total base OM&A spending in 2007 was $1.5M below budget.

Maintenance expenses were $1.5M below plan as a result of the following changes from plan: cost containment for OPG's portion of the American eel studies and initiatives ($0.7M), lower joint works expenses than estimated from the New York Power Authority ($0.3M), staff vacancies, shifting of maintenance staff to execute projects, and the deferral of some community initiatives and activities.

Cost variances for R.H. Saunders operations and Ottawa/St. Lawrence Plant Group common cost allocations were less than ten percent. As such, they are not explained as per section 2.5.1 of the OEB Filing Guidelines.

2007 Actual versus 2006 Actual

Hydroelectric Central Support Groups

The $0.5M total increase in the 2007 actual cost allocations as compared to 2006 is due to a number of factors including: increases in labour rates and payroll burdens, the addition of one staff person in the Aboriginal program and additional costs associated with the pre-concept phase of the potential new development at Lake Gibson GS (upstream of DeCew Falls I & II).

Niagara Plant Group

As presented in Ex. F1-T2-S2 Table 2a, the total base OM&A spending for the Niagara Plant Group of $34.8M in 2007 was $3.0M higher than the 2006 actual base OM&A expenditures. The most significant increase in OM&A costs for 2007 is related to maintenance.

Maintenance costs for 2007 were $4.7M greater than 2006 and $3.7M over the 2007 budget. Maintenance cost increases are attributed to an increase in maintenance activities, as described above in the 2007 actual versus 2007 budget discussion, combined with increases in labour rates and payroll burdens. Operational costs in 2007 were approximately $0.5M over the 2006 actual. The operations cost increases were a result of increased costs under the NYPA joint works program and increases in labour rates and payroll burdens. Administration costs were $2.2M lower mainly due to the one time cost recovery from Hydro One of $1.6M described above in the 2008 Plan versus 2007 actual discussion.

R.H. Saunders Generating Station

As presented in Ex. F1-T2-S2 Table 3a, total station base OM&A spending was $37.4M for R.H. Saunders in 2007. Excluding the extraordinary expense of $27.2M in 2007 related to past grievance settlement with a First Nation, base OM&A spending was $10.3M which is only $0.5M higher than the 2006 actual base OM&A expenditures, and only $0.1M more than the 2006 approved budget. Excluding the extraordinary expense, cost changes in operations and maintenance are less than ten percent. As such, they are not explained as per section 2.5.1 of the OEB Filing Guidelines.

Allocated OSPG common support costs were $0.4M lower in 2007 than the 2006 actual. In 2006, the actual allocated OSPG common support costs were much higher than budgeted. This was the result of three unforeseen events described below that were subsequently treated as an approved variance to the original budgets. However the OSPG Central Support Department cost allocations are expected to level off during the bridge year and test period.

The most significant event related to the trial that resulted from a 2002 public safety incident. The trial resulted in a number of staff being away from their regular positions so a consulting firm was engaged to assist with developing an operational protocol to sustain operations across the entire plant group. In addition, the firm provided assistance to staff at all work centres and counselling services to those affected. The other two items were OPG's contribution to a marine by-pass project on the Ottawa River and emergent safety boom repairs.

Although the majority of the unplanned events were not directly related to R.H. Saunders operations, the accepted practice until the end of 2006 was to charge the expenses to the manager delegated the task of managing the unplanned events. The unfavourable impact to the allocation of common costs demonstrated the need to update the existing practice.

Effective January 1, 2007, unplanned expenses not directly related to the regulated operations at R.H. Saunders are being charged back to the appropriate facility regardless of the manager tasked with managing the work. Also the budgeted costs have now been reallocated from the common support departments to R.H. Saunders where directly attributable.

3.0 PERIOD-OVER-PERIOD CHANGES – HISTORICAL YEARS

Exhibit F1-T2-S2 Table 1 presents the base OM&A costs for the Hydroelectric Central Support Groups that are allocated to the regulated facilities for the historical period.

Exhibit F1-T2-S2 Table 2a presents the base OM&A for the Niagara Plant Group for the historical period and includes the allocated base OM&A costs allocated from the Hydroelectric Central Support Groups.

Exhibit F1-T2-S2 Table 3a presents the base OM&A for R.H. Saunders for the historical period and includes the allocated base OM&A costs from the Ottawa - St. Lawrence Plant Group Central Support Departments and the Hydroelectric Central Support Groups. In 2005, common costs were allocated based on full time equivalents, while in 2006 common costs were allocated primarily on the basis of the percentage of base OM&A. For a discussion of the OSPG cost allocation methodology, see Ex. F1-T2-S1.

<u>2006 Actual versus 2006 Budget</u>

<u>Hydroelectric Central Support Groups</u>

Hydroelectric Central Support Groups 2006 actual costs variances versus budget were under ten percent. As such, they are not explained as per section 2.5.1 of the OEB Filing Guidelines.

Niagara Plant Group

The Niagara Plant Group total base OM&A spending in 2006 was $0.5M or two percent under budget. However, Operations costs for 2006 were $1.8M (26 percent) lower than budget in 2006. As described in Ex. F1-T2-S1, the Production Department is responsible for both the operation and maintenance of the Niagara Plant Group facilities. Included in the operations budget of the Production Department is funding for unforeseen events that could impact the operational performance of the Niagara generating stations. In 2006, DeCew Falls experienced unforeseen operational issues costing approximately $0.7M of additional unplanned expenses that was collected under the category of Maintenance. In addition, operations costs were also under budget due in part to reduced overtime costs and vacant operator positions while replacing the positions. Maintenance cost variances were under 10 percent. As such, they are not explained as per section 2.5.1 of the OEB Filing Guidelines.

Administration costs for 2006 were $0.6M (16 percent) over budget. The over expenditures are attributed to the unplanned hiring of a full time temporary staff member to assist the Human Resource department, an over compliment Manager cancelling early retirement plans in 2006, and $0.4M of unplanned moving expenses.

R.H. Saunders Generating Station

R.H. Saunders direct OM&A cost variances for 2006 (actual versus budget) were under ten percent. As such, they are not explained as per section 2.5.1 of the OEB Filing Guidelines.

Ottawa - St. Lawrence Plant Group common costs allocated in 2006 were $0.6M (51 percent) higher than planned due to the reasons outlined above in the discussion of 2007 actual versus 2006 actual OM&A spending.

2006 Actual versus 2005 Actual

Hydroelectric Central Support Group

The 2006 actual costs were $1.3M (22 percent) lower than the 2005 actual costs primarily for the following reasons:

- The number of EP Central Support staff allocated from EP to Hydroelectric as part of the split at the end of 2005 was insufficient to support existing and new work program/project needs of the Hydroelectric business, especially in the Engineering Services area. This staff shortage was in part caused by the major downsizing of central support engineering functions that occurred in EP during 2002/2003. The level of central engineering support in EP was lower than required to support the on-going and planned work programs and projects in the Hydroelectric portion of the business.
- The 2006 Hydroelectric Central Support Group allocation base did not include any contingency for unforeseen work, while the 2005 EP Central Support allocations to Hydroelectric included contingency.
- The allocation methodology changed from a full time equivalents (staff count) allocation approach in 2005, to a base OM&A and direct assignment allocation approach in 2006, as recommended by R.J. Rudden and Associates and discussed in Ex. F1-T2-S1.

Niagara Plant Group

Actual total 2006 OM&A spending at Niagara was $1.6M or five percent over 2005 expenditures. The majority of the increase is attributable to labour cost and payroll burden increases. The increase in Administration of $0.5M (12 percent) over the 2005 actual costs is attributed to a number of factors including: the unplanned hiring of a full time temporary staff member to assist the Human Resource department, and $0.4M of additional unplanned moving expenses. Operations and maintenance costs changes were under ten percent. As such, they are not explained as per Section 2.5.1 of the OEB Filing Guidelines.

R.H. Saunders Generating Station

R.H. Saunders direct OM&A spending in 2006 was unchanged from 2005. Operations costs were $0.3M (18 percent) higher in 2006 as a result of higher standard labour rates and higher overtime expenses to cover a vacancy during the year. Maintenance, administration, and allocated OSPG support cost changes were under ten percent. As such, they are not explained as per section 2.5.1 of the OEB Filing Guidelines.

2005 Actual versus 2005 Budget

Hydroelectric Central Support Groups (supported Electricity Production)

Hydroelectric Central Support Groups 2005 actual costs variances versus budget were under ten percent. As such, they are not explained as per section 2.5.1 of the OEB Filing Guidelines.

Niagara Plant Group

The Niagara Plant Group OM&A expenditures were on budget for 2005. Operations costs were $2.0M (29 percent) under budget due to a number of factors including an unbudgeted $0.4M in cost recovery through the joint works program and $0.4M in other reduced costs. As described above in the 2006 actual versus budget discussion, included in the operations budget of the Production Department is funding for unforeseen events that could impact the operational performance of the Niagara generating stations. In 2005, the Production Department experienced unforeseen equipment failures. Emergency repairs to this equipment resulted in approximately $1.2M of operational expenses being re-allocated to maintenance. The impact of the re-allocation contributed to lower operations costs and higher maintenance costs. The majority ($0.9M) of this re-allocation went to cover costs related to the discovery of rotor cracking at the Sir Adam Beck Pump Generating Station. Additional maintenance costs incurred in 2005 included an unplanned $1M payment under the Niagara Exchange Agreement, for the maintenance of the Rankine Generating Station, offset by approximately $0.3M in reduced planned maintenance. Maintenance and administration cost variances were under ten percent. As such, they are not explained as per section 2.5.1 of the OEB Filing Guidelines.

R.H. Saunders Generating Station

R.H. Saunders total base OM&A spending was on budget in 2005 at $9.8M and the associated cost variances were under ten percent. As such, they are not explained as per section 2.5.1 of the OEB Filing Guidelines.

The OSPG common support actual OM&A expenditures in 2005 were $0.2M (14 percent) higher than planned. This was due to a number of activities requiring greater time and resources than originally planned, including higher numbers of employee moves and related relocation expenses, higher training costs to catch up on a backlog of regulatory training, as well as additional assessment work for programming and project execution. The other items related to unplanned expenditures on public safety boom repairs and temporary labour to backfill for a long-term absence.

Numbers may not add due to rounding.

Updated: 2008-03-14
EB-2007-0905
Exhibit F1
Tab 2
Schedule 2
Table 1

Table 1
Comparison of Base OM&A ($M)
Central Support Groups - Regulated Hydroelectric

Line No.	Group	2005 Budget	(c)-(a) Change	2005 Actual	(e)-(c) Change	2006 Actual	(e)-(g) Change	2006 Budget	(i)-(e) Change	2007 Actual
		(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)
1	**Business Support & Reg'ty Affairs**	0.2	(0.1)	0.1	0.2	0.3	(0.2)	0.5	0.1	0.4
2	**Water Resources & Aboriginal Affairs**	0.8	(0.1)	0.7	0.2	0.9	0.1	0.8	(0.0)	0.9
3	**Dam Safety & Emergency Prep**	0.4	(0.0)	0.3	0.0	0.3	(0.0)	0.4	(0.0)	0.3
4	**Environment**	0.0	0.0	0.0	0.3	0.3	(0.1)	0.4	0.1	0.4
5	**Supply Chain**	0.6	(0.1)	0.4	(0.1)	0.3	(0.0)	0.4	0.2	0.5
6	**Hydroelectric Development**	0.0	0.0	0.0	0.1	0.1	(0.0)	0.1	0.2	0.3
7	**Engineering Services**	3.5	(0.0)	3.5	(1.6)	1.9	(0.0)	1.9	0.2	2.1
8	**EVP Office**	0.8	(0.2)	0.6	(0.3)	0.3	0.1	0.2	(0.2)	0.1
9	**Total**	6.3	(0.6)	5.7	(1.3)	4.4	(0.2)	4.6	0.5	4.9

Line No.	Group	2007 Budget	(c)-(a) Change	2007 Actual	(e)-(c) Change	2008 Plan	(g)-(e) Change	2009 Plan
		(a)	(b)	(c)	(d)	(e)	(f)	(g)
10	**Business Support & Reg'ty Affairs**	0.6	(0.2)	0.4	0.3	0.7	0.1	0.8
11	**Water Resources & Aboriginal Affairs**	1.0	(0.1)	0.9	0.2	1.1	0.0	1.1
12	**Dam Safety & Emergency Prep**	0.4	(0.1)	0.3	0.1	0.4	0.0	0.4
13	**Environment**	0.5	(0.1)	0.4	0.1	0.5	0.0	0.5
14	**Supply Chain**	0.6	(0.0)	0.5	0.1	0.6	0.0	0.6
15	**Hydroelectric Development**	0.3	(0.1)	0.3	0.1	0.3	0.0	0.4
16	**Engineering Services**	2.2	(0.2)	2.1	0.4	2.4	0.2	2.6
17	**EVP Office**	0.8	(0.7)	0.1	1.4	1.5	(0.3)	1.2
18	**Total**	6.3	(1.4)	4.9	2.5	7.5	0.1	7.6

Numbers may not add due to rounding.

Table 2a
Comparison of Base OM&A ($M)
Niagara Plant Group

Line No.	Group	2005 Budget	(c)-(a) Change	2005 Actual	(e)-(c) Change	2006 Actual	(e)-(g) Change	2006 Budget	(i)-(e) Change	2007 Actual
		(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)
	Niagara Plant Group:									
1	**Operations**	6.9	(2.0)	4.9	0.2	5.1	(1.8)	6.9	0.5	5.6
2	**Maintenance**	19.5	1.9	21.4	0.9	22.3	0.7	21.6	4.7	27.0
3	**Administration**	3.7	0.2	3.9	0.5	4.4	0.6	3.8	(2.2)	2.2
4	**Total Niagara Plant Group**	30.2	0.0	30.2	1.6	31.8	(0.5)	32.3	3.0	34.8
	Allocated Central Support Group Costs:									
5	**Business Support & Reg'ty Affairs**	0.2	(0.1)	0.1	0.1	0.2	(0.1)	0.4	0.0	0.3
6	**Water Resources & Aboriginal Affairs**	0.6	(0.0)	0.6	0.2	0.7	0.1	0.6	(0.2)	0.5
7	**Dam Safety & Emergency Prep**	0.3	(0.0)	0.2	0.0	0.2	(0.0)	0.3	(0.1)	0.2
8	**Environment**	0.0	0.0	0.0	0.2	0.2	(0.1)	0.3	0.0	0.2
9	**Supply Chain**	0.4	(0.1)	0.3	(0.1)	0.2	(0.0)	0.3	0.1	0.3
10	**Hydroelectric Development**	0.0	0.0	0.0	0.1	0.1	(0.0)	0.1	0.2	0.3
11	**Engineering Services**	2.7	(0.0)	2.6	(1.2)	1.5	0.0	1.5	0.1	1.6
12	**EVP Office**	0.6	(0.2)	0.5	(0.3)	0.2	0.0	0.2	(0.2)	0.1
13	**Total Allocated Costs**	4.8	(0.4)	4.3	(0.9)	3.4	(0.1)	3.5	(0.0)	3.4
14	**Total**	35.0	(0.4)	34.6	0.7	35.2	(0.6)	35.8	3.0	38.2

Numbers may not add due to rounding.

Table 2b
Comparison of Base OM&A ($M)
Niagara Plant Group

Line No.	Group	2007 Budget	(c)-(a) Change	2007 Actual	(e)-(c) Change	2008 Plan	(g)-(e) Change	2009 Plan
		(a)	(b)	(c)	(d)	(e)	(f)	(g)
	Plant Group:							
1	**Operations**	7.6	(2.0)	5.6	0.5	6.1	0.2	6.3
2	**Maintenance**	23.3	3.7	27.0	(1.5)	25.5	0.6	26.1
3	**Administration**	4.3	(2.1)	2.2	2.1	4.3	0.4	4.7
4	**Total Plant Group**	35.2	(0.4)	34.8	1.1	35.9	1.2	37.1
	Allocated Central Support Group Costs:							
5	**Business Support & Reg'ty Affairs**	0.4	(0.2)	0.3	0.3	0.5	0.1	0.6
6	**Water Resources & Aboriginal Affairs**	0.7	(0.2)	0.5	0.3	0.8	0.0	0.8
7	**Dam Safety & Emergency Prep**	0.3	(0.1)	0.2	0.1	0.3	0.0	0.3
8	**Environment**	0.4	(0.1)	0.2	0.2	0.4	0.0	0.4
9	**Supply Chain**	0.4	(0.0)	0.3	0.0	0.4	0.0	0.4
10	**Hydroelectric Development**	0.3	(0.1)	0.3	0.1	0.3	0.0	0.4
11	**Engineering Services**	1.7	(0.2)	1.6	0.4	1.9	0.2	2.1
12	**EVP Office**	0.6	(0.5)	0.1	1.1	1.1	(0.2)	0.9
13	**Total Allocated Costs**	4.9	(1.5)	3.4	2.4	5.8	0.1	5.9
14	**Total**	40.1	(1.8)	38.2	3.5	41.7	1.3	43.0

Numbers may not add due to rounding.

Table 3a
Comparison of Base OM&A ($M)
Saunders GS

Line No.	Group	2005 Budget	(c)-(a) Change	2005 Actual	(e)-(c) Change	2006 Actual	(e)-(g) Change	2006 Budget	(i)-(e) Change	2007 Actual
		(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)
	Station:									
1	**Operations**	1.8	(0.1)	1.7	0.3	1.9	(0.2)	2.1	0.1	2.1
2	**Maintenance**	8.0	0.1	8.1	(0.2)	7.9	(0.4)	8.3	27.4	35.3
3	**Administration**	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.1	0.1
4	**Total Station**	9.8	(0.0)	9.8	0.1	9.8	(0.6)	10.4	27.6	37.4
	Allocated Plant Group Common Costs:									
5	**Plant Group Management**	0.1	(0.0)	0.1	0.4	0.5	0.4	0.1	(0.3)	0.2
6	**Business Support**	0.2	0.0	0.2	0.1	0.3	0.0	0.2	0.1	0.3
7	**HR Support Services**	0.3	0.1	0.4	(0.0)	0.4	0.0	0.4	(0.0)	0.3
8	**Asset Mgmt & Technical Support**	0.8	0.1	0.8	(0.4)	0.4	0.2	0.3	(0.1)	0.4
9	**Project Management**	0.1	(0.0)	0.1	0.0	0.1	(0.0)	0.2	(0.1)	0.1
10	**Total Plant Group Allocated Costs**	1.4	0.2	1.6	0.1	1.7	0.6	1.1	(0.4)	1.3
	Allocated Central Support Group Costs:									
11	**Business Support & Reg'ty Affairs**	0.1	(0.0)	0.0	0.0	0.1	(0.0)	0.1	0.1	0.2
12	**Water Resources & Aboriginal Affairs**	0.2	(0.0)	0.2	0.0	0.2	0.0	0.2	0.2	0.4
13	**Dam Safety & Emergency Prep**	0.1	(0.0)	0.1	0.0	0.1	(0.0)	0.1	0.1	0.1
14	**Environment**	0.0	0.0	0.0	0.1	0.1	(0.0)	0.1	0.1	0.2
15	**Supply Chain**	0.1	(0.0)	0.1	0.0	0.1	(0.0)	0.1	0.0	0.2
16	**Hydroelectric Development**	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
17	**Engineering Services**	0.8	(0.0)	0.8	(0.4)	0.4	(0.0)	0.4	0.1	0.5
18	**EVP Office**	0.2	(0.1)	0.1	(0.1)	0.1	0.0	0.1	(0.0)	0.0
19	**Total Allocated Central Support Costs**	1.5	(0.1)	1.4	(0.4)	1.0	(0.1)	1.1	0.5	1.5
20	**Total**	12.7	0.0	12.7	(0.2)	12.5	(0.1)	12.6	27.7	40.3

Numbers may not add due to rounding.

Table 3b
Comparison of Base OM&A ($M)
Saunders GS

Line No.	Group	2007 Budget	(c)-(a) Change	2007 Actual	(e)-(c) Change	2008 Plan	(g)-(e) Change	2009 Plan
		(a)	(b)	(c)	(d)	(e)	(f)	(g)
	Station:							
1	**Operations**	2.1	(0.1)	2.1	0.2	2.3	0.1	2.4
2	**Maintenance**	9.6	25.7	35.3	(25.9)	9.4	0.3	9.6
3	**Administration**	0.0	0.1	0.1	(0.1)	0.0	0.0	0.0
4	**Total Station**	11.7	25.7	37.4	(25.8)	11.7	0.4	12.0
	Allocated Plant Group Common Costs:							
5	**Plant Group Management**	0.2	(0.0)	0.2	(0.1)	0.2	0.0	0.2
6	**Business Support**	0.2	0.1	0.3	(0.1)	0.2	0.0	0.2
7	**HR Support Services**	0.4	(0.0)	0.3	(0.0)	0.3	0.0	0.3
8	**Asset Mgmt & Technical Support**	0.4	(0.0)	0.4	0.0	0.4	0.0	0.4
9	**Project Management**	0.2	(0.1)	0.1	(0.1)	0.0	0.0	0.0
10	**Total Plant Group Allocated Costs**	1.4	(0.1)	1.3	(0.2)	1.1	0.1	1.1
	Allocated Central Support Group Costs:							
11	**Business Support & Reg'ty Affairs**	0.2	0.0	0.2	(0.0)	0.2	0.0	0.2
12	**Water Resources & Aboriginal Affairs**	0.3	0.1	0.4	(0.1)	0.3	0.0	0.3
13	**Dam Safety & Emergency Prep**	0.1	0.0	0.1	(0.0)	0.1	0.0	0.1
14	**Environment**	0.1	0.0	0.2	(0.0)	0.1	0.0	0.1
15	**Supply Chain**	0.2	(0.0)	0.2	0.0	0.2	0.0	0.2
16	**Hydroelectric Development**	0.0	0.0	0.0	0.0	0.0	0.0	0.0
17	**Engineering Services**	0.5	0.0	0.5	0.0	0.5	0.0	0.5
18	**EVP Office**	0.2	(0.2)	0.0	0.3	0.4	(0.1)	0.3
19	**Total Allocated Central Support Costs**	1.5	0.1	1.5	0.1	1.7	0.0	1.7
20	**Total**	14.6	25.7	40.3	(25.9)	14.4	0.4	14.8

PROJECT OM&A – REGULATED HYDROELECTRIC

1.0 PURPOSE

This evidence provides a summary of the OM&A project expenses for the regulated hydroelectric facilities.

2.0 OVERVIEW

OPG's OM&A projects are distinguished from base OM&A work by way of a clearly defined materiality threshold, non-recurring scope of work, and generally longer timeline for each project, whereas base OM&A work activities are typically of an ongoing or routine nature. OM&A projects are distinct from capital projects because they do not meet the criteria for capitalization under OPG's capitalization procedure (see Ex. A2-T2-S1). Hydroelectric plant groups manage both capital and OM&A projects (including those for the regulated facilities) in a project listing that forms the basis for budgeting during the annual business planning process. Projects are identified through routine inspections, engineering reviews and detailed plant condition assessments. The process for identifying and prioritizing projects is described in Ex. A2-T2-S1.

OM&A projects are mainly "sustaining" expenditures for repairs and maintenance, such as major unit overhauls. The costs are above a dollar materiality threshold (typically $50k), but do not meet the rules for capitalization. In addition to maintenance projects for production equipment, there are many projects related to aging civil structures. In particular, the Niagara Plant Group has 53 bridges[1] and 11 major culverts associated with its facilities. The Niagara Plant Group is required to maintain 32 of the bridges and all of the culverts, with the maintenance of the remaining bridges being the responsibility of other third parties, as directed by various agreements. The Niagara Plant Group's liability for bridges and culverts arises from the original construction of the regulated assets where construction of the waterways affected existing travel routes. Routine bridge inspection and maintenance is carried out every two years. When inspections identify a need for repairs, the work is planned and budgeted for as an OM&A project.

[1] 25 of the bridges are accessible to the public.

Overall OM&A project expenditures for the regulated hydroelectric facilities are expected to range between $7M and $13M per year during the period from 2006 - 2009.

There are no large OM&A projects planned for the R.H. Saunders Generating Station during the test period.

The management of Hydroelectric OM&A projects is identical to that of capital projects as described in Ex. D1-T1-S1.

Numbers may not add due to rounding.

Table 1
Project OM&A - Regulated Hydroelectric ($M)

Line No.	Prescribed Facility	2005 Actual	2006 Actual	2007 Actual	2008 Plan	2009 Plan
		(a)	(b)	(c)	(d)	(e)
1	**Niagara Plant Group**	4.9	7.8	6.5	10.8	10.3
2	**Saunders GS**	1.7	1.6	0.4	2.1	1.8
3	**Total**	6.6	9.4	7.0	12.9	12.1

COMPARISON OF PROJECT OM&A – REGULATED HYDROELECTRIC

1.0 PURPOSE

This evidence presents the OM&A project expenses by plant group and by project category (regulatory, sustaining, value enhancing/strategic), along with period-over-period comparisons.

Exhibit F1-T3-S2 Tables 1 and 2 show comparisons by plant group and by project category respectively.

2.0 PERIOD-OVER-PERIOD CHANGES – TEST PERIOD

2009 Plan versus 2008 Plan

From 2008 to 2009, overall regulated hydroelectric OM&A project expenditures are expected to decrease by $0.7M to a total of $12.1M. Of this, Niagara Plant Group project expenditures are expected to decrease by $0.5M to $10.3M. This decrease is due to the deferral of two concrete repair projects at Sir Adam Beck I Generating Station beyond the test period and the advancement of a bridge repair project into 2008. Decreases are offset by new projects at DeCew Falls to rehabilitate Unit G8, repair canals and drains, and to modify a transformer oil containment system. A number of additional projects are planned for the Sir Adam Beck I Generating Station including penstock repairs, powerhouse roof replacement and drain replacements. There are two new projects in 2009 related to the retirement of the 25Hz system, which is scheduled for decommissioning in 2009. R.H. Saunders project expenditures are expected to remain in the $2.0M range for the test period.

Expenditures, when viewed by project category, show an increase in regulatory projects due to a number of erosion protection projects (associated with riverbank erosion) planned for 2009, while sustaining projects decrease for 2009 as a number of concrete repair projects are completed in 2008.

<u>2008 Plan versus 2007 Actual</u>

From 2007 to 2008, overall regulated hydroelectric OM&A project expenditures are expected to increase by $5.9M to a total plan of $12.9M. This is comprised of an increase in Niagara Plant Group project expenditures of $4.2M and an increase of $1.6M at R.H. Saunders. Niagara's total increase results from $2.1M in underspent projects in 2007 combined with new projects identified in the 2008 Business Plan. The 2008 increased expenditures are due in part to five projects totalling approximately $1.3M planned for 2007 that were not completed combined with the advancement of a $0.8M bridge repair project into 2008. Other changes include the addition of new projects related to health and safety issues, regulatory issues related dam safety and bridges, and projects related to maintaining reliable operations of Niagara's regulated facilities. R.H. Saunders has a planned increase of $1.6M for a number of small civil and mechanical repair projects. The largest of these projects is a $0.6M project to repair and upgrade a number of access roads around the facility. It also includes $0.3M to complete the elevator rehab project which was deferred from 2007 and discussed below.

Expenditures by project category show an increase in regulatory projects that can be attributed to a number of bridge repair and maintenance projects in the Niagara Plant Group. The small increase in sustaining projects can be attributed to a number of civil repair projects as described above, offset by the completion of the major overhauls of the turbine-generators at DeCew Falls II Generating Station in 2007.

3.0 PERIOD-OVER-PERIOD CHANGES – BRIDGE YEAR

<u>2007 Actual versus 2007 Budget</u>

For 2007, overall regulated hydroelectric OM&A project expenditures were $2.9M below plan. Niagara expenditures were approximately $2.1M under budget. The reduced expenditures were a result of deferring the Decew Falls G6 and G8 overhaul projects totalling $1.1M, the delayed execution of the Decew Falls headworks road repairs project totalling $0.75M, and $0.4M under spent on the Sir Adam Beck I screenhouse wall repairs resulting from delays due to weather conditions.

R.H. Saunders OM&A project expenses in 2007 were $0.4M which was approximately $0.7M below the budget of $1.2M. This was the result of the reclassification of two projects to capital after determining that it was more cost effective to replace the systems than to repair/upgrade them ($0.3M) and the deferral of two projects into 2008 to allow for better execution of the HVAC replacement project and the Station Service Water replacement project. Deferred projects were the elevator rehabilitation ($0.3M) and the repair of dam safety instrumentation ($0.2M).

<u>2007 Actual versus 2006 Actual</u>

From 2006 to 2007, overall regulated hydroelectric OM&A project expenditures decreased by $2.4M to a total expenditure of $7.0M. R.H. Saunders expenditures decreased by $1.1M in 2007 from $1.6M in 2006, while Niagara Plant Group project expenditures decreased by $1.2M to $6.5M. These cost changes, primarily in sustaining projects, are due to changes in the number of small civil and mechanical repair projects at both the Niagara plants and R.H. Saunders.

4.0 PERIOD-OVER-PERIOD CHANGES – HISTORICAL YEARS

<u>2006 Actual versus 2006 Budget</u>

For 2006, overall regulated hydroelectric OM&A project expenditures were $9.4M or $0.1M higher than budget. For the Niagara Plant Group OM&A project costs were $0.2M below budget. The variance was due to the deferral of several projects for bridge repairs and maintenance. However, the deferral of those costs have been largely offset by discovery work associated with the turbine-generator overhaul project at DeCew Falls II and higher costs for other projects at DeCew Falls I and Sir Adam Beck II. The 2006 actual project OM&A expenses for R.H. Saunders were $0.3M higher than budget due to higher than estimated contractor costs to repair the station entrance and improve drainage. Expenditures by project category were on budget.

<u>2006 Actual versus 2005 Actual</u>

From 2005 to 2006, overall regulated hydroelectric OM&A project expenditures increased by $2.8M, from $6.6M to $9.4M. Niagara Plant Group OM&A project spending in 2006 was

$2.9M higher than 2005 actual spending of $4.9M. The higher spending in 2006 is related to the continuation of the DeCew Falls II Unit 1 overhaul, combined with the overhaul of DeCew Falls I Unit 7, and the start of the DeCew Falls II Unit 2 overhaul. R.H. Saunders OM&A project spending in 2006 was essentially unchanged from 2005. Sustaining projects increased due to the overhaul projects at DeCew Falls I and II.

<u>2005 Actual versus 2005 Budget</u>

For 2005, overall regulated hydroelectric OM&A project expenditures were $6.6M or $0.1M higher than budget.

Niagara Plant Group OM&A project spending in 2005 was $0.3M below budget. The lower than budgeted spending is attributed to the reclassification of the DeCew Falls II headgate project from OM&A to capital, the cancellation of two elevator refurbishment projects, and lower than planned costs related to some other projects. These reduced project expenditures were offset by additional unforeseen costs related to projects such as the DeCew Falls II Unit 1 overhaul and the DeCew Falls I Unit 5 turbine repair, Sir Adam Beck I turbine shaft seal repairs, and the Sir Adam Beck Pump Generating Station cracked generator rotor repairs.

R.H. Saunders OM&A project spending in 2005 was $0.4M higher than budget as a result of more work being carried forward from 2004 than was originally expected. This included the revenue metering upgrade and control room upgrade projects. The other sustaining project variance was due to the erection bay crane rehabilitation project costing more than planned because of additional required work discovered after the crane was disassembled.

Numbers may not add due to rounding.

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Schedule 2
Table 1

Table 1
Comparison of Project OM&A - Regulated Hydroelectric ($M)

Line No.	Prescribed Facility	2005 Budget	(c)-(a) Change	2005 Actual	(e)-(c) Change	2006 Actual	(e)-(g) Change	2006 Budget	(i)-(e) Change	2007 Actual
		(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)
1	**Niagara Plant Group**	5.2	(0.3)	4.9	2.9	7.8	(0.2)	8.0	(1.2)	6.5
2	**Saunders GS**	1.3	0.4	1.7	(0.1)	1.6	0.3	1.3	(1.1)	0.4
3	**Total**	6.5	0.1	6.6	2.8	9.4	0.1	9.3	(2.4)	7.0

Line No.	Prescribed Facility	2007 Budget	(c)-(a) Change	2007 Actual	(e)-(c) Change	2008 Plan	(g)-(e) Change	2009 Plan
		(a)	(b)	(c)	(d)	(e)	(f)	(g)
4	**Niagara Plant Group**	8.7	(2.1)	6.5	4.2	10.8	(0.5)	10.3
5	**Saunders GS**	1.2	(0.7)	0.4	1.6	2.1	(0.2)	1.8
6	**Total**	9.9	(2.9)	7.0	5.9	12.9	(0.7)	12.1

Numbers may not add due to rounding.

Table 2
Comparison of Project OM&A by Category - Regulated Hydroelectric ($M)

Line No.	OM&A Project Category	2005 Budget	(c)-(a) Change	2005 Actual	(e)-(c) Change	2006 Actual	(e)-(g) Change	2006 Budget	(i)-(e) Change	2007 Actual
		(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)
1	**Regulatory**	2.0	(0.1)	1.9	(0.7)	1.2	0.0	1.2	(0.8)	0.4
2	**Sustaining**	4.5	0.2	4.7	3.5	8.2	0.1	8.1	(1.6)	6.6
3	**Value Enhancing/Strategic**	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
4	**Total**	6.5	0.1	6.6	2.8	9.4	0.1	9.3	(2.4)	7.0

Line No.	OM&A Project Category	2007 Budget	(c)-(a) Change	2007 Actual	(e)-(c) Change	2008 Plan	(g)-(e) Change	2009 Plan
		(a)	(b)	(c)	(d)	(e)	(f)	(g)
5	**Regulatory**	1.0	(0.6)	0.4	5.5	5.8	2.3	8.1
6	**Sustaining**	8.9	(2.3)	6.6	0.4	7.0	(3.0)	4.0
7	**Value Enhancing/Strategic**	0.0	0.0	0.0	0.0	0.0	0.0	0.0
8	**Total**	9.9	(2.9)	7.0	5.9	12.9	(0.7)	12.1

DETAILS OF OM&A PROJECTS – REGULATED HYDROELECTRIC

1.0 PURPOSE

The purpose of this evidence is to provide a project listing and business case summaries for OM&A project expenditures for the regulated hydroelectric facilities during the test period.

2.0 OVERVIEW

A tiered reporting structure for OM&A projects has been used:

- Tier 1: For projects with a total cost of $10M or greater and which have budgeted expenditures during the test period, project summaries are provided.
- Tier 2: All projects with a total cost of $5M to $10M are individually listed, with the project name, description and project cost information provided.
- Tier 3: An aggregated total of the budgeted expense for all projects with a total cost of $0 to $5M is provided.

This approach provides an appropriate level of information on OM&A project expenditures for the regulated hydroelectric facilities, recognizing that more information is warranted for the larger projects.

Based on the tiered reporting structure, there are no regulated hydroelectric projects that fall into Tiers 1 or 2 (Ex. F1-T3-S3 Tables 1 and 2). Tier 3 projects are shown in Ex. F1-T3-S3 Table 3.

Numbers may not add due to rounding.

Table 1
OM&A Project Listing - Regulated Hydroelectric
Projects >$10M Total Project Cost[1]

Line No.	Project Name	Project Summary Ref. No.	Category	Start Date	In-Service Date	Total Project Cost ($M)
	(a)	(b)	(c)	(d)	(e)	(f)
	Project summaries for the following projects are included in this section of the application					
	Niagara Plant Group					
1	No projects in this category					0.0
	Saunders GS					
2	No projects in this category					0.0
3	**Total**					0.0

1 Projects with expenditures during Test Period

Numbers may not add due to rounding.

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Table 2
OM&A Project Listing - Regulated Hydroelectric
Projects $5M - $10M Total Project Cost[1]

Line No.	Project Name	Category	Project Description	Total Project Cost ($M)
	(a)	(b)	(c)	(d)
	Niagara Plant Group			
1	No projects in this category			0.0
	Saunders GS			
2	No projects in this category			0.0
3	**Total**			0.0

1 Projects with expenditures during Test Period

Numbers may not add due to rounding.

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Table 3
OM&A Project Listing - Regulated Hydroelectric
Projects <$5M Total Project Cost[1]

Line No.	Project Description	Number of Projects	Total Project Cost ($M)	Average Cost Of All Projects ($M)
		(a)	(b)	(c)
	Niagara Plant Group			
1	**Aggregate Total All Projects <$5M**	41	37.4	0.9
	Saunders GS			
2	**Aggregate Total All Projects <$5M**	17	7.2	0.4
3	**Total**	58.0	44.6	0.8

1 Projects with expenditures during Test Period

GROSS REVENUE CHARGE – REGULATED HYDROELECTRIC

1.0 PURPOSE

This evidence describes and presents a summary of the gross revenue charges ("GRC") that are imposed on OPG pursuant to legislative and regulatory requirements.

2.0 GROSS REVENUE CHARGE ON HYDROELECTRIC GENERATING STATIONS

The GRC refers to the taxes and charges that, as of January 2001, are imposed specifically on owners of hydroelectric generating stations pursuant to section 92.1 of the *Electricity Act, 1998*. The GRC consists of two components:

1. A property tax component payable to the Minister of Finance or the Ontario Electricity Financial Corporation.
2. A water rental component payable to the Minister of Finance by all holders of water power leases.

Each of the six regulated hydroelectric stations are subject to the GRC property tax component. Four of the regulated hydroelectric stations, Sir Adam Beck I, Sir Adam Beck II, Sir Adam Beck Pump Generating Station and R.H. Saunders, are subject to water rental charges. Since the land and reservoirs associated with operation of the DeCew Falls stations are not subject to water power leases, the DeCew Falls stations are not subject to the GRC water rental component charge, but are subject to a charge paid to the St. Lawrence Seaway Management Corporation as described below.

Ontario Regulation 124/02 under the *Electricity Act, 1998* defines the methodology for calculating the GRC. For the period January 1, 2001 to December 31, 2007, the GRC has been determined by multiplying the station's annual generation (described below) by a legislatively deemed price of $40/MWh and by the appropriate GRC rate (described below). For the purposes of this Application, the current price of $40/MWh has been assumed to apply throughout the proposed test period. However, should the Province of Ontario increase the deemed price of $40/MWh or the GRC rates used for the GRC calculation during the test period, OPG may need to seek an accounting order from the OEB.

Ontario Regulation 124/02 also defines how a station's annual generation is determined for purposes of calculating GRC. A station's "annual generation for a year is the amount of electricity generated by the station during the year, other than electricity that is consumed directly in the generation of electricity at the station without being conveyed through a transmission or distribution system". Ontario Regulation 124/02 also prescribes the methodology for determining a station's annual generation when such station has used water associated with another station or has allowed another station to use the water normally associated with it (see Ex. G1-T1-S1 for a discussion of Water Transactions).

The GRC property tax component charge consists of graduated tax rates through four tiers of production and applies to each of the six regulated hydroelectric generating stations. The GRC property component charge is assessed at 2.5 percent on gross revenue from the first 50 gigawatt-hours of annual generation from the generating station, at 4.5 percent on gross revenue from the next 350 gigawatt-hours (from 50 to 400 GWh), at 6 percent on gross revenue from the next 300 gigawatt-hours (from 400 to 700 GWh), and at 26.5 percent on gross revenue from annual generation in excess of 700 gigawatt-hours.

The GRC water rental component charge is assessed at the fixed rate of 9.5 percent on the gross revenue calculated from annual generation determined for each of Sir Adam Beck I, Sir Adam Beck II, Sir Adam Beck Pump Generating Station, and R.H. Saunders.

Rates applicable for the GRC property and water rental components are summarized in the following chart:

Chart 1

GRC Components

Station Production GWhr/yr	Water Rental Rate	Property Graduated Rate	Total GRC Rate
0 – 50	9.5%	2.5%	12.0%
50 – 400	9.5%	4.5%	14.0%
400 – 700	9.5%	6.0%	15.5%
> 700	9.5%	26.5%	36.0%

The GRC property tax component charges applicable to the regulated hydroelectric stations are payable to the Ontario Electricity Financial Corporation. Pursuant to section 3 (1) of the *Assessment Act* (Ontario), land, buildings and structures used in connection with a hydroelectric generating station are exempt from taxation under the *Assessment Act* (Ontario), including those held by OPG. However, property tax on land and buildings not used in connection with the hydroelectric generating stations is paid by OPG pursuant to the provisions of the *Assessment Act* (Ontario).

The GRC water rental component charges applicable to the four regulated hydroelectric sites, which are operated pursuant to water power leases (Sir Adam Beck I, II, and Pump Generating Station, and R.H. Saunders), are payable to the Ontario Minister of Finance, with the exception that a portion of the GRC water rental component payable with respect to the Sir Adam Beck Complex is payable to the Niagara Parks Commission pursuant to O. Reg. 135/02 under the *Electricity Act, 1998.*

Ontario Regulation 124/02 also provides for an exemption by way of deduction in the calculation of gross revenue. Eligible capacity associated with new, redeveloped, or upgraded hydroelectric generating stations may be subject to a deduction as described in Ontario Regulation 124/02.

As previously identified, the land and reservoirs associated with the operation of the DeCew plants are not held pursuant to water power leases, and are therefore not subject to the GRC water rental component charge. However, charges are incurred by OPG under an agreement with the St. Lawrence Seaway Management Corporation. Water used for power generation at the DeCew plants is withdrawn from the Welland Ship Canal at Allanburg. OPG compensates the St. Lawrence Seaway Management Corporation for its operational costs of conveying water from Lake Erie through the St. Lawrence Seaway Management Corporation's canal to the Allanburg intakes. The amount of compensation is not determined based on the volume of water withdrawn, but rather is determined by calculating a theoretical value for the water used at DeCew Falls. This value of water is computed based on the incremental difference in theoretical production for both Niagara River (Sir Adam Beck) stations and DeCew Falls stations combined versus the Niagara (Sir Adam Beck) stations alone, using the total Lake Erie outflow available for power generation purposes. A cost factor is applied to convert the value of water in terms of production to monetary terms. As per the agreement, annual costs associated with the St. Lawrence Seaway Management Corporation conveyance charges can vary significantly (ranging from about $1M to $8M), but are expected to be in the order of $5M/year from 2007 - 2009. The St. Lawrence Seaway Management Corporation costs have been included with the Niagara Plant Group's GRC totals in Ex. F1-T4-S1 Table 1.

All aspects of GRC payments made by OPG to the Province of Ontario are governed by legislation or regulation. As such, OPG has no control over the GRC charges associated with its regulated hydroelectric facilities.

Numbers may not add due to rounding.

Table 1
Gross Revenue Charge - Regulated Hydroelectric ($M)

Line No.	Prescribed Facility	2005 Actual	2006 Actual	2007 Actual	2008 Plan	2009 Plan
		(a)	(b)	(c)	(d)	(e)
1	**Niagara Plant Group**	158.4	152.6	151.8	144.9	156.2
2	**Saunders GS**	92.7	92.9	90.2	83.4	87.9
3	**Total**	251.2	245.5	242.0	228.2	244.1

4	**NYPA Water Transactions**	5.2	4.1	1.4	0.4	1.4

COMPARISON OF GROSS REVENUE CHARGE

1.0 PURPOSE

This evidence presents the gross revenue charge ("GRC") that OPG is obligated to pay for the regulated hydroelectric facilities, as well as period-over-period comparisons of the actual or expected GRC imposed on OPG.

2.0 OVERVIEW

The GRC is calculated in accordance with O. Reg. 124/02 under the *Electricity Act, 1998*. "gross revenue" is calculated under O. Reg. 124/02 as a station's annual generation (as described in O. Reg. 124/02) multiplied by $40/MWh. For the purposes of this Application, OPG has assumed that the price of $40/MWh will be extended through the proposed test period. As described previously, GRC rates are graduated tax rates through four tiers of production. Exhibit F1-T4-S2 Table 1 shows a comparison of GRC by plant group. The rates and calculation methodology are described in Ex. F1-T4-S1.

3.0 PERIOD-OVER-PERIOD CHANGES – TEST PERIOD

<u>2009 Plan versus 2008 Plan</u>

Given the assumption in this Application that the fixed price of $40/MWh will be extended through the proposed test period, the year-over-year change in GRC is due to changes in the production forecasts for the regulated generating stations. The regulated hydroelectric production is expected to increase from 17.4 TWh in 2008 to 18.5 TWh in 2009 (Ex. E1-T1-S2), resulting in an increase in the GRC from $228.2M to $244.1M.

<u>2008 Plan versus 2007 Actual</u>

Given the assumption in this Application that the fixed price of $40/MWh will be extended through the proposed test period, the year-over-year change in GRC is due to changes in the production forecasts for the regulated generating stations. The regulated hydroelectric production is expected to decrease from 18.2 TWh in 2007 to 17.4 TWh in 2008 (Ex. E1-T1-S2), resulting in a decrease in the GRC from $242.0M to $228.2M.

4.0 PERIOD-OVER-PERIOD CHANGES – BRIDGE YEAR

2007 Actual versus 2007 Budget

Given that the price was fixed at $40/MWh in 2007 by O. Reg. 124/02, the difference in GRC between the 2007 budget and the 2007 actual is due solely to differences in forecast and actual production. The production budget for 2007 was 17.5 TWh versus actual production of 18.2 TWh (Ex. E1-T1-S2). This difference resulted in an increase in the GRC from a budget value of $228.9M to an actual value of $242.0M.

2007 Actual versus 2006 Actual

Given that the price was fixed at $40/MWh in 2006 and 2007 by O. Reg. 124/02, the difference in GRC between 2006 and 2007 is solely due to year-over-year changes in production for the regulated hydroelectric generating stations. The actual production decreased from 18.4 TWh in 2006 to 18.2 TWh in 2007 (Ex. E1-T1-S2). This resulted in a GRC decrease from $245.5M in 2006 to $242.0M in 2007.

5.0 PERIOD-OVER-PERIOD CHANGES – HISTORICAL YEARS

2006 Actual versus 2006 Budget

Given that the price was fixed at $40/MWh in 2006 by O. Reg. 124/02, the difference in GRC between the 2006 budget and the 2006 actual is due solely to differences in forecast and actual production. The production budget for 2006 was 17.7 TWh versus actual production of 18.4 TWh (Ex. E1-T1-S2). This difference resulted in an increase in the GRC from the budgeted $234.2M to actual of $245.5M.

2006 Actual versus 2005 Actual

Given that the price was fixed at $40/MWh in 2005 and 2006 by O. Reg. 124/02, the difference in GRC between 2005 and 2006 is solely due to year-over-year changes in production for the regulated hydroelectric generating stations. The actual production decreased from 18.7 TWh in 2005 to 18.4 TWh in 2006 (Ex. E1-T1-S2). This resulted in a GRC decrease from $251.2M in 2005 to $245.5M in 2006.

<u>2005 Actual versus 2005 Budget</u>

Given that the price was fixed at $40/MWh in 2005 by O. Reg. 124/02, the change in GRC is solely due to changes in actual 2005 production for the regulated hydroelectric facilities from the 2005 production forecasts prepared for budget purposes. The production budget for 2005 was 18.5 TWh versus actual production of 18.7 TWh (Ex. E1-T1-S2). This difference resulted in an increase in the GRC from the budgeted $240.5M to actual of $251.2M.

Numbers may not add due to rounding.

Table 1
Comparison of Gross Revenue Charge - Regulated Hydroelectric ($M)

Line No.	Prescribed Facility	2005 Budget	(c)-(a) Change	2005 Actual	(e)-(c) Change	2006 Actual	(e)-(g) Change	2006 Budget	(i)-(e) Change	2007 Actual
		(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)
1	**Niagara Plant Group**	148.8	9.6	158.4	(5.9)	152.6	7.1	145.4	(0.8)	151.8
2	**Saunders GS**	91.7	1.0	92.7	0.2	92.9	4.1	88.8	(2.7)	90.2
3	**Total**	240.5	10.7	251.2	(5.7)	245.5	11.3	234.2	(3.5)	242.0
4	**NYPA Water Transactions**	4.6	0.6	5.2	(1.1)	4.1	3.7	0.4	(2.7)	1.4

Line No.	Prescribed Facility	2007 Budget	(c)-(a) Change	2007 Actual	(e)-(c) Change	2008 Plan	(g)-(e) Change	2009 Plan
		(a)	(b)	(c)	(d)	(e)	(f)	(g)
5	**Niagara Plant Group**	143.0	8.8	151.8	(6.9)	144.9	11.3	156.2
6	**Saunders GS**	85.9	4.3	90.2	(6.9)	83.4	4.5	87.9
7	**Total**	228.9	13.1	242.0	(13.8)	228.2	15.9	244.1
8	**NYPA Water Transactions**	1.0	0.4	1.4	(1.0)	0.4	1.0	1.4

OM&A PURCHASED SERVICES – REGULATED HYDROELECTRIC

1.0 PURPOSE

The purpose of this exhibit is to present the purchases of OM&A services and products for the regulated hydroelectric facilities that meet the threshold of one percent of the OM&A expense before taxes consistent with the OEB filing guidelines for OPG's Application.

2.0 OVERVIEW

An overview of OPG's procurement process which is applicable to the regulated hydroelectric facilities is presented in Ex. F3-T5-S1.

The regulated hydroelectric OM&A expense before taxes is equal to the sum of the regulated hydroelectric base OM&A plus the project OM&A expense. This amount ranges from $53.9M in 2005 to a high of $85.6M in 2007 as presented in Ex. F1-T1-S1 Table 1. For the regulated hydroelectric facilities the threshold of one percent of the OM&A expense before taxes is approximately $500,000.

Information on vendor contracts for OM&A purchased services within the regulated hydroelectric business that are equal to or in excess of the $500,000 threshold for any of the years 2005, 2006 and 2007 is presented in Chart 1.

Chart 1
Purchase of Services – Regulated Hydroelectric OM&A Contracts

Vendor Name	Description/Nature of Activities	Request for Proposal Process		Rationale if Single Source
		Competitive	Single Source	
941042 Ontario Limited	Installation, removal and maintenance of ice booms at Saunders.		✓	This vendor has worked with Saunders to establish safe practices and there are no viable alternative vendors.
Aecon Industrial	Wide range of construction activity at Niagara plant group, including paving, roof repair, and removal of surplus equipment.	✓		
Allied Fabricators Inc	Supply of trash racks for Sir Adam Beck 2.	✓		
Charles Jones Industrial Limited	Supply of tools and shop equipment.	✓		
Comstock Canada	Wide range of construction activities at Niagara plant group, including transformer containment, bridge repair, powerhouse painting.	✓		
ES Fox Limited	A range of construction activities at Niagara plant group including a public announcement system and elevator work.	✓		
General Electric Canada	Continuation of work to refurbish field poles of Beck generators.		✓	GE had performed the work on prior units and continuity and consistency was required.

Total 2005 Spend ($M) = 4.1
Total 2006 Spend ($M) = 6.1
Total 2007 Spend ($M) = 5.7

BASE OM&A – NUCLEAR

1.0 PURPOSE

The purpose of this evidence is to present the OPG Nuclear base OM&A expense for the period 2005 - 2009. Base OM&A primarily funds routine operations and maintenance related activities in support of the production of electricity from OPG's generating units.

2.0 OVERVIEW

The Nuclear base OM&A budget is established through the business planning process (see Ex. A2-T2-S1), in support of:

- The ongoing production of electricity from the operating units.
- Ensuring safe operation of the plants.
- Maintaining or improving reliability for future production.
- Ensuring compliance with applicable legislation and nuclear regulatory requirements.

Base OM&A provides the main source of funding for operating and maintaining the nuclear stations. In addition to the routine activities listed here, base OM&A is also used to fund the cost of:

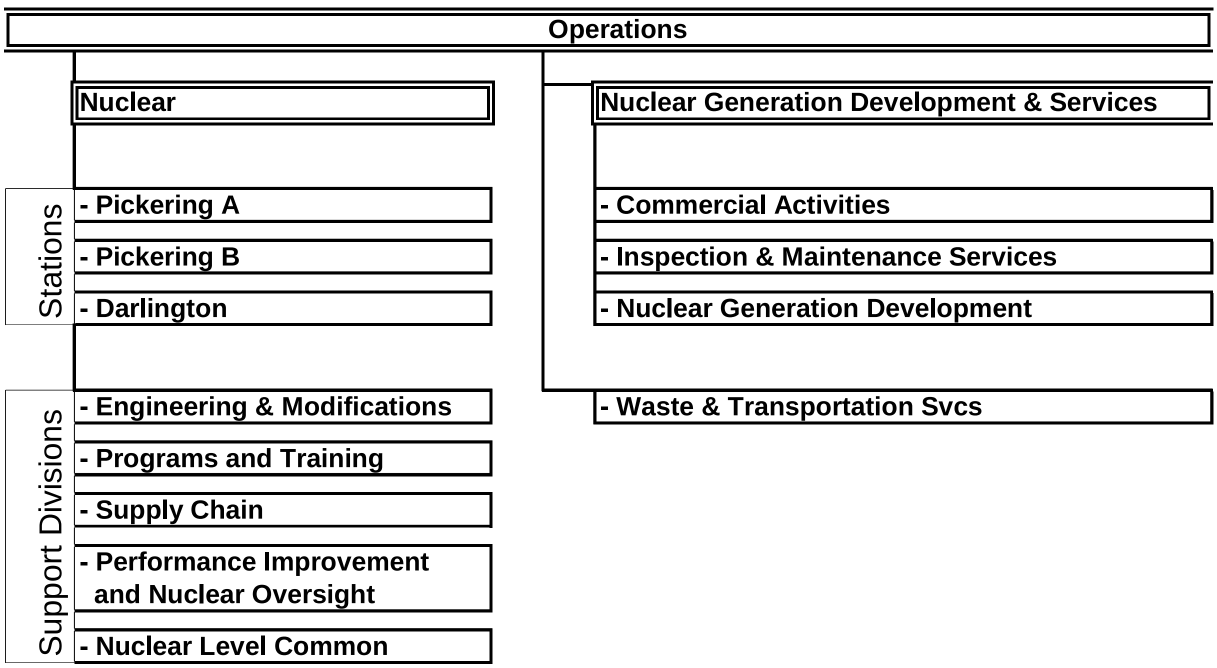
- Regular staff labour for planned outages.
- All costs of forced outages, planned derates, and forced derates. While there are generally no significant OM&A costs associated with derates, forced outages can require significant efforts to correct a problem and return a unit to operation. As these are unplanned events for which no budget is provided, other base OM&A work is reduced or deferred to accommodate costs. (See Ex. F2-T4-S1 section 5.0 for further details of outage costing.)
- Inventory adjustments that periodically revalue inventory (see section 2.3), including an obsolescence provision.
- Investigations into plant refurbishment options and new generation development (see Ex. D2-T1-S3).
- Indirect costs associated with commercial activities and the provision of inspection and maintenance services to OPG stations and external customers (see below).

While base OM&A is the predominant funding source for the nuclear business, there are other sources of funding over the station life cycle, as noted here:

- Outage OM&A (Ex. F2-T4-S1), which provides incremental funding for work performed during planned outages, excluding regular staff labour (as noted above), and excluding all project OM&A or project capital work (as described in Ex. F2-T3-S1 and Ex. D2-T1-S1).
- Fuel OM&A (Ex. F2-T5-S1), which funds all nuclear fuel bundles issued for loading into the reactors, the variable cost component of OPG's nuclear used fuel management liabilities as well as the cost of fuel for standby generators.
- Project OM&A (Ex. F2-T3-S1) and project capital (Ex. D2-T1-S1), which fund non-repetitive, incremental work reflecting an investment of greater than $200k per unit.
- Purchased minor fixed assets (Ex. A2-T2-S1), which provides for purchase of lower value, generally portable items such as tools. Effective January 1, 2007, OPG increased the materiality limit for capitalization of these expenditures from $2,000 to $25,000. The effect is an increase to base OM&A materials of $8.9M in 2007 (and similar amounts in 2008 and 2009) with a corresponding reduction in capital expenditures. Refer to Ex. A2-T2-S1 for further discussion.
- Pickering A return to service ("PARTS") regulated asset OM&A (Ex. J1-T1-S1) and PARTS capital, which funded the return-to-service of Pickering A Units 1 and 4. No charges are expected for these accounts in the test years.
- Decommissioning Fund (Ex. H1-T1-S1) funds the Pickering A Unit 2 and 3 safe storage project during the historic, bridge and test periods, and will ultimately fund decommissioning activities and management of low and intermediate level waste at all OPG reactors.
- Used Fuel Fund (Ex. H1-T1-S1) funds handling of used fuel when it is removed from the irradiated fuel storage bay.

The base OM&A budget includes funding for all Nuclear divisions (Chart 1).

Chart 1: Nuclear Divisions



In addition to the three generating stations (Pickering A, Pickering B, and Darlington – as described in Ex. A1-T4-S3), the nuclear divisions are: the support divisions (Engineering and Modifications, Programs and Training, Supply Chain, Performance Improvement, and Nuclear Oversight ["PINO"]) and Nuclear Level Common; and, on the Nuclear Generation Development and Services side, the divisions Commercial Activities, Generation Development, and Inspections and Maintenance Services Division.

The required work programs, activities, and resources are identified in the business plans of each division, which are developed via the business planning process as outlined in Ex. A2-T2-S1. The Nuclear base OM&A requirement is built up from these divisional inputs, which are reviewed and challenged by the Chief Nuclear Officer and (for 2008 business planning) the Senior Vice President, Nuclear Generation Development and Services. Following review, results are consolidated, and presented for review by the Chief Operating Officer, the Chief Financial Officer, and the Chief Executive Officer. Following Chief Executive Officer review, the proposed base OM&A business plan and budget are tabled with the Nuclear Operations

Committee of the Board of Directors for review prior to being tabled with the Board of Directors for final approval as part of the overall OPG business plan. Exhibit F2-T2-S1 Table 1 provides a summary of base OM&A over the 2005 - 2009 period.

To ensure appropriate resources to execute planned work, a series of standard resource types are used. Specifically, the major resource types used in budgeting are:

- Labour: Salary and benefit cost of staff on OPG payroll, both regular and temporary.
- Overtime: Pay for staff on OPG payroll, both regular and temporary, for work outside of normal shift schedule.
- Augmented Staff: Costs of specialized, incremental resources paid by purchase order, but supervised by OPG staff; for example, specialized engineering staff supplementing core resources for peak workload.
- Materials: Costs of all consumables, replacement parts, and associated transportation service costs incurred in performance of ongoing maintenance and repair work, as well as cost of all such items used during forced outages.
- License: Costs of licensing-related fees paid to the Canadian Nuclear Safety Commission (“CNSC”).
- Other Purchased Services: Costs of specialized resources paid by purchase order, but supervised by the external company; for example, construction and maintenance services, personal protective equipment laundry services, specialised technical services including research and development, testing services and security services; also includes Inspections and Maintenance Services to the stations.
- Other: Costs of miscellaneous items such as staff travel, fees to industry peer groups, utility expenses (water, sewage, and electricity for administration buildings), inventory adjustments, and contingency provisions.

Exhibit F2-T2-S1 Table 2 provides a summary of base OM&A over the 2005 - 2009 period by resource type.

Included with Nuclear base OM&A is OM&A-funded station support for conventional waste and transportation services, provided by Nuclear Waste Management Division.

2.1 Key Drivers of Base OM&A

The nuclear industry stands apart from other regulated industries and other forms of electrical generation due to the nature of its technology, the criticality of safety in operations and the nature of nuclear regulations. Consequently, there are a number of key drivers that influence the level of base OM&A associated with OPG's nuclear operations to a degree not seen in other regulated industries. Specifically:

- Safety: OPG must ensure that the stations are operated and maintained safely at all times, and remain safe even when non-operational. For example, even when a unit is shut down, nuclear fuel continues to produce heat that must be removed to ensure safety and prevent fuel or equipment damage.

  The requirement to meet nuclear safety regulations and standards imposed by the federal *Nuclear Safety and Control Act*, and the need to satisfy OPG's nuclear regulator, the CNSC, drives a large number of base OM&A work activities. These include scheduled "periodic inspections" of specified equipment, in-depth analysis and assessments of systems, systems operations and component conditions, and preventive and remedial activities. OPG has an ongoing requirement under the *Nuclear Safety And Control Act* regulations and its CNSC operating licences (as described in Ex. A1-T6-S1) to demonstrate that each station, in its current condition (e.g., after upgrades, modifications, and whatever aging has accumulated over time), conforms to the terms of its operating license and the *Nuclear Safety And Control Act* requirements. In addition to ongoing activities, there is also extensive effort for relicensing of each station every five years and the potential of additional requirements and costs associated with the license renewal. The base OM&A activities presented here support meeting those requirements.

  While nuclear safety is an obvious driver of maintenance and monitoring activities and therefore of costs, there has also been a trend in recent years for the CNSC to mandate changes to organizations and facilities to address changing requirements in such areas as physical security, emergency response, and fire protection. For example, there has been a significant increase in armed response resources at generating stations following the events of September 11, 2001, as well as an increase in the ongoing operating and maintenance costs of new security facilities. These new requirements have increased base OM&A costs.

- Complexity: Nuclear plants are technologically sophisticated facilities, with a large number of safety and process systems, and a high level of redundancy for critical components within the plant. As a consequence of their technical sophistication, nuclear generating stations contain in excess of 300k unique parts, and tens of thousands of plant components, a feature that drives up the volume, and therefore cost, of maintenance activities.

- Training: A further consequence of complexity is that OPG must hire staff with special skills that require extensive and ongoing training. This need for training not only impacts specialized engineering, operations and maintenance staff but also the support divisions that must develop or acquire the necessary training, deliver it to the employees who require it and ensure that it remains up to date. The following provides an example of the impact of training in the critical area of nuclear operators, to obtain their station-specific certification:
    - Non-licensed Operators: When a new field operator is hired, it typically takes approximately two years of training before the operator is able to perform work in the station. At this point, the non-licensed operator is able to work independently, but may still be required to work alongside an experienced operator for sensitive activities.
    - Licensed Operators: As opposed to the field-based non-licensed operators, licensed operators are authorized to physically operate the station within the main control room. Certification to become a fully authorized nuclear operator typically requires two to six years of field work as a trained operator, followed by four to five years of study and regulatory examination to be allowed to operate as a unit panel operator on an independent basis. Certification further requires ongoing training (one week out of five).

- Material Standards: Equipment in a nuclear station can be subjected to demanding conditions on an ongoing basis and may be required to operate in a harsh environment (e.g., steam environment, increased radiation, high temperature and pressure or seismic acceleration) under postulated accident conditions. The harsh environment not only necessitates more frequent maintenance or replacement of parts, but also requires tightly-specified replacement parts that are environmentally-qualified for operations under such conditions, and detailed maintenance procedures to ensure that such qualification is not inadvertently compromised. To ensure appropriate quality, material standards for equipment and spare parts require a demonstrable adherence to exacting codes and standards throughout the entire supply chain process. Some of the codes and standards are unique to the nuclear industry (for example, the very stringent Canadian Standards Association Z286 and Z299 quality assurance standards), requiring a level of effort not seen in other regulated industries. Supply Chain must create and maintain the infrastructure to identify and audit vendors who can meet the stringent requirements from both a technical and quality assurance program standpoint, complying with all applicable codes and standards. “Cradle to grave” traceability (from the material manufacturer of record, to the exact end use location within the station along with the qualifications of all staff who handled the item while in process), is an example of the very costly process that is required for many components.

- Work Environment: In addition to the direct impact on materials costs and demanding maintenance procedures as noted above, work environment (primarily radiation) also constrains labour productivity, since maintenance in some physical locations of the nuclear plant requires both protective procedures (for example, a radiation exposure permit and support of radiation safety specialists) and equipment (for example, the wearing of cumbersome plastic suits, with dedicated breathing air). Furthermore, exposure to radiation during routine activities can require higher overall staff levels, as individual employees may no longer be available for a given task due to personal radiation exposure limits. Maximum personal radiation exposure limits are expressly set out in the *Nuclear Safety And Control Act* regulations, and violation of these is a violation of the *Nuclear Safety And Control Act* and of OPG’s operating license thereunder.

Furthermore, it is OPG's policy to limit personal exposure in accordance with the industry best-practice As Low as Reasonably Achievable ("ALARA") principles. Thus, both within and outside radiation areas, labour productivity is significantly impacted by the need for:

- o Stringent security procedures required of all staff prior to entering protected areas of the plant (such as badging, security clearances, and metal detection).
- o Turnover communications/pre-job briefing for all staff, including procedure review for the specific job at hand.
- o Obtaining work authorization from operating staff, so that operating staff are aware of and approve all activities which might affect plant operation.
- o Obtaining radiation protection approvals, and adjusting protective equipment or receiving additional briefing as required.
- o Having equipment physically taken out-of-service, or appropriately isolated, such that work can proceed safely.
- o Ensuring job quality, via step-by-step signoff while executing procedures.
- o Ensuring safety, by having a "safety person" observe and ensure work is completed safely where required.
- o Reversing the work approval processes, to safety return the equipment to service and exit the work environment.

- Non-Standard Fleet: While OPG's ten nuclear units are all heavy water moderated CANDU (Canadian Deuterium Uranium) reactors, they reflect three generations of design philosophy and technology with: Pickering A, B, and Darlington built in the 1960's, 1970's, and 1980's respectively. This results in significant variations among the three nuclear stations including generating unit size (for example, gross generating capacity of 934 MW at Darlington versus 540 MW at Pickering B); technology (for example, more extensive digital control at newer versus older stations), and overall design (for example, the units at Pickering A and B have more heat transport pumps and steam generators than units at Darlington, but operate at lower pressure and flow velocity). More specifically:
  - o Darlington has a much smaller "containment" structure than Pickering, resulting in a greater number of components located outside containment and are therefore more

physically accessible for on-line maintenance at Darlington versus Pickering A or B. However, since the larger containment volume at Pickering includes the majority of the steam generator components, Darlington requires a larger number of "steam-protected" rooms outside containment to protect critical components from steam ingress in the event of steam line failures.

- o Pickering B and Darlington have two fully separated, functionally diverse sets of systems to handle critical nuclear safety functions (Group 1 and Group 2), while Pickering A does not (as per original design criteria).
- o Darlington units are larger generating capacity, but have fewer major components (for example, four steam generator/heat transport pump installations versus 12 steam generators and 16 heat transport pumps at Pickering).
- o Dedicated, unit-specific fuelling machines at Pickering A and B versus three fuelling machines that serve all four Darlington units.
- o Extensive use of digital equipment control for Darlington versus greater reliance on analog control technology at Pickering.
- o Different philosophy with respect to primary heat transport coolant system conditions.
- o Different control room layout and design philosophy at Pickering versus Darlington.

This lack of standardization due to "generation of design" limits OPG's ability to integrate operations and apply uniform approaches across the stations. These differences also impact on the extent and nature of operations and maintenance activity at each station. While OPG has successfully pursued cost saving strategies, such as opportunities for consolidating support from each station into the support divisions (for example, utilizing one nuclear level fire engineer instead of separate functions at each station), the lack of standardization limits the potential reductions in base OM&A expenditures.

In addition, this lack of standardization also significantly impacts:

- o Licensing Costs: With respect to the CNSC operating licenses, each station requires a fully separate licensing process; the operating license requirements uniquely reflect the design philosophy of that station and the specific issues of concern; and design and safety analysis is generally not transportable between stations. This translates into extensive effort to provide station-specific operating policies and principles (explicitly required by the operating license) as well as a comprehensive station-specific safety report which provides a detailed description of the station design as well as comprehensive safety analysis to demonstrate compliance with station licensing conditions.

- Training Costs: With the exception of basic skills training (for example, safety, chemistry, and science fundamentals), the majority of technical training is not transportable between stations. This requires not only station-specific staff training, but also the development and maintenance of all materials associated with such training; periodic re-qualification of staff; and, extensive retraining of staff moving between stations to ensure appropriate familiarization with their new facility. Standards are set and frequently upgraded, by the CNSC. Significant differences between stations also necessitates separate, full-function simulators (used to train control room operators) which are staffed, maintained and operated to requirements mandated and audited by the CNSC.
- Other Costs: Differences between stations also mandate the need for station-specific technical procedures, and maintaining extensive inventories associated with station-specific parts.

- <u>Aging Technology</u>: OPG's nuclear stations contain the first large-scale commercial CANDU units ever built, the result being that many of the technological issues OPG faces are being addressed for the first time in the nuclear industry. Addressing issues affecting critical components such as steam generators, feeder pipes, and pressure tubes has demanded and will continue to demand extensive effort. This work includes high cost maintenance activities such as the feeder replacement program, and preservation of fuel channels through restoration of spacing margin to prevent deterioration (spacer location and relocation program). Aging technology also drives OPG's ongoing investment in research and development programs. To the greatest extent possible, life cycle plans for all major components assist in identifying areas of concern; however, the fact that there is limited late-life operating experience introduces the possibility of unexpected technological issues which must be addressed.

- Evolving/Escalating Regulatory Standards: While existing facilities in other industries may be subject to grandfathering as standards evolve and improve over time, the nature of the nuclear industry is that evolving standards (especially related to safety) must be retrofitted and involve significant cost; for example, the second, enhanced shutdown system retrofitted at Pickering A and the Pickering auxiliary power system installation project (see Ex. D2-T2-S2). These requirements are mandated by regulatory authorities (primarily the CNSC) as described in Ex. A1-T6-S1, and are effected through CNSC staff that are resident at each of the nuclear stations. Frequently, changes to standards result from incidents or experience elsewhere in the nuclear industry, for example: impact of the Brown's Ferry Nuclear Station fire on OPG fire protection requirements; and, impact of the Three Mile Island incident on the environmental qualification of components required to operate under post-accident conditions. Other world events (9/11 and other terrorist events) have significantly changed security requirements. OPG also critically reviews operating experience from plants around the world to identify trends and issues that may affect our plants, and makes improvements based on this experience where it is justified.

- Advancements in Technology: Research and development activities lead to advancements that improve the operability and safety of the stations, with various impacts on cost. For example:
  - Specialized diagnostic tools, such as vibration monitoring equipment and non-intrusive testing such as oil analysis, help predict when equipment may need to be overhauled or maintained, as opposed to doing maintenance on a pre-scheduled basis (or as a result of unanticipated failure). While the result may increase upfront maintenance activity, it is expected to improve reliability and decrease maintenance costs in the long-term (less corrective maintenance).
  - New analytical codes, such as thermal efficiency cycle analysis and advanced nuclear safety analysis codes, support the operation of the units to safely maximize the power output of the plant, but may also identify previously unforeseen issues requiring resolution.

- Improved inspection capabilities, which make it possible to inspect an increasing range of components to a higher degree of precision, and, investigate a greater range of postulated material degradation mechanisms. Such advancements are important for monitoring the long term health of the generating stations, and allow a programmatic approach to managing issues (for example, the feeder thinning program which addresses all stations). While these enhanced capabilities provide a better assessment of station condition, this knowledge may lead to increased investigatory work or analysis (generally base OM&A funded), and the need for remedial intervention. However, increased capabilities may also be useful to supplement more conservative analytical models (for example, the extent of predicted thinning in a critical feeder), which can be used to justify continued operation prior to need for replacement.

2.2 Operational Functions Supported by Base OM&A

The Nuclear business plan outlines base OM&A requirements for each generating station and support division and Nuclear Generation Development and Services, as noted previously. This section provides an overview of the activities performed by these divisions, to provide context and support for base OM&A cost data that is provided on this divisional (or "operational function") view.

For the operational functions listed below, the vast majority of funding is provided by base OM&A. However, some functions are partially funded by project OM&A (Ex. F2-T3-S1), outage OM&A (Ex. F2-T4-S1) or project capital (Ex. D2-T1-S1), as outlined in those exhibits. Where significant, this is indicated below.

2.2.1 Operational Functions within Generating Stations

At each of the generating stations, operational functions are broken down into four main components: Work Management, Station Engineering, Support Services, and Operations and Maintenance, as described here.

- Operations and Maintenance includes:

- Operations: Operations staff operates the plant on a 24-hour basis, which includes starting up and shutting down components/systems/plant, system monitoring, ensuring safety of stations operations, responding to non-standard conditions, and performing activities associated with preparing and placing systems and components in- and out-of-service for maintenance. The CNSC approves the Operations organization structure, including mandating minimum shift complement to address foreseeable emergency response requirements. CNSC certification is required for key positions on shift including shift manager, control room shift supervisor, and control room shift operating supervisor (where applicable), authorized nuclear operator, and certified control room operators. All positions require rigorous initial and continuing training, and periodic recertification.

- Maintenance: Performs all activities directly related to the preventative, elective, and corrective maintenance of structures, systems, or components so as to address material condition issues, maintain equipment reliability, and optimize equipment life. It is the largest component of the Operations and Maintenance workforce. This function also addresses emergent maintenance issues which, if unaddressed, might lead to unit shutdown. Specialized groups within Maintenance (e.g., mechanical, electrical, and custodial) focus on specific equipment or aspects of plant maintenance. Another specialized group (Maintenance Support) provides support to accomplishing work efficiently. This includes developing specific work instructions for unique jobs, specific procedures for routine testing, and specific model work orders for preventative maintenance tasks. They also manage contracts to bring in external resources or expertise to meet work demand, and coordinate training activities to ensure individuals are qualified to perform specified work activities.

- Fuel Handling: Includes all activities in support of refuelling the reactor during unit operation; maintenance of the fuelling machines, and related systems; support of outage activities requiring fuelling machine or related systems; and, management of new fuel storage. Fuel Handling also has a large role during outages as many of the activities (e.g., fuel channel inspections) require fuelling machines or related systems for access.

- o Radiation Protection, Chemistry, and Environment: Includes assistance with radiation protection during plant operation and maintenance activities, and administration of the program for keeping radiation ALARA; operation of the chemistry lab; environmental compliance and monitoring; and, assistance in managing plant chemistry.

- Station Engineering: Provides engineering oversight, analysis, and support for Work Management and Operations and Maintenance at the stations in the areas of components and equipment, performance engineering, plant design, and reactor safety. Component engineering focuses on monitoring, analyzing, and troubleshooting at the component level across all systems, while performance engineering focus on monitoring, analyzing, and troubleshooting at the systems level. Reactor safety has the responsibility for determining the fuelling strategy for the reactor, monitoring testing to ensure system and component reliability targets are achieved, and monitoring the operation of the plant to ensure it is maintained well within the safe operating envelope. Plant design has responsibility for producing modifications required to support plant operation.

- Work Management: Includes two main functions – Work Control and Outage Planning. The Work Control function utilizes a 16 week rolling schedule to ensure corrective, elective, and preventative maintenance is performed effectively and efficiently. The Outage Planning function (funded by base OM&A) supports outage execution by utilizing an 18 month planning process to develop specific milestones for critical activities such as scope definition, long lead materials, schedule development, and pre-requisite work. This detailed planning process is within the envelope of the Integrated Nuclear Outage Plan and Nuclear Business Planning Process.

- Support Services: Includes Business and Strategic Planning, Fire Protection, and station-specific aspects of both PINO (see section 2.2.2), and Regulatory Affairs. In more detail:

- Business Support is accountable for the accounting/controllership function, cost reporting and analysis, business plan coordination, and financial target setting.
- Strategic Planning is accountable for producing long range outage plans; supporting outage scoping, forced loss rate assessments, and asset management/investment planning efforts; and, providing support for financial modeling of staffing requirements.
- Fire protection is accountable for around-the-clock fire protection, first aid, and hazardous materials response at the stations. In addition, they are accountable for hot work inspections (involving heat or open flame), and performing surveillance of fire protection systems and equipment. There is a minimum staffing level specified in each station's operating license.
- PINO is accountable for managing each station's human performance, operating experience, and corrective action programs, supporting station performance improvements, and providing support to the corporate audit function for compliance with nuclear programs and standards. This is done within the context of the nuclear level governance framework provided by the central PINO function (see Section 2.2.2).
- Regulatory Affairs is accountable for managing the station regulatory affairs function, in particular, interactions with the CNSC. This includes completing regulatory reporting requirements specified in the operating licenses; submitting annual reports in accordance with CNSC requirements; and, seeking any and all regulatory approvals for each site, including station re-licensing. The function typically involves management of over 400 pieces of correspondence per site per year.

The Tritium Removal Facility ("TRF") which is located at Darlington provides tritium removal services to all OPG nuclear stations and third party customers (as discussed in Ex. G2-T1-S1). Tritium removal is an integral part of the overall heavy water management program at the stations. Further details are provided in Appendix A.

While work activities and associated organization structures are to a large extent consistent across generating stations, there are some areas where OPG has pursued cost savings through consolidating for efficiency. Specifically, Pickering A includes a "Common Services" group within its Operations and Maintenance unit that manages heavy water for and operates facilities common to Pickering A and Pickering B (e.g., heavy water upgraders and radioactive waste management). In addition, the Pickering B Chemistry and Environment Department provides services to Pickering A while costs remain with Pickering B – the same arrangement as for Pickering B Support Services (specifically, Fire Protection and Regulatory Affairs).

2.2.2 Operational Functions within the Support Divisions

Support divisions are accountable for providing specialized services to the generating stations, as well as the common procedural framework within which the stations operate. As noted previously, the support divisions are Engineering and Modifications, Programs and Training, Supply Chain, PINO, and the Nuclear Level Common. Key functions of the support divisions are outlined here.

Engineering and Modifications is accountable for:

- Engineering Services, including generic and nuclear common support, project design support, nuclear safety analysis, and life cycle plans for steam generators and fuel channels.
- Science and Technology Development, which provides administration of the nuclear research and development program as well as specialized technical support for key nuclear plant systems and equipment.
- Engineering Codes, Standards and Quality Programs, which provides expert-level support on nuclear industry codes and standards; interfaces with technical standard organizations (the CNSC, as well as Technical Standards and Safety Association, and Canadian Standards Association); and, manages governance for programs such as the engineering change control program.
- Projects and Modifications, which functions as an internal general contractor, executing or managing the execution of the majority of project work carried out at the generating stations or their associated sites. Project work (in contrast to base OM&A work) is defined at Ex. D2-T1-S1. While the Projects and Modifications function is primarily project OM&A

and capital funded (Ex. F2-T3-S1 and Ex. D2-T1-S1), the description is included here for completeness.

Programs and Training consists of three basic units, with accountabilities as described here:

- Nuclear Programs and Training designs and delivers required training across the Nuclear organization. This includes conventional safety, general orientation, licensed and non-licensed operator training, skilled trades, engineering and leadership training. Nuclear Programs and Training also maintains the major programs in the areas of Operations, Maintenance, Radiation Protection, Fire Protection, Work Management, and Emergency Preparedness. This involves setting standards and providing governance in the performance of these functions, that is in line with regulatory standards and industry best practices. This function also plans for and administers new hires into the engineering, operator, and maintenance job families, under a program referred to as the workforce development program.
- Security, which provides security of nuclear sites and facilities, and ensures compliance with all CNSC security requirements.
- Facilities, Records and Admin (Nuclear Integration), which provides centralized business services (clerical/administration/records), maintains the governing document framework for all nuclear divisions, and manages all nuclear facilities outside of the protected area of the generation stations, but within the station boundary.

Supply Chain is accountable for:

- Providing the materials and services required by the Nuclear business. Supply Chain performs this function by executing risk-managed purchases of fuel, materials and services; providing material storage, delivery, disposal; and, surplus equipment management.

PINO, as a central function that provides the framework and governance for station PINO departments, is accountable for:

- Driving performance improvements across OPG's nuclear fleet through the common human performance program, operating experience program, and corrective action

- program that are implemented by station PINO departments; performing audits and assessments; regulatory affairs management, such as interfacing with the CNSC; and, administering nuclear license requirements. A key component of their function is management of the corrective action program, which drives identification and resolution of issues affecting operational safety or performance.

Nuclear Level Common covers:

- Centralized costs required to manage the Nuclear business overall that are not directly attributable to any one plant or support organization. Typical costs include nuclear level consulting contracts and a budget allowance for major, unforeseen maintenance and repair costs which historically have arisen in the operation of a multi-unit, multi-location fleet of reactors. In addition, Nuclear Level Common includes the actual cost of labour price variances between nuclear payroll and the standard labour costing model used in the divisions.

2.2.3 Operational Functions within Nuclear Generation Development and Services

Nuclear Generation Development and Services includes those divisions that are involved in external sale/lease of OPG assets, products and services, as well as those involved in planning future nuclear generation capacity. Specifically:

SVP Office is accountable for:

- Executive office costs, business unit consulting contracts and fees, and, indirect costs (sickness, vacation, health and other causes) for staff working on New Nuclear Build and Refurbishment.

Commercial Activities is accountable for:

- Managing the Bruce Lease (long-term lease of the Bruce A and Bruce B Generating Stations to Bruce Power, see Ex. G2-T2-S1).
- Coordinating management of heavy water for OPG as well as third parties (see Appendix A for a description of heavy water management program, and Ex. G2-T1-S1).

- Marketing and management of sales of isotope products and services to third parties (see Ex. G2-T1-S1).

Generation Development is accountable for:

- Refurbishment Programs: assessing options for refurbishment, and continuing to operate Pickering B and Darlington units beyond their currently-predicted end of service life (see Ex. D2-T1-S3).
- New Nuclear Build: investigation of potential new nuclear units at the Darlington site as directed by the Ontario Minister of Energy in 2006 (see Ex. D2-T1-S3).

Inspections and Maintenance Services Division is accountable for the provision of services to supplement those carried out by station staff, where the nature of the skills or equipment required makes these more effectively managed as a central function for all stations, or where there is the potential for external marketing of services. Specifically:

- Specialized inspection services (e.g., fuel channels, steam generators, and other heat exchangers).
- Specialized maintenance services (e.g., steam generator tube plugging and removal, fuel channel replacement, and spacer location and relocation program).
- These services are provided internally, as well as to external customers, as described in greater detail in Ex. G2-T1-S1.

2.2.4 Waste and Transportation Services

Waste and Transportation Services includes OM&A-funded station support provided by Nuclear Waste Management Division. Specifically, it includes:

- Managing recycled conventional wastes, such as scrap metal and office materials, and contracts associated with pick up and disposal of hazardous waste.
- Providing a transportation service for all stations, including transfer of tritiated heavy water for the Darlington TRF.
- Accepting and managing all spent solvents generated from chemical cleaning of steam generators at the Pickering generating station. The Spent Solvent Treatment Facility

provides storage of the spent solvents, and treats them using ultrafiltration and reverse osmosis. Treated solvents are then shipped via contract for disposal off-site.

2.3 Base OM&A by Resource Type

Exhibit F2-T2-S1 Table 2 demonstrates that the majority of base OM&A costs are staff labour, accounting for approximately 73 percent of total base OM&A expenditures, which is comparable to other nuclear utilities. Percentages included below are based on 2007 actual costs, but are generally reflective of all years. Further details of each resource type are provided here.

Labour: Labour escalation and benefit cost increases have historically been in the range of $49.1M to $52.7M per year (Ex. F2-T2-S1 Table 4). This reflects the labour cost impact of increases to payroll benefits and wage scales, in accordance with negotiated labour agreements that cover the test period (See Ex. F3-T4-S1). The exception to this general range in labour escalation occurs in 2008, where the increase is less than the historical average, due to a reduction in the payroll burden percentage of standard labour rates for that year (see Ex. F3-T4-S1). Exhibit F2-T2-S1 Table 4 also includes the additional impact of $16.9M in 2006, reflecting the fact that divisional budgeting is on a fiscal year basis as opposed to the calendar year basis used for corporate financial reporting. As there are 364 days in a fiscal year versus nominally 365 in the calendar year used for corporate financial reporting, it is necessary to periodically insert a 53rd fiscal week in a budget year to avoid growing misalignment between the fiscal and financial reporting calendars. This effect (which impacts only labour) is offset for corporate financial reporting purposes by a corporate fiscal calendar adjustment as outlined in Ex. F3-T1-S1.

As noted in Ex. F2-T2-S1 Table 3, nuclear full-time equivalents (“FTEs”) decrease after the 2008 peak, which partly offsets the cost impact of labour escalation and benefit cost increases expected in 2009. This decrease in planned FTEs reflects primarily station and support division labour reductions associated with equipment performance and supply chain improvement initiatives (Appendices B and C),and the planned completion of the Pickering A safe storage project. These planned labour decreases are partly offset by labour increases within Nuclear Generation Development and Services, associated with planned staff increases for Darlington refurbishment and new nuclear build assessment work (see Ex. D2-T1-S3), and within Inspection and Maintenance Service (to reduce the reliance on augmented staff, as discussed in Ex. G2-T2-S1).

While Ex. F2-T2-S1 Table 3 includes staff funded by all funding sources (base OM&A, outage OM&A, projects, etc.), the great majority of staff are base OM&A funded, except for the following:

- Pickering A Unit 2 and 3 safe storage project staff (funded by decommissioning provision or capital and OM&A project portfolio for Pickering A Unit 2 and 3 isolation project, with the majority of affected FTEs indicated in Table 3, Line 40).
- Inspection and Maintenance Services staff directly involved in external business that are funded by cost of goods and services sold (approximately 90 FTE per year of totals shown in Table 3, Line 35, increasing to approximately 140 in 2008 in line with higher than normal external workload and plans to reduce the reliance on augmented staff, as noted above).
- Engineering and Modifications staff involved in supporting capital/OM&A projects (essentially all of the Projects and Modifications staff noted in Table 3, Line 27, and approximately 145 FTEs/year of Other Engineering and Modifications staff noted in Table 3, Line 28.
- Approximately 100 FTEs per year of station staff and 85 FTEs of other support division staff are directly involved in OM&A and capital projects work, and would be funded by that work as opposed to base OM&A.

Other Purchased Services: After Labour, the next largest cost element is other purchased services, approximately 11 percent of total base OM&A. For the generating stations, other purchased services represents work done by specialized contractors, such as Laundry Services ($12M in 2007), maintenance contractors, material repairs, environmental compliance testing, facility services, as well as engaging external contractors to perform base work that cannot be accomplished due to staff shortages (i.e., vacancies or staff on extended training). For the support divisions, other purchased services again reflects some coverage for regular staff vacancies, but more significantly, nuclear safety analysis services ($14.7M in 2007), research and development ("R&D") program contract costs ($15.1M in 2007), and contracted security services. In the case of the R&D program, services are contracted to CANDU Owners Group, an association conducting research and development work on industry-wide issues which allows utilities to share R&D costs, specifically; Atomic Energy of Canada Limited pays 25 percent of costs, while the balance is divided between participating utilities such as Hydro Quebec, Bruce Power, and New Brunswick Power on the basis of the number of nuclear generating units. For further details, see Appendix G. For Nuclear Generation Development and Services, other purchased services reflects primarily the efforts of external contractors planned for assessment work on the refurbishment and new nuclear build programs.

<u>Materials:</u> Materials (approximately seven percent of total base OM&A) are the next most significant component. Costs include all consumables and replacement parts used in the performance of ongoing maintenance and repair work, as well as items used during forced outages (charged to base OM&A, as indicated above). Increasing costs over the 2005 - 2007 period reflect efforts to reduce corrective maintenance backlogs.

<u>Overtime:</u> Overtime (approximately five percent in 2005 down to three percent of total base OM&A in 2009) is the next most significant cost element at the stations. Overtime covers the cost of staff working beyond core hours, for example; forced outages or urgent repairs, coverage of licensed positions and providing backup for absent staff so as to maintain minimum staff complement on shifts. In addition to other purchased services, overtime is also used to perform work impacted by unfilled vacancies. In the support divisions, the majority of overtime is associated with maintaining minimum complement for security services and training delivery (during times of peak demand) as provided by Programs and Training, and also within Supply Chain to meet demand for materials in support of outages, as well as providing warehouse support for areas not covered by the 24/7 duty crew coverage.

<u>Other:</u> The resource type 'Other' (approximately three percent of total base OM&A costs), covers costs related to utilities for nuclear facilities (water, sewage, electricity for

administrative buildings), maintenance of OPG work equipment and vehicles, and travel and accommodations for staff (associated with off-site technical training, participation in industry conferences, technical standard working committees, World Association of Nuclear Operators audits as well as conducting supplier audits by Supply Chain. In previous years, 'Other' also included a planning estimate for contingency, reflecting preliminary estimates for potential issues at the time of 2007 - 2011 business planning. This contingency has been allocated to identified work during 2008 business planning. The final component of 'Other' is inventory adjustments, which are addressed in two ways:

- An inventory valuation provision, which is assessed on a quarterly basis and adjusted as required. The provision addresses inventory which has been de-valued due to shelf-life expiry, quality ('Q-level') changes and inventory losses.
- An obsolescence provision, which is assessed on an annual basis. The provision recognizes the unique nature of the majority of nuclear materials, and their limited use outside of OPG, by offsetting expected residual inventory value at end of station life. This provision also addresses the cost impact of technical obsolescence, due to design changes or other technical factors that would preclude inventory use within the stations.

License: The resource type "License" (approximately one percent of total base OM&A) covers fixed costs of the station operating licenses, as well as a forecast of the costs to be charged by CNSC on a fee-for-service basis relating to services for review of additional work programs such as refurbishment and new nuclear build programs.

Staff Augmentation: The resource type "Staff Augmentation" (less than one percent of total Base OM&A) reflects the limited costs of engaging external personnel to backfill for vacancies within the organization or provide specialist expertise within an organization.

3.0 BASE OM&A PROGRAM OVERVIEW: 2005 - 2009

OPG Nuclear effort over the 2005 - 2009 period is focused on achieving more dependable and predictable performance through:

- Continuing focus on high safety performance.
- Improving equipment performance through backlog reduction.

- Improving human performance and productivity.

In addition, effort is being directed towards preparing for future supply options, through investigation of the refurbishment option and new generation development for nuclear.

Recent performance trends have been favourable in the areas of safety and human performance. In addition, improvement to plant material condition (as measured through plant condition index and elective and corrective maintenance backlog reduction, see Appendix B) is also trending positively and, in time, will improve cost performance and production reliability as included in the business plan targets and this filing.

Base OM&A expenditures over the period 2005 - 2009 reflect a continued refinement and realignment of resources reflecting a gradual shift of emphasis from improving plant material condition (corrective and elective maintenance activities) towards maintaining plant condition (preventative maintenance activities) and sustaining the benefits of improvement programs to retain improved performance until end of plant life.

3.1 Base OM&A Trends

Analysis of Ex. F2-T2-S1 Table 1 reveals several trends.

Base OM&A costs increase from 2005 - 2008, before leveling off in 2009. This trend reflects primarily: resourcing for station and supply chain improvement initiatives in 2005 - 2008 as outlined below, then reducing resources in 2008 - 2009 as indicated in Ex. F2-T2-S1 Table 3; the impact of the decision not to restart Pickering A Units 2 and 3, but to place them in safe storage as approved by the OPG Board of Directors in August 2005 (resulting in sharing of some Pickering A staff with the Pickering A Unit 2 and Unit 3 Safe Storage Project); and, continued evolution of security requirements. For 2009, the cost impact of staff reductions is largely offset by the impact of labour escalation, as detailed in Ex. F2-T2-S1 Table 4.

The base OM&A split between stations and support divisions remains relatively constant over the 2005 - 2009 period.

Within the stations, the relatively lower cost for operating Pickering A reflects the fact that it is a two unit station (following the 2005 decision not to proceed with the plan to re-start Units 2 and 3) versus four units at Darlington and Pickering B. As there are certain minimum functions required at a station regardless of the number of units supported, resources required for Pickering A do not reflect a simple 50 percent pro-rating of Pickering B. The relatively higher cost of Darlington with respect to its four-unit counterpart Pickering B reflects primarily the costs of operating the TRF at Darlington. Further breakdown of the Operations and Maintenance effort and explanation of cost trends can be found in Ex. F2-T2-S2.

Within the support divisions, the majority of costs are with Programs and Training, reflecting the required level of infrastructure associated with providing core services in the key areas outlined above, including developing and delivering training, managing the overall security function for the generating stations and support divisions, administrative support and records management, facilities management, and the extensive effort involved in monitoring and maintenance of major programs employed across all stations, including operations programs, maintenance programs, outage programs, work control programs and the workforce development program (see below). Further breakdown of Programs and Training functions and explanation of year-over-year trends for all support divisions can be found in Ex. F2-T2-S2.

Within Nuclear Generation Development and Services, costs increase over the 2006 - 2008 period, reflecting primarily the increasing effort in plant refurbishment programs (Darlington and Pickering B), as well as preliminary investigations into a new nuclear build at the Darlington site.

To minimize the impact of the significant drivers of base OM&A outlined above, Nuclear has undertaken cost containment initiatives as follows:

- Efficiency improvements in the materials acquisition and distribution process (particularly, the Supply Chain improvement initiative, Appendix C), to ensure material availability when needed and potentially future productivity improvements.

- Efficiency improvements in the "on-line" (as opposed to outage) work management processes, with associated reductions primarily in the maintenance function in the test years.
- Improving forced loss rate performance to reduce forced outage impact on base OM&A.
- Improvements in the preventive maintenance program implementation, with potential benefits for forced loss rate predictability and cost savings due to reduced corrective maintenance.
- Participation in the corporate support function review (see Ex. F3-T1-S1), with incorporation of savings of $10.9M in 2008 and $11.6M in 2009 in the business plan. Savings are related to activities such as streamlining of station work management processes, and consolidation of station support for Pickering A and B.

These improvements, some of which are further elaborated upon in Ex. E2-T1-S1, will help stations to meet the maintenance backlog targets, thereby improving material condition of the plants and achieving forced loss rate targets. Improved generation performance and improved productivity based on these initiatives have been factored into the business plan, allowing Nuclear to minimize the impact of labour cost escalation, as discussed below. This is demonstrated in FTE reductions in 2009, as indicated in Ex. F2-T2-S1 Table 3.

3.2 Base OM&A Initiatives

A limited number of factors most influence the work program over the planning period. Key programmatic responses are noted here, with impact on variances and year-over-year changes noted in Ex. F2-T2-S2.

<u>Improving Equipment Performance to Support Reliable Performance:</u> As indicated in Ex. E2-T1-S1, one of the key initiatives to improve outage performance is improving future reliability by reducing maintenance backlogs. As noted there, this initiative is focused on efforts to reduce the number of on-line corrective and elective maintenance backlogs at all three stations. Maintenance backlogs represent deficiencies at the plant and are used as an indicator of station health. In the past, as discussed at Ex. A1-T4-S3, OPG reduced its investment in plant material condition, with a resulting negative impact on equipment

performance and increase in maintenance backlogs. Throughout the 2005 - 2009 period, the stations are investing significant resources in Equipment Performance Improvement Initiatives (Appendix B) with the expectation that this will support achievement of production targets in a cost-effective manner. As efforts peak in 2007 - 2008, completion of improvement efforts and reallocation of resources in 2008 - 2009 contributes to reduced base OM&A requirements in the test years. For further details, see Appendix B.

<u>Supply Chain Improvement Initiatives (Appendix C)</u>: Supply Chain is part way through their performance improvement plan which commenced in 2005, with a focus on three broad program objectives that include: improving material availability, establishing a competent nuclear supply chain organization, and re-establishing commercial leverage. Early results have demonstrated the improvement in materials available to support the Equipment Performance improvement initiative, as demonstrated through the reduction in average aging cycle time backlogs from an average of 930 days in 2005 to 56 days at the end of November 2007. In addition, both the outage milestones and on-line scope compliance results for materials showed significant improvement in 2007. The focus in 2008 and beyond will be to drive efficiency improvements while continuing to improve upon service levels. The FTE reductions for Supply Chain noted in 2009 are a direct result of these initiatives. For further details, see Appendix C.

<u>Addressing Demographics of an Aging Workforce (Appendix D)</u>: Consistent with experience in the nuclear industry and other industries, workplace demographics mean that OPG will be facing a significant loss of key staff in the very near future. In response to this, a workforce development plan, initiated in 2004, continues throughout the bridge and test periods. The goal of this plan is to attract, hire and retain new staff to address the challenge of an aging workforce. Costs relate to the hiring and initial salary costs of inexperienced new hires as well as strategic partnerships with colleges and universities to help ensure a supply of high quality candidates. In addition to engineering graduates, the workforce development plan targets skilled trades, including an apprenticeship program, and licensed/non-licensed operator positions.

Addressing Tritium Removal Facility Reliability: The TRF condition has degraded over the years, such that reliability is impacting station performance and limiting revenue from external sales of detritiation services. The TRF improvement plan (Appendix E) is an initiative to improve the facility's material condition, thereby improving reliability and reducing outages. Through these improvements, the goal by 2011 is to increase the volume of heavy water treated (detritiated) to 2,300 Mg/yr (on a three year average), from a historical average of 1600 Mg/yr. Base OM&A is required to support project execution/coordination and improvements to procedures. Increased external revenues are expected starting in 2010.

Addressing Programs and Training Infrastructure: Over the 2007 - 2009 period, Programs and Training is facing increased program and resource demands in three key areas; facilities, training, and security. As noted above, the Division's accountability includes management of all nuclear site facilities outside of the generating station boundary. There are increased costs of operating site facilities (specifically, an increased number of buildings to be maintained including security structures, and an increased level of effort in demonstrating compliance with fire protection codes and standards). The demand for training continues to be high based on demographics of the workforce and regulatory expectations. The security program is being adjusted and resources augmented where appropriate to comply with regulatory requirements. In addition to the program and resource changes to meet the increasing demands in these areas, Programs and Training has initiated several key improvement initiatives that will result in overall benefits for the Nuclear business. These Programs and Training infrastructure initiatives include the Leadership Academy, preparation of Nuclear pandemic plans, upgrading maintenance and non-licensed operator training program material and developing/upgrading authorization training program material (approximately $3.4M 2007, $2.4M 2008, and $1.9M in 2009). Upgrading of training courses and training backlog reductions are in line with CNSC directives and external assessments. The total investment in these specific initiatives is approximately $7.7M over 2007 - 2009. For further details, see Appendix F.

Addressing Shareholder Expectations for Generation Options: In response to a June 2006 Directive from the Minister of Energy, the bridge and test years include amounts to formally assess plant refurbishment options for Pickering B and Darlington units, as well as to perform a preliminary assessment of new nuclear units ("New Nuclear Build") at the Darlington site. Plant refurbishment costs of $24.6M for 2008 and $22.7M for 2009 have been included in this filing. New nuclear build costs are also included ($75.4M in 2008 and $67.2M in 2009). This is shown in Ex. F2-T2-S1 Tables 5 and 6. Further details are provided in Ex. D2-T1-S3.

Addressing Under-staffing in Key Areas: In 2006, it was apparent that a vulnerability to staff shortages in key operations and maintenance areas resulted in loss of generation (for example, the forced outage extension at Darlington due to shortage of fuel handling operators), with a continued threat of similar shortages in the future. Staff complements have been increased in critical areas at the stations (such as fuel handling staff at all stations, maintenance assessors at Pickering A, reactor maintenance staff for increased feeder replacement activities and life cycle plan requirements).

LIST OF ATTACHMENTS

Appendix A: Description of Heavy Water maintenance and Processing

Appendix B: Equipment Performance Improvement Initiatives

Appendix C: Supply Chain Improvement Initiatives

Appendix D: Workforce Development Program

Appendix E: Tritium Removal Facility Improvement Plan

Appendix F: Programs & Training Infrastructure Improvements

Appendix G: Research and Development Program Overview

Appendix A

Description of Heavy Water Maintenance and Processing

Heavy water is a manufactured product, required for CANDU reactor operations. For this reason, OPG has a heavy water maintenance program designed to manage its inventory of heavy water, whether in storage or in use within its reactors.

CANDU reactors use heavy water as a moderator for the nuclear reaction and as a heat transport medium in the reactor. The moderator slows down neutrons released by fission to a level where a self-sustaining chain reaction can occur (i.e., each fission produces at least one neutron, resulting in a subsequent fission). Heavy water is used as a moderator when natural uranium is used (as in CANDUs) because light water absorbs too many neutrons to result in a sustained reaction. This statement, and the fact that isotopic limits are specified in the station operating licenses, illustrates the importance of maintaining the purity of the moderator, referred to as its isotopic level. As heavy water is diluted with light water, it behaves more like light water: a higher number of neutrons are absorbed, reducing the population available for a reaction. This translates into a loss of efficiency, i.e., a “high burn rate”, as a higher consumption of fuel is required to maintain the same output. When the isotopic level is too low, the chain reaction becomes impossible.

The heavy water in the heat transport system circulates over the fuel, collecting the heat created by the nuclear fission process, thus cooling the fuel at the same time, and goes to the steam generators where heat exchangers remove the heat. This heat is used to boil normal light water, resulting in steam, which is then fed to turbines for the generation of electricity.

Heat transport system isotopic requirements are lower than for the moderator, but cleaning heavy water and maintaining isotopic purity is a key driver of the heavy water processing program, regardless of use as moderator or heat transport medium. This function is provided by upgrading plants, located at the Darlington and Pickering sites, to remove impurities and restore the heavy water isotopic level by removing light water that may have been introduced.

Tritium removal (detritiation) is the second major component of heavy water maintenance management. A by-product of the nuclear reaction is the interaction of neutrons with heavy water, resulting in the production of radioactive isotopes. One particular isotope, tritium, builds up in concentration over the life of the reactor in both the moderator and heat transport heavy water. The heat transport system operates under high temperature and pressure and therefore is more prone to leakage, a condition which does not exist to the same extent for the moderator system (which operates at a lower temperature and pressure). Personal protective equipment and breathing apparatus are required for such work where tritium could be present, to protect workers from exposure.

Because of these safety issues, the Canadian Nuclear Safety Commission ("CNSC") has prescribed tritium concentration limits for each OPG station. To manage this prescribed limit, OPG operates a TRF, located at Darlington. The purpose of the TRF is to remove tritium from heavy water used in CANDU reactors and to process water from out-of-service units prior to moving it to long term storage. As discussed at Ex. G2-T2-S1, OPG provides detritiation services to Bruce Power under the terms of the Bruce Lease Agreement.

Loss make-up is the third component of heavy water maintenance. The heavy water that is used as moderator is contained within the calandria. It is also circulated to heat exchangers, removing excess heat that is created over time in order to avoid the resulting pressure build-up. A number of other systems (e.g., liquid poison injection system which is used to assist with reactor shut down, or the purification system which removes impurities to reduce corrosion/erosion damage) are also connected to the moderator circulating system.

The use of heavy water as a moderator for the nuclear reaction and as a heat transport medium in the reactor results in a number of potential leak points. While the extent of losses has been minimized through design and maintenance efforts, and there are systems in place to capture leakage, in the course of plant operations some heavy water is lost through:

- Vapour losses in the heat transport system (largest contributor).
- Discharge of fuel bundles into the irradiated fuel bay.
- Heavy water sampling and analysis.
- Component decontamination.
- Maintenance work.

OPG strives to minimize the impact of this by having collection systems to recover heavy water from various points. Successful campaigns have been implemented to improve heavy water recovery.

Chemistry control and the removal of impurities is the fourth and last component of heavy water maintenance.

Appendix B
Equipment Performance Improvement Initiatives

Objective

In order to safely, efficiently, and reliably operate nuclear units, it is essential that plant equipment is operated and maintained to industry-accepted standards. The objective of this program has therefore been to develop processes (or adopt them from other utilities) for: assessing nuclear system performance "health"; setting equipment performance improvement targets as part of the annual business planning process; and, investing the required resources to achieve targets.

Background

As indicated above, maximizing a generating unit's equipment availability directly supports reliable and cost-effective electricity generation. Not only is this the business strategy and operating philosophy of OPG, but it is the expectation of both the CNSC and World Association of Nuclear Operators. OPG is periodically evaluated to ensure that the number and significance of the equipment deficiencies are in line with industry standards.

To this end, business planning targets are set to improve equipment performance, and performance against these measures is tracked throughout the year.

With respect to equipment and system performance, the plant condition index ("PCI") is a composite index that is used to measure the overall "health" of station systems and components. PCI is a performance metric used in business planning and performance is tracked against it.

In addition, due to the correlation between equipment maintenance and production reliability, there is strong emphasis on minimizing the number of equipment deficiencies (physical or document-related), which are tracked as "backlogs". Corrective maintenance backlog is a measure of the number of out-of-service or broken pieces of equipment (for example, a pump which will not operate). Elective maintenance backlog is a measure of the number of pieces of equipment that can still operate, but have a deficiency (for example, an oil or water leak) that could develop into a corrective maintenance problem. Maintenance may be carried out online (while station is in operation), or during an outage (where required due to access or other considerations). To this end, online elective and corrective maintenance backlog is an important planning and reporting measure.

There are a number of other factors that also impact unit reliability.

- Outage Maintenance Backlogs: As part of the outage program (Ex. E2-T1-S1), OPG tracks equipment deficiencies that can only be addressed with the unit shut down. Significant effort is put into addressing such deficiencies as part of outage maintenance initiatives to improve production reliability. This is distinct from the backlog metric for online backlogs (displayed in Chart 2), which are deficiencies that can be repaired with the unit operating.
- Single Component Vulnerabilities: Based on station design, there are a number of single equipment failures (or single failure modes) which can result in a unit shutdown. The newer the station, the more redundancy there is and hence, the lower the risk that failure of one piece of equipment will result in a shut down or de-rate. Because of its age and design, Pickering A is more susceptible to being shut down due to a failure of a single component. At each station, programs are in place, or have been initiated, to address single component vulnerabilities that could potentially result in a unit de-rate or shutdown.
- Legacy Equipment Issues: At each station there are a number of long standing equipment problems which are either very difficult to resolve, occur intermittently (and are therefore difficult to trouble shoot), or where the original equipment manufacture expertise is not readily available. OPG's nuclear units are operated in such a manner that these issues do not impact nuclear safety, but may affect unit reliability. These issues are therefore being actively addressed.

Program Overview

As opposed to a standalone program, this initiative is a collection of station programs to improve the performance of the units. And each station's improvement plan will have elements to address equipment and human performance. While each station had chosen a "branding" (for Pickering B - "85/5", for Pickering A - "Pathway to Excellence", and for Darlington - "Navigator") that lines up with the culture and objectives of the station, the common elements to all programs is equipment and human performance. This “nuclear level” focus was reinforced during 2008 business planning, with abandonment of the station-specific programs referred to above in favour of the common priorities and messaging of a “fleet” approach.

As indicated above, OPG has selected a number of key indicators to drive and monitor our improvement programs.

As noted in Chart 1, PCI for Darlington and Pickering B has improved over the 2005 - 2007 period, and further improvements are planned for the test years. For Pickering A, the first reliable data was available in 2007, when sufficient post-return-to-service operating data had been collected. PCI improvement efforts may be funded by base OM&A, or specific OM&A or capital projects may be involved.

Chart 1

Plant Condition Index

Plant Condition Index	**2005**	**2006**	**2007**	**2008**	**2009**
	Actual	Actual	Actual	Plan	Plan
Darlington	65	67	69	69	70
Pickering A			54	58	60
Pickering B	54	60	60	66	67

Another element of the equipment performance improvement plans deals with online elective and corrective maintenance backlog reduction. At present, and moving forward, the stations are allocating resources to programs that reduce outstanding maintenance items (“backlogs”), thereby improving reliability and reducing the number of force production losses due to unplanned outages. Backlog reduction initiative efforts are largely funded by base OM&A, and involve numerous functions (operations, engineering, maintenance, and/or work control).

The magnitude of the backlog varies from station to station depending on the rate of new deficiencies identified, available resources to support backlog reduction, and ability to address repetitive or longstanding equipment failures. The specific backlog targets are set by the plants as part of business planning process, based on industry standards.

At Darlington, the focus is on reducing elective backlogs which are above the industry standard of 350 work orders per unit. The level of corrective backlogs is comparable with the industry standard of 20 to 25 work orders per unit. For Pickering B, the initial focus has been on reducing corrective backlogs before major steps can be made to reduce the elective maintenance backlogs. At Pickering A, the focus is on reducing the elective maintenance backlogs, and addressing a number of the longstanding equipment issues and reducing the number of single component vulnerabilities. To achieve this, Pickering A has undertaken a reliability restoration plan in 2008. Chart 2 provides an overview of backlog reduction history and future plans.

Chart 2

Online Elective and Corrective Maintenance Backlogs per Unit

Station	Backlog **Description**	**2005 Actual**	**2006 Actual**	**2007 Actual**	**2008 Plan**	**2009 Plan**
Pickering A	Elective	541	558	428	425	375
	Corrective	8	17	14	20	15
Pickering B	Elective	805	885	926	700	575
	Corrective	148	71	22	25	25
Darlington	Elective	767	584	373	350	325
	Corrective	20	14	13	15	15

<u>Current Status/Results:</u>

As indicated in Chart 2, all stations are at industry standards for their corrective maintenance backlogs. Since there are in total hundreds of thousands of operating components in the stations, being able to maintain this level is a significant challenge. With respect to elective maintenance, Darlington and Pickering A are approaching the industry standard backlog targets (see Ex. A1-T4-S3). In the 2008 business planning period, OPG will be increasing investment at Pickering B to help reduce its elective maintenance backlogs to industry standard.

Resource Profile

As indicated throughout the base OM&A exhibit, Equipment Performance Improvement Initiatives ("EPII") have accounted for significant year-over-year changes in Base OM&A and the associated FTE effort. Specifically, resources were ramped up in 2007 tied to major backlog reduction effort, and then will be reduced in 2008 - 2009 as targets are achieved.

While station efforts on this program were not explicitly accounted for separately, the chart below provides an indication of the magnitude of resources involved in these incremental improvement initiatives – and the FTE reductions expected in the test years.

Chart 3

Base OM&A Costs/FTES for EPII

($ Million)	2005	2006	2007	2008	2009
	Actual	Actual	Actual	Plan	Plan
Darlington	12.2	10.8	18.5	8.0	1.4
Pickering A	3.1	5.2	4.7	6.6	7.5
Pickering B	14.8	20.9	18.5	5.0	4.0
Total OM&A	30.1	36.9	41.7	19.6	12.9
FTEs					
Darlington	80	80	138	53	9
Pickering A	7	13	21	21	6
Pickering B	29	102	111	75	15

APPENDIX C
Supply Chain Improvement Initiatives

Background

In late 2004 and early 2005, performance of the Supply Chain organization was not meeting expectations, and was significantly impacting the Nuclear organization's ability to achieve their business plan results. Independent assessments indicated concerns with leadership, employee engagement, and management processes fundamental to high performance organizations. The Nuclear Supply Chain performance improvement plan, established in 2005, was based on a clear strategy to put these foundation elements in place, improve service levels in 2006 and 2007, then, drive efficiencies and cost reductions in 2008 and beyond.

Objective and Program Overview

The Nuclear Supply Chain organization has established their improvement plan which will achieve benchmarked performance in the nuclear utility industry by end of year 2010. This will be achieved through three broad program objectives:

1. Improve material availability to meet station requirements through reducing our supply chain backlogs, establishing service level agreements and restoring the objectivity for material delivery through performance measures, targets, and initiative milestone. The specific initiatives that are being pursued in this improvement plan include:
    - Sustained backlog reduction – eliminate process backlogs to a point that work flows can be managed in a programmatic and planned manner.
    - Integrated Supply/Maintenance Strategy – establish the maintenance strategy for plant equipment and align the supply and inventory processes.
    - Collaborative demand planning – predict the stations needs and demands based on usage analysis resulting in increased service, quality, and cost.
    - Inventory optimization – improve inventory planning and visibility across the business in order to increase service levels while reducing the cost of inventory.

- Warehouse and logistics optimization – standardize and simplify warehouse and logistics processes in order to drive cost and service performance.

Key performance metrics for this program are average aging of cycle times, online and outage milestone adherence, and alignment to cost and service metrics. This program is a key enabler for the equipment performance improvement program, as described in Appendix B.

2. Establish a competent Nuclear Supply Chain organization to sustain service improvements through a focus on managerial competencies, restoring compliance with governance, and establishing an integrated management system that is registered to the ISO 9001, ISO 14001 and OHSAS 18001 (Quality, Environment and Health and Safety) standards. The specific initiatives that are being pursued in this improvement plan include:

- Information technology strategy implementation – provide an end-to-end process that is collaborative and integrated with our vendors and internal customers.
- "View of the Business" – manage the business in a transparent and efficient manner using objective qualitative and quantitative performance measures.
- "Cradle to Grave" accountability – implement processes which will consolidate roles, reduce handoffs, and increase staff capability.
- Relationship management – implement changes in the organization to shift from reactive labour and customer relations to proactive.

Key performance metrics for this program are the improvement in employee engagement scores, corrective action plan health index, training index, registration to IS0 9001, ISO 14001 and OHSAS 18001 and achievement of full-time equivalent reductions aligned with the business plan.

3. Re-establish commercial leverage with the vendor base to improve our control of costs while improving the quality of vendor performance and improving our service levels to our internal customers. The specific initiatives that are being pursued in this improvement plan include:

- Strategic sourcing and procurement – leverage the systematic approach to managing the acquisition of materials and services that achieves the lowest total cost of ownership.
- Contract management – improve the integration with maintenance and project schedules, resource utilization, and supplier quality.
- Supplier relationship management – adopt a fully integrated approach of managing supplier performance
- Vendor managed inventory – engage our vendors in the establishment of optimized processes for managing inventory either on site or at vendor site in order to improve material availability while reducing cost.

Key performance metrics for this program are the implementation of the strategic sourcing five year plan which commenced as part of the 2007 business plan in accordance with established milestones and deliverables.

Resource Profile

Chart 1 presents total resources associated with Nuclear Supply Chain – both financial and staff resources (actual regular staff headcount for 2005-2007, and planned regular staff 'full time equivalents (FTEs) for 2008-2009). As noted in Chart 1, the incremental costs of the temporary organization (Business Integration and Change Management, "BICM") that was put in place during the 2005 - 2007 period was $13.8M with the primary objective of commencing the Supply Chain improvement initiatives and then transitioning the balance of the initiatives to the base organization. Savings of approximately $25.4M have been built into the business plan. Savings are primarily in the form of reduced staff levels within Supply Chain, directly reflecting process improvements and efficiencies.

Chart 1

Nuclear Supply Chain Cost ($million) and FTEs/Headcount

Nuclear Supply Chain Cost ($million) and FTEs/Headcount	**2005**	**2006**	**2007**	**2008**	**2009**
	Actual	Actual	Actual	Plan	Plan
OM&A Costs [(1)]	54.9	65.5	63.8	60.4	56.3
(BICM $ that are included above) [(2)]	*4.3*	*6.7*	*2.8*		
Regular FTEs/Headcount [(3)]	434	459	431	423	377
Obsolescence Provision	2.5	2.5	10.5	14.3	14.3
Inventory Valuation Provision	4.0	5.0	5.9	5.0	5.0

Note 1: Costs exclude obsolescence and inventory valuation provisions listed separately.

Note 2: Costs of temporary Business Integration and Change Management organization ($13.8M)

Note 3: Actuals in 2005, 2006 and 2007 are year-end headcount, 2008 and 2009 are planned FTEs.

Current Results/Status: Key Indicators

The Supply Chain improvement program is proceeding as planned. The status of the key performance indicators are as follows:

- The cycle time average aging has improved from 930 days at the beginning of 2005 to 56 days by year-end 2007.
- Outage milestone compliance is 88 percent at 2007 year-end, versus a plan of 90 percent.
- Online scope compliance is on target at 98 percent at 2007 year-end.
- Successful registration of the integrated management system to ISO 9001, ISO 14001 and OHSAS 18001 standards.
- OM&A actual performance better than plan for 2006 and 2007.
- FTE equivalent reduction performance better than plan for 2006 and 2007.
- Vendor managed inventory, strategic sourcing and procurement and supplier relationship management on track in accordance with the strategic sourcing five year plan.

APPENDIX D
Workforce Development Program

Objective

The nuclear divisions are facing a staffing challenge with "critical skill" jobs (nuclear operators, engineers, control maintainers, and mechanical maintainers), primarily due to an expectation of unusually high attrition based on current staff demographics. The workforce development program ("WDP") is a cost-effective, centrally-managed program to ensure that sufficient skilled resources are available as indicated by the business plan.

Program Overview

Skills critical to the operation of the OPG's plants require specialized training both in the classroom and on the job. Depending on the skill set, accreditation can take several years to complete. Workforce development program is planned, budgeted, and administered by Programs and Training. The main features of WDP are:

- A five year "staff demand plan" based on divisional business plan resource requirements and estimated attrition rates.
- Centralized recruiting and staff selection processes.
- A consistent and integrated approach to training new staff, through existing programs.

The WDP includes the following costs associated with new staff:

1. Cost of trainee labour during initial in-class training and preliminary on the job training:

- Nuclear Operators in Training – 18 months funding
- Operations Co-op Students – 4 to 12 months funding (as per co-op programs)
- Engineering Trainees – 6 months funding
- Engineering Interns (Students) – 12 months funding
- Maintenance Apprentices – 12 months funding
- Maintenance Co-op Students – 4 or 12 months funding (as per co-op programs)
- Experienced Maintenance and Engineering New Hires - 0 months funding

2. Travel and purchased services related to advertising, selection, and testing of new staff.

Resource Profile

The incremental costs required to implement WDP are shown in Chart 1. Chart 2 provides staff hiring and FTE data comprised of the number of actual and planned new hires for the bridge and test periods, respectively, and resulting FTEs (indicating the annualized cost impact of hiring times within a given year, and program duration greater than or less than 12 months).

Chart 1

Incremental Cost of Workforce Development Program

Chart 1: Costs ($M)	**2005**	**2006**	**2007**	**2008**	**2009**
	Actual	Actual	Actual	Plan	Plan
Operations WDP	12.1	8.8	6.8	10.0	11.9
Maintenance WDP	7.5	3.7	4.2	4.5	4.7
Engineering WDP	2.8	3.8	4.9	5.7	5.9
Total	**22.5**	**16.4**	**15,9**	**20.1**	**22.5**

Note: May not add due to rounding.

Chart 2

Hiring and FTE Impact of Workforce Development Program

Chart 2: Hiring Plan and Resulting FTEs (excludes Experienced New Hires)					
Critical Skill Job Family (includes non regular students)	**Duration of WPD Funding**	**New hires 2007 (Actual)**	**New hires 2008 (Plan)**	**New hires 2009 (Plan)**	**Actual/ Planned FTEs 2007/08/09 (1)**
Maintenance					
Control Mtce Apprentices	12 months	12	12	12	12 - 12 - 12
Mechanical Mtce Apprentices	12 months	12	12	12	12 - 12 - 12
Maintenance Co-op Students	12 months	16	16	16	16 - 16 - 16
Maintenance Co-op Students	4 months	18	18	18	6 - 6 – 6
Operations					
Nuclear Operators in Training	18 months	52	55	55	54 - 73 – 79
Operations Co-Op Students	4-12 mths	0	15	30	0 - 9 - 20
Engineering					
Graduate Trainees	6 months	72	72	72	30 - 36 - 36
Engineering Interns	12 months	18	20	20	18 - 20 - 20
TOTAL		**200**	**220**	**235**	**148 - 184 – 201**

Current Status/Results

The WDP is routinely revisited to validate assumptions (for example, actual retirements or levels of other attrition), and adjusted if necessary. If demand in a skill area is expected to be less than originally planned, future hiring is adjusted downwards. Similarly, if demand is forecast to exceed planned WDP staff levels, hiring would be ramped up with additional WDP funding provided as required.

APPENDIX E

Tritium Removal Facility Improvement Plan

Objective

The objective of this initiative is to improve TRF performance, such that by 2011, the volume of heavy water treated (detritiated) can be reliably increased to 2,300 Mg/yr (on a three year average), from a historical average of 1600 Mg/yr.

Background

As noted in Section 3.2, TRF physical condition has degraded over the years, such that reliability is limiting revenue from external sales of detritiation services. In addition to the increased revenue resulting from completion of TRF improvement initiatives (beginning in 2010), improved TRF performance is expected to result in lower worker radiation dose levels, improved environmental performance, and reduced risk of generation impact due to reaching tritium-related operating license limits.

Program Overview

The objective is to be achieved by focusing on three key strategic initiatives:

- Maintenance improvement initiative project
- Life cycle plan and projects
- Conduct of operations

Maintenance Improvement Initiative Project

This initiative will facilitate the procurement of identified critical and obsolete spares, minimizing impact on TRF operation due to unavailability of failed critical components. This initiative will also reduce delays in maintenance activities due to non-availability of critical spares.

Life Cycle Plan and Projects

This initiative will complete life cycle templates for approximately 3000 critical components and implement critical component replacement and obsolescence strategy. This initiative also includes development of a strategy for securing external design, engineering and project management partnerships to meet life cycle plan project and modification implementation.

Conduct of Operations

This initiative focuses on human performance by improving the conduct of TRF operations and alignment with work control and outage processes. This includes developing strategies to reduce TRF start-up and run-down time and developing a TRF training improvement strategy.

Resource Profile

Chart 1

Tritium Removal Facility Resources Profile

($ Million)	**2005**	**2006**	**2007**	**2008**	**2009**
	Actual	Actual	Actual	Plan	Plan
MIIP	0.5	0.6	0.2	0.6	0.6
Life Cycle Plan/Projects	0.0	0.2	0.3	0.7	0.7
Conduct of Operations	0.7	0.9	0.2	1.0	1.1
Outage Program			**0.5**	**0.7**	**2.2**
Total	**1.2**	**1.7**	**1.4**	**3.0**	**4.6**

Current Status/Results

All initiatives have been started. 2007 progress was delayed primarily due to resource availability. Resource requirements for 2008 and 2009 have been adjusted accordingly.

APPENDIX F

Programs and Training Infrastructure Improvements

Objective

The purpose of these strategic initiatives on Programs and Training infrastructure is to address specific performance improvement drivers, or to mitigate significant business risks.

Background

During 2007 business planning, three areas were identified as warranting incremental investment in the 2007 - 2009 period, specifically:

- OPG Nuclear is focused on achieving more dependable and predictable performance through improving human performance and productivity, as indicated in Section 3.0. The leadership development initiative targets developing improved supervisory and managerial capability, with priority on the Operations and Maintenance areas, as key to sustaining and improving human performance levels.
- Assessed health threats from Bird Flu have increased over time, and a flu pandemic would have wide-ranging implications that would threaten continued power generation. The Nuclear pandemic planning initiative will meet provincial and federal government requirements for associated risk mitigation strategies and contingency plans.
- Due to placing priority on training delivery, significant backlogs have developed for revision of training program materials. The materials that are currently being used in the classrooms, shops, and on the control room simulators have become dated. This poses a risk to human performance at the stations, potentially increases the number of World Association of Nuclear Operators and CNSC audit findings, and causes trainee frustration due to program errors and outdated material.

Program Overview

Development of training program materials and pandemic planning require experienced staff, so these programs will be resourced on this basis (generally from training delivery positions or other planning experts) requiring backfilling of their base positions. Development of Leadership Academy materials will be accomplished with purchased services, which will also be retained to help reduce the initial leadership training backlog. Ongoing leadership training will be carried out with base resources. Additional detail is provided here.

- Leadership Academy Program Development: This initiative will implement a new strategy, and develop and deliver a two week Leadership Academy for new supervisors and gap training for incumbents, with significant senior management and program owner involvement. Development was completed in 2006, and additional resources will be retained until end of 2008 when current backlogs are driven down.
- Pandemic Planning: By year-end 2007, relevant nuclear divisions and the stations will have developed and implemented coordinated pandemic risk mitigation strategies. Focus in 2008 will be on implementation of longer term pandemic planning initiatives, including working with suppliers to ensure that critical materials would be available.
- Maintenance and Non-Licensed Operator Training Program Material Updates: By year-end 2009, identified revision backlogs for non-licensed operator and maintenance training will be completed. Training program materials will be updated for: governance standards; operational experience; current and future job performance requirements, considering changes in station configuration and processes; and specific qualification areas. All associated training materials will be updated.
- Licensed Operator Training Program Material Updates: Similar to the initiative outlined above, the focus is on the removal of the identified revision backlog (for all classroom materials, examination, supporting, and simulator training materials) by 2009 year-end.

Resource Profile

Chart 1: Program and Training Infrastructure Improvements Resource Profile

($ Million)	**2005**	**2006**	**2007**	**2008**	**2009**
	Actual	Actual	Actual	Plan	Plan
Leadership Academy	0.4	0.4	0.3	0.3	-
Pandemic Planning	-	-	0.4	0.3	-
Maintenance/Non-Licensed Operator Training Material Upgrade	-	-	2.1	1.2	1.3
Authorization Training Program Material Upgrade	-	-	0.6	0.6	0.6
Total	**0.4**	**0.4**	**3.4**	**2.4**	**1.9**

Current Status/Results

Initiatives are currently on track for completion as per scheduled dates.

APPENDIX G

Research and Development Program Overview

Objective

The objective of the OPG nuclear R&D program is to develop knowledge, tools and methods to address various technical, design basis, and operational issues in its fleet of CANDU reactors.

Background

There is a CNSC regulatory obligation to fund nuclear research, with current expectations in the order of $17M/year. Experience has shown that R&D in support of OPG's nuclear plants is most cost-effectively handled on a shared-basis with other CANDU owners, and that is the basis for the programs outlined below.

Program Overview

OPG invests approximately $17M annually on nuclear R&D programs in partnership with other industry participants. The main elements are:

- CANDU Owners Group ("COG") R&D Program (~$40M/year), shared by OPG (~$13.5M/year), Bruce Power, Atomic Energy of Canada Limited ("AECL"), Hydro-Quebec, New Brunswick Power, and SNN of Romania.
- CANDU Owners Group Feeder Integrity Joint Project (~$6.5M/year) shared by OPG (~$1M/year), Bruce Power, AECL, Hydro Quebec, New Brunswick Power, KHNP of Korea, and SNN of Romania.
- Membership in the U.S. Electric Power Research Institute ("EPRI") Nuclear Sector (~3M/year) shared by OPG (~$1.5M/year), Bruce Power, Hydro Quebec, New Brunswick Power, and SNN of Romania.
- University Network of Excellence in Nuclear Engineering ("UNENE") research and training programs (~ $3M/year) shared by OPG (~$0.9M/year), Bruce Power, and AECL.

To achieve the objectives noted above, the program focuses on the following key areas:

1. Addressing safety and design basis issues, mainly aimed at resolving regulatory-

mandated generic action items.

2. Developing, validating, and qualifying industry standard computer codes used in nuclear safety analysis in support of reactor design and licensing base. They include codes modeling containment response, thermal hydraulics, reactor physics, and fuel and fuel channels.
3. Investigating materials and system degradation issues that impact the safety and reliability of the plants. This work encompasses a broad range of components including fuel channels, feeders, and steam generators. It develops mitigation strategies, non destructive examination methods and tools, fitness-for-service guidelines, and assessment techniques. The work is focused on CANDU-specific issues for which solutions are not available in international R&D programs.
4. Addressing radiation protection and environmental safety issues: to ensure that the impacts of nuclear plant operations on people and environment are ALARA.
5. Providing access to the EPRI Nuclear R&D program: This U.S. research program addresses a broad range of topics in material reliability and life cycle management, risk and safety management, corrosion and chemistry control, instrumentation and control, non-destructive examination, equipment assessment and maintenance, repair and replacement, steam generators/steam turbine technologies, radiation exposure, and waste management. Although primarily focused on light water reactor issues, the technology created by the program is largely relevant to CANDU.
6. Creating a university-based nuclear engineering program: The UNENE initiative sponsors university-based research on critical CANDU topics, trains nuclear professionals and creates a network of credible experts for public, industry, and regulatory consultations.

<u>Program Benefits</u>

The R&D program comprises a large number of projects. The majority of these have produced results which have been of direct benefit to the safe and reliable operation of the OPG plants. The following examples outline typical benefits of the R&D program.

1. Pressure tube technology: Pressure tubes are CANDU-unique components that operate under harsh conditions. Understanding pressure tube degradation mechanisms is important to ensure that CANDU units safely attain their design end-of-life. The CANDU

Owners Group R&D program is the principal source of understanding of pressure tube behaviour.

2. Safety and Licensing: OPG manages long standing design basis issues and newly developing issues using results from the R&D program.
3. Components and Materials: The large number of components unique to CANDU reactors poses challenges, and R&D results have been beneficial in addressing many issues. For example, qualification of a mechanical cleaning process for removal of magnetite deposits on the primary side of CANDU of steam generator tubes.
4. Health and Safety: CANDU reactors pose some unique radiological and environmental hazards which are addressed through the R&D program. For example, validation of the model for calculating derived release limits and annual dose to the public, to provide assurance to OPG's stakeholders, regulators, and the public that the calculated annual dose is correct.
5. Feeders: Feeders are CANDU-specific components which have degraded unexpectedly. Industry-wide R&D has determined the mechanism of feeder thinning and has tested the impact of potential mitigation methods. An extensive array of inspection tools has been developed to characterize the thinning of the feeders and detect cracks. A major effort is underway to determine the mechanism(s) of cracking in feeders to support risk assessments. A 'fitness for service guideline' has been developed to provide guidance on managing all forms of feeder degradation.
6. EPRI products and services: The use of EPRI products has grown over the past four years and the value of utilized products has increased to $27M/year. Numerous cases of beneficial application of EPRI products have been reported, which represents major financial benefits in avoiding forced outages or very expensive solutions.

Resource Profile

Chart 1
Research and Development Program Resource Profile

($ Million)	2005	2006	2007	2008	2009
	Actual	Actual	Actual	Plan	Plan
COG R&D Program	11.3	12.0	12.7	13.7	14.3
COG Feeder Program	1.6	1.5	0.9	1.0	0.8
EPRI	0.8	0.8	1.5	1.6	1.6
UNENE	0.8	0.9	0.9	0.9	0.9
Total	**14.5**	**15.2**	**16.1**	**17.3**	**17.6**

Current Status/Results

The investment which OPG makes in nuclear R&D addresses a broad range of CANDU-specific technical and design basis issues, provides access to a large body of nuclear technology in the U.S., and creates a nuclear engineering program in several Ontario universities. The majority of the projects in the R&D program produce results which are applied to improving the safety and reliability of the OPG nuclear fleet.

Numbers may not add due to rounding.

Table 1
Base OM&A - Nuclear ($M)

Line No.	Division	2005 Actual	2006 Actual	2007 Actual	2008 Plan	2009 Plan
		(a)	(b)	(c)	(d)	(e)
	Nuclear Stations					
1	Darlington NGS	243.1	278.6	294.6	311.2	314.9
2	Pickering A NGS	172.9	169.5	177.1	197.7	201.3
3	Pickering B NGS	246.9	263.2	272.7	278.6	275.7
4	**Total Stations**	662.8	711.3	744.5	787.5	791.9
	Nuclear Support Divisions					
5	Engineering & Modifications	67.2	73.6	71.3	74.7	75.0
6	Programs & Training	165.3	179.7	201.9	216.1	231.3
7	Supply Chain	61.4	73.0	80.2	79.7	75.6
8	Performance Imprvmnt & Oversight	24.6	26.6	28.8	29.4	29.9
9	Nuclear Level Common	22.7	18.1	11.1	14.2	12.1
10	**Total Support**	341.2	371.0	393.2	414.0	424.0
	Nuclear Generation Development & Services					
11	SVP Office	0.0	0.0	0.1	4.3	4.8
12	Inspection & Mtce Services	25.2	33.5	37.7	46.3	48.3
13	Generation Development	1.3	11.5	35.0	100.0	90.0
14	Commercial Activities	1.7	2.0	1.3	3.5	3.5
15	**Total NGD&S**	28.2	47.0	74.1	154.1	146.6
16	**Waste & Transportation Services**	4.2	4.5	4.8	5.3	5.6
17	**Total**	1,036.4	1,133.8	1,216.6	1,360.8	1,368.0

Numbers may not add due to rounding.

Table 2
Base OM&A - Nuclear ($M)

Line No.	Resource Type	2005 Actual	2006 Actual	2007 Actual	2008 Plan	2009 Plan
		(a)	(b)	(c)	(d)	(e)
1	**Labour Regular**	736.8	836.8	883.5	952.3	978.9
2	**Overtime**	48.8	50.1	58.0	34.7	35.1
3	**Augmented Staff**	17.9	7.4	10.3	3.9	2.5
4	**Materials**	64.1	68.2	81.5	81.1	78.7
5	**License**	14.2	15.3	17.0	16.5	17.0
6	**Other Purchased Services**	122.2	130.7	129.4	227.4	210.2
7	**Other**	32.5	25.3	36.9	45.0	45.5
8	**Total**	1,036.4	1,133.8	1,216.6	1,360.8	1,368.0

Numbers may not add due to rounding.

Table 3
Total Work Program Regular Headcount or FTEs

Line No.	Division	2005 Actual (Headcount)	2006 Actual (Headcount)	2007 Actual (Headcount)	2008 Plan (FTEs)	2009 Plan (FTEs)
		(a)	(b)	(c)	(d)	(e)
	Nuclear Stations					
	Darlington NGS					
	Operations & Maintenance					
1	- Operations	389	370	400	402	413
2	- Maintenance	625	650	620	674	647
3	- Fuel Handling	127	136	141	156	154
4	- Rad Prot, Chemistry & Envrnt	92	88	94	96	96
5	Station Engineering	215	201	195	194	183
6	Work Management	79	72	73	86	82
7	Support Services	86	89	88	91	90
8	Tritium Removal Facility	77	84	91	102	100
9	Subtotal	1,690	1,690	1,702	1,800	1,764
	Pickering A NGS					
	Operations & Maintenance					
10	- Operations	367	390	380	385	386
11	- Maintenance	518	339	326	319	296
12	- Fuel Handling	95	120	105	94	94
13	- Rad Prot, Chemistry & Envrnt	24	26	21	23	21
14	Station Engineering	139	153	154	148	143
15	Work Management	51	54	60	72	82
16	Support Services	8	30	35	34	32
17	Subtotal	1,202	1,112	1,081	1,074	1,053
	Pickering B NGS					
	Operations & Maintenance					
18	- Operations	368	355	359	374	359
19	- Maintenance	582	592	627	602	579
20	- Fuel Handling	151	139	148	148	147
21	- Rad Prot, Chemistry & Envrnt	122	123	120	129	124
22	Station Engineering	231	227	227	206	198
23	Work Management	87	86	81	81	70
24	Support Services	98	101	102	100	97
25	Subtotal	1,639	1,623	1,664	1,640	1,573
26	**Subtotal**	4,531	4,425	4,447	4,515	4,390
	Nuclear Support Divisions					
	Engineering & Modifications					
27	- Projects & Mods	378	352	366	374	366
28	- Other E&M	310	319	308	319	308
29	Programs & Training	1,173	1,230	1,179	1,292	1,323
30	Supply Chain	434	459	431	435	377
31	PINO	64	66	69	68	65
32	Nuclear Level Common	3	2	4	9	3
33	**Subtotal**	2,362	2,428	2,357	2,496	2,442
	Nuclear Generation Development & Services					
34	SVP Office	0	0	1	3	3
35	Inspection & Mtce Services	440	507	539	680	699
36	Generation Development	14	50	85	178	199
37	Commercial Activities	6	7	8	10	10
38	**Subtotal**	460	564	633	871	911
39	**Waste & Transportation Services**	22	22	22	22	22
40	**P2/P3 Safe Storage Project and Isolation Projects**	107	95	108	205	168
	(PARTS in 2005)					
41	**Total Regular Staff**[1]	7,482	7,534	7,567	8,109	7,934

1 Total regular staff numbers reflect staff currently working in and being paid by Nuclear (non home-base assignment)

Numbers may not add due to rounding.

Table 4
OM&A Base Labour Escalation and 53rd Week Impact ($M)

Line No.	Function	2006 Actual 53rd Week	2006 Actual Escalation	2007 Actual	2008 Plan	2009 Plan
		(a)	(b)	(c)	(d)	(e)
	Operational Functions - Station					
	Darlington NGS					
	Operations & Maintenance					
1	- Operations	1.1	3.1	3.4	1.0	3.1
2	- Maintenance	1.6	4.6	5.3	1.6	4.4
3	- Fuel Handling	0.4	1.0	1.1	0.3	1.0
4	- Rad Prot, Chemistry & Envrnt	0.2	0.7	0.8	0.2	0.6
5	Station Engineering	0.5	1.5	1.6	0.4	1.2
6	Work Management	0.1	0.6	0.7	0.2	0.6
7	Support Services	0.2	0.7	0.8	0.2	0.6
8	Tritium Removal Facility	0.2	0.5	0.7	0.2	0.7
9	Subtotal	4.4	12.7	14.2	4.2	12.2
	Pickering A NGS					
	Operations & Maintenance					
10	- Operations	0.9	2.9	3.0	0.9	2.8
11	- Maintenance	0.9	3.3	2.6	0.8	2.1
12	- Fuel Handling	0.2	0.7	0.7	0.2	0.6
13	- Rad Prot, Chemistry & Envrnt	0.1	0.2	0.2	0.1	0.1
14	Station Engineering	0.4	1.0	1.1	0.3	0.9
15	Work Management	0.1	0.4	0.5	0.1	0.6
16	Support Services	0.1	0.3	0.3	0.1	0.2
17	Subtotal	2.6	8.8	8.4	2.5	7.4
	Pickering B NGS					
	Operations & Maintenance					
18	- Operations	1.0	3.1	3.2	0.9	2.8
19	- Maintenance	1.2	4.1	4.5	1.4	3.9
20	- Fuel Handling	0.3	1.1	1.1	0.3	1.0
21	- Rad Prot, Chemistry & Envrnt	0.3	1.0	1.1	0.3	0.9
22	Station Engineering	0.6	1.7	1.8	0.5	1.3
23	Work Management	0.3	0.8	0.8	0.2	0.6
24	Support Services	0.3	0.7	0.7	0.2	0.7
25	Subtotal	4.0	12.5	13.2	3.9	11.0
26	**Total Stations**	11.0	34.0	35.8	10.6	30.6
	Operational Functions - Support					
27	Engineering & Modifications	1.1	2.3	2.4	0.7	1.7
	Programs & Training					
28	- Facilities, Records and Admin	0.9	2.7	3.1	0.9	2.6
29	- Nuclear Programs & Training	1.1	3.4	3.5	1.1	3.5
30	- Security	0.5	1.4	1.5	0.5	1.5
31	Supply Chain	0.8	2.6	3.4	1.0	2.5
32	PINO	0.2	0.5	0.6	0.2	0.5
33	Nuclear Level Common	0.0	0.0	0.0	0.0	0.1
34	**Total Support**	4.6	12.9	14.4	4.3	12.4
	Operational Functions - NGD&S					
35	SVP Office	0.0	0.0	0.0	0.0	0.0
36	Inspection & Mtce Services	0.9	1.8	2.0	0.6	2.0
	Generation Development					
37	- Refurbishment Programs	0.1	0.0	0.3	0.1	0.4
38	- New Nuclear Build	0.0	0.0	0.0	0.0	0.6
39	Commercial Activities	0.0	0.1	0.1	0.0	0.1
40	**Total NGD&S**	1.1	1.9	2.3	0.8	3.2
41	**Waste & Transportation Services**	0.2	0.3	0.1	0.2	0.2
42	**Total**	16.9	49.1	52.7	15.9	46.5

Numbers may not add due to rounding.

Updated: 2008-03-14
EB-2007-0905
Exhibit F2
Tab 2
Schedule 1
Table 5

Table 5
Nuclear Base OM&A by Function ($M)
Plan - Calendar Year Ending December 31, 2009

Line No.	Function	Darlington NGS	Pickering A NGS	Pickering B NGS	Total
		(a)	(b)	(c)	(d)
	Operational Functions - Station				
1	Operations & Maintenance				602.6
2	- Operations	73.3	71.7	62.4	207.3
3	- Maintenance	116.6	55.9	115.1	287.6
4	- Fuel Handling	27.7	15.9	23.8	67.4
5	- Rad Protection, Chemistry & Envrnt	17.6	3.1	19.6	40.3
6	Station Engineering	32.4	29.6	29.2	91.2
7	Work Management	12.1	14.7	11.2	38.0
8	Support Services	16.3	10.5	14.5	41.2
9	Tritium Removal Facility	18.9			18.9
10	**Total Stations**	314.9	201.3	275.7	791.9
	Operational Functions - Support				
11	Engineering & Modifications				75.0
12	Programs & Training				231.3
13	- Facilities, Records and Admin				76.4
14	- Nuclear Programs & Training				89.8
15	- Security				65.1
16	Supply Chain				75.6
17	Performance Improvement & Oversight				29.9
18	Nuclear Level Common				12.1
19	**Total Support**	0.0	0.0	0.0	424.0
	Operational Functions - NGD&S				
20	SVP Office				4.8
21	Inspection & Maintenance Services				48.3
22	Generation Development				90.0
23	- Refurbishment Programs				22.7
24	- New Nuclear Build				67.2
25	Commercial Activities				3.5
26	**Total NGD&S**	0.0	0.0	0.0	146.6
27	**Waste & Transportation Services**				5.6
28	**Total Nuclear**	314.9	201.3	275.7	1,368.0

Numbers may not add due to rounding.

Updated: 2008-03-14
EB-2007-0905
Exhibit F2
Tab 2
Schedule 1
Table 6

Table 6
Nuclear Base OM&A by Function ($M)
Plan - Calendar Year Ending December 31, 2008

Line No.	Division	Darlington NGS	Pickering A NGS	Pickering B NGS	Total
		(a)	(b)	(c)	(d)
	Operational Functions - Station				
1	Operations & Maintenance				597.4
2	- Operations	71.6	71.8	61.1	204.5
3	- Maintenance	117.3	56.1	112.5	285.8
4	- Fuel Handling	27.0	15.2	23.0	65.3
5	- Rad Protection, Chemistry & Envrnt	16.6	3.2	21.9	41.8
6	Station Engineering	33.1	28.5	30.3	92.0
7	Work Management	13.1	12.7	12.4	38.3
8	Support Services	15.7	10.1	17.3	43.1
9	Tritium Removal Facility	16.7			16.7
10	**Total Stations**	311.2	197.7	278.6	787.5
	Operational Functions - Support				
11	Engineering & Modifications				74.7
12	Programs & Training				216.1
13	- Facilities, Records and Admin				74.3
14	- Nuclear Programs & Training				86.5
15	- Security				55.3
16	Supply Chain				79.7
17	Performance Improvement & Oversight				29.4
18	Nuclear Level Common				14.2
19	**Total Support**	0.0	0.0	0.0	414.0
	Operational Functions - NGD&S				
20	SVP Office				4.3
21	Inspection & Maintenance Services				46.3
22	Generation Development				100.0
23	- Refurbishment Programs				24.6
24	- New Nuclear Build				75.4
25	Commercial Activities				3.5
26	**Total NGD&S**	0.0	0.0	0.0	154.1
27	**Waste & Transportation Services**				5.3
28	**Total Nuclear**	311.2	197.7	278.6	1,360.8

Numbers may not add due to rounding.

Updated: 2008-03-14
EB-2007-0905
Exhibit F2
Tab 2
Schedule 1
Table 7

Table 7
Nuclear Base OM&A by Function ($M)
Actual - Calendar Year Ending December 31, 2007

Line No.	Function	Darlington NGS	Pickering A NGS	Pickering B NGS	Total
		(a)	(b)	(c)	(d)
	Operational Functions - Station				
1	Operations & Maintenance				574.9
2	- Operations	60.1	59.8	58.9	178.8
3	- Maintenance	122.3	57.6	111.2	291.1
4	- Fuel Handling	26.9	12.7	23.2	62.8
5	- Rad Protection, Chemistry & Envrnt	17.2	4.5	20.5	42.2
6	Station Engineering	29.8	26.4	30.8	87.1
7	Work Management	11.3	8.5	13.5	33.4
8	Support Services	14.1	7.6	14.6	36.3
9	Tritium Removal Facility	12.9			12.9
10	**Total Stations**	294.6	177.1	272.7	744.5
	Operational Functions - Support				
11	Engineering & Modifications				71.3
12	Programs & Training				201.9
13	- Facilities, Records and Admin				75.9
14	- Nuclear Programs & Training				78.2
15	- Security				47.8
16	Supply Chain				80.2
17	Performance Improvement & Oversight				28.8
18	Nuclear Level Common				11.1
19	**Total Support**	0.0	0.0	0.0	393.2
	Operational Functions - NGD&S				
20	SVP Office				0.1
21	Inspection & Maintenance Services				37.7
22	Generation Development				35.0
23	- Refurbishment Programs				23.8
24	- New Nuclear Build				11.2
25	Commercial Activities				1.3
26	**Total NGD&S**	0.0	0.0	0.0	74.1
27	**Waste & Transportation Services**				4.8
28	**Total Nuclear**	294.6	177.1	272.7	1,216.6

Numbers may not add due to rounding.

Table 8
Nuclear Base OM&A by Function ($M)
Budget - Calendar Year Ending December 31, 2007

Line No.	Function	Darlington NGS	Pickering A NGS	Pickering B NGS	Total
		(a)	(b)	(c)	(d)
	Operational Functions - Station				
1	Operations & Maintenance				585.2
2	- Operations	68.5	69.1	60.0	197.6
3	- Maintenance	114.5	53.2	115.2	282.9
4	- Fuel Handling	25.2	14.5	23.3	63.0
5	- Rad Protection, Chemistry & Envrnt	16.5	3.3	21.9	41.8
6	Station Engineering	32.1	27.2	33.6	92.9
7	Work Management	13.1	8.3	14.3	35.7
8	Support Services	15.7	11.4	15.7	42.8
9	Tritium Removal Facility	16.0			16.0
10	**Total Stations**	301.6	187.1	283.9	772.6
	Operational Functions - Support				
11	Engineering & Modifications				73.3
12	Programs & Training				204.9
13	- Facilities, Records and Admin				71.4
14	- Nuclear Programs & Training				83.9
15	- Security				49.6
16	Supply Chain				84.4
17	Performance Improvement & Oversight				29.4
18	Nuclear Level Common				14.0
19	**Total Support**	0.0	0.0	0.0	406.0
	Operational Functions - NGD&S				
20	SVP Office				0.5
21	Inspection & Maintenance Services				37.5
22	Generation Development				32.3
23	- Refurbishment Programs				22.3
24	- New Nuclear Build				10.0
25	Commercial Activities				2.1
26	**Total NGD&S**	0.0	0.0	0.0	72.4
27	**Waste & Transportation Services**				5.2
28	**Total Nuclear**	301.6	187.1	283.9	1,256.1

Numbers may not add due to rounding.

Table 9
Nuclear Base OM&A by Function ($M)
Actual - Calendar Year Ending December 31, 2006

Line No.	Function	Darlington NGS	Pickering A NGS	Pickering B NGS	Total
		(a)	(b)	(c)	(f)
	Operational Functions - Station				
1	Operations & Maintenance				542.2
2	- Operations	59.3	58.8	57.2	175.4
3	- Maintenance	110.1	51.3	104.4	265.8
4	- Fuel Handling	23.3	14.1	21.9	59.3
5	- Rad Protection, Chemistry & Envrnt	16.2	4.2	21.4	41.8
6	Station Engineering	30.4	24.7	30.8	85.9
7	Work Management	11.7	7.8	14.2	33.8
8	Support Services	14.5	8.5	13.2	36.2
9	Tritium Removal Facility	13.2			13.2
10	**Total Stations**	278.6	169.5	263.2	711.3
	Operational Functions - Support				
11	Engineering & Modifications				73.6
12	Programs & Training				179.7
13	- Facilities, Records and Admin				66.3
14	- Nuclear Programs & Training				67.8
15	- Security				45.6
16	Supply Chain				73.0
17	Performance Improvement & Oversight				26.6
18	Nuclear Level Common				18.1
19	**Total Support**	0.0	0.0	0.0	371.0
	Operational Functions - NGD&S				
20	SVP Office				0.0
21	Inspection & Maintenance Services				33.5
22	Generation Development				11.5
23	- Refurbishment Programs				11.3
24	- New Nuclear Build				0.3
25	Commercial Activities				2.0
26	**Total NGD&S**	0.0	0.0	0.0	47.0
27	**Waste & Transportation Services**				4.5
28	**Total Nuclear**	278.6	169.5	263.2	1,133.8

Table 10
Nuclear Base OM&A by Function ($M)
Budget - Calendar Year Ending December 31, 2006

Line No.	Function	Darlington NGS	Pickering A NGS	Pickering B NGS	Total
		(a)	(b)	(c)	(d)
	Operational Functions - Station				
1	Operations & Maintenance				538.6
2	- Operations	60.7	62.7	59.1	182.6
3	- Maintenance	104.2	48.1	106.7	258.9
4	- Fuel Handling	22.5	13.4	22.3	58.2
5	- Rad Protection, Chemistry & Envrnt	16.1	3.1	19.8	39.0
6	Station Engineering	31.1	26.1	33.2	90.4
7	Work Management	10.1	7.5	15.2	32.8
8	Support Services	15.2	9.7	12.6	37.5
9	Tritium Removal Facility	11.4			11.4
10	**Total Stations**	271.3	170.5	268.9	710.7
	Operational Functions - Support				
11	Engineering & Modifications				74.8
12	Programs & Training				182.4
13	- Facilities, Records and Admin				66.2
14	- Nuclear Programs & Training				70.4
15	- Security				45.9
16	Supply Chain				74.9
17	Performance Improvement & Oversight				27.7
18	Nuclear Level Common				52.1
19	**Total Support**	0.0	0.0	0.0	411.8
	Operational Functions - NGD&S				
20	SVP Office				0.0
21	Inspection & Maintenance Services				31.6
22	Generation Development				8.9
23	- Refurbishment Programs				8.9
24	- New Nuclear Build				0.0
25	Commercial Activities				2.0
26	**Total NGD&S**	0.0	0.0	0.0	42.5
27	**Waste & Transportation Services**				5.3
28	**Total Nuclear**	271.3	170.5	268.9	1,170.4

Numbers may not add due to rounding.

Table 11
Nuclear Base OM&A by Function ($M)
Actual - Calendar Year Ending December 31, 2005

Line No.	Function	Darlington NGS	Pickering A NGS	Pickering B NGS	Total
		(a)	(b)	(c)	(d)
	Operational Functions - Station				
1	Operations & Maintenance				497.5
2	- Operations	55.7	52.0	52.0	159.8
3	- Maintenance	89.5	63.1	96.4	249.0
4	- Fuel Handling	19.7	13.2	20.1	53.0
5	- Rad Protection, Chemistry & Envrnt	14.1	3.1	18.4	35.6
6	Station Engineering	26.4	24.1	29.4	79.8
7	Work Management	9.8	6.0	15.9	31.7
8	Support Services	17.4	11.3	14.7	43.4
9	Tritium Removal Facility	10.4			10.4
10	**Total Stations**	243.1	172.9	246.9	662.8
	Operational Functions - Support				
11	Engineering & Modifications				67.2
12	Programs & Training				165.3
13	- Facilities, Records and Admin				58.0
14	- Nuclear Programs & Training				66.0
15	- Security				41.3
16	Supply Chain				61.4
17	Performance Improvement & Oversight				24.6
18	Nuclear Level Common				22.7
19	**Total Support**	0.0	0.0	0.0	341.2
	Operational Functions - NGD&S				
20	SVP Office				0.0
21	Inspection & Maintenance Services				25.2
22	Generation Development				1.3
23	- Refurbishment Programs				1.3
24	- New Nuclear Build				0.0
25	Commercial Activities				1.7
26	**Total NGD&S**	0.0	0.0	0.0	28.2
27	**Waste & Transportation Services**				4.2
28	**Total Nuclear**	243.1	172.9	246.9	1,036.4

Numbers may not add due to rounding.

Table 12
Nuclear Base OM&A by Function ($M)
Budget - Calendar Year Ending December 31, 2005

Line No.	Function	Darlington NGS	Pickering A NGS	Pickering B NGS	Total
		(a)	(b)	(c)	(d)
	Operational Functions - Station				
1	Operations & Maintenance				494.4
2	- Operations	50.6	57.1	53.2	160.9
3	- Maintenance	87.5	63.4	90.0	240.9
4	- Fuel Handling	20.6	13.9	20.9	55.4
5	- Rad Protection, Chemistry & Envrnt	15.3	3.1	18.8	37.2
6	Station Engineering	30.0	24.9	29.0	84.0
7	Work Management	9.7	6.5	20.1	36.2
8	Support Services	19.9	10.9	11.8	42.6
9	Tritium Removal Facility	11.7			11.7
10	**Total Stations**	245.4	179.8	243.7	668.9
	Operational Functions - Support				
11	Engineering & Modifications				68.1
12	Programs & Training				165.3
13	- Facilities, Records and Admin				55.4
14	- Nuclear Programs & Training				70.1
15	- Security				39.7
16	Supply Chain				53.8
17	Performance Improvement & Oversight				25.4
18	Nuclear Level Common				60.5
19	**Total Support**	0.0	0.0	0.0	373.0
	Operational Functions - NGD&S				
20	SVP Office				0.0
21	Inspection & Maintenance Services				23.0
22	Generation Development				3.0
23	- Refurbishment Programs				3.0
24	- New Nuclear Build				0.0
25	Commercial Activities				1.7
26	**Total NGD&S**	0.0	0.0	0.0	27.7
27	**Waste & Transportation Services**				4.4
28	**Total Nuclear**	245.4	179.8	243.7	1,073.9

Numbers may not add due to rounding.

Table 1

Operating Costs Summary - Nuclear ($M)

Line No.	Cost Item	2005 Actual	2006 Actual	2007 Actual	2008 Plan	2009 Plan
		(a)	(b)	(c)	(d)	(e)
	OM&A:					
1	**Base OM&A**	1,036.4	1,133.8	1,216.6	1,360.8	1,368.0
2	**Project OM&A**	155.9	142.0	111.6	144.6	137.1
3	**Outage OM&A**	163.0	187.7	215.6	192.2	207.9
4	**Allocation of Corporate Costs**	356.2	423.2	446.8	457.0	430.2
5	**Asset Service Fee**	14.7	30.8	33.2	29.9	25.5
6	**P2/3 Impairment Charges and Write-Offs**[1]	120.0	0.0	0.0	0.0	0.0
7	**Total OM&A**	1,846.2	1,917.5	2,023.8	2,184.6	2,168.7
8	**Nuclear Fuel Costs**	100.5	104.9	113.0	162.4	204.2
	Other Operating Cost Items:					
9	**Depreciation**[2]	259.6	242.8	300.7	294.4	316.4
10	**Income Tax**	5.7	0.0	0.0	0.0	0.0
11	**Capital Tax**	8.6	9.0	7.9	7.9	7.8
12	**Property Tax**	7.5	16.8	8.2	13.9	14.2
13	**Total Operating Costs**	2,228.1	2,291.0	2,453.5	2,663.1	2,711.3
14	**Total Regular Staff FTEs**	7,311.7	7,484.7	7,542.0	8,109.1	7,933.8
15	**Non-Regular Staff FTEs**	787.2	624.5	736.8	379.3	250.9
16	**Total Staff FTEs**	8,098.9	8,109.2	8,278.8	8,488.4	8,184.7

1 Impairment charge ($63M) associated with construction work in progress and fixed assets for Pickering A Units 2 & 3; and write-off of inventory ($57M) for Pickering A Units 2 & 3.

2 Includes nuclear waste management variable expenses (2005 Actual - $4.0M, 2006 Actual - $3.6M, 2007 Actual - $1.6M, 2008 Plan - $1.7M, 2009 Plan - $1.8M)

COMPARISON OF BASE OM&A – NUCLEAR

1.0 PURPOSE

This evidence presents period-over-period comparisons of base OM&A costs for the nuclear facilities, as well as comparison of actual to budget for 2005 and 2006.

2.0 OVERVIEW

As indicated in Ex. F2-T2-S1, labour escalation has a significant impact on year-over-year changes in costs.

To identify variances requiring written explanation (ten percent or greater, subject to a minimum materiality limit of $1M), standard variance tables (Ex. F2-T2-S2 Tables 1, 3, 5, 7, 8, and 10) are used, with variance amounts and percentage provided for each operational function.

To facilitate analysis of cost changes, escalation-adjusted variance tables (Ex. F2-T2-S2 Tables 2, 4, 6, and 9) use the information provided in Ex. F2-T2-S1 Table 4, to provide the net “work-driven” cost changes.

3.0 PERIOD-OVER-PERIOD CHANGES – TEST PERIOD

2009 Plan versus 2008 Plan

Exhibit F2-T2-S2 Table 1 presents a 2009 base OM&A increase of $7.2M (one percent) from 2008 plan, and indicates those operational functions with variances greater than or equal to ten percent.

As outlined above, this $7.2M increase includes labour cost escalation of $46.5M (Ex. F2-T2-S1 Table 4), resulting in an escalation-adjusted work program reduction (-$39.3M) as shown in Ex. F2-T2-S2 Table 2. Variance references below are to F2-T2-S2 Table 2.

Within the stations, the reportable escalation-adjusted variances are:

- Tritium Removal Facility ($1.5M) reflecting primarily the planned increase in effort for the Tritium Removal Facility improvement plan as outlined in Ex. F2-T2-S1 Appendix E.

Within the support divisions, the reportable escalation-adjusted variances are:

- Security ($8.4M) reflecting primarily the transition from contracted to OPG security forces and increased CNSC requirements.
- Nuclear Level Common (as described in Ex. F2-T2-S1 Section 2.2.2) decrease (-$2.1M) reflects primarily a reduction in planned nuclear level consulting contracts.

Within Nuclear Generation Development and Services, the reportable escalation-adjusted variances are:

- New Nuclear Build (-$8.8M) reflecting expected completion of significant project deliverables, as described in Ex. D2-T1-S3.

<u>2008 Plan versus 2007 Actual</u>

Exhibit F2-T2-S2 Table 3 presents a 2008 base OM&A increase of $144.2M (12 percent) from 2007 actual, and indicates those operational functions with variances greater than ten percent.

As outlined above, this $144.2M increase includes labour cost escalation of $15.9M (Ex. F2-T2-S1 Table 4), resulting in an escalation-adjusted work program increase ($128.4M) as shown in Ex. F2-T2-S2 Table 4. Variance references below are to Ex. F2-T2-S2 Table 4.

Within the stations, the reportable escalation-adjusted variances are:

- Operations ($22.9M) primarily due to:
    - o Darlington ($10.5M) reflecting primarily increased staffing as per the approved operations staffing model, the impact of delayed spending on the certification program originally planned for early 2007 and overtime to backfill for staff assigned to certification training ($8.2M total), and addressing issues such as condenser cooling water debris filters and boilerhouse condition assessments ($1.5M).

  - Pickering A ($11.1M) reflecting filling of regular staff vacancies ($3.0M primarily common services and operations), impact of improvement initiative delays in 2007 ($2.9M for waste management reduction and procedures improvement initiatives), operating costs for the recently-completed auxiliary power supply ($1.8M), hiring additional entry-level staff to address anticipated attrition ($1.8M for nuclear operators in training and co-op students), and other increases to reach planned resource levels for Pickering common services ($1.5M).
- Work Management ($4.4M) reflecting:
  - Pickering A ($4.0M) primarily for increased effort to support improved outage planning (forced outage team, and support for 2010 vacuum building outage).
  - Darlington ($1.6M) reflecting the full-year impact of filling vacancies from 2007 (budget under spent in 2007) and resourcing for the 2009 vacuum building outage.
  - Pickering B (-$1.3M) reflecting planned staff reductions associated with the Equipment Performance Improvement Initiative (Appendix B).
- Support Services ($6.3M) reflecting:
  - Pickering A ($2.3M) improvement initiatives deferred from 2007 due to forced outage support, and the impact of 2007 low level radioactive waste credit.
  - Pickering B ($2.5M) for additional consulting services for process efficiency reviews and improvements, and the impact of 2007 low level radioactive waste credit.
  - Darlington ($1.4M) reflecting filling of vacancies and WANO-related initiatives.
- Tritium Removal Facility ($3.6M) reflecting primarily the impact of 2007 underspend with Tritium Removal Facility Improvement Initiative (-$1.6M), and the filling of TRF operational vacancies ($1.6M) to improve its operations in response to audit findings.

Within the support divisions, the reportable escalation-adjusted variances are:

- Nuclear Programs and Training ($7.2M) reflecting primarily filling of pre-existing training vacancies ($4.7M), work program increases ($1.9M e.g., initial operations training, continuing leadership training), and timing of workforce development program hiring ($1.6M). These increases are partly offset by planned reductions associated with the programs and training infrastructure improvements (Appendix F).
- Security ($7.0M) reflecting primarily the first year of a transition from contracted to OPG security forces.

- Nuclear level common ($3.1M) reflecting primarily an increase in planned nuclear level consulting contracts and staff for nuclear-wide maintenance strategy improvement initiatives, partly offset by a reduction in expected labour price variance.

Within Nuclear Generation Development and Services, the reportable escalation-adjusted variances are:

- SVP Office ($4.2M) reflecting primarily a planned increase in management consultant contracts ($3.0M), increased indirect costs associated with additional staff working on planned Pickering B refurbishment projects and the impact of CNSC refurbishment-related licensing services fee credit received in 2007.
- Inspection and Maintenance Services ($8.0M) reflecting the impact of planned staff increases to reduce reliance on augmented staff and improve the quality of work standards (as discussed in Ex. G2-T2-S1), and the associated indirect costs.
- New Nuclear Build ($64.1M) reflecting planned increase in effort for this major work program, as discussed in Ex. D2-T1-S3.
- Commercial Activities ($2.2M) reflecting increased Bruce lease management support ($1.6M), and full annual impact of additional staff associated with Bruce lease management office and isotopes and heavy water programming.

4.0 PERIOD-OVER-PERIOD CHANGES – BRIDGE YEAR

<u>2007 Actual versus 2007 Budget</u>

Exhibit F2-T2-S2 Table 5 presents 2007 actual base OM&A under budget by $39.5M (-3 percent) for the year, and indicates those operational functions with variances greater than or equal to ten percent.

With the stations, the reportable variances are:

- Support Services under budget (-$6.5M) reflecting primarily:
    - Pickering A (-$3.8M) due to unbudgeted low level waste management credits, and lower than planned expenditures on common services programs due to focus on forced outages.

- Darlington (-$1.6M) reflecting primarily staff vacancies and budget funding allocated to greater than planned outage work in other divisions.
- Tritium Removal Facility under budget (-$3.1M) reflecting delays in tritium removal facility improvement plan (Ex. F2-T2-S1, Appendix E) and unfilled staff vacancies.

Within the support divisions, the reportable variance is:

- Nuclear Level Common under budget (-$3.0M) reflecting lower than planned spending on nuclear level consulting contracts.

Within Nuclear Generation Development and Services, reportable variances are:

- New Nuclear Build is over budget ($1.2M) reflecting actual work program requirements versus the preliminary $10M budget for this start-up year, as discussed in Ex. D2-T1-S3.

<u>2007 Actual versus 2006 Actual</u>

Exhibit F2-T2-S2 Table 6 presents a 2007 base OM&A growth of $82.8M (7 percent) over 2006 actual costs, and indicates those operational functions with variances greater than ten percent.

As outlined above, this $82.8M increase includes labour cost escalation of $52.7M and cost impact of a 53rd fiscal week in 2006 of $16.9M (Ex. F2-T2-S1 Table 4), resulting in an escalation-adjusted work program increase ($47.0M) as shown in Ex. F2-T2-S2 Table 7. The variance explanations below refer to values in Ex. F2-T2-S2 Table 7.

Within the stations, the only reportable escalation-adjusted change is Maintenance ($16.7M), reflecting primarily:

- Darlington ($8.6M) primarily due to unbudgeted outage incentive program ($5.3M), and increased overtime and materials associated with the Equipment Performance Improvement Initiative (Ex. F2-T2-S1, Appendix B).
- Pickering A ($4.5M) due to higher than planned labour and material costs associated with forced outages and emergent work.

- Pickering B ($3.6M) due to effort on and materials associated with equipment performance improvement initiative (Ex. F2-T2-S1, Appendix B), partly offset by lower than planned laundry costs.

Within the support divisions, the reportable escalation-adjusted changes are:

- Facilities, Records and Administration ($7.4M), reflecting primarily higher utility costs following historically under-recorded consumption ($4.0M), increased facility infrastructure costs associated with fire protection and support facility code compliance work programs ($2.5M).
- Nuclear Programs and Training ($8.0M), reflecting primarily increased effort on programs and training infrastructure improvements ($2.8M, Ex. F2-T2-S1, Appendix F), impact of changes to minor fixed assets materiality limit ($2.4M), implementation of radiation protection project crew ($1.0M), and timing of hiring for staff on workforce development program (Ex. F2-T2-S1, Appendix D).
- Supply Chain increases ($4.7M), reflecting primarily increased obsolescence provision expense in 2007 ($8M) and net labour increases in Supply Chain site support departments ($1.8M) to implement improved processes and sustain program benefits (part of Supply Chain improvement initiative, Ex. F2-T2-S1, Appendix C); partly offset by savings due to efficiency and effectiveness improvements (-$4.1M) resulting from the Supply Chain improvement initiative.
- Nuclear Level Common decreases (-$7.0M), reflecting primarily lower than planned nuclear level consulting contracts (-$2.0M), and lower labour price variance in 2007 (-$5.4M), as follows. While labour is charged to work packages at standard rates, there is a need to reconcile these cost allocations with actual payroll which can be affected by a variety of factors during the year, such as grievance settlements. This reconciliation is done in Nuclear Level Common, and any discrepancy between payroll and cost allocation to work is charged there. The decrease from 2006 - 2007 reflects a difference in the amount of true-up required.

Within Nuclear Generation Development and Services, the reportable escalation-adjusted changes are:

- Inspection and Maintenance Services ($3.2M) reflecting primarily impact of the change in minor fixed assets materiality limit as discussed in Ex. F2-T2-S1 Section 2.0, ($1.8M), and increased indirect costs associated with additional new hires.
- Refurbishment programs increases ($12.4M) reflecting increased effort on Pickering B refurbishment phase 1, leading to a recommendation to the Board of Directors. For further information, see Ex. F2-T3-S1 and Ex. D2-T1-S3.
- New Nuclear Build increases ($11.0M) reflecting continuation of work programs started in late 2006. Primary focus was on preparation of the site preparation application and technology selection, as outlined in Ex. F2-T3-S1 Section 3.0 and Ex. D2-T1-S3.

PERIOD-OVER-PERIOD CHANGES – HISTORICAL YEARS

The decision by the Board of Directors in August 2005, to place Pickering A Units 2 and 3 in safe storage as opposed to returning them to service, impacted actual costs in 2005 and 2006. This decision had two major impacts:

- Pickering A Return to Service ("PARTS") Project (regulated asset): The Board decision led to demobilization of the PARTS project, with cancellation of contracts, leases, insurance, and completion of the conditions to the environmental assessment (see Ex. J1-T1-S1). In support of this, a team was established to redeploy OPG regular staff that had been working on the PARTS project. Costs of PARTS staff awaiting deployment were charged to the PARTS demobilization project (regulated asset) as discussed at Ex. J1-T1-S1 and Ex. J1-T3-S1. There was no direct impact on base OM&A.
- Base OM&A: The 2005 Pickering A base OM&A budget allowed for ramping up staff levels to operate a four unit station, with a target of having operations and maintenance staff in place approximately 18 months in advance of start-up to ensure adequate training. Following the mid-year Pickering Unit 2 and 3 safe storage decision, there were 2005 base OM&A cost savings of approximately $10M due to hiring freezes resulting in unfilled vacancies (-$6.1M), and deployment of over-complement operations and maintenance staff to Pickering Unit 2 and 3 safe storage project (-$3.8M, funded by the decommissioning provision). To the extent possible, staff were also assigned to support Pickering B and Darlington outages to further mitigate the base OM&A impact.

Redeployment activities continued into 2006, resulting in a Pickering A Operations and Maintenance base OM&A 2006 budget push of approximately $5M.

2006 Actual versus 2006 Budget

Exhibit F2-T2-S2 Table 8 presents 2006 actual base OM&A under budget by $36.6M (-3 percent) for the year, and indicates those operational functions with variances greater than or equal to ten percent.

Within the stations, Tritium Removal Facility is over budget ($1.8M) reflecting catch-up of Tritium Removal Facility improvement plan delays from 2005.

Within the support divisions (-$40.8M, 10 percent under budget), Nuclear Level Common is under budget (-$33.9M) reflecting unspent contingency (-$30.5M) and lower than planned spending primarily on housing assistance for staff moves to new Nuclear Headquarters, and lower than planned management hires.

Within Nuclear Generation Development and Services ($4.5M, 10.5 percent over budget), reflecting primarily:

- Refurbishment programs is over budget ($2.4M) reflecting revised work program estimate which was approved in May 2006, to correct preliminary budget estimates of work required.
- New Build programs is over budget ($0.3M) reflecting nominal expenditures for start-up activity, as discussed in Ex. D2-T1-S3

Within Waste and Transportation Services (-$0.8M, 15 percent under budget), variance reflects primarily rescheduling of planned boiler cleaning support work to 2007.

2006 Actual versus 2005 Actual

Exhibit F2-T2-S2 Table 9 shows actual base OM&A growth of $97.4M (9 percent) from 2005 - 2006, and indicates those operational functions with variances greater than or equal to ten percent.

As outlined in Ex. F2-T2-S2 Table 10 and in Ex. F2-T2-S1 Table 4, labour cost escalation ($49.1M) and cost impact of a 53rd fiscal week in 2006 ($16.9M) account for $66.0M of this increase, leaving $31.5M of work program growth – the significant contributors to which are described below.

Acknowledging the significant impact of labour escalation on year-over-year growth, the analysis presented here addresses the other drivers of work program growth (net of labour cost escalation and fiscal year cost impacts) as presented in Ex. F2-T2-S2 Table 10.

Within the stations ($3.5M, Ex. F2-T2-S2 Table 10):

- Operations increases ($3.5M), reflecting primarily Pickering A ($3.1M), due to planned increase in station improvement initiatives (e.g., chemical waste management, waste reduction management and facility upgrades programs).
- Fuel Handling increases ($2.7M), reflecting primarily Darlington ($2.2M) due to the Fuel Handling Operations Recovery Program, requiring hiring/training of additional qualified fuel handling panel operators, and materials for fuel handling system repairs.
- Radiation Protection, Chemistry and Environment increases by $3.6M, reflecting primarily:
  - o Pickering B ($1.8M), due to increased resources to provide radiation protection support in the longer planned outages in 2006 (primarily SLAR [spacer location and relocation] activities).
  - o Darlington ($1.1M), due to increased outage support requirements (“green man services”) associated with the more extensive outages planned for 2006 (the first year of moving to the three year outage cycle).
- Support Services decreases by $9.6M, reflecting:
  - o Darlington (-$3.9M) primarily due to transfer of accountability for the Contracts Office to Maintenance in 2006 (-$5M), partially offset by transfer of controllership staff to Nuclear from Corporate Finance (+$1.2M).
  - o Pickering A (-$3.2M) primarily due to lower staff benefit costs due completion of Unit 1 Return to Service and Demobilization Projects in 2005. Sickness-Vacation-Health-

Other ("SVHO") costs for PARTS regular staff were charged to Base OM&A in 2005 (the final year of the project), in accordance with corporate policy. Impact is partially offset by transfer of controllership staff to Nuclear (+$1.3M).

- o Pickering B (-$2.4M) primarily due to completion of equipment performance improvement initiatives in 2005 (-$1.3M) and incentive credit received (-$1.3M) due to lower than planned radioactive waste produced. Impact is partially offset by transfer of controllership to Nuclear (+$1.3M).

- Tritium Removal Facility increases by $2.1M, reflecting increase in Tritium Removal Facility improvement plan work; and, filling of vacancies.

Within the support divisions ($12.3M, Ex. F2-T2-S2 Table 10):

- Engineering and Modifications increases ($3.0M) reflecting filling of previous vacancies
- Facilities, Records and Administration increases ($4.7M) to address the increased scope of the facilities work program (e.g., servicing new security buildings and vehicles), additional office space requirements and office equipment and supplies to implement the electronic document management strategy.
- Security increases ($2.4M), reflecting planned staff increases in line with CNSC expectations.
- Supply Chain increases ($8.2M), reflecting top-up of the inventory valuation provision ($1M) as described in Ex. F2-T2-S1, and planned increases in Supply Chain improvement initiatives ($11.6M); partly offset by underspending on other purchased services (-$4.1M).

Increases are offset by:

- Nuclear Level Common decreases (-$4.6M), reflecting primarily lower labour price variance in 2006. The decrease from 2005 - 2006 reflects a difference in the amount of true-up required.

Within Nuclear Generation Development and Services ($15.8M, Ex. F2-T2-S2 Table 10), increase is driven primarily by two functions:

- Inspection and Maintenance Services ($5.5M), reflecting increased indirect costs due to implementation of a divisional work management system, and indirect costs associated with additional staffing to achieve growing work program requirements.
- Refurbishment programs ($9.8M) reflecting planned increases primarily associated with phase 1 activities of the Pickering refurbishment project, as discussed at Ex. D2-T1-S3.
- New Nuclear Build programs ($0.3M) reflecting nominal expenditures for start-up activity, as discussed in Ex. D2-T1-S3
- Commercial Activities ($0.2M) reflecting primarily increased heating costs for the heavy water management building.

Within Waste and Transportation Services, escalation-adjusted decrease in 2006 (-$0.2M, Ex. F2-T2-S2 Table 10) reflects minor work program variations.

<u>2005 Actual versus 2005 Budget</u>

Exhibit F2-T2-S2 Table 11 shows 2005 actual base OM&A is $37.5M (-3 percent) under budget for the year, and indicates those operational functions with variances greater than or equal to ten percent.

Within the stations (-$6.1M), reportable variances are:

- Work Management is under budget (-$4.6M) primarily due to Pickering B (-$4.1M) reflecting deferral of planned Inspection and Maintenance Services effort (on-power inspections and equipment upgrades) from late 2005 to early 2006 to mitigate budget pressures.
- Tritium Removal Facility is under budget (-$1.3M) reflecting delays in implementing Tritium Removal Facility improvement plan, and staff vacancies.

Within the support divisions (-$31.7M), reportable variances are:

- Supply Chain is over budget ($7.6M) reflecting primarily greater than planned labour, overtime and staff augmentation for start-up of Supply Chain improvement initiatives ($7.5M).
- Nuclear Level Common is under budget (-$37.7M) reflecting:

- o Avoiding use of contingency (-$28M).
- o Lower than planned housing assistance related to Nuclear Headquarters relocation (more commuting versus relocation) (-$5.1M).
- o Lower than planned management search/hires, which were planned to proactively increase management capability given the upcoming demographic challenge (-$2.3M).
- o Lower than planned CNSC license fees (-$1.9M). Consistent with CNSC cost-recovery regulations, fees are estimated in advance based on OPG description of upcoming work activities, with billing based on actual level of services used.

With Nuclear Generation Development and Services ($0.5M), reportable variances are:

- Inspection and Maintenance Services ($2.2M) reflecting earlier than planned commencement of hiring program to increase staff levels (causing higher than planned SVHO and indirect costs), and physical consolidation of distributed office facilities (three locations into one).
- Refurbishment programs (-$1.7M) reflecting delays in staffing and engaging contracted services for start-up work.

Within Waste and Transportation Services, the underspend (-$0.2M, 4 percent under budget) reflects primarily less than planned requirement for detritiated heavy water transportation.

Numbers may not add due to rounding.

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Exhibit F2
Tab 2
Schedule 2
Table 1

Table 1
Nuclear Base OM&A by Function ($M)
Variance - 2009 Plan less 2008 Plan

Line No.	Function	Darlington NGS	Pickering A NGS	Pickering B NGS	Total	Variance Percentage Calculation: 2008 Plan	Variance Percentage Calculation: Variance (%)
		(a)	(b)	(c)	(d)	(e)	(f)
	Operational Functions - Station						
1	Operations & Maintenance				5.2	597.4	1%
2	- Operations	1.7	(0.1)	1.3	2.8	204.5	1%
3	- Maintenance	(0.7)	(0.2)	2.6	1.8	285.8	1%
4	- Fuel Handling	0.7	0.7	0.8	2.1	65.3	3%
5	- Rad Protection, Chemistry & Envrnt	1.0	(0.1)	(2.3)	(1.5)	41.8	-4%
6	Station Engineering	(0.8)	1.1	(1.1)	(0.8)	92.0	-1%
7	Work Management	(1.0)	2.0	(1.3)	(0.3)	38.3	-1%
8	Support Services	0.5	0.4	(2.8)	(1.9)	43.1	-4%
9	Tritium Removal Facility	2.2			2.2	16.7	**13%**
10	**Total Stations**	3.7	3.7	(2.9)	4.4	787.5	1%
	Operational Functions - Support						
11	Engineering & Modifications				0.4	74.7	1%
12	Programs & Training				15.2	216.1	7%
13	- Facilities, Records and Admin				2.0	74.3	3%
14	- Nuclear Programs & Training				3.3	86.5	4%
15	- Security				9.8	55.3	**18%**
16	Supply Chain				(4.0)	79.7	-5%
17	Performance Improvement & Oversight				0.5	29.4	2%
18	Nuclear Level Common				(2.1)	14.2	**-15%**
19	**Total Support**	0.0	0.0	0.0	10.0	414.0	2%
	Operational Functions - NGD&S						
20	SVP Office				0.5	4.3	**11%**
21	Inspection & Maintenance Services				2.0	46.3	4%
22	Generation Development				(10.1)	100.0	**-10%**
23	- Refurbishment Programs				(1.9)	24.6	-8%
24	- New Nuclear Build				(8.2)	75.4	**-11%**
25	Commercial Activities				0.0	3.5	1%
26	**Total NGD&S**	0.0	0.0	0.0	(7.6)	154.1	-5%
27	**Waste & Transportation Services**				0.3	5.3	6%
28	**Total Nuclear**	3.7	3.7	(2.9)	7.2	1,360.8	1%

Numbers may not add due to rounding.

Table 2
Nuclear Base OM&A by Function ($M)
Escalation-adjusted Variance - 2009 Plan less 2008 Plan

Line No.	Function	Darlington NGS	Pickering A NGS	Pickering B NGS	Total
		(a)	(b)	(c)	(d)
	Operational Functions - Station				
1	Operations & Maintenance				(18.1)
2	- Operations	(1.5)	(3.0)	(1.6)	(6.0)
3	- Maintenance	(5.0)	(2.3)	(1.2)	(8.5)
4	- Fuel Handling	(0.3)	0.0	(0.2)	(0.5)
5	- Rad Protection, Chemistry & Envrnt	0.4	(0.3)	(3.2)	(3.1)
6	Station Engineering	(1.9)	0.1	(2.4)	(4.2)
7	Work Management	(1.6)	1.4	(1.8)	(2.0)
8	Support Services	(0.1)	0.2	(3.5)	(3.4)
9	Tritium Removal Facility	1.5			1.5
10	**Total Stations**	(8.6)	(3.7)	(13.9)	(26.2)
	Operational Functions - Support				
11	Engineering & Modifications				(1.4)
12	Programs & Training				7.6
13	- Facilities, Records and Admin				(0.5)
14	- Nuclear Programs & Training				(0.2)
15	- Security				8.4
16	Supply Chain				(6.6)
17	Performance Improvement & Oversight				0.0
18	Nuclear Level Common				(2.1)
19	**Total Support**	0.0	0.0	0.0	(2.5)
	Operational Functions - NGD&S				
20	SVP Office				0.4
21	Inspection & Maintenance Services				(0.0)
22	Generation Development				(11.1)
23	- Refurbishment Programs				(2.3)
24	- New Nuclear Build				(8.8)
25	Commercial Activities				(0.0)
26	**Total NGD&S**	0.0	0.0	0.0	(10.8)
27	**Waste & Transportation Services**				0.2
28	**Total Nuclear**	(8.6)	(3.7)	(13.9)	(39.3)

Numbers may not add due to rounding.

Updated: 2008-03-14
EB-2007-0905
Exhibit F2
Tab 2
Schedule 2
Table 3

Table 3
Nuclear Base OM&A by Function ($M)
Variance - 2008 Plan less 2007 Actual

Line No.	Function	Darlington NGS	Pickering A NGS	Pickering B NGS	Total	Variance Percentage Calculation 2007 Actual	Variance (%)
		(a)	(b)	(c)	(d)	(e)	(f)
	Operational Functions - Station						
1	Operations & Maintenance				22.5	574.9	4%
2	- Operations	11.5	12.0	2.2	25.7	178.8	**14%**
3	- Maintenance	(5.0)	(1.5)	1.2	(5.3)	291.1	-2%
4	- Fuel Handling	0.1	2.6	(0.2)	2.5	62.8	4%
5	- Rad Protection, Chemistry & Envrnt	(0.5)	(1.3)	1.4	(0.4)	42.2	-1%
6	Station Engineering	3.3	2.1	(0.5)	4.8	87.1	6%
7	Work Management	1.8	4.2	(1.0)	4.9	33.4	**15%**
8	Support Services	1.6	2.4	2.8	6.8	36.3	**19%**
9	Tritium Removal Facility	3.8	0.0	0.0	3.8	12.9	**30%**
10	**Total Stations**	16.6	20.5	5.9	42.9	744.5	6%
	Operational Functions - Support						
11	Engineering & Modifications				3.4	71.3	5%
12	Programs & Training				14.2	201.9	7%
13	- Facilities, Records and Admin				(1.6)	75.9	-2%
14	- Nuclear Programs & Training				8.3	78.2	**11%**
15	- Security				7.5	47.8	**16%**
16	Supply Chain				(0.5)	80.2	-1%
17	Performance Improvement & Oversight				0.5	28.8	2%
18	Nuclear Level Common				3.1	11.1	**28%**
19	**Total Support**	0.0	0.0	0.0	20.7	393.2	5%
	Operational Functions - NGD&S						
20	SVP Office				4.2	0.1	**5565%**
21	Inspection & Maintenance Services				8.6	37.7	**23%**
22	Generation Development				65.0	35.0	**186%**
23	- Refurbishment Programs				0.9	23.8	4%
24	- New Nuclear Build				64.1	11.2	**570%**
25	Commercial Activities				2.2	1.3	**170%**
26	**Total NGD&S**	0.0	0.0	0.0	80.1	74.1	**108%**
27	**Waste & Transportation Services**				0.5	4.8	**10%**
28	**Total Nuclear**	16.6	20.5	5.9	144.2	1,216.6	**12%**

Table 4
Nuclear Base OM&A by Function ($M)
Escalation-adjusted Variance - 2008 Plan less 2007 Actual

Line No.	Function	Darlington NGS	Pickering A NGS	Pickering B NGS	Total
		(a)	(b)	(c)	(d)
	Operational Functions - Station				
1	Operations & Maintenance				14.5
2	- Operations	10.5	11.1	1.3	22.9
3	- Maintenance	(6.7)	(2.3)	(0.2)	(9.1)
4	- Fuel Handling	(0.2)	2.4	(0.5)	1.7
5	- Rad Protection, Chemistry & Envrnt	(0.8)	(1.3)	1.1	(1.0)
6	Station Engineering	2.9	1.7	(1.1)	3.6
7	Work Management	1.6	4.0	(1.3)	4.4
8	Support Services	1.4	2.3	2.5	6.3
9	Tritium Removal Facility	3.6			3.6
10	**Total Stations**	12.3	18.0	2.0	32.4
	Operational Functions - Support				
11	Engineering & Modifications				2.7
12	Programs & Training				11.7
13	- Facilities, Records and Admin				(2.5)
14	- Nuclear Programs & Training				7.2
15	- Security				7.0
16	Supply Chain				(1.5)
17	Performance Improvement & Oversight				0.4
18	Nuclear Level Common				3.1
19	**Total Support**	0.0	0.0	0.0	16.4
	Operational Functions - NGD&S				
20	SVP Office				4.2
21	Inspection & Maintenance Services				8.0
22	Generation Development				64.8
23	- Refurbishment Programs				0.7
24	- New Nuclear Build				64.1
25	Commercial Activities				2.2
26	**Total NGD&S**	0.0	0.0	0.0	79.2
27	**Waste & Transportation Services**				0.3
28	**Total Nuclear**	12.3	18.0	2.0	128.4

Numbers may not add due to rounding.

Updated: 2008-03-14
EB-2007-0905
Exhibit F2
Tab 2
Schedule 2
Table 5

Table 5
Nuclear Base OM&A by Function ($M)
Variance - Actual less Budget - Calendar Year Ending December 31, 2007

Line No.	Function	Darlington NGS	Pickering A NGS	Pickering B NGS	Total	Variance Percentage Calculation: 2007 Budget	Variance Percentage Calculation: Variance (%)
		(a)	(b)	(c)	(d)	(e)	(f)
	Operational Functions - Station						
1	Operations & Maintenance				(10.3)	585.2	-2%
2	- Operations	(8.4)	(9.3)	(1.1)	(18.7)	197.6	-9%
3	- Maintenance	7.8	4.3	(3.9)	8.2	282.9	3%
4	- Fuel Handling	1.7	(1.8)	(0.1)	(0.2)	63.0	0%
5	- Rad Protection, Chemistry & Envrnt	0.6	1.2	(1.4)	0.4	41.8	1%
6	Station Engineering	(2.2)	(0.8)	(2.8)	(5.8)	92.9	-6%
7	Work Management	(1.7)	0.2	(0.8)	(2.3)	35.7	-7%
8	Support Services	(1.6)	(3.8)	(1.1)	(6.5)	42.8	**-15%**
9	Tritium Removal Facility	(3.1)			(3.1)	16.0	**-20%**
10	**Total Stations**	(6.9)	(10.0)	(11.1)	(28.0)	772.6	-4%
	Operational Functions - Support						
11	Engineering & Modifications				(2.1)	73.3	-3%
12	Programs & Training				(3.0)	204.9	-1%
13	- Facilities, Records and Admin				4.5	71.4	6%
14	- Nuclear Programs & Training				(5.7)	83.9	-7%
15	- Security				(1.8)	49.6	-4%
16	Supply Chain				(4.2)	84.4	-5%
17	Performance Improvement & Oversight				(0.6)	29.4	-2%
18	Nuclear Level Common				(3.0)	14.0	**-21%**
19	**Total Support**	0.0	0.0	0.0	(12.8)	406.0	-3%
	Operational Functions - NGD&S						
20	SVP Office				(0.4)	0.5	**-85%**
21	Inspection & Maintenance Services				0.1	37.5	0%
22	Generation Development				2.8	32.3	9%
23	- Refurbishment Programs				1.5	22.3	7%
24	- New Nuclear Build				1.2	10.0	**12%**
25	Commercial Activities				(0.8)	2.1	**-38%**
26	**Total NGD&S**	0.0	0.0	0.0	1.7	72.4	2%
27	**Waste & Transportation Services**				(0.4)	5.2	**-8%**
28	**Total Nuclear**	(6.9)	(10.0)	(11.1)	(39.5)	1,256.1	-3%

Table 6
Nuclear Base OM&A by Function ($M)
Variance - 2007 Actual less 2006 Actual

Line No.	Function	Darlington NGS	Pickering A NGS	Pickering B NGS	Total	Variance Percentage Calculation 2006 Actual	Variance (%)
		(a)	(b)	(c)	(d)	(e)	(f)
	Operational Functions - Station						
1	Operations & Maintenance				32.6	542.2	6%
2	- Operations	0.8	1.0	1.7	3.5	175.4	2%
3	- Maintenance	12.2	6.2	6.9	25.4	265.8	**10%**
4	- Fuel Handling	3.6	(1.4)	1.2	3.4	59.3	6%
5	- Rad Protection, Chemistry & Envrnt	1.0	0.3	(0.9)	0.4	41.8	1%
6	Station Engineering	(0.5)	1.7	0.0	1.2	85.9	1%
7	Work Management	(0.4)	0.7	(0.8)	(0.4)	33.8	-1%
8	Support Services	(0.4)	(0.9)	1.3	0.1	36.2	0%
9	Tritium Removal Facility	(0.3)			(0.3)	13.2	-2%
10	**Total Stations**	16.0	7.7	9.5	33.2	711.3	5%
	Operational Functions - Support						
11	Engineering & Modifications				(2.4)	73.6	-3%
12	Programs & Training				22.2	179.7	**12%**
13	- Facilities, Records and Admin				9.5	66.3	**14%**
14	- Nuclear Programs & Training				10.4	67.8	**15%**
15	- Security				2.2	45.6	5%
16	Supply Chain				7.2	73.0	**10%**
17	Performance Improvement & Oversight				2.2	26.6	8%
18	Nuclear Level Common				(7.0)	18.1	**-39%**
19	**Total Support**	0.0	0.0	0.0	22.2	371.0	6%
	Operational Functions - NGD&S						
20	SVP Office				0.1	0.0	**New**
21	Inspection & Maintenance Services				4.2	33.5	**13%**
22	Generation Development				23.5	11.5	**204%**
23	- Refurbishment Programs				12.5	11.3	**111%**
24	- New Nuclear Build				11.0	0.3	**4259%**
25	Commercial Activities				(0.7)	2.0	**-36%**
26	**Total NGD&S**	0.0	0.0	0.0	27.1	47.0	**58%**
27	**Waste & Transportation Services**				0.3	4.5	6%
28	**Total Nuclear**	16.0	7.7	9.5	82.8	1,133.8	7%

Numbers may not add due to rounding.

Table 7
Nuclear Base OM&A by Function ($M)
Escalation-adjusted Variance - 2007 Actual less 2006 Actual

Line No.	Function	Darlington NGS	Pickering A NGS	Pickering B NGS	Total
		(a)	(b)	(c)	(d)
	Operational Functions - Station				
1	Operations & Maintenance				13.9
2	- Operations	(1.5)	(1.2)	(0.4)	(3.1)
3	- Maintenance	8.6	4.5	3.6	16.7
4	- Fuel Handling	2.9	(2.0)	0.5	1.4
5	- Rad Protection, Chemistry & Envrnt	0.5	0.2	(1.7)	(1.0)
6	Station Engineering	(1.6)	1.0	(1.2)	(1.8)
7	Work Management	(0.9)	0.4	(1.3)	(1.9)
8	Support Services	(0.9)	(1.1)	0.9	(1.1)
9	Tritium Removal Facility	(0.8)			(0.8)
10	**Total Stations**	6.2	1.9	0.3	8.4
	Operational Functions - Support				
11	Engineering & Modifications				(3.6)
12	Programs & Training				16.5
13	- Facilities, Records and Admin				7.4
14	- Nuclear Programs & Training				8.0
15	- Security				1.1
16	Supply Chain				4.7
17	Performance Improvement & Oversight				1.8
18	Nuclear Level Common				(7.0)
19	**Total Support**	0.0	0.0	0.0	12.4
	Operational Functions - NGD&S				
20	SVP Office				0.1
21	Inspection & Maintenance Services				3.2
22	Generation Development				23.4
23	- Refurbishment Programs				12.4
24	- New Nuclear Build				11.0
25	Commercial Activities				(0.8)
26	**Total NGD&S**	0.0	0.0	0.0	25.8
27	**Waste & Transportation Services**				0.4
28	**Total Nuclear**	6.2	1.9	0.3	47.0

Numbers may not add due to rounding.

Table 8
Nuclear Base OM&A by Function ($M)
Variance - Actual less Budget - Calendar Year Ending December 31, 2006

Line No.	Function	Darlington NGS	Pickering A NGS	Pickering B NGS	Total	Variance Percentage Calculation 2006 Budget	Variance (%)
		(a)	(b)	(c)	(d)	(e)	(f)
	Operational Functions - Station						
1	Operations & Maintenance				3.6	538.6	1%
2	- Operations	(1.4)	(3.9)	(2.0)	(7.3)	182.6	-4%
3	- Maintenance	5.9	3.3	(2.3)	6.9	258.9	3%
4	- Fuel Handling	0.8	0.7	(0.3)	1.2	58.2	2%
5	- Rad Protection, Chemistry & Envrnt	0.1	1.1	1.7	2.8	39.0	7%
6	Station Engineering	(0.7)	(1.4)	(2.4)	(4.5)	90.4	-5%
7	Work Management	1.6	0.3	(1.0)	0.9	32.8	3%
8	Support Services	(0.7)	(1.2)	0.6	(1.3)	37.5	-3%
9	Tritium Removal Facility	1.8			1.8	11.4	**16%**
10	**Total Stations**	7.3	(1.1)	(5.7)	0.5	710.7	0%
	Operational Functions - Support						
11	Engineering & Modifications				(1.2)	74.8	-2%
12	Programs & Training				(2.7)	182.4	-1%
13	- Facilities, Records and Admin				0.2	66.2	0%
14	- Nuclear Programs & Training				(2.6)	70.4	-4%
15	- Security				(0.3)	45.9	-1%
16	Supply Chain				(1.9)	74.9	-3%
17	Performance Improvement & Oversight				(1.1)	27.7	-4%
18	Nuclear Level Common				(33.9)	52.1	**-65%**
19	**Total Support**	0.0	0.0	0.0	(40.8)	411.8	**-10%**
	Operational Functions - NGD&S						
20	SVP Office				0.0	0.0	0%
21	Inspection & Maintenance Services				1.8	31.6	6%
22	Generation Development				2.7	8.9	**30%**
23	- Refurbishment Programs				2.4	8.9	**27%**
24	- New Nuclear Build				0.3	0.0	**New**
25	Commercial Activities				(0.0)	2.0	-1%
26	**Total NGD&S**	0.0	0.0	0.0	4.5	42.5	**11%**
27	**Waste & Transportation Services**				(0.8)	5.3	**-15%**
28	**Total Nuclear**	7.3	(1.1)	(5.7)	(36.6)	1,170.4	-3%

Numbers may not add due to rounding.

Table 9
Nuclear Base OM&A by Function ($M)
Variance - 2006 Actual less 2005 Actual

Line No.	Function	Darlington NGS	Pickering A NGS	Pickering B NGS	Total	Variance Percentage Calculation: 2005 Actual	Variance Percentage Calculation: Variance (%)
		(a)	(b)	(c)	(d)	(e)	(f)
	Operational Functions - Station						
1	Operations & Maintenance				44.7	497.5	9%
2	- Operations	3.6	6.8	5.1	15.6	159.8	**10%**
3	- Maintenance	20.5	(11.7)	7.9	16.7	249.0	7%
4	- Fuel Handling	3.6	0.9	1.8	6.3	53.0	**12%**
5	- Rad Protection, Chemistry & Envrnt	2.1	1.0	3.1	6.1	35.6	**17%**
6	Station Engineering	3.9	0.6	1.5	6.0	79.8	8%
7	Work Management	2.0	1.8	(1.7)	2.1	31.7	7%
8	Support Services	(2.9)	(2.9)	(1.4)	(7.2)	43.4	**-17%**
9	Tritium Removal Facility	2.8			2.8	10.4	**27%**
10	**Total Stations**	35.5	(3.4)	16.3	48.4	662.8	7%
	Operational Functions - Support						
11	Engineering & Modifications				6.4	67.2	**10%**
12	Programs & Training				14.4	165.3	9%
13	- Facilities, Records and Admin				8.3	58.0	**14%**
14	- Nuclear Programs & Training				1.7	66.0	3%
15	- Security				4.3	41.3	**10%**
16	Supply Chain				11.6	61.4	**19%**
17	Performance Improvement & Oversight				2.0	24.6	8%
18	Nuclear Level Common				(4.6)	22.7	**-20%**
19	**Total Support**	0.0	0.0	0.0	29.8	341.2	9%
	Operational Functions - NGD&S						
20	SVP Office				0.0	0.0	**New**
21	Inspection & Maintenance Services				8.2	25.2	**33%**
22	Generation Development				10.2	1.3	**794%**
23	- Refurbishment Programs				10.0	1.3	**774%**
24	- New Nuclear Build				0.3	0.0	**New**
25	Commercial Activities				0.4	1.7	**21%**
26	**Total NGD&S**	0.0	0.0	0.0	18.8	28.2	**67%**
27	**Waste & Transportation Services**				0.3	4.2	**7%**
28	**Total Nuclear**	35.5	(3.4)	16.3	97.4	1,036.4	9%

Numbers may not add due to rounding.

Table 10
Nuclear Base OM&A by Function ($M)
Escalation-adjusted Variance - 2006 Actual less 2005 Actual

Line No.	Function	Darlington NGS	Pickering A NGS	Pickering B NGS	Total
		(a)	(b)	(c)	(d)
	Operational Functions - Station				
1	Operations & Maintenance				10.8
2	- Operations	(0.6)	3.1	1.0	3.5
3	- Maintenance	14.3	(15.9)	2.6	1.1
4	- Fuel Handling	2.2	0.0	0.4	2.7
5	- Rad Protection, Chemistry & Envrnt	1.1	0.7	1.8	3.6
6	Station Engineering	1.9	(0.8)	(0.8)	0.4
7	Work Management	1.2	1.3	(2.7)	(0.2)
8	Support Services	(3.9)	(3.2)	(2.4)	(9.6)
9	Tritium Removal Facility	2.1			2.1
10	**Total Stations**	18.4	(14.8)	(0.1)	3.5
	Operational Functions - Support				
11	Engineering & Modifications				3.0
12	Programs & Training				4.4
13	- Facilities, Records and Admin				4.7
14	- Nuclear Programs & Training				(2.8)
15	- Security				2.4
16	Supply Chain				8.2
17	Performance Improvement & Oversight				1.3
18	Nuclear Level Common				(4.6)
19	**Total Support**	0.0	0.0	0.0	12.3
	Operational Functions - NGD&S				
20	SVP Office				0.0
21	Inspection & Maintenance Services				5.5
22	Generation Development				10.0
23	- Refurbishment Programs				9.8
24	- New Nuclear Build				0.3
25	Commercial Activities				0.2
26	**Total NGD&S**	0.0	0.0	0.0	15.8
27	**Waste & Transportation Services**				(0.2)
28	**Total Nuclear**	18.4	(14.8)	(0.1)	31.4

Numbers may not add due to rounding.

Table 11
Nuclear Base OM&A by Function ($M)
Variance - Actual less Budget - Calendar Year Ending December 31, 2005

Line No.	Function	Darlington NGS	Pickering A NGS	Pickering B NGS	Total	Variance Percentage Calculation: 2005 Budget	Variance Percentage Calculation: Variance (%)
		(a)	(b)	(c)	(d)	(e)	(f)
	Operational Functions - Station						
1	Operations & Maintenance				3.0	494.4	1%
2	- Operations	5.1	(5.1)	(1.1)	(1.1)	160.9	-1%
3	- Maintenance	2.0	(0.3)	6.4	8.1	240.9	3%
4	- Fuel Handling	(0.9)	(0.7)	(0.7)	(2.4)	55.4	-4%
5	- Rad Protection, Chemistry & Envrnt	(1.2)	0.1	(0.4)	(1.6)	37.2	-4%
6	Station Engineering	(3.6)	(0.9)	0.3	(4.1)	84.0	-5%
7	Work Management	0.1	(0.5)	(4.1)	(4.6)	36.2	**-13%**
8	Support Services	(2.5)	0.5	2.9	0.9	42.6	2%
9	Tritium Removal Facility	(1.3)			(1.3)	11.7	**-11%**
10	**Total Stations**	(2.3)	(7.0)	3.2	(6.1)	668.9	-1%
	Operational Functions - Support						
11	Engineering & Modifications				(0.9)	68.1	-1%
12	Programs & Training				0.1	165.3	0%
13	- Facilities, Records and Admin				2.6	55.4	5%
14	- Nuclear Programs & Training				(4.1)	70.1	-6%
15	- Security				1.5	39.7	4%
16	Supply Chain				7.6	53.8	**14%**
17	Performance Improvement & Oversight				(0.8)	25.4	-3%
18	Nuclear Level Common				(37.7)	60.5	**-62%**
19	**Total Support**	0.0	0.0	0.0	(31.7)	373.0	-9%
	Operational Functions - NGD&S						
20	SVP Office				0.0	0.0	**New**
21	Inspection & Maintenance Services				2.2	23.0	**10%**
22	Generation Development				(1.7)	3.0	**-57%**
23	- Refurbishment Programs				(1.7)	3.0	**-57%**
24	- New Nuclear Build				0.0	0.0	0%
25	Commercial Activities				(0.1)	1.7	-4%
26	**Total NGD&S**	0.0	0.0	0.0	0.5	27.7	2%
27	**Waste & Transportation Services**				(0.2)	4.4	**-4%**
28	**Total Nuclear**	(2.3)	(7.0)	3.2	(37.5)	1,073.9	-3%

PROJECT OM&A – NUCLEAR

1.0 PURPOSE

The purpose of this evidence is to present an overview description of the Nuclear OM&A project budget for the historical years, bridge year, and test period.

2.0 OVERVIEW OF PROJECT MANAGEMENT PROCESSES

A description of the initiation, review and approval process for OM&A and capital projects in OPG Nuclear is provided in Ex. D2-T1-S1.

3.0 OVERVIEW OF OM&A PROJECT EXPENDITURES

OM&A projects are those work items that meet the criteria for project categorization as outlined in Ex. D2-T1-S1 Section 2.0, and are classified as OM&A by the classification rules found at Ex. A2-T2-S1.

Exhibit F2-T3-S1 Table 1 presents Nuclear OM&A project expenditures by sponsoring division and category for the period 2005 - 2009.

Project OM&A expenditures have been categorized in Ex. F2-T3-S1 Table 1 as released facility projects, facility projects to be released, listed work to be released, P2/P3 isolation project and Pickering B refurbishment projects, which are defined in Ex. D2-T1-S1. In addition, unique to project OM&A is the category of infrastructure, which includes four elements:

- Project support funding for staff whose responsibilities support the entire nuclear project portfolio, for example portfolio management and reporting staff whose efforts cannot appropriately or efficiently be charged to individual projects.
- An allocation for minor modifications at each of the three nuclear sites and for the centrally-managed facilities function. Minor modifications are initiatives identified in the project identification phase which are characteristically low cost (generally, less than $200,000 per generating unit), for which the full project management process is

unwarranted. For administrative efficiency, these initiatives are funded via drawdown of the minor modifications budget allocated to each station and central facilities.

- A provision for conceptual funding to undertake project initiation work, as identified in Ex. D2-T1-S1 Section 2.1.
- Actual costs of capital project cancellations or write-offs. Accounting policy requires that if a capital project is cancelled, its value is written-off to OM&A in the year the decision is made. The practice in nuclear is to account for these write-off amounts as part of project OM&A infrastructure costs in the year incurred. As the write-off occurs in the year of the decision and cannot be predicted, there is no budget for these items and their impact must be managed by other project under-spends in a particular year or through use of portfolio-level project contingency.

In addition, project OM&A expenditures have been categorized in Ex. F2-T3-S1 Table 2 by the categories of regulatory, sustaining or value enhancing/strategic as defined in Ex. A2-T2-S1.

As indicated in Ex. D2-T1-S1, the nuclear project portfolio is approved via the OPG business planning process, with the OPG Board of Directors approving the OM&A and capital project portfolio budget which is then administered via the portfolio management process. As part of the 2008 business planning process, the OPG Board of Directors approved $290M ($172 M capital and $118M OM&A) as the appropriate and required level of ongoing project expenditure to maintain the generating assets and associated infrastructure. In addition to this ongoing project portfolio investment, there are expenditures associated with the P2/P3 isolation project and Pickering B refurbishment project (see Section Ex. D2-T2-S1 for descriptions). The total cost of OM&A projects are presented in Ex. F2-T3-S1 Table 1.

Exhibit F2-T3-S1 Table 1 presents the following trends over the 2005 - 2009 period. Definition of terms is as provided in Ex. D2-T1-S1:

- “Released Facility Projects” work decreases from $65.0M in 2007 to $29.0M in 2009, reflecting completion of current project work, while the some 2008 and 2009 work is yet to be released. As the data presented reflects 2008 business planning information (provided in late 2007), this is consistent with industry experience, where up to two years of released work is the norm.

- "Facility Projects to be Released" increases in the test years (complementary to the trend for "released" work discussed above), reflecting expected further release of funds to complete ongoing project work currently in the project definition or early execution phase, with a partial or developmental release in place.
- "Infrastructure" costs are relatively stable in the test years $29.4M in 2008, 29.0M in 2009) including $1M for conceptual funding, $12.3M for project support and $16.0M for minor modifications at Pickering A, Pickering B, Darlington, and programs and training facilities. The reduction in infrastructure costs from $41.1M in 2006 to a projected $29.0M in 2009 reflects the following:
  - o 2005, 2006 and 2007 include project write-offs which were incurred in that year ($11.7M in 2005, $7.7M in 2006, $3.0M in 2007); these are not budgeted in advance, and would only be incurred if specific capital projects were identified for cancellation and write-off in the 2008 - 2009 period.
  - o Project support decreases by $3.7M over the 2007 - 2009 period, reflecting primarily: transfer of operating costs for the Pickering shower/change/lunch facility to Pickering A base OM&A, transfer of funding for Procurement Engineering staff to Supply Chain base OM&A, and reduced project support staff numbers as a result of process efficiencies. In addition, conceptual funding is reduced by $1.5M between 2007 - 2008 reflecting an expected downturn in new projects as Pickering B nears end-of-life (assuming no refurbishment or life extension is undertaken).
- "Listed Work to be Released" increases over the test period, consistent with expectations that listed projects will continue to move from the project identification and initiation phases into the project development phase during 2008. Exhibit F2-T3-S1 Table 4a/b provides a list of potential OM&A projects currently under review.
- "P2/P3 Isolation Project" increases in 2008 reflecting peak project activity, then ramps down to completion in 2009. This OM&A work includes moving, isolating or repositioning safety or control systems that are required for continued operation of Pickering A Units 1 and 4 after the safe storage of Pickering A Units 2 and 3.

- "Pickering B Refurbishment Project" reflects potential expenditures if the OPG Board decides to proceed with one of the life extension options for the four affected units. See Ex. D2-T1-S3.

Ex. F2-T3-S3 presents further details of OM&A projects included in these expenditures.

3.1 OM&A Project Drivers

Sustaining projects have been a major factor in OM&A project expenditures over the 2005 - 2009 period.

In 2005, predominating effort was sustaining work on Pickering B Units 5 and 6 boiler divider plate inspection and repair ($23.5M) and Pickering B boiler water lancing ($10.2M).

In 2006, the major OM&A initiative was again sustaining in nature, with Pickering B boiler water lancing ($10.9M). The next most significant expenditures were regulatory in nature, associated with Pickering A Unit 4 boiler chemical clean and flushing ($15.1M total) and the Darlington environmentally-qualified component replacement project ($8.5M).

In 2007, the largest individual project expenditures were regulatory, particularly the Darlington environmentally-qualified component replacement ($12.2M) and single fuel channel replacement execution ($9.7M).

In 2008, the major planned items are regulatory and boiler maintenance. Specifically, Darlington environmentally-qualified component replacement ($12.2M) is regulatory. The next most significant planned expenditures are sustaining work related to Pickering B Units 7 and 8 boiler locking tab and divider plate repair ($7.4M) and Pickering B boiler water lancing ($4.9M).

In 2009, the major planned items are again sustaining work directed to Pickering B boiler water lancing ($10.5M) and Darlington boiler primary side cleaning ($7.8M). The next most significant planned expenditures are Darlington environmentally-qualified component replacement ($6.9M) and Pickering administration building rehabilitation ($3.0M).

For projects with cash flows in the test period, additional project information can be found in Ex. F2-T3-S3.

Numbers may not add due to rounding.

Table 1
Project OM&A Summary - Nuclear ($M)

Line No.	Facility Projects	2005 Actual	2006 Actual	2007 Actual	2008 Plan	2009 Plan
		(a)	(b)	(c)	(d)	(e)
	Facility Projects (Released)					
1	Darlington NGS	34.0	28.2	26.8	21.5	14.1
2	Pickering A NGS	25.3	35.3	12.5	8.7	0.7
3	Pickering B NGS	52.9	32.9	22.0	22.7	12.1
4	Engineering & Modifications	4.3	2.9	3.0	7.4	2.0
5	Programs & Training	1.1	0.0	0.0	0.0	0.0
6	Supply Chain	0.0	0.0	0.0	0.0	0.0
7	Inspection & Maintenance Services	0.0	0.0	0.6	0.0	0.0
8	**Total Facility Projects (Released)**	117.6	99.3	65.0	60.3	29.0
9	**Facility Projects to be Released**	N/A	N/A	0.0	11.8	24.4
10	**Infrastructure**	38.3	41.1	37.1	29.4	29.0
11	**Contingency[1]**	0.0	0.0	0.0	0.0	0.0
12	**Listed Work to be Released**	0.0	0.0	0.0	16.5	35.7
13	**Subtotal Project OM&A (Portfolio)**	155.9	140.4	102.1	118.0	118.0
14	**P2/P3 Isolation Project**	0.0	1.6	9.5	26.6	14.0
15	**Pickering B Refurbishment Project**	0.0	0.0	0.0	0.0	5.1
16	**Total Project OM&A**	155.9	142.0	111.6	144.6	137.1

1 Contingency was budgeted in 2005 and 2006 but was not utilized. There were no contingencies in 2007 and no contingencies are planned for 2008 and 2009.

Table 2
Project OM&A Summary - Nuclear ($M)
By Project Category

Line No.	OM&A Project Category	2005 Actual	2006 Actual	2007 Actual	2008 Plan	2009 Plan
		(a)	(b)	(c)	(d)	(e)
	Facility Projects (Released)					
1	**Regulatory**	45.5	45.9	16.3	15.6	7.7
2	**Sustaining**	72.1	53.4	48.7	44.7	21.3
3	**Value Enhancing/Strategic**	0.0	0.0	0.0	0.0	0.0
4	**Total**	117.6	99.3	65.0	60.3	29.0

COMPARISON OF PROJECT OM&A – NUCLEAR

1.0 PURPOSE

This evidence presents period-over-period comparisons of project OM&A for the nuclear facilities.

2.0 OVERVIEW

2.1 Period-over-Period Changes - Test Period

Year-over-year variances are presented by facility in Ex. F2-T3-S2 Table 1b and are explained here. Where projects have expenditures in the test period, more detailed project information is contained in Ex. F2-T3-S3.

<u>2009 Plan versus 2008 Plan</u>

The decrease in planned spending for 2009 (-$7.5M) reflects planned completion of work for the P2/P3 isolation project in 2009 (-$12.6M), partly offset by the execution of Pickering B projects that were deferred pending the Pickering B refurbishment decision ($5.1M).

<u>2008 Plan versus 2007 Actual</u>

The increase in planned spending in 2008 ($33.1M) is a direct result of the increase in project portfolio OM&A funding to $118M (increase of $15.9M) as part of the $290M project portfolio budget approved by OPG's Board of Directors. Increased work effort is related to a number of OM&A projects, with the most significant increases associated with Pickering B boiler maintenance projects (locking tab repair and waterlancing, $10.6M total). In addition, there is an increase in the P2/P3 isolation project spending ($17.2M) reflecting peak project activity in 2008

2.2 Period-over-Period Changes – Bridge Year

Year-over-year variances are presented by facility in Ex. F2-T3-S2 Table 1a and 1b, and explained here. Where projects have cash flows in the test period, and only for those projects, more detailed project information is contained in Ex. F2-T3-S3.

2007 Actual versus 2007 Budget

Project OM&A was underspent in 2007 (-$25.8M), primarily due to delays in the P2/P3 isolation project work (-$17.5M). As noted in Ex. D2-T1-S1, P2/P3 isolation project delays reflect deferral of construction and maintenance ramp-up (to allow greater progress on engineering/ assessment activities), and the new Canadian Nuclear Safety Commission requirement for an environmental assessment for the project (with conservative deferral of potentially-impacted activities). The balance of the variance (-$8.2M,) reflects the net impact of positive and negative variances resulting from day-to-day decisions and execution challenges across 124 OM&A projects that were managed in 2007. The largest individual contributors to the underspending are:

- Pickering A vacuum building MV13 repairs, which were put on hold to allow the review of the scope of planned project work as it relates to all vacuum building reliability risks (-$1.8M).
- Pickering A boiler chemical clean project, which was deferred to 2012 (-$1.3M).
- Darlington minor modifications project, which was under plan (-$1.2M) due to scheduling issues.

2007 Actual versus 2006 Actual

Total project OM&A decreased (-$30.4M). For facility projects (released), the year-over-year reduction (-$34.3M) is driven largely by Pickering A (-$22.8M) and Pickering B (-$10.9M). At Pickering A, the decrease is primarily due to the 2006 completion of steam generator feedwater nozzle and thermal sleeve repairs (-$10.2M) and steam generator flushing and chemical clean preparations for 2008 outage (-$12.5M). At Pickering B, major project completions in 2006 include the scheduled phase of the steam generator water lancing (-$10.6M), steam generator divider plate repairs (-$3.2M), and main output transformer subsurface investigation (-$2.5M).

Other factors contributing to the year-over-year change are infrastructure costs (-$4.7M) reflecting largely the impact of extraordinary capital write-offs in 2006, and planned increases in P2/P3 isolation project work ($7.9M).

2.3 Period-over-Period Changes – Historical Years

Year-over-year variances are presented by facility in Ex. F2-T3-S2 Table 1a and are explained here. Where projects have cash flows in the test period, and only for those projects, more detailed project information is contained in Ex. F2-T3-S3.

<u>2006 Actual versus 2006 Budget</u>

The variance to budget in 2006 (-$14.9M) is primarily due to project delays. Specifically, the facility projects (released) under-variance is influenced by the deferral of the Pickering B Unit 6 boiler divider plate repairs (-$11.3M) - a new repair method is being developed to reduce execution time, radiation dose to workers, and costs, and this method will be implemented in 2008. Adding to the variance was delay of the Pickering B transformer secondary spill containment projects (-$2.9M) offset by a number of minor project advancements. At Pickering A, major drivers were Pickering A Unit 4 boiler maintenance work (boiler chemical cleaning, boiler flushing, and feedwater nozzle replacement [$9.7M] which was advanced**,** with a partial offset primarily due to deferral of Pickering A Unit 1 and Unit 4 feeder replacement work (-$3.9M), Pickering A Unit 2 and 3 safe storage (-$2.3M) and administration building refurbishment (-$1.8M). The variance for engineering and modifications (-$1.9M) reflects delays in commencement of digital control computer aging management**,** while at Darlington, delay is in environmentally-qualified component replacement (-$1.5M) and feeder replacement project (-$1.4M), partly offset by numerous minor project variances.

In infrastructure, the over-variance is due to the write-off of several older capital projects that were cancelled and their value written-off ($7.7M). In addition, conceptual funding was increased by $2.4M in 2006 to allow more detailed scope development of future projects, to facilitate improved cost estimates for input to the portfolio management process.

Contingency (-$10M) was not required in 2006 due to the beneficial cost impact of project delays.

<u>2006 Actual versus 2005 Actual</u>

The change in spending 2005 - 2006 (-$13.9M) is primarily due to completion of Pickering B Unit 5 and Unit 6 boiler divider plate inspection/rework projects in 2005 (-20.7M), offset by numerous lower value project variances.

2005 Actual versus 2005 Budget

The variance to budget in 2005 (-$14.6M) is primarily due to the fact that contingency was not required in 2005 (-$15.9M), partly offset by numerous lower value project variances.

Table 1a
Comparison of Project OM&A - Nuclear ($M)

Line No.	Facility Projects	2005 Budget	(c)-(a) Change	2005 Actual	(e)-(c) Change	2006 Actual	(e)-(g) Change	2006 Budget	(i)-(e) Change	2007 Actual
		(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)
	Facility Projects (Released)									
1	Darlington NGS	35.8	(1.8)	34.0	(5.8)	28.2	(1.5)	29.7	(1.4)	26.8
2	Pickering A NGS	36.0	(10.7)	25.3	10.0	35.3	0.8	34.5	(22.8)	12.5
3	Pickering B NGS	46.7	6.2	52.9	(20.0)	32.9	(13.8)	46.7	(10.9)	22.0
4	Engineering & Modifications	6.3	(2.0)	4.3	(1.4)	2.9	(1.9)	4.8	0.1	3.0
5	Programs & Training	0.9	0.2	1.1	(1.1)	0.0	0.0	0.0	0.0	0.0
6	Supply Chain	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
7	Inspection & Maintenance Services	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.6	0.6
8	**Total Facility Projects (Released)**	125.7	(8.1)	117.6	(18.3)	99.3	(16.4)	115.7	(34.3)	65.0
9	**Facility Projects to be Released**	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
10	**Infrastructure**	28.9	9.4	38.3	2.8	41.1	12.2	28.9	(4.0)	37.1
11	**Contingency**	15.9	(15.9)	0.0	0.0	0.0	(10.0)	10.0	0.0	0.0
12	**Listed Work to be Released**	0.0	0.0	0.0	0.0	0.0	0.1	(0.1)	0.0	0.0
13	**Subtotal Project OM&A (Portfolio)**	170.5	(14.6)	155.9	(15.5)	140.4	(14.1)	154.5	(38.3)	102.1
14	**P2/P3 Isolation Project**	0.0	0.0	0.0	1.6	1.6	(0.8)	2.4	7.9	9.5
15	**Pickering B Refurbishment Project**	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
16	**Total Project OM&A**	170.5	(14.6)	155.9	(13.9)	142.0	(14.9)	156.9	(30.4)	111.6

Numbers may not add due to rounding.

Table 1b
Comparison of Project OM&A - Nuclear ($M)

Line No.	Facility Projects	2007 Budget	(c)-(a) Change	2007 Actual	(e)-(c) Change	2008 Plan	(g)-(e) Change	2009 Plan
		(a)	(b)	(c)	(d)	(e)	(f)	(g)
	Facility Projects (Released)							
1	Darlington NGS	27.3	(0.5)	26.8	(5.3)	21.5	(7.4)	14.1
2	Pickering A NGS	19.5	(7.0)	12.5	(3.8)	8.7	(8.0)	0.7
3	Pickering B NGS	22.6	(0.6)	22.0	0.7	22.7	(10.7)	12.1
4	Engineering & Modifications	4.8	(1.8)	3.0	4.4	7.4	(5.4)	2.0
5	Programs & Training	0.3	(0.3)	0.0	(0.0)	0.0	0.0	0.0
6	Supply Chain	0.0	0.0	0.0	0.0	0.0	0.0	0.0
7	Inspection & Maintenance Services	0.0	0.6	0.6	(0.6)	0.0	0.0	0.0
8	**Total Facility Projects (Released)**	74.5	(9.6)	65.0	(4.6)	60.3	(31.4)	29.0
9	**Facility Projects to be Released**	0.0	0.0	0.0	11.8	11.8	12.6	24.4
10	**Infrastructure**	36.2	0.9	37.1	(7.7)	29.4	(0.4)	29.0
11	**Contingency**	0.0	0.0	0.0	0.0	0.0	0.0	0.0
12	**Listed Work to be Released**	(0.4)	0.4	0.0	16.5	16.5	19.2	35.7
13	**Subtotal Project OM&A (Portfolio)**	110.3	(8.2)	102.1	15.9	118.0	(0.0)	118.0
14	**P2/P3 Isolation Project**	27.0	(17.5)	9.5	17.2	26.6	(12.6)	14.0
15	**Pickering B Refurbishment Project**	0.0	0.0	0.0	0.0	0.0	5.1	5.1
16	**Total Project OM&A**	137.3	(25.8)	111.6	33.1	144.6	(7.5)	137.1

DETAILS OF OM&A PROJECTS – NUCLEAR

1.0 PURPOSE

The purpose of this evidence is to provide project listings and supporting information for Nuclear OM&A project expenditures.

2.0 OVERVIEW

A tiered reporting structure consistent with OEB filing guidelines has been used to present the evidence for all OM&A projects which have budgeted expenses during the test period.

- Tier 1 - Projects with a total cost of $10M or greater, for which summary level information is provided as well as a project summary form (Appendix A).
- Tier 2 - Projects with a total cost of $5M to $10M, for which summary level information is provided herein.
- Tier 3 - Projects with a total cost of less than $5M, for which aggregated information is provided herein.

Consistent with the definitions presented in Ex. D2-T1-S1 and Ex. F2-T3-S1, information on facility projects in the following tables is categorized as released amount, balance to be released, and listed work to be released. The information is then further sorted by sponsoring division.

As per Ex. F2-T3-S3 Table 1, there are 10 released projects with total project cost $10M or greater that have expenditures in the test period, and two of these projects have a future balance to be released during the test period. In general, the future balances to be released represent amounts associated with the project execution phase following successful completion of the project definition phase. Project forms are provided for each of these projects in Appendix A, with variance explanations provided for completed projects where actual project costs exceed the initial full release by 10 percent or more.

As indicated in Ex. F2-T3-S1, boiler maintenance and repair programs are a major driver for the OM&A projects $10M or greater (six of ten projects), Further details are provided in the project summary forms.

As per Ex. F2-T3-S3 Table 2, there are 14 released projects with total project costs between $5M and $10M that have expenditures in the test period, and five of these projects have a future balance to be released during the test period. As noted above, the future balances to be released represent amounts associated with the project execution phase following successful completion of the project definition phase. With the exceptions of worker safety modifications for feedwater chemical addition and the inspection qualification project, which are regulatory projects, the balance of projects in the $5M to $10M total cost range are sustaining in nature, driven by the need for system repair, refurbishment or the replacement of obsolete components.

As per Ex. F2-T3-S3 Table 3, there are a total of 48 projects with total project costs less than $5M that have expenditures in the test period. The average value of these projects is $1.5M with 8 projects being regulatory in nature, and the balance sustaining (generally repair, refurbishment or obsolescence as noted above). Summary level information is provided in Ex. F2-T3-S3 Table 3.

As per Ex. F2-T3-S3 Tables 4a/4b, there are a total of 71 projects categorized as "Listed Work to be Released". This potential work is currently in the project identification or project definition phases, and could be started in the test period as a result of the portfolio management process.

LIST OF ATTACHMENTS

Appendix A: Ontario Power Generation – Project Summary Forms

- Project Number: 38296 (OM&A) – Darlington Boiler Primary Side Cleaning
- Project Number: 38457 – Darlington Environmentally Qualified Component Replacements
- Project Number 40412 - Pickering B Standby Generator Upgrade
- Project Number 40618 - Pickering B Remote Emergency Power Generator (Operating Costs)
- Project Number: 40641 – Pickering B P7 and P8 Tab and Divider Plate Repair
- Project Number: 40645 – Pickering B Boiler Water Lancing
- Project Number: 49201 – Pickering A Unit 4 Boiler Chemical Clean
- Project Number: 49204 – Pickering A Unit 4 Boiler Flushing
- Project Number: 49248 – Pickering A Units 1 and 4 - Replace Boiler Divider Plate Locking Tabs
- Project Number 62553 - Digital Control Computer Aging Management

APPENDIX A

Ontario Power Generation – Project Summary

Project Name: Darlington Boiler Primary Side Cleaning

Project Number:	Project Category:	Project Type:
38296 (OM&A)	☐ Regulatory ☒ Sustaining ☐ Value Enhancing / Strategic	☐ Capital ☒ OM&A

Project Start Date (month, year):	In-Service Date (month, year):
May 2001	June 2013

Project Description:

Remove magnetite deposits from the inside of the boiler (steam generator) tubes to restore heat transfer in the primary heat transport system and reduce reactor inlet header temperature.

Project Need (i.e., justification for the project):

Inside fouling of the boiler tubes occurs as a consequence of dissolution of magnetite in the carbon steel outlet feeders by hot primary heat transport fluid, and deposition of the magnetite inside of the boiler tubes as primary heat transport fluid cools. This fouling reduces the heat transfer rate in the boilers resulting in increased reactor inlet header temperature. Reactor inlet header temperature is measured and controlled to ensure that the maximum channel outlet temperature does not exceed power reactor operating license limits. If the magnetite is not removed, reactor power would have to be reduced to meet operating licence requirements.

Project Costs:

$ 000	LTD 2005 Actual	2006 Actual	2007 Actual	2008 Plan	2009 Plan	Future Plan	Total Costs
Capital		0					
OM&A	23,461	671	59	1,910	7,800	109,939	143,840

Initial Full Release (A):	Actual or Forecasted Project Completion Cost (B):	Variance (B-A):
N/A – Partial Release	N/A	

Variance Explanation (if Variance > 10% of Initial Full Release): N/A

Ontario Power Generation – Project Summary

Project Name: Darlington Environmentally-Qualified Component Replacements

Project Number:	Project Category:	Project Type:
38457	☒ Regulatory ☐ Sustaining ☐ Value Enhancing / Strategic	☐ Capital ☒ OM&A

Project Start Date (month, year):	In-Service Date (month, year):
October 2004	November 2010

Project Description:

Restore Darlington to full environmental qualified status by December 2010 as required by Canadian Nuclear Safety Commission regulatory commitment and in accordance with the Darlington power reactor operating license. Scope of work includes development of an auditable environmental qualified components listing, replacement of life-expired environmental qualified components and replacement of previous non-qualified components that have to be upgraded to reflect the licensing basis of the station.

Project Need (i.e., justification for the project):

Environmental qualification ensures that components required to function under postulated operating or accident conditions are specified, purchased, installed and maintained so as to meet that requirement. Lack of a sustaining environmental qualified program for post-installation activities (maintenance and system modifications) has resulted in degradation of environmental qualified status at Darlington over the years of operation. This project will ensure that a comprehensive program is put in place to restore and maintain station environmental qualification.

Project Costs:

$ 000	LTD 2005 Actual	2006 Actual	2007 Actual	2008 Plan	2009 Plan	Future Plan	Total Costs
Capital							
OM&A	6,396	8,522	12,213	12,246	6,985	6,848	53,210

Initial Full Release (A):	Actual or Forecasted Project Completion Cost (B):	Variance (B-A):
$63,110k	$53,210	-$9,900

Variance Explanation (if Variance >10% of Initial Full Release): N/A

1 **Ontario Power Generation – Project Summary**

Project Name: Pickering B Standby Generator Upgrade

Project Number:	Project Category:	Project Type:
40412	☐ Regulatory ☒ Sustaining ☐ Value Enhancing / Strategic	☐ Capital ☒ OM&A

Project Start Date (month, year):	In-Service Date (month, year):
March 2000	July 2008

Project Description:

This objective to provide a reliable power source to ensure operation of the high pressure emergency coolant injection pumps under all conditions including loss of coolant accident and loss of bulk electricity system to be achieved through three phases:

Phase I Logic Modification (governing pump start-up & change over to back up)
Phase II New Power Supply to high pressure emergency coolant injection pumps (from the existing Standby Generators)
Phase III Pickering B Standby Generator Upgrade (replace numerous components; upgrade lube oil condition monitor)

Project Need (i.e., justification for the project):

The performance of the existing Pickering B standby generators has deteriorated over time due to end of life equipment failures, lack of original equipment manufacturer support and parts unavailability due to obsolescence.

Project Costs:

	LTD 2005 Actual	2006 Actual	2007 Actual	2008 Plan	2009 Plan	Future Plan	Total Costs
Capital							
OM&A	7,965	704	113	196	0	0	8,978

Initial Full Release (A):	Actual or Forecasted Project Completion Cost (B):	Variance (B-A):
$11,035k	$8,978	-$2,057

Variance Explanation (if Variance >10% of Initial Full Release): N/A

Ontario Power Generation – Project Summary

Project Name: Pickering B Remote Emergency Power Generator Operating Costs

Project Number:	Project Category:	Project Type:
40618	☒ Regulatory ☐ Sustaining ☐ Value Enhancing / Strategic	☐ Capital ☒ OM&A

Project Start Date (month, year):	In-Service Date (month, year):
June 2004	December 2008

Project Description:

Operating and maintenance costs for the remote emergency power generator, which was installed to provide backup power until the permanent solution is installed (reference 49104 Pickering auxiliary power system).

Project Need (i.e., justification for the project):

On August 14, 2003 Pickering experienced a loss of the bulk electrical system for approximately five hours. None of the three operating units at Pickering B survived the event leading to a total loss of class IV power across the two stations (Pickering A and B) and the site electrical system being unavailable.

Project Costs:

	LTD 2005 Actual	2006 Actual	2007 Actual	2008 Plan	2009 Plan	Future Plan	Total Costs
Capital							
OM&A	2,316	1,632	1,383	1,676	0	0	7,007

Initial Full Release (A):	Actual or Forecasted Project Completion Cost (B):	Variance (B-A):
$11,700k	$7,007	-$4,693

Variance Explanation (if Variance >10% of Initial Full Release): N/A

Ontario Power Generation – Project Summary

Project Name: Pickering B Boiler Tab and Divider Plate Repair (Unit 7 and Unit 8)

Project Number:	Project Category:	Project Type:
40641	☐ Regulatory ☒ Sustaining ☐ Value Enhancing / Strategic	☐ Capital ☒ OM&A

Project Start Date (month, year):	In-Service Date (month, year):
February 2007	May 2011

Project Description:

Design, install, and commission new locking devices in all 12 steam generators in Unit 7 during the 2008 outage and Unit 8 during the 2010 outage.

Project Need (i.e., justification for the project):

Locking tabs are used to hold steel “skins” in place, separating the inlet and outlet water flows within each steam generator. Locking tab design problems were first experienced when broken pieces of locking tabs and sealing skins were found on the hot leg (inlet) side of the Unit 5 steam generators during the P551 outage. Similar problems were later found in Unit 6. OPG has an internal operating requirement to shut down the units after 6.3 equivalent full power years because of the threat of fatigue failure of the cold leg locking tabs. If the tabs are not replaced, loose parts could enter the heat transport system and potentially result in damage to the fuel and pressure tubes.

Project Costs:

$ 000	LTD 2005 Actual	2006 Actual	2007 Actual	2008 Plan	2009 Plan	Future Plan	Total Costs
Capital							
OM&A	0	0	421	7,428	406	7,875	16,130

Initial Full Release (A):	Actual or Forecasted Project Completion Cost (B):	Variance (B-A):
$20,505k	$16,130	-$4,375

Variance Explanation (if Variance >10% of Initial Full Release): N/A

1 **Ontario Power Generation – Project Summary**

Project Name: Pickering B Steam Generator Water Lancing

Project Number:	Project Category:	Project Type:
40645	☐ Regulatory ☒ Sustaining ☐ Value Enhancing / Strategic	☐ Capital ☒ OM&A

Project Start Date (month, year):	In-Service Date (month, year):
April 2007	December 2010

Project Description:

Perform water lancing to remove accumulated sludge in each unit boiler as required by the Pickering B Steam Generators Life Cycle Management Plan. Water-lancing at regular intervals will keep the boiler tube-sheets clean and free (or minimum) hard sludge piles.

Project Need (i.e., justification for the project):

Maintenance water lancing is required to keep boiler deposits low, minimizing boiler tube degradation by under-deposit corrosion. The historic operating trends for Pickering B steam generators have shown a correlation between tube leaks and the intervals between chemical cleaning and water lancing. Under-deposit pitting due to sludge build-up is one of the main failure mechanisms causing tube leaks in the steam generators.

Project Costs:

	LTD 2005 Actual	2006 Actual	2007 Actual	2008 Plan	2009 Plan	Future Plan	Total Costs
Capital							
OM&A	0	0	1,294	4,868	10,487	5,924	22,573

Initial Full Release (A):	Actual or Forecasted Project Completion Cost (B):	Variance (B-A):
$24,973k	$22,573	-$2,400

Variance Explanation (if Variance >10% of Initial Full Release): N/A

Ontario Power Generation – Project Summary

Project Name: Pickering A Unit 4 Boiler Chemical Clean

Project Number:	Project Category:	Project Type:
49201	☒ Regulatory ☐ Sustaining ☐ Value Enhancing / Strategic	☐ Capital ☒ OM&A

Project Start Date (month, year):	In-Service Date (month, year):
July 2003	December 2012

Project Description:

Perform chemical cleaning of Unit 4 boilers (steam generators) to maximize deposit removal from the secondary side of the boilers while minimizing corrosion of the boiler tubing and boiler internals.

Project Need (i.e., justification for the project):

During normal, steady state operation of nuclear power plants, small amounts of metallic impurities, principally iron, nickel, zinc and copper, are transported via the feedwater to the secondary side of the boilers where they slowly accumulate. For Pickering A, completion of this program was deemed a regulatory requirement, as part of the return to service project.

Pickering has adopted boiler chemical cleans as part of its life cycle management plan to remove these deposits to slow or stop boiler tube degradation mechanisms, and protect the generating assets.

Project Costs:

$ 000	LTD 2005 Actual	2006 Actual	2007 Actual	2008 Plan	2009 Plan	Future Plan	Total Costs
Capital							
OM&A	11,586	7,873	2,241	400	206	20,770	43,076

Initial Full Release (A):	Actual or Forecasted Project Completion Cost (B):	Variance (B-A):
$55,306k	$43,076	-$12,230

Variance Explanation (if Variance >10% of Initial Full Release): N/A

1 **Ontario Power Generation – Project Summary**

Project Name: Pickering A Unit 4 Boiler Flushing

Project Number:	Project Category:	Project Type:
49204	☒ Regulatory ☐ Sustaining ☐ Value Enhancing / Strategic	☐ Capital ☒ OM&A

Project Start Date (month, year):	In-Service Date (month, year):
July 2003	December 2012

Project Description:

- Perform secondary side flushing of the Unit 4 boilers prior to and after boiler chemical cleaning.
- Repair/add of boiler handholes and other site modifications to support this operation.

Project Need (i.e., justification for the project):

During normal, steady state operation of nuclear power plants, small amounts of metallic impurities, principally iron, nickel, zinc and copper, are transported via the feedwater to the secondary side of the boilers where they slowly accumulate atop the tube supports and the tubesheet. For Pickering A, completion of this program was deemed a regulatory requirement as part of the return to service project.

Pickering has adopted boiler chemical cleans as part of its life cycle management plan to remove these deposits to slow or stop boiler tube degradation mechanisms, and protect the generating assets.

Boiler flushing is required to support the boiler chemical clean project. Boiler flushing must be performed prior to and after chemical cleaning. The pre-flush will remove the build up of soft deposits, exposing the "hard" deposits to the chemical clean process, while the post-flush will remove the deposits dislodged or "softened" by the chemical clean.

Project Costs:

$ 000	LTD 2005 Actual	2006 Actual	2007 Actual	2008 Plan	2009 Plan	Future Plan	Total Costs
Capital							
OM&A	2,203	7,201	306	200	25	2,865	12,800

Initial Full Release (A):	Actual or Forecasted Project Completion Cost (B):	Variance (B-A):
$14,700k	$12,800	-$1,900

Variance Explanation (if Variance >10% of Initial Full Release): N/A

Ontario Power Generation – Project Summary

Project Name: Pickering A Replace Boiler Divider Plate Locking Tabs (Unit 1 and Unit 4)

Project Number:	Project Category:	Project Type:
49248	☐ Regulatory ☒ Sustaining ☐ Value Enhancing / Strategic	☐ Capital ☒ OM&A

Project Start Date (month, year):	In-Service Date (month, year):
June 2007	June 2011

Project Description:

Replace the current locking tabs installed in Units 1 and 4 with a new design that will allow the boilers to function until end of station life without possibility of locking tab failure.

Project Need (i.e., justification for the project):

Locking tabs are used to hold steel “skins” in place, separating the inlet and outlet water flows within each boiler (steam generator). Re-design and installation of the boiler divider plate component locking devices (and possible skin panels) is required in Pickering Units 1 and 4 following the failure of similar parts discovered in Pickering Units 5 - 8. If not replaced, failure of the tabs on the cold leg of the boilers could result in loose parts in the heat transport system and possible fuel damage.

Project Costs:

$ 000	LTD 2005 Actual	2006 Actual	2007 Actual	2008 Plan	2009 Plan	Future Plan	Total Costs
Capital							
OM&A	0	0	87	385	520	15,043	16,035

Initial Full Release (A):	Actual or Forecasted Project Completion Cost (B): N/A	Variance (B-A):
N/A – Developmental Release		

Variance Explanation (if Variance >10% of Initial Full Release): N/A

Ontario Power Generation – Project Summary

Project Name: Digital Control Computer Aging Management

Project Number:	Project Category:	Project Type:
62553	☐ Regulatory ☒ Sustaining ☐ Value Enhancing / Strategic	☐ Capital ☒ OM&A

Project Start Date (month, year):	In-Service Date (month, year):
March 2004	December 2012

Project Description:

Complete a number of actions required to manage digital control computer aging, including:

- Replacement of Pickering A main control room operator interface system
- Digital control computer training for Darlington and Pickering A and B staff
- Procurement of strategic spare parts for Pickering A and B
- Repair/refurbishment/replacement of identified components
- Participation in the joint Canadian Deuterium Uranium digital control computer replacement project, to be in a position of readiness to replace the Pickering B digital control computers when required

Project Need (i.e., justification for the project):

This project is required to manage digital control computer aging issues that challenge Pickering A and B unit operators and control maintenance staff, and threaten reliable station operation and planned capacity targets.
A number of issues challenge both near- and long-term viability of the digital control computers, specifically:

- Uncertain availability of digital control computer spare parts and excessive maintenance, as well as operational challenges with existing components
- Old technology that is approaching the point of increasing lifetime unreliability
- Operating experience confirming aging-related problems at other reactors (eg., digital control computer field input cable degradation), and an incipient problem at Pickering B
- Impending loss of knowledgeable staff who are currently able to trouble-shoot and repair Varian digital control computer faults
- Long lead time to engineer, qualify and license a digital control computer replacement.

Project Costs:

	LTD 2005 Actual	2006 Actual	2007 Budget	2008 Plan	2009 Plan	Future Plan	Total Costs
Capital							
OM&A	572	764	690	2,700	2,000	5,266	11,992

Initial Full Release (A):	Actual or Forecasted Project Completion Cost (B):	Variance (B-A):
$14,492k	$11,992	-$2,500

Variance Explanation (if Variance >10% of Initial Full Release): N/A

Numbers may not add due to rounding.

Updated: 2008-03-14
EB-2007-0905
Exhibit F2
Tab 3
Schedule 3
Table 1

Table 1
OM&A Project Listing - Nuclear
Facility Projects - Released Amount and Balance to be Released
Projects >$10M Total Project Cost[1]

Line No.	Project Name	Project Summary Ref. No.	Category	Start Date	In-Service Date	Released Amount ($M)	Balance To Be Released ($M)
	(a)	(b)	(c)	(d)	(e)	(f)	(g)
	Project summaries for the following projects are included in this section of the application						
	Darlington NGS						
1	Boiler Primary Side Cleaning	38296	Sustaining	May-01	Jun-13	24.7	119.1
2	Environmentally-Qualified Component Replacement	38457	Regulatory	Oct-04	Nov-10	53.2	0.0
	Pickering A NGS						
3	Unit 4 Boiler Chemical Clean	49201	Regulatory	Jul-03	Dec-12	43.1	0.0
4	Replace Locking Tabs on Boiler Divider Plate (P1 & P4)	49248	Sustaining	Jun-07	Jun-11	1.0	15.0
5	Unit 4 Boiler Flushing	49204	Regulatory	Jul-03	Dec-12	12.8	0.0
	Pickering B NGS						
6	Steam Generator Water Lancing	40645	Sustaining	Apr-07	Dec-10	22.6	0.0
7	Boiler Tab & Divider Plate Repair (P7 & P8)	40641	Sustaining	Feb-07	May-11	16.2	0.0
8	Remote Emergency Power Generator (Operating Costs)	40618	Regulatory	Jun-04	Dec-08	7.0	0.0
9	Standby Generator Upgrade	40412	Sustaining	Mar-00	Jul-08	9.0	0.0
	Engineering & Modifications						
10	Digital Control Computer Aging Management	62553	Sustaining	Mar-04	Dec-12	12.0	0.0
11	**Subtotal Facility Projects**					201.7	134.1

1 Projects with expenditures during Test Period

Numbers may not add due to rounding.

Table 2
OM&A Project Listing - Nuclear
Facility Projects - Released Amount and Balance to be Released
Projects $5M - $10M Total Project Cost[1]

Line No.	Project Name	Category	Project Description	Released Amount ($M)	Balance To Be Released ($M)
	(a)	(b)	(c)	(d)	(e)
	Darlington NGS				
1	Steam Generator Water Lancing	Sustaining	Remove deposits from secondary side of Steam Generators to prevent under-deposit corrosion.	9.6	0.0
2	Steam Generator Water Lancing (Future campaigns)	Sustaining	Remove deposits from secondary side of Steam Generators to prevent under-deposit corrosion.	8.4	0.0
3	Standby Generator Gas Generator and Power Turbine Overhaul	Sustaining	Complete overhaul and refurbishment of the Standby Generators	6.6	0.0
4	Fuel Handling Power Track Improvement	Sustaining	Modify Fuel Handling Power Track to improve reliability and add condition monitoring capability.	0.3	4.7
	Pickering A NGS				
5	Administration Building Rehabilitation	Sustaining	Upgrade Administration Building structures and systems to current codes and requirements.	1.7	8.0
6	Pickering Vacuum Building Fiber Reinforced Plastic Components Modifications	Sustaining	Perform laboratory testing to confirm lifespan of fiber reinforced plastic in vacuum conditions and replace components as required.	0.7	7.9
7	Vacuum Building Leakage Repairs	Sustaining	Perform repairs to the Vacuum Building to reduce leakage.	6.6	0.0
	Pickering B NGS				
8	Liquid Zone Control Pumps/Mounting Frame Replacement	Sustaining	Replace & relocate Liquid Zone Control Pumps to improve reliability and address obsolescence of existing pumps.	7.8	0.0
9	Main Output Transformer Subsurface Investigation	Sustaining	Investigate, confirm and arrest the possibility of costly damage and/or forced outages caused by sub-surface instability under the Main Output Transformers	2.8	3.9
10	Contractor Lunch Room Facility	Sustaining	Provide change, shower and lunch room facilities within the protected area and demolish old life-expired facility.	5.6	0.0
11	Digital Control Computer Obsolesence Management	Sustaining	Upgrade display hardware; replace fuel handling printers, moving arm disc, core memory, and power supplies; and procure critical scarce spares.	5.4	0.0
12	Worker Safety Modifications for Feedwater Chemical Addition	Regulatory	Comply with OHSA limits for hydrazine exposure and provide overpressure protection.	5.2	0.0
	Engineering & Modifications				
13	Inspection Qualification	Regulatory	Construct facility to validate component crack / flaw detection capability.	1.0	6.0
14	Feeder Repair by Weld Overlay Proof of Concept	Sustaining	Confirm concept of repairing thinning feeders by overlaying weld material within the confines of the spaces available.	5.1	0.0
15	**Subtotal Facility Projects**			66.9	30.6

1 Projects with expenditures during Test Period

Numbers may not add due to rounding.

Table 3
OM&A Project Listing - Nuclear
Projects <$5M Total Project Cost[1]

Line No.	Project Description	Number of Projects	Total Project Cost ($M)	Average Cost Of All Projects ($M)
		(a)	(b)	(c)
	Facility Projects (Released Amount)			
1	Darlington NGS	13	22.0	1.7
2	Pickering A NGS	12	15.8	1.3
3	Pickering B NGS	16	16.7	1.0
4	Engineering & Modifications	3	4.7	1.6
5	Programs & Training	4	3.7	0.9
6	Subtotal Facility Projects (Released Amount)	48	63.0	1.3
	Facility Projects (Balance to Be Released)			
7	Darlington NGS	2	3.2	1.6
8	Pickering A NGS	5	8.7	1.7
9	Pickering B NGS	6	7.1	1.2
10	Subtotal Facility Projects (Balance to be Released)	6	7.1	1.2
11	**Total**	48	70.1	1.5

1 Projects with expenditures during Test Period

Table 4a
OM&A Project Listing - Nuclear
Facility Projects - Listed Work to be Released

Line No.	Project Name	Category	Potential Start Date
	(a)	(b)	(c)
	Facility Projects (Listed Work to be Released)		
	Darlington NGS		
1	Underground Fuel Pipe Replacement	Sustaining	2008
2	Single Fuel Channel Replacement	Regulatory	2008
3	DN Fuel Channel Closure Plug Leakage Elimination (Note 2)	Sustaining	2008
4	Primary Heat Transport Liquid Relief Valve Modifications	Regulatory	2008
5	Warehouse Annex Fire Suppression System	Sustaining	2008
6	Freon Replacement in CO2 Supply System	Regulatory	2009 or Future
7	Emergency Power Generator 1 Gas Generator & Power Turbine Overhall	Sustaining	2009 or Future
8	Main Generator Excitation Controls Replacement	Sustaining	2009 or Future
9	Main Generator Hydrogen Cooling Temperature Control Valve 20 Redesign	Sustaining	2009 or Future
10	Computer Development Facility	Sustaining	2009 or Future
11	Underground Services Upgrade	Sustaining	2009 or Future
12	Generator Liquid Pot Drain Modifications	Sustaining	2009 or Future
13	Retrofit Lighting in Main Control Room	Sustaining	2009 or Future
14	Install Permanent Cables for Temporary Power Supplies for Critical Loads	Sustaining	2009 or Future
15	Upgrade Containment Boundary Isolation Valves	Sustaining	2009 or Future
16	Shutdown System 2 Radiation Reduction Tooling	Sustaining	2009 or Future
17	Main Boiler Feed Pump Major Refurbishment	Sustaining	2009 or Future
	Pickering A NGS		
18	Vacuum Building Performance Improvement	Sustaining	2008
19	Vacuum Building Fiber-Reinforced Plastic Component Replacement	Sustaining	2008
20	Reactor Auxiliary Bay/Irradiated Fuel Bay Ventilation	Regulatory	2009 or Future
21	PA Gates and Handrails on Turbine Hall Crane Access Platforms	Regulatory	2009 or Future
22	Vacuum Building Exhaust Activity Monitors Replacement	Sustaining	2009 or Future
23	Unit 1 Fuel Channel East Pressure Tube Shift	Sustaining	2009 or Future
24	Stator Cooling System Alkalyzer Installation	Sustaining	2009 or Future
25	Primary Heat Transport D2O Storage Tank Pressure Control Improvement	Sustaining	2009 or Future
26	Primary Heat Transport Main Circulating Pump Vibration Instrumentation Refurbishment	Sustaining	2009 or Future
27	U4 Shutdown Cooling Heat Exchange Temperature Control Valve Back Up Instrument Air	Sustaining	2009 or Future
28	Upgrade Existing Turbovisory System	Sustaining	2009 or Future
29	Adjuster Rod Replacement	Sustaining	2009 or Future
30	Forced Loss Rate Reduction	Sustaining	2009 or Future
31	Pickering Incoming/Outgoing Transfer System TDO Filling Station Filter Installation	Sustaining	2009 or Future
32	Reactor Structure - Guide Tube Tension	Sustaining	2009 or Future
33	Pickering Upgrader Chiller Replacement	Sustaining	2009 or Future
34	As Low As Reasonably Achievable Source Term/Dose Reduction	Sustaining	2009 or Future
35	Active Liquid Waste Management System Tanks Sludge Removal	Sustaining	2009 or Future
36	Mens Change Room Rehabilitation	Sustaining	2009 or Future
37	Reactivity Mechanism Rehearsal Facility	Sustaining	2009 or Future
38	Replacement of Irradiated Fuel Bay, West Annex, Service Wing, and Auxiliary Irradiated Fuel Bay Stack Monitors	Sustaining	2009 or Future
39	Steam Generator Primary Side Cleaning	Sustaining	2009 or Future
40	Powerhouse/Turbine Auxiliary Bay Ventilation Units Replacement	Sustaining	2009 or Future
41	Legacy Fire Protection Panel Replacement	Sustaining	2009 or Future
42	West Annex Ventilation Equipment Replacement	Sustaining	2009 or Future
43	Moderator Cover Gas System Flowmeter Replacement	Sustaining	2009 or Future
44	Environmentally Qualify Additional Air Conditioning Unit in Fuelling Machine Vaults	Sustaining	2009 or Future
45	Boiler Room Air Conditioning Unit Jib Crane Replacement	Sustaining	2009 or Future
46	Moderator Resin Slurry Modification	Sustaining	2009 or Future
47	Emergency Command Center Heating, Ventilation & Air Condtioning Upgrade	Sustaining	2009 or Future
48	Swing Grating Upgrade	Sustaining	2009 or Future
49	Refurbish/Replace Boiler Room Crane	Sustaining	2009 or Future
50	PA Sulzer B Outage	Sustaining	2009 or Future
51	PA UPP-B Distributor Cleaning Outage	Sustaining	2009 or Future
	Table continues on Ex. F2, Tab 3, Sch. 3 Table 4b		

1 Projects with expenditures during Test Period
2 Projects anticipated to cost > $10M

Table 4b
OM&A Project Listing - Nuclear
Facility Projects - Listed Work to be Released

Line No.	Project Name	Category	Potential Start Date
	(a)	(b)	(c)
	Facility Projects (Listed Work to be Released) - Continued		
	Pickering B NGS		
52	Removal of Wood from TMB Ceiling	Regulatory	2008
53	Reactor Building Service Water Dechlorination and Municipal Industrial Strategy for Abatement Cleanup	Sustaining	2008
54	Heat Tracing of Emergency Coolant Injection Recovery Line	Sustaining	2008
55	Unit 7 Calandria Tube Replacement (Note 2)	Sustaining	2008
56	Powerhouse Office Facilities	Sustaining	2008
57	Remove the CO2 Fire Suppression System in the Standby Generator & Emergency Power Generator Buildings	Sustaining	2008
58	Shutdown Cooling Pump Seal Replacement	Sustaining	2008
59	Machine Guarding Improvement on Low Risk Equipment	Regulatory	2009 or Future
60	Zone Optimization	Sustaining	2009 or Future
61	Replacement of Obsolete Fire Alarm Systems	Sustaining	2009 or Future
62	Main Control Room Annunciation Reduction	Sustaining	2009 or Future
63	Deaerator Level Control Algorithm	Sustaining	2009 or Future
64	IESO Real Time Generator Delivery Points	Sustaining	2009 or Future
65	Emergency Coolant Injection Fuelling Machine Vault Dikes	Sustaining	2009 or Future
66	Replace Obsolete Analog Fuelling Machine Magazine Controllers	Sustaining	2009 or Future
67	Diking Installation	Sustaining	2009 or Future
	Engineering & Modifications		
68	Hydrogen Effusion Monitor Development	Sustaining	2009 or Future
69	Passive Addition of Titanium	Sustaining	2009 or Future
70	Feeder Integrity - Weld Overlay Feeder Repairs Implementation	Sustaining	2009 or Future
	Nuclear Programs & Training		
71	10 km Alert Sirens	Regulatory	2009 or Future

1 Projects with expenditures during Test Period
2 Projects anticipated to cost > $10M

OUTAGE OM&A – NUCLEAR

1.0 PURPOSE

The purpose of this evidence is to present, in summary form, the methodology for the derivation of Nuclear outage OM&A budget and present actual outage OM&A costs for 2005 - 2007 and a forecast of outage OM&A costs for the period 2008 - 2009.

2.0 NUCLEAR OUTAGE OM&A: OVERVIEW

Nuclear planned outages are necessary to execute inspection and maintenance work on systems and equipment where access is not possible under normal operating conditions. Outage work activities generally fall into two categories: a) inspection and maintenance work related to effective asset management and regulatory requirements generally recurring at various time intervals of a plant life cycle and b) project work. Outages also give OPG the opportunity to perform systems and equipment upgrades, configuration changes, and other improvements and modifications.

Completion of specific outages requires both base work program resources and incremental resources. Base work program resource costs, including the cost of regular labour, are captured within Nuclear base OM&A (Ex. F2-T2-S1). Incremental costs over and above the base work program required to perform the outage per the approved outage schedule are captured in outage OM&A. Accordingly, the total costs of an outage are accounted for in both Nuclear base OM&A and outage OM&A. Incremental outage OM&A costs, as discussed below, are such costs as incremental short-term labour to meet expected non-regular staffing needs for peak work periods, materials, or the costs for specialized services such as inspection and maintenance work by Inspection and Maintenance Services ("IMS").

The costs associated with the completion of projects undertaken during an outage are captured in either project OM&A or capital, as applicable.

Nuclear outage OM&A is established through the business planning process (see Ex. A2-T2-S1). Each station prepares its own five year outage OM&A budget. The nuclear support groups also prepare five year outage OM&A budgets at the same time as the stations to reflect the cost of their required contribution to the planned outages.

The main input into OPG's nuclear outage OM&A budget is the five year integrated nuclear outage and generation plan, which is discussed in detail at Ex. E2-T1-S1. The forecast Nuclear outage OM&A budget is derived by reference to, and in parallel with, the development of the approved generation plans and outage schedule for each station. The first two years of the five year plan (in particular the first year) are subject to the most detailed scope reviews of the planned outage. In particular, identification of the major work scope to be completed is finalized, do-ability within the scheduled timeframe reviewed, resources assessed and economic justification of discretionary activities analyzed within the constraints of the business plan. This establishes a target for all outage stakeholders to deliver on the approved scope, duration, and cost. The "three outer years" of the five year plan are subject to lesser scrutiny, given that during the five year cycle, the outage scope, duration, and costs of these later years will be subject to renewed assessment as they come closer to the year of execution.

The key consideration in assessing the need for incremental resources during an outage is the ability to optimize available base work resources and skills. For example, the availability of regular maintenance staff for outage work has to be assessed relative to a) demand for regular staff for the ongoing maintenance requirements of the running units and b) peak staff resources required to complete the bulk of the outage scope within the outage maintenance window timeframe. Relative to Nuclear base OM&A, the Nuclear outage OM&A forecast focuses on the need and cost of the incremental labour resources (e.g., temporary staff and external contractors) required over and above regular base staff to execute the outage. The Nuclear outage OM&A budget is approved as one component of the business plan process as described at Ex. A2-T2-S1.

3.0 DEVELOPING THE OUTAGE OM&A BUDGET

3.1 Resource Types

As shown in Ex. F2-T4-S1 Tables 3 - 9, outage OM&A for each station and related nuclear support service group is budgeted on the basis of the resource types as described below:

- Regular Labour: These are the costs of regular staff of OPG's IMS division. All other regular OPG staff costs are included in base OM&A.
- Non-Regular Labour: The cost of temporary labour on OPG's payroll and directly supervised by OPG staff, usually construction (e.g., laborers) and trade workers (e.g., electricians) and co-op students.
- Overtime: The cost of overtime incurred by regular, non-regular labour, and augmented staff during the outage. Regular labour refers to OPG nuclear full time staff. While overtime costs for regular staff working on an outage is budgeted to outage OM&A, remaining costs for regular labour, with one exception, is budgeted as base OM&A. The one exception is IMS labour, as discussed below.
- Augmented Staff: The cost of non-regular staff for peak work periods, i.e., temporary additions to staff complements directly supervised by OPG staff but not on OPG's payroll, usually in the form of professional staff (e.g., engineers, assessors, operation procedure writers or analyst work).
- Materials: The cost of the various materials and supplies used in the outage.
- Other Purchased Services: The cost of outside contractors, who are not on OPG payroll and where the employees of the contractor are under the supervision of the contractor. In addition, other purchased services includes charges by OPG's IMS division. The main function of the IMS division is to provide specialized inspection and maintenance services (e.g., feeder piping, fuel channel, and steam generator inspections) during an outage. Further discussion of IMS services can be found at Ex. G2-T1-S1. Outage OM&A may also include the costs, whether internal or externally driven, of major equipment refurbishments.

OPG uses incremental staffing 1) for peak labour needs because it is more cost effective and flexible to bring on incremental resources, as needed, for the outage than to maintain permanent staffing, 2) to obtain specialized skill capabilities (given the highly specialized nature of outage inspection and maintenance, specialized skills are required from IMS or external contractors), and 3) because the nature of the maintenance activity mandates the use of original equipment manufacturer expertise. The use of incremental staffing resources to complete outage work activities is consistent with industry practice.

3.2 Costing of Required Resource Types

For the resource types referenced above, the forecast of outage OM&A costs are developed through an iterative process by considering the following:

- The work load in an outage is analyzed with respect to the work orders, sequencing and the skills and resources required.
- Work orders are examined for type and number of activities and tasks involved in completing the work order.
- Tasks are segregated into blocks of activities, either natural complementary groupings or attached to specific equipment. These blocks are placed in “windows” for execution purposes.
- Using productivity information from past outages (such as total hours per day, total hours per work order/task, and number of tasks/work order), a time budget is established, and by considering type of skilled resources required to execute the work (job classification) a cost estimate can be derived for regular labour, which is a component of base OM&A. Consideration of outage duration, outage schedule and historical statistical information (overtime hours per work order/task) allows for identification of the incremental labour required. For example, the outage’s duration and schedule establish “do-ability constraints” (e.g., congested work areas and operational constraints) thereby delineating needs for incremental peak labour and overtime.
- Work planning yields information as to specific parts or materials for the outage. Information referenced from past outage and risk assessment (e.g., materials/work order of a specific type) is used to estimate supplies (e.g., consumables such as work gloves and radiation protection) and contingency material needs. Contingency material needs refers to the practice of ordering certain parts or materials, due to the lead times required, in anticipation of a need for the part or material not specifically identified during work planning as part of outage scope.
- Work planning also provides information regarding preparation requirements, pre-requisites, associated execution requirements (e.g., radiation protection services and specific staffing/skills/equipment required), and the cost of this additional support work is estimated in a manner similar to direct work.
- For contractor services, OPG’s outage OM&A budgets are based on historical unit hourly rates charged by the contractors (adjusted for inflation) or on actual tender quotes

(depending upon the timeframe of the planned outage), multiplied by the level of planned work activity.

- Inspection and Maintenance Services provides services to both internal and external customers. Inspection and Maintenance Services derives a cost for each OPG outage, in accordance with the work, time and resources required. Inspection and Maintenance Services then recovers its costs consistent with market negotiated services to third parties such as Bruce Power (as described at Ex. G2-T1-S1).

4.0 OUTAGE OM&A VARIANCES

Each of the components that drive the outage OM&A budget (duration, scope, and resources) can change from forecast. OPG repeatedly updates its forecast of future planned outages, work activity, and related costs through the five year integrated nuclear outage and generation plan cycle reviews and through its tri-annual planning process. Consequently, scope definition is more precise for near-term outages compared to the later years of the five year outage planning cycle.

Some of the changes that can cause updates to the five year outage OM&A plan include:

- The results of ongoing OPG outage inspection and maintenance work could impact the scope of work planned for future outages, even if the future outages are at a different unit or station.
- New Canadian Nuclear Safety Commission regulatory requirements may add to outage scope and outage costs.
- The nuclear industry traditionally shares operational information thereby providing OPG with awareness of potential emerging issues from other nuclear industry operations. This can result in additional scope and costs to future outages, i.e., inspections would assess the extent the emergent issue impacts, if at all, on OPG’s nuclear units thereby potentially resulting in additional scope and costs in future outages.
- The impact of collective bargaining agreements, internal and external, on labour costs and materials.

- OPG may curtail the scope of an outage resulting in additional work/additional scope being added to a future outage, or conversely drag scope from a future outage into a current outage.
- In some cases scope of work activity can be increased without impacting outage duration (but increasing outage OM&A costs) if the work can be performed in parallel with other critical path activities.
- Subject to IESO market rules, circumstances may allow OPG to defer outages for later periods, e.g., if the majority of the planned outage scope could be undertaken during a forced outage, the remaining scope of the planned outage could be deferred to a future period.

All changes of this nature are approved by senior executive management.

5.0 OUTAGE CATEGORIES

The outage OM&A forecast is derived solely by costing the planned outages in the integrated nuclear outage and generation plan (Ex. E2-T1-S1). Outage OM&A costs, if any, for planned derates would be incorporated in the base OM&A budget, although such costs tend to be modest. Also, as discussed in Ex. E2-T1-S1, the integrated nuclear outage and generation plan includes a forecast of forced loss rate equivalent outage days (forced outages or forced derates) but the cost consequences of such events are not recognized as incremental outage OM&A. Rather it is assumed that regular base OM&A work resources can complete the required work.

Actual outage OM&A will reflect actual incremental costs of the planned outages. In addition, as described in Ex. F2-T4-S1 Table 2, actual outage OM&A will include unbudgeted costs due to the forced extension to a planned outage, planned outage extension, or unbudgeted planned outage. Generally, the incremental unit cost of an extension tends to be lower compared to the unit cost of a planned outage. All costs incurred due to forced outages, planned derates or forced derates, which could include overtime costs for regular base staff, are recorded in base OM&A.

6.0 OUTAGE OM&A 2005 - 2009

The Nuclear outage OM&A forecast for 2008, and 2009 is shown in Ex. F2-T4-S1 Table 1, along with comparable historic figures for 2005, 2006 and 2007. In Ex. F2-T4-S1 Table 1, the cost of IMS outage work for OPG is captured as a component of the station's outage OM&A costs and therefore there are no outage OM&A costs shown directly under IMS.

The main drivers to outage OM&A variances (year-over-year and actual to budget) are the number of outages, scope, planned duration, and actual duration (i.e., extensions of planned outages in a year). As shown in Ex. F2-T4-S1 Table 1, the trend in outage OM&A over the period 2005 – 2009 for the combined nuclear fleet is for outage OM&A to increase year-over-year from 2005, peaking in 2007, followed by a decline in 2008. There is an increase in outage OM&A for the combined nuclear fleet in 2009, primarily due to an increase in the level of outage activities at Pickering A.

For 2006, the number of forced extensions of planned outages in 2006 was a major driver to actual 2006 outage OM&A costs and largely explains the variances between actual and planned 2006 outage OM&A costs at the stations.

The variance in nuclear programs and training between 2005 and 2006 as shown in Ex. F2-T4-S1 Table 1 relates to reallocation in 2006 of approximately $2.0M of outage OM&A costs related to radiation protection services from nuclear programs and training to Darlington.

In 2007, outage OM&A costs peak, largely driven by increased activity at Darlington as two units were on outage in 2007 for a total of 131 days, and there was an unbudgeted planned outage at Darlington Unit 3. The Darlington outage OM&A costs in 2007 also reflect the additional work completed as the three year outage cycle is implemented.

There is a decline in forecast outage OM&A in 2008 for the combined nuclear fleet primarily because of Darlington, where only one unit is on planned outage for a total of 75 days. This is as a result of the transition to a three year outage cycle for the Darlington units, the benefits of which will be a reduction in the number of planned outage days (with a corresponding increase in production) over a number of outage cycles, as described in Ex E2-T1-S1. Material costs are forecast to be higher in 2008 versus 2007 at Darlington, even though the number of outage days is lower in 2008 compared to 2007, due to differences in outage scope.

Another driver to the forecast of reduced outage OM&A for the combined nuclear fleet in 2008 (and 2009) are shorter planned outage durations at Pickering B, reflecting improvements made in plant material condition, and other initiatives discussed in Ex. E2-T1-S1.

In 2009, outage OM&A for the combined nuclear fleet is forecast to increase relative to 2008, primarily driven by outage activity at Pickering A which will be undertaking additional feeder replacement and turbine blade replacement.

In addition, both Pickering A and B have additional outage OM&A expenditures in 2009 for advanced preparation for a 2010 vacuum building outage (VBO) at the site.

Explanations of all outage OM&A variances are more fully described in Ex. F2-T4-S2.

Numbers may not add due to rounding.

Table 1
Outage OM&A - Nuclear ($M)

Line No.	Division	2005 Actual	2006 Actual	2007 Actual	2008 Plan	2009 Plan
		(a)	(b)	(c)	(d)	(e)
	Nuclear Stations					
1	Darlington NGS	45.5	61.2	97.1	72.4	71.8
2	Pickering A NGS	17.2	38.7	42.1	48.5	61.1
3	Pickering B NGS	93.3	80.2	69.6	66.7	70.5
4	**Total Stations**	155.9	180.1	208.8	187.5	203.4
	Nuclear Support Divisions					
5	Engineering & Modifications	2.9	5.5	4.2	2.6	2.6
6	Programs & Training	3.4	0.8	1.0	0.7	0.4
7	Supply Chain	0.8	1.2	1.6	1.3	1.4
8	Performance Imprvmnt & Oversight	0.0	0.0	0.0	0.0	0.0
9	Nuclear Level Common	0.0	0.0	0.0	0.0	0.0
10	**Total Support**	7.1	7.6	6.8	4.6	4.5
	Nuclear Generation Development & Services					
11	Inspection & Mtce Services	0.0	0.0	0.0	0.0	0.0
12	Gen Dev / Commercial Activities	0.0	0.0	0.0	0.0	0.0
13	**Total NGDS**	0.0	0.0	0.0	0.0	0.0
14	**Total**	163.0	187.7	215.6	192.2	207.9

Table 2
Categories of Outage OM&A - Nuclear ($M)
Actual vs. Budget

Line No.	Outage Category	BUDGET				ACTUAL			
		Revenue (Days)		Cost ($)		Revenue (Days)		Cost ($)	
		Planned Outage	FLR	Outage OM&A	Base OM&A	Planned Outage	FLR	Outage OM&A	Base OM&A
		(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)
1	**Planned Outage**	Yes		Yes		Yes		Yes	
2	**Forced Outage**		Yes		Yes		Yes		Yes
3	**Forced Extension of Planned Outages**					Yes		Yes	
4	**Planned Outage Extensions**					Yes		Yes	
5	**Unbudgeted Planned Outages**					Yes		Yes	
6	**Planned Derates**	Yes			Yes	Yes			Yes
7	**Forced Derates**		Yes		Yes		Yes		Yes

Numbers may not add due to rounding.

Table 3
Outage OM&A by Resource Type - Nuclear ($M)
Plan - Calendar Year Ending December 31, 2009

Line No.	Division	Regular Labour	Non-Regular Labour	Overtime	Augmented Staff	Materials	Other Purchased Services	Other	Total Outage OM&A
		(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)
	Nuclear Stations								
1	Darlington NGS	0.0	4.0	16.5	3.6	10.7	32.6	4.5	71.8
2	Pickering A NGS	0.0	2.5	6.6	0.0	5.3	46.7	0.0	61.1
3	Pickering B NGS	0.0	2.4	11.0	3.6	10.0	43.5	0.0	70.5
4	**Total Stations**	0.0	9.0	34.1	7.2	25.9	122.8	4.5	203.4
	Nuclear Support Divisions								
5	Engineering & Modifications	0.0	0.0	0.0	0.0	0.0	2.6	0.0	2.6
6	Programs & Training	0.0	0.0	0.4	0.0	0.0	0.0	0.0	0.4
7	Supply Chain	0.0	0.0	1.4	0.0	0.0	0.0	0.0	1.4
8	Performance Imprvmnt & Oversight								0.0
9	Nuclear Level Common								0.0
10	**Total Support**	0.0	0.0	1.9	0.0	0.0	2.6	0.0	4.5
	Nuclear Generation Development & Services								
11	Inspection & Mtce Services	18.3	0.5	7.3	16.4	7.8	(50.8)	0.5	0.0
12	Gen Dev / Commercial Activities								0.0
13	**Total NGDS**	18.3	0.5	7.3	16.4	7.8	(50.8)	0.5	0.0
14	**Total**	18.3	9.5	43.3	23.5	33.7	74.6	5.0	207.9

Numbers may not add due to rounding.

Table 4
Outage OM&A by Resource Type - Nuclear ($M)
Plan - Calendar Year Ending December 31, 2008

Line No.	Division	Regular Labour	Non-Regular Labour	Overtime	Augmented Staff	Materials	Other Purchased Services	Other	Total Outage OM&A
		(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)
	Nuclear Stations								
1	Darlington NGS	0.0	4.0	11.7	0.6	19.8	35.6	0.7	72.4
2	Pickering A NGS	0.0	2.4	6.3	0.0	5.0	34.7	0.0	48.5
3	Pickering B NGS	0.0	4.4	12.9	0.0	11.0	38.4	0.0	66.7
4	**Total Stations**	0.0	10.8	30.9	0.6	35.8	108.7	0.7	187.5
	Nuclear Support Divisions								
5	Engineering & Modifications	0.0	0.0	0.0	0.0	0.0	2.6	0.0	2.6
6	Programs & Training	0.0	0.0	0.7	0.0	0.0	0.0	0.0	0.7
7	Supply Chain	0.0	0.0	1.3	0.0	0.0	0.0	0.0	1.3
8	Performance Imprvmnt & Oversight								0.0
9	Nuclear Level Common								0.0
10	**Total Support**	0.0	0.0	1.9	0.0	0.0	2.6	0.0	4.6
	Nuclear Generation Development & Services								
11	Inspection & Mtce Services	18.3	0.5	7.3	16.4	7.8	(50.8)	0.5	0.0
12	Gen Dev / Commercial Activities								0.0
13	**Total NGDS**	18.3	0.5	7.3	16.4	7.8	(50.8)	0.5	0.0
14	**Total**	18.3	11.3	40.2	17.0	43.6	60.5	1.2	192.2

Numbers may not add due to rounding.

Table 5
Outage OM&A by Resource Type - Nuclear ($M)
Actual - Calendar Year Ending December 31, 2007

Line No.	Division	Regular Labour	Non-Regular Labour	Overtime	Augmented Staff	Materials	Other Purchased Services	Other	Total Outage OM&A
		(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)
	Nuclear Stations								
1	Darlington NGS	0.0	6.9	20.9	1.0	15.7	52.5	0.1	97.1
2	Pickering A NGS	0.0	3.0	7.0	1.1	5.3	25.7	0.0	42.1
3	Pickering B NGS	0.0	4.2	15.9	5.5	13.7	30.3	0.1	69.6
4	**Total Stations**	0.0	14.1	43.7	7.6	34.7	108.5	0.2	208.8
	Nuclear Support Divisions								
5	Engineering & Modifications	0.0	0.6	1.2	0.0	0.0	2.4	0.0	4.2
6	Programs & Training	0.0	0.4	0.5	0.1	0.0	(0.0)	0.0	1.0
7	Supply Chain	0.0	0.0	1.6	0.0	0.0	0.0	0.0	1.6
8	Performance Imprvmnt & Oversight								0.0
9	Nuclear Level Common								0.0
10	**Total Support**	0.0	1.0	3.3	0.1	0.0	2.4	0.0	6.8
	Nuclear Generation Development & Services								
11	Inspection & Mtce Services	13.4	0.6	10.7	23.9	9.9	(59.2)	0.7	0.0
12	Gen Dev / Commercial Activities								0.0
13	**Total NGDS**	13.4	0.6	10.7	23.9	9.9	(59.2)	0.7	0.0
14	**Total**	13.4	15.7	57.8	31.6	44.6	51.6	0.9	215.6

Numbers may not add due to rounding.

Table 6
Outage OM&A by Resource Type - Nuclear ($M)
Budget - Calendar Year Ending December 31, 2007

Line No.	Division	Regular Labour	Non-Regular Labour	Overtime	Augmented Staff	Materials	Other Purchased Services	Other	Total Outage OM&A
		(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)
	Nuclear Stations								
1	Darlington NGS	0.0	7.4	20.2	4.2	11.5	42.1	0.4	85.7
2	Pickering A NGS	0.0	0.0	5.9	0.0	6.4	28.8	0.0	41.0
3	Pickering B NGS	0.0	5.7	11.6	0.0	10.0	36.6	0.0	63.9
4	**Total Stations**	0.0	13.1	37.7	4.2	27.9	107.4	0.4	190.6
	Nuclear Support Divisions								
5	Engineering & Modifications						1.0		1.0
6	Programs & Training			0.4					0.4
7	Supply Chain			1.5					1.5
8	Performance Imprvmnt & Oversight								0.0
9	Nuclear Level Common								0.0
10	**Total Support**	0.0	0.0	1.9	0.0	0.0	1.0	0.0	2.9
	Nuclear Generation Development & Services								
11	Inspection & Mtce Services	18.2	0.0	7.6	20.6	7.6	(54.3)	0.4	(0.0)
12	Gen Dev / Commercial Activities								0.0
13	**Total NGDS**	18.2	0.0	7.6	20.6	7.6	(54.3)	0.4	(0.0)
14	**Total**	18.2	13.1	47.1	24.7	35.4	54.2	0.8	193.5

Table 7
Outage OM&A by Resource Type - Nuclear ($M)
Actual - Calendar Year Ending December 31, 2006

Line No.	Division	Regular Labour	Non-Regular Labour	Overtime	Augmented Staff	Materials	Other Purchased Services	Other	Total Outage OM&A
		(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)
	Nuclear Stations								
1	Darlington NGS		4.3	16.8	1.2	11.2	26.2	1.5	61.2
2	Pickering A NGS		1.7	7.6	7.4	4.9	17.1	0.0	38.7
3	Pickering B NGS		6.5	14.8	15.5	16.2	27.1	0.1	80.2
4	**Total Stations**	0.0	12.4	39.2	24.1	32.4	70.4	1.7	180.1
	Nuclear Support Divisions								
5	Engineering & Modifications		0.6	1.1	1.4	0.0	2.4	0.0	5.5
6	Programs & Training		0.3	0.4	0.1	0.0		0.0	0.8
7	Supply Chain		0.1	1.1		0.0			1.2
8	Performance Imprvmnt & Oversight								0.0
9	Nuclear Level Common								0.0
10	**Total Support**	0.0	1.1	2.6	1.5	0.0	2.4	0.0	7.6
	Nuclear Generation Development & Services								
11	Inspection & Mtce Services	11.8	0.2	9.7	17.9	8.4	(49.0)	1.0	0.0
12	Gen Dev / Commercial Activities								0.0
13	**Total NGDS**	11.8	0.2	9.7	17.9	8.4	(49.0)	1.0	0.0
14	**Total**	11.8	13.7	51.5	43.4	40.8	23.8	2.7	187.7

Numbers may not add due to rounding.

Table 8
Outage OM&A by Resource Type - Nuclear ($M)
Budget - Calendar Year Ending December 31, 2006

Line No.	Division	Regular Labour	Non-Regular Labour	Overtime	Augmented Staff	Materials	Other Purchased Services	Other	Total Outage OM&A
		(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)
	Nuclear Stations								
1	Darlington NGS		5.3	14.9	1.6	7.4	23.8	0.0	53.1
2	Pickering A NGS		(0.2)	8.2	0.1	10.0	23.0		41.1
3	Pickering B NGS		4.5	11.7	(0.1)	11.8	42.7		70.5
4	**Total Stations**	0.0	9.6	34.8	1.6	29.1	89.5	0.0	164.8
	Nuclear Support Divisions								
5	Engineering & Modifications		0.5	0.7			3.2		4.4
6	Programs & Training		0.4	0.6			0.1		1.1
7	Supply Chain			1.3			0.1		1.3
8	Performance Imprvmnt & Oversight								0.0
9	Nuclear Level Common								0.0
10	**Total Support**	0.0	0.9	2.6	0.0	0.0	3.4	0.0	6.8
	Nuclear Generation Development & Services								
11	Inspection & Mtce Services	13.3	0.0	6.7	19.1	8.5	(48.4)	0.8	(0.0)
12	Gen Dev / Commercial Activities								0.0
13	**Total NGDS**	13.3	0.0	6.7	19.1	8.5	(48.4)	0.8	(0.0)
14	**Total**	13.3	10.5	44.1	20.8	37.6	44.4	0.9	171.6

Numbers may not add due to rounding.

Table 9
Outage OM&A by Resource Type - Nuclear ($M)
Actual - Calendar Year Ending December 31, 2005

Line No.	Division	Regular Labour	Non-Regular Labour	Overtime	Augmented Staff	Materials	Other Purchased Services	Other	Total Outage OM&A
		(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)
	Nuclear Stations								
1	Darlington NGS		4.8	13.7	0.6	8.3	17.9	0.1	45.5
2	Pickering A NGS		0.4	3.3	5.3	1.5	6.8	0.0	17.2
3	Pickering B NGS		6.3	14.8	2.8	14.1	55.2	0.1	93.3
4	**Total Stations**	0.0	11.5	31.8	8.7	23.9	79.9	0.1	155.9
	Nuclear Support Divisions								
5	Engineering & Modifications		0.6	0.6		0.1	1.7	0.0	2.9
6	Programs & Training		1.1	1.1	1.2	0.0	(0.0)	0.0	3.4
7	Supply Chain		0.1	0.7	0.0	(0.0)			0.8
8	Performance Imprvmnt & Oversight								0.0
9	Nuclear Level Common								0.0
10	**Total Support**	0.0	1.7	2.4	1.3	0.1	1.7	0.0	7.1
	Nuclear Generation Development & Services								
11	Inspection & Mtce Services	8.8	0.4	7.5	23.9	6.7	(49.5)	2.3	0.0
12	Gen Dev / Commercial Activities								0.0
13	**Total NGDS**	8.8	0.4	7.5	23.9	6.7	(49.5)	2.3	0.0
14	**Total**	8.8	13.5	41.7	33.9	30.7	32.0	2.4	163.0

Numbers may not add due to rounding.

Table 10
Outage OM&A by Resource Type - Nuclear ($M)
Budget - Calendar Year Ending December 31, 2005

Line No.	Division	Regular Labour	Non-Regular Labour	Overtime	Augmented Staff	Materials	Other Purchased Services	Other	Total Outage OM&A
		(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)
	Nuclear Stations								
1	Darlington NGS	0.0	5.2	12.2	0.2	7.7	18.8	0.0	44.1
2	Pickering A NGS	0.0	1.0	5.3		4.0	22.1	0.0	32.4
3	Pickering B NGS	0.0	7.3	13.0	1.8	7.6	54.5	0.0	84.2
4	**Total Stations**	0.0	13.6	30.5	2.0	19.2	95.4	0.0	160.7
	Nuclear Support Divisions								
5	Engineering & Modifications	0.0	0.5	0.3	0.0	0.0	2.6	0.0	3.4
6	Programs & Training	0.0	0.8	1.3	0.8	0.0	1.4	0.0	4.4
7	Supply Chain	0.0	0.0	0.3	0.0	0.0	0.0	0.0	0.3
8	Performance Imprvmnt & Oversight	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
9	Nuclear Level Common	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
10	**Total Support**	0.0	1.3	1.9	0.8	0.0	4.0	0.0	8.0
	Nuclear Generation Development & Services								
11	Inspection & Mtce Services	12.7	0.0	5.9	27.4	10.3	(56.6)	0.4	(0.0)
12	Gen Dev / Commercial Activities	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
13	**Total NGDS**	12.7	0.0	5.9	27.4	10.3	(56.6)	0.4	(0.0)
14	**Total**	12.7	14.9	38.3	30.2	29.5	42.8	0.4	168.8

COMPARISON OF NUCLEAR OUTAGE OM&A

1.0 PURPOSE

This evidence presents period-over-period comparisons of outage OM&A broken down by divisions.

2.0 OVERVIEW

Tables 3 - 9 in Exhibit F2-T4-S1 set out outage OM&A by resource type for calendar years 2005 - 2009. Definitions of the resource types of regular labour; non-regular labour, overtime, augmented staff; materials, and other purchased services are found in Ex. F2-T4-S1.

Outage scope over the period 2005 - 2009 is different at each OPG station reflecting various inspection activities (fuel channels, steam generators, and turbine/generators). The largest component of outage OM&A is typically other purchased services, which represents contracted services from external contractors as well as Inspection and Maintenance Services ("IMS") provided by OPG's IMS group. As discussed in Ex. F2-T4-S1, the cost of IMS outage work for OPG generating stations is captured as a component of the station's outage OM&A costs.

While there are many standard elements of outage scope, there can also be unique activities specific to each outage. While OPG is moving towards standardized outages as discussed in Ex. E2-T1-S1, there are certain programs/major equipment campaigns that are unit specific such as single fuel channel replacement. Hence it is difficult to provide a meaningful year-over-year comparison of outage OM&A amounts budgeted or spent given these unique programs for unit specific outages.

In addition, OPG units have traditionally been on a two year outage cycle. With a four unit station and a two year cycle, generally OPG plans on two outages per year. Generally, there are standard work activities performed in each of these outages. However, the scope of an individual outage is primarily a function of the unit's condition at that point in time. Units do not necessarily age or deteriorate in a uniform way or at a uniform rate. They can be different physically or in their construction (i.e., different alloys with different aging characteristics), and can vary in terms of accumulated operating hours. Hence, it is highly unlikely that the outage scope for a unit will precisely match the outage scope for another unit.

For the above reasons, explanations of the year-over-year variances in outage OM&A costs below must be limited to description of the differences in scope and duration of the outages in each year.

<u>2005 Budget</u>

The following planned work activities represent the bulk of the outage OM&A in the 2005 budget:

- The Pickering B 2005 outage activity was largely driven by the spacer location and relocation program ("SLAR") campaign on fuel channels on Unit 5 and Unit 6. Spacer location and relocation program work is primarily performed by IMS. In addition, the Unit 5 planned outage scope included steam generator repairs.
- At Darlington, 2005 outage work activity included fuel channel replacement, which was largely completed by IMS.
- At Pickering A, there were no planned outages in 2005 on Unit 1 (commercially available in November 2005) and a 66 day planned outage on Unit 4 to address mandatory post return to service inspections and regulatory requirements.

<u>2006 Budget</u>

The following planned work activities represent the bulk of the outage OM&A in the 2006 budget:

- At Pickering A, the 2006 planned outage activity included fuel channel inspections, steam generator inspections, and turbine/generators inspections. Fuel channel inspection is usually done by IMS along with some of the steam generator inspections. Turbine/generator work is usually done by internal maintenance staff but with the use of specialized external contractors for technical support.

- The Pickering B 2006 outage activity was largely driven by the need to complete the SLAR campaign and in addition, feeder inspections. Spacer location and relocation program work is primarily performed by IMS.
- At Darlington, 2006 outage work activity included feeder inspections, which are largely completed by IMS.

2007 Budget

The following planned work activities represent the bulk of the outage OM&A in the 2007 budget:

- At Pickering A, the outage work includes fuel channel inspections, steam generator inspections, and turbine/generators inspections. The bulk of this work is typically performed by external contractors.
- The Pickering B outage is largely driven by the need to inspect selected fuel channels that were subject to the SLAR campaign in 2006 to confirm the program's effectiveness. In some cases there will be a need to restore the spacing around some fuel channels that has deteriorated since the last round of restoration. Spacer location and relocation program work is primarily performed by IMS. Inspection and maintenance programs similar to those undertaken at Pickering A and steam generator and feeder piping inspections are also main contributors to the overall outage cost.
- At Darlington, the shift to a three year outage cycle requires that additional steam generator inspection work activity be undertaken by IMS. Also included in the Darlington outage work is the replacement of feeders and some fuel channel reconfigurations.

2008 Plan and 2009 Plan

A significant work program in 2008 and 2009 for OPG's nuclear fleet is feeder replacement. The cost of feeder replacement in 2008 and 2009 has major impacts on outage OM&A, particularly in regard to overtime, augmented staff and materials. OPG Nuclear is planning feeder replacements at all three stations.

In addition, all three stations will continue with fuel channel inspections. Fuel channel inspections typically consume a large number of probes and other small supplies specially designed and built to operate in highly irradiated field, hence the incremental costs of IMS materials.

3.0 PERIOD-OVER-PERIOD CHANGES – TEST PERIOD

<u>2008 Plan versus 2009 Plan</u>

Outage OM&A expenditures are forecast to increase by eight percent from $192.2M in 2008 plan to $207.9M in 2009 plan. The main drivers to changes in outage OM&A costs are as follows:

- Pickering A outage costs are expected to be higher (26 percent) in 2009 than in 2008 The primary drivers to the increase in 2009 outage OM&A costs are other purchased services for additional inspection work by IMS in regard to feeder replacements and an equipment upgrade (turbine blade replacement). In addition, Pickering A (and Pickering B) will incur costs with respect to preparations for a 2010 VBO at the site.
- Pickering B, outage OM&A costs are forecast to be higher (six percent) in 2009 compared to 2008 even though there are 14 fewer planned outage days. The increase in outage OM&A costs reflects minor fluctuations in outage scope as well as costs incurred with respect to advanced preparations for a 2010 VBO at the site.
- Darlington costs are expected to be slightly lower (one percent) despite the number of planned outage days increasing in 2009 to 175 days compared to 75 planned outage days in 2008. At Darlington, there is a VBO scheduled for 2009 with the entire facility shut down while the containment system is tested and required maintenance is performed. While the vacuum building outage effectively increases the number of outages day by a factor of four during the vacuum building outage (i.e., all four units are required to be shut down at the same time), outage OM&A costs do not increase by the same factor. This is because, due to operational, logistical and resource constraints, the outage work can only focus primarily on the containment system, and not the normal routine inspections typical to a planned outage. At the end of the vacuum building outage, one unit will stay on outage for routine planned outage inspections.

<u>2007 Actual versus 2008 Plan</u>

As explained above, it is difficult to provide meaningful year-over-year comparisons of outage OM&A, as actual outage OM&A, compared to plan, can be impacted by the costs incurred during forced extensions to planned outages, planned outage extensions, and unbudgeted planned outages.

Outage OM&A expenditures are forecast to decrease by 11 percent from $215.6M in 2007 to $192.2M in 2008. The key changes in outage OM&A costs are as follows:

- Pickering A outage costs are expected to be higher (15 percent) in 2008 compared to 2007 primarily due to increased outage scope in 2008 compared to 2007 (calandria vault inspections, advanced work on the 2010 VBO and turbine replacement work). A partial offset to the costs due to increased outage scope is less outage days for forced extensions of planned outages. In 2007, Pickering A outage OM&A includes costs incurred during 60.2 FEPO days. There are no FEPOs forecast in 2008.
- Pickering B, outage OM&A costs are forecast to be lower (four percent) in 2008 than 2007, primarily reflecting fewer planned outage days and differences in outage scope. In addition, Pickering B 2007 outage OM&A includes costs incurred during 68 FEPO days. There are no FEPO days forecast in 2008.
- At Darlington, 2008 outage OM&A costs are forecast to be lower (25 percent) than in 2007 reflecting that, as part of the transition to the three year outage cycle, two units were on outage in 2007 for a total of 134 days versus only one unit on planned outage in 2008 for a total of 75 days. In addition there was an unbudgeted planned outage in 2007. The rationale for the three-year outage cycle is discussed at Ex. E2-T1-S1 Section 4.0. The 2007 outage OM&A costs also include additional work completed on the units in the transition to a three year outage cycle. This work involved a substantial amount of steam generator inspections, which are highly cost intensive due to additional labour and tooling. The higher 2007 costs also involved work to reconfigure some fuel channels on Unit 2 where feeders were replaced.

4.0 PERIOD-OVER-PERIOD CHANGES – BRIDGE YEAR

2007 Actual versus 2007 Budget

Actual outage OM&A costs in 2007 were $22.2M (or 11 percent) over budget for OPG's combined nuclear fleet, principally due to higher than planned outage OM&A at Darlington ($11.4M or 13 percent). Outage OM&A was over budget at Pickering B (by nine percent) and on budget at Pickering A.

The key drivers behind these budget variances were:

- Pickering B outage OM&A costs were nine percent over budget. Better than budget performance on the Unit 6 fall outage which resulted in outage OM&A cost savings of approximately $5.5M was offset by unforeseen costs arising from turbine spindle repairs, advanced work associated with the Unit 8 spring 2008 outage and costs incurred due to the inadvertent release by a third party contractor of resin into the demineralized water system.

- Darlington outage OM&A costs were (13 percent) over budget. A major component of this overage was related to the decision, after the business plan was approved, to utilize regular labour resources for the ongoing maintenance requirements of the running units. This required obtaining additional external contractor services to complete the planned outage work. This approach is consistent with the outage staffing strategy and the need to optimize available base work resources and skills as set out in Ex. F2-T4-S1 section 2. In addition, the Unit 4 outage incurred additional overtime and material costs due to a large amount of discovery work.

- Pickering A outage OM&A was three percent over budget reflecting incremental costs for overtime, decontamination services and adjuster rod repairs as well as higher IMS costs related to boiler inspections and mobilization costs related to advancing fall planned outage work into the summer inter-station transfer bus (ISTB) outage.

<u>2007 Actual versus 2006 Actual</u>

Total outage OM&A expenditures increased by 15 percent from $187.7M in 2006 to $215.6M in 2007. The two main drivers to the year-over-year change in outage OM&A are explained below:

- At Darlington, outage OM&A cost increased (59 percent) from $61.2M 2006 actual to $97.1M 2007 actual. A key driver to this increase is that the number of planned outage days increased from 95 days in 2006 to 134 days in 2007. The outage work in 2007 versus 2006 reflects additional steam generator inspection activity along with replacement of feeders and fuel channel reconfigurations, due to the implementation of a three year outage cycle. Such activities are more cost intensive relative to outage scope activities in 2006. In addition, the Unit 4 outage incurred additional overtime and material costs due to a large amount of discovery work and higher costs were incurred for external contractor services to support welding, moisture separator reheater (MSR) repairs, turbine flow liners and bulk maintenance. The increase in outage OM&A costs in 2007 relative to 2006 was partially offset by fewer forced extension to planned outages (three days in 2007 versus 26 days in 2006). However, Unit 4 outage costs associated with FEPO days are typically lower than the unit cost associated with a planned outage day, since the FEPO is focused on the remaining work activities required to completing the outage whereas the planned outage budget would include cost of all work activities.
- At Pickering B, outage OM&A costs decreased (13 percent) from $80.2M actual in 2006 to $69.6M actual 2007. A key driver to the decrease was the number of planned outages days declined from 154 days in 2006 to 132 days in 2007. Pickering B also incurred outage OM&A costs during 120 FEPO days in 2006. The main reason for the decrease in Pickering B planned outage days in 2007 versus actual 2006 is a change in outage scope as well as reflecting past improvements made in plant material condition and other initiatives discussed in Ex. E2-T1-S1. Pickering B also completed its SLAR program in 2006, which was a cost intensive program.
- Pickering A outage OM&A costs increased (9 percent) from $38.7M 2006 to $42.1M 2007. This cost increases reflects costs incurred during the additional FEPO days in 2007 (60 days) versus 2006 (21 days) as well as higher IMS costs related to boiler inspections and mobilization costs related to advancing fall planned outage work into the summer ISTB outage.

5.0 PERIOD-OVER-PERIOD CHANGES – HISTORICAL YEARS

2005 Actual versus 2005 Budget

Actual outage OM&A costs in 2005 were $5.8M under budget for OPG's combined nuclear fleet. Outage OM&A was under budget at Pickering A, which was partially offset by Pickering B and Darlington outage OM&A costs being somewhat over budget. The key drivers behind these budget variances were:

- Pickering A Unit 4: There was a 107 day forced outage at Pickering A Unit 4 in the spring of 2005 to inspect and repair, where needed, thinning of feeder pipe elbows in response to new information on feeder thinning rates from Unit 1. This forced outage allowed OPG to do some of the work that had been planned for the fall outage. This allowed OPG to defer the 66 day Unit 4 outage planned for the fall of 2005 to 2006. Some of the cost of the work activity planned for the fall outage completed during the forced outage was charged to 2005 outage OM&A. Overall, the deferment resulted in positive cost variance of $16.5M relative to the 2005 outage OM&A budget.
- Pickering B Unit 5 and Unit 6: A main component of the $9.0M Pickering B overage was due to the planned outage at Pickering B Unit 5 being force extended for 9 days due to leaks in both the shutdown cooling heat exchanger and the stator cooling water system. This resulted in higher costs for materials and other purchased services including additional IMS work activities. At the same time, the Unit 6 outage was reduced by 14 days by way of a deferred start-date due to a change in outage duration related to a universal delivery machine installation and a single fuel channel replacement.
- Darlington Unit 2: Technical problems with the single fuel channel replacement resulted in a forced extension of the Unit 2 planned outage by 14.4 days. In addition, after the OM&A budget was set for 2005, the outage duration was extended by 5.0 days. This extension was required because limitations in fuel handling capacity meant that OPG would be unable to meet the planned outage critical path activities while concurrently maintaining fueling priorities on the remaining operating units.
- Darlington Unit 4: An additional planned outage was added to the 2005 schedule after completion of the 2005 business plan for moisture separator reheater inspection and repair. Without the addition of this planned outage, continued operation would have

resulted in a significant reduction in the life of the low pressure turbine blades, bundles, and casing with an increased risk of material damage in the future.

2006 Actual versus 2006 Budget

Incremental outage OM&A costs in 2006 were $16.1M over budget for OPG's combined nuclear fleet. Outage OM&A was over budget at Pickering B and Darlington, which was partially offset by Pickering A outage OM&A costs being below budget. Among the key drivers to the budget overage were:

- Pickering B Unit 7: The planned outage at Pickering B Unit 7 included extensive SLAR work. Of the $9.7M Pickering B overage, the Unit 7 outage accounted for the major portion due to additional inspection work, higher material consumption and the extension of the outage duration period. This outage was also impacted by the early mobilization of resources to bring the start date of the planned outage forward due to a force outage which occurred prior to the planned outage start date. The extension of the outage was necessary to complete service water system maintenance and repair moderator pumps. The outage was further extended due to steam generator chemistry issues arising from inadvertent release by a third party contractor of resin from the feedwater purification system into the station's demineralized water supply.
- Darlington Unit 3: Of the $8.1M overage in Darlington's outage OM&A, approximately $5M is associated with Darlington Unit 3. The outage at Darlington Unit 3 was higher than budget primarily due to lack of resource availability (i.e., fuel handling major panel operators), the extension of the outage due to additional outage scope and delays in completing feeder inspections as well as fuelling machines performance issues.
- Pickering A Unit 4 and Unit 1: Outage costs at Pickering A Unit 4 exceeded budget by $2.0M driven in part by the outage extension, higher IMS costs, and contractor performance that did not meet expectations. These costs overruns were more than mitigated by cost savings achieved on the Unit 1 outage.

2005 Actual versus 2006 Actual

Actual outage OM&A costs in 2006 were $187.7M, which is an increase of $24.7M over actual outage OM&A costs of $163.0M in 2005. With respect to comparisons between 2005 and 2006, the key drivers are:

- Pickering A: Actual Pickering A 2006 outage OM&A increased by $21.5M compared to 2005 primarily because of more outage days. The increased number of outage days in 2006 versus 2005 reflects a full year of Unit 1 operations and the shift of the budgeted Unit 4 fall outage from 2005 into 2006. The shift of the Unit 4 fall planned outage into 2006 resulted in a shift of some, but not all of 2005 budgeted outage OM&A costs into 2006. Some of the work activity planned for the Unit 4 2005 fall planned outage was undertaken in the spring of 2005 during a forced outage. While OPG normally accounts for costs associated with forced outages in base OM&A, the work activity in the 2005 Unit 4 spring force outage that was associated with the Unit 4 fall planned outage was charged to 2005 outage OM&A.
- Pickering B: Actual Pickering B 2006 outage OM&A was lower by $13.0M compared to 2005 because of fewer planned outage days in 2006 (154.5 planned outage days plus 120.5 FEPO) versus 2005 (251.0 planned outage days plus 17.5 FEPO). The 251.0 planned outage days in 2005 reflect extensive SLAR work activity, not repeated in 2006, SLAR work activity is cost intensive compared to more routine outage work activity. While there were extensive FEPO days in 2006, as noted elsewhere, outage costs related to the work activities related to the extension of a planned outage are typically less than the outage costs associated with a planned outage.
- Darlington: Actual Darlington 2006 outage OM&A increased by $15.8M compared to 2005. While the number of outage days remained stable (94.8 planned outage days plus 22.3 FEPO in 2005 versus 95.0 planned outage days plus 25.5 FEPO in 2006), the increase in outage OM&A expenditures was related to increase outage scope due to the transition to the three year outage cycle (i.e., additional work was performed on the unit because the next planned outage would be approximately three years away as opposed to two years).

Numbers may not add due to rounding.

Table 1a
Comparison of Outage OM&A - Nuclear ($M)

Line No.	Division	2005 Budget	(c)-(a) Change	2005 Actual	(e)-(c) Change	2006 Actual	(e)-(g) Change	2006 Budget	(i)-(e) Change	2007 Actual
		(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)
	Nuclear Stations									
1	Darlington NGS	44.1	1.4	45.5	15.8	61.2	8.1	53.1	35.9	97.1
2	Pickering A NGS	32.4	(15.2)	17.2	21.5	38.7	(2.4)	41.1	3.4	42.1
3	Pickering B NGS	84.2	9.0	93.3	(13.0)	80.2	9.7	70.5	(10.6)	69.6
4	**Total Stations**	160.7	(4.8)	155.9	24.2	180.1	15.4	164.8	28.7	208.8
	Nuclear Support Divisions									
5	Engineering & Modifications	3.4	(0.5)	2.9	2.6	5.5	1.1	4.4	(1.3)	4.2
6	Programs & Training	4.4	(0.9)	3.4	(2.6)	0.8	(0.2)	1.1	0.2	1.0
7	Supply Chain	0.3	0.5	0.8	0.5	1.2	(0.1)	1.3	0.4	1.6
8	Performance Imprvmnt & Oversight	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
9	Nuclear Level Common	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
10	**Total Support**	8.0	(0.9)	7.1	0.5	7.6	0.8	6.8	(0.7)	6.8
	Nuclear Generation Development & Services									
11	Inspection & Mtce Services	(0.0)	0.0	0.0	(0.0)	0.0	0.0	(0.0)	0.0	0.0
12	Gen Dev / Commercial Activities	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
13	**Total NGDS**	(0.0)	0.0	0.0	(0.0)	0.0	0.0	(0.0)	0.0	0.0
14	**Total**	168.8	(5.8)	163.0	24.7	187.7	16.1	171.6	27.9	215.6

Table 1b
Comparison of Outage OM&A - Nuclear ($M)

Line No.	Division	2007 Budget	(c)-(a) Change	2007 Actual	(e)-(c) Change	2008 Plan	(g)-(e) Change	2009 Plan
		(a)	(b)	(c)	(d)	(e)	(f)	(g)
	Nuclear Stations							
1	Darlington NGS	85.7	11.4	97.1	(24.7)	72.4	(0.6)	71.8
2	Pickering A NGS	41.0	1.0	42.1	6.4	48.5	12.6	61.1
3	Pickering B NGS	63.9	5.7	69.6	(2.9)	66.7	3.8	70.5
4	**Total Stations**	190.6	18.2	208.8	(21.3)	187.5	15.9	203.4
	Nuclear Support Divisions							
5	Engineering & Modifications	1.0	3.2	4.2	(1.5)	2.6	(0.0)	2.6
6	Programs & Training	0.4	0.6	1.0	(0.3)	0.7	(0.2)	0.4
7	Supply Chain	1.5	0.2	1.6	(0.3)	1.3	0.1	1.4
8	Performance Imprvmnt & Oversight	0.0	0.0	0.0	0.0	0.0	0.0	0.0
9	Nuclear Level Common	0.0	0.0	0.0	0.0	0.0	0.0	0.0
10	**Total Support**	2.9	3.9	6.8	(2.2)	4.6	(0.1)	4.5
	Nuclear Generation Development & Services							
11	Inspection & Mtce Services	(0.0)	0.0	0.0	(0.0)	0.0	0.0	0.0
12	Gen Dev / Commercial Activities	0.0	0.0	0.0	0.0	0.0	0.0	0.0
13	**Total NGDS**	(0.0)	0.0	0.0	(0.0)	0.0	0.0	0.0
14	**Total**	193.5	22.2	215.6	(23.5)	192.2	15.7	207.9

NUCLEAR FUEL COSTS

1.0 PURPOSE

The purpose of this evidence is to describe OPG's nuclear fuel supply, set out the forecast of nuclear fuel costs over the calendar years 2005 to 2009, and identify key cost drivers and assumptions.

2.0 NUCLEAR FUEL SUPPLY

2.1 General

The accountability for developing supply strategies, executing procurement processes and administering nuclear fuel supply contracts rests with the Nuclear Supply Chain. OPG's nuclear fuel supply strategy is reviewed and approved by the Chief Executive Officer following review by the Chief Operating Officer, Chief Nuclear Officer, and Chief Financial Officer.

The nuclear fuel supply objectives and strategies are:

- High Quality: Fuel quality is assured by sourcing from suppliers that conform to the various Canadian Standards Association CAN3-Z299 quality standards. Supplier quality assurance program conformance is verified by OPG through source surveillance and audit.
- Security of Supply: OPG must ensure that its reactors are not shut down due to lack of fuel, and in that respect must ensure that each step in the supply chain is not substantially delayed due to lack of materials.
- Cost: OPG seeks to obtain supply at the lowest cost consistent with the above objectives.

OPG's nuclear fuel procurement strategies take into account new fuel requirements, existing inventories, existing supply arrangements and fuel supply market conditions.

OPG's standard procurement practice for nuclear fuel is to issue a request for proposals to a pre-determined group of suppliers, and to then evaluate proposals against pre-determined evaluation criteria that include quality, security of supply and costs. However, OPG may also review and accept unsolicited proposals on a case-by-case basis.

OPG's nuclear fuel supply chain is made up of the following stages:

- The purchase of uranium concentrate.
- The purchase of services for the conversion of uranium concentrate to uranium dioxide.
- The purchase of services for the manufacture of fuel bundles containing the uranium dioxide.

OPG currently purchases each of these components separately and maintains ownership of the uranium throughout the supply chain. Nuclear fuel inventories are discussed at Ex. B1-T1-S1 Section 3.2.2.

All of OPG's nuclear stations incorporate heavy water moderated CANDU (Canadian Deuterium Uranium) reactors. The fuel used in a CANDU reactor contains the naturally occurring proportion of the ^{235}U isotope (0.7 percent). The supply chain for the required uranium conversion and fuel bundle manufacturing services for CANDU reactors is limited because the majority of the world's reactors are light water reactors, which require conversion of uranium concentrate to uranium hexafluoride and enrichment to a higher proportion of the ^{235}U isotope.

The CANDU fuel bundle is an integral assembly of hermetically sealed, zirconium clad, cylindrical fuel elements containing ceramic uranium dioxide pellets. Each Pickering reactor uses fuel bundles that have a 28-element configuration. Each Pickering A reactor (Units 1 and 4) has 390 fuel channels containing 12 fuel bundles each (4,680 bundles per reactor). Each Pickering B reactor (Units 5 through 8) has 380 fuel channels containing 12 fuel bundles each (4,560 bundles per reactor). Each Darlington reactor uses fuel bundles that have a 37-element configuration. Each Darlington reactor has 480 fuel channels containing 13 fuel bundles each (6,240 bundles per reactor).

2.2 Fuel Planning

OPG's fuel procurement planning begins with a forecast of fuel bundle reactor loading requirements. The quantity of fuel bundles required for normal fueling is determined by converting OPG's forecast of electrical energy production, as referenced at Ex. E2-T1-S1, into a forecast of fuel bundles required for fueling ("usage") using forecasts of fuel burn-up and reactor thermal efficiency rates.

OPG maintains inventories at each stage of the nuclear fuel supply chain. An inventory of fuel bundles equivalent to 12 months of expected forward usage is maintained to allow continued fueling in the event of a disruption in the supply of fuel bundles or uranium conversion. A working inventory of uranium dioxide is maintained to feed the fuel manufacturing process and an inventory of uranium concentrates and recycled uranium dioxide scrap from the manufacturing process is maintained to feed the production of uranium dioxide.

From the forecast of fuel bundle requirements, and with consideration of existing inventories, OPG can then work backwards to first determine its need for delivery of new manufactured fuel bundles, which in turn determines the need for uranium dioxide conversion services and then the need to procure and deliver new supplies of uranium concentrates.

The annual quantities to meet usage and inventory requirements from 2007 - 2009 are shown below in Chart 1:

Chart 1

Annual Nuclear Fuel Requirements

Requirements (000 kgU)	2007 Actual	2008 Plan	2009 Plan
Uranium Concentrates	721	792	760
Uranium Conversion	749	830	792
28-element Fuel Bundles	247	300	425
37-element Fuel Bundles	443	475	335

2.3 Fuel Bundle Manufacturing

A key objective in fuel bundle manufacturing is high quality. An improperly manufactured fuel bundle is more likely to fail within a reactor and create additional costs to locate and remove the defective fuel bundle as well as purify and decontaminate reactor systems. This could potentially lead to reactor shutdown and an increased radiological risk. As such, OPG requires the manufacturing process to conform to the Canadian Standards Association quality standard CAN3-Z299.1 to ensure that all phases, including design, procurement, manufacturing and inspection are appropriately controlled. OPG performs surveillance of all manufacturing processes and verifies conformance to quality standard CAN3-Z299.1.

OPG currently has a supply contract with one of the two domestic CANDU fuel bundle manufacturing suppliers. Most other countries using CANDU reactors have purchased or developed their own manufacturing capabilities. However these offshore facilities are not qualified by OPG nor do they have capacity available to produce the 28-element and 37-element fuel designs required for OPG reactors. OPG's supplier has a well developed quality program and OPG has not had a manufacturing-related defect from this supplier in over 15 years.

Pricing under this contract is volume dependant and indexed to such factors as inflation and foreign exchange rates.

2.4 Uranium Conversion

The supplier's processes must conform to the Canadian Standards Association quality standard CAN3-Z299.2 to ensure that all phases, including procurement, manufacturing, and inspection, are appropriately controlled. OPG performs surveillance of the conversion process and verifies conformance to the quality standard.

OPG has a supply contract with the sole domestic supplier of uranium conversion services, which covers requirements through the test period. OPG generally maintains a two to three month uranium dioxide working inventory and the supplier is also contractually required to maintain an inventory of certified uranium dioxide for OPG's use in the event of a supply interruption. Pricing under this contract is volume dependant and indexed to inflation.

2.5 Uranium Concentrates

2.5.1 <u>Overview</u>

OPG's strategy for the supply of uranium concentrates is to maintain an adequate level of supply for future years based on existing inventory levels, contractual arrangements for future delivery, and planned future purchases. OPG maintains a portfolio of uranium concentrates supply arrangements, diversified by source, contract term, and pricing mechanism.

Portfolio diversity provides supply security ensuring that a supply disruption from any single supplier would not impact on OPG's entire supply. Portfolio diversity also reduces cost volatility.

OPG's uranium concentrate requirements are expected to be met over 2008 and 2009 through deliveries under existing contracts with five suppliers, and the partial drawdown of existing inventories. Over the 2008 - 2009 period, existing contracts will provide 1,348,000 kgU and inventory will provide 204,000 kgU.

The existing contracts for uranium concentrates were entered into over the 2004 to 2007 period and contain a mixture of pricing provisions. Under contracts with market-related pricing terms, quantities are priced at market price, established at or near the time of delivery. Contracts with indexed pricing include base prices, set at the time of contract signing, but which escalate to the time of delivery by formula or by published indexes. The quantities of contract deliveries for the existing contracts are shown by year and by pricing category (market-related and indexed pricing) in Chart 2 below:

Chart 2

Existing Contracts by Pricing Category

	2007	2008	2009	Total
Market Related (000's kgU)	255	524	192	971
Indexed (000's kgU)	301	301	331	933
Total	556	825	523	1904

2.5.2 Market Conditions

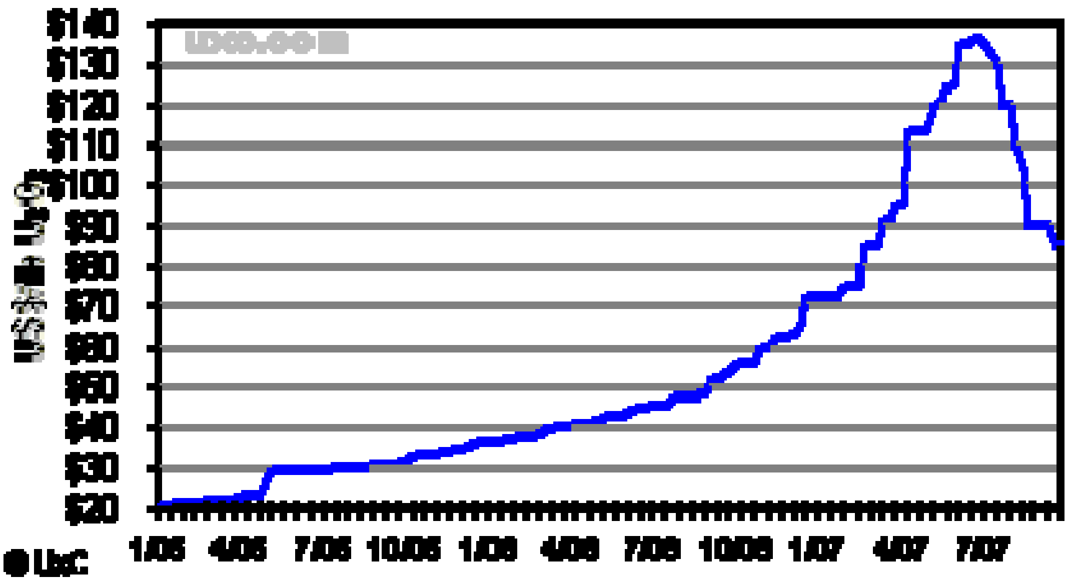
Over the 15 years prior to 2003, the uranium market was generally characterized by stable demand and a drawdown of worldwide inventories. This resulted in declining market prices, a consolidation of suppliers, as well as limited investment in uranium mine expansion and new development. By 2003, as much as 40 percent of annual worldwide uranium requirements were being satisfied by the drawdown of inventories. The sources of these inventories included government and utility inventories built up in expectation of significant nuclear programs which did not materialize, the flow of material to the western world following the breakup of the Soviet Union, and the use of uranium formerly contained in weapons as nuclear fuel.

Starting in 2003, demand for uranium began to increase in response to a number of factors including; supply disruption events which highlighted the production risks (including floods in Saskatchewan and Australian mines and a fire in an Australian mill), a renaissance of nuclear programs worldwide, particularly in Asia, and the realization of limits to inventory reductions. On the supply side, significant exploration is currently occurring and investments are being made in new uranium mining projects around the world. However, the lead time between discovery of an economic deposit and production of uranium in the western world is ten years or more, driven largely by regulatory requirements. Therefore, the combination of speculative demand, modest real growth in demand, the prospect of future growth in nuclear generation, temporary losses from current production and the lag in new uranium production has created a strong seller's market. Spot market prices increased to an all time peak of US $136 per pound (US $354 per kgU) in 2007 before declining to around US $90 per pound

(US $234 per kgU), as shown in the following Figure 1.0 based on the Ux Consulting Company's U308 weekly spot price, and this has impacted OPG's market priced and indexed contracts.

Figure 1.0

UxC Price Indicators- Current and Forecast



Suppliers are now demanding long-term commitments from buyers, largely based on the supplier's contract terms and conditions, with market-related prices (at time of delivery) and "floor prices" above US $50 per pound (US $130 per kgU). This situation is expected to continue at least through 2010, when additional supplies are expected to come into the market in response to higher prices.

The majority of worldwide uranium purchases (approximately 90 percent by volume) are provided under long term contracts. The remainder is traded on the spot market, defined as having delivery within one year. OPG has recently implemented a revised spot market procurement process to facilitate potential future spot market purchasing. While a number of market observers publish spot market price indicators based on physical spot market trading in uranium, the financial derivative markets for uranium (i.e., NYMEX futures; over the counter) is still in the developmental phase.

3.0 NUCLEAR FUEL COST FORECAST

The nuclear fuel cost forecast for the calendar years 2008 and 2009 is shown in Ex. F2-T5-S1 Table 1 along with comparable figures for 2005 through 2007. The nuclear fuel costs as shown in Ex. F2-T5-S1 Table 1 represent the total cost of each finished fuel bundle in aggregate as it is loaded into a reactor. The nuclear fuel costs in Ex. F2-T5-S1 Table 2 are the same as Ex. F2-T5-S1 Table 1, but restated in $/MWh.

The total cost of a finished fuel bundle as it is loaded into a reactor includes the cost of each of the three components (uranium concentrate, uranium conversion, and fuel bundle manufacturing). In that regard, the relative weighting of the cost of the uranium concentrate to the total cost of the finished fuel bundle as it is loaded into a reactor is expected to shift from approximately 36 percent in 2006 to a forecasted 63 percent uranium concentrate in 2009. The higher percentage of costs reflects the recent market price increases as discussed in section 2.5.2 above. Indeed, with the increased volatility associated with the price of uranium concentrates, there is a great deal of uncertainty related to predicting future nuclear fuel costs. By comparing high and low industry uranium concentrate price forecasts against OPG's current base forecast, OPG has recently calculated a potential variance range of +$24M / –$7M in 2009 nuclear fuel costs as loaded into the reactor. For these reasons, OPG is proposing to establish a Nuclear Fuel Cost variance account to address fuel cost risk as described in Ex. J1-T3-S1.

Exhibit F2-T5-S1 Table 1 also includes costs related to nuclear used fuel management services as discussed at Ex. H1-T1-S2, and fuel oil which are used to run stand-by generators.

The key cost drivers impacting the year-over-year increases in nuclear fuel costs as shown in Ex. F2-T5-S1 Table 1 are:

- Uranium concentrate contract price increases under market priced and indexed contracts.
- Escalation of uranium conversion service and fuel bundle manufacturing contract prices at general inflation rates.

- Changes in OPG energy production, e.g., the return to service of Unit 1 at Pickering A for a full year of operations in 2006.

Explanations of nuclear fuel cost variances are more fully described at Ex. F2-T5-S2

Numbers may not add due to rounding.

Table 1
Nuclear Fuel Costs ($M)

Line No.	Prescribed Facility	2005 Actual	2006 Actual	2007 Actual	2008 Plan	2009 Plan
		(a)	(b)	(c)	(d)	(e)
	Uranium:					
1	**Darlington NGS**	49.8	50.8	57.5	78.9	98.2
2	**Pickering A NGS**	6.8	11.1	6.9	17.0	23.7
3	**Pickering B NGS**	26.6	26.0	27.9	43.1	58.6
4	**Total Uranium**	83.1	87.9	92.3	139.1	180.4
5	**Used Fuel Management**[1]	14.2	15.4	16.4	20.6	20.9
6	**Fuel Oil**	3.1	1.6	4.3	2.7	2.8
7	**Total**	100.5	104.9	113.0	162.4	204.2

1 Used Fuel Management is discussed in Ex. H1-T1-S2.

Numbers may not add due to rounding.

Table 2
Nuclear Fuel Costs ($/MWh)

Line No.	Prescribed Facility	2005 Actual	2006 Actual	2007 Actual	2008 Plan	2009 Plan
		(a)	(b)	(c)	(d)	(e)
1	**Darlington NGS**	1.81	1.88	2.11	2.76	3.70
2	**Pickering A NGS**	1.89	1.74	1.89	2.40	3.23
3	**Pickering B NGS**	1.92	1.92	2.09	2.74	3.66
4	**Total**	1.85	1.87	2.09	2.70	3.62

COMPARISON OF NUCLEAR FUEL COSTS

1.0 PURPOSE

The purpose of this evidence is to present period-over-period comparisons of nuclear fuel costs.

2.0 OVERVIEW

Exhibit F2-T5-S2 Table 1 sets out the comparison of budget and actual nuclear fuel costs over the calendar years 2005 - 2009. See Ex. F2-T5-S1 for a general discussion of key drivers associated with nuclear fuel costs

3.0 PERIOD-OVER-PERIOD CHANGES - TEST PERIOD

<u>2009 Plan versus 2008 Plan</u>

The increase in nuclear fuel costs for Darlington is due to higher unit prices for new fuel loaded ($25.1M) partially offset by lower energy production ($5.9M).

The increase in nuclear fuel costs for Pickering A is due to higher unit prices for new fuel loaded ($6.1M) and higher energy production ($0.5M).

The increase in nuclear fuel costs for Pickering B is due to higher unit prices for new fuel loaded ($14.7M) and higher energy production ($0.8M).

Higher unit prices for new fuel loaded are mainly due to the impact of increases in uranium market prices on uranium supply contract prices as explained in Ex. F2-T5-S1.

<u>2008 Plan versus 2007 Actual</u>

The increase in nuclear fuel costs for Darlington is due to higher energy production ($2.8M) and higher unit prices for new fuel loaded ($18.6M).

The increase in nuclear fuel costs for Pickering A is due to higher unit prices for new fuel loaded ($3.7M) and higher energy production ($6.5M).

The increase in nuclear fuel costs for Pickering B is due to higher unit prices for new fuel loaded ($10.3M) and higher energy production ($4.9M).

Higher unit prices for new fuel loaded are mainly due to the impact of increases in uranium market prices on uranium supply contract prices as explained in Ex. F2-T5-S1.

4.0 PERIOD-OVER-PERIOD CHANGES - BRIDGE YEAR

2007 Budget versus 2007 Actual

The increase in nuclear fuel costs for Darlington is due to higher energy production ($0.9M) and higher unit prices for new fuel loaded ($2.5M).

The decrease in nuclear fuel costs for Pickering A is due to lower energy production (-$7.3M).

The decrease in nuclear fuel costs for Pickering B is due to lower energy production (-$4.8M) and higher fuel utilization efficiency (-$1.3M).

2007 Actual versus 2006 Actual

The increase in nuclear fuel costs for Darlington is due to higher unit prices for new fuel loaded ($6.2M), and higher energy production ($0.5M).

The decrease in nuclear fuel costs for Pickering A is due to lower energy production (-$4.8M), partially offset by higher unit prices for new fuel loaded ($0.5M).

The increase in nuclear fuel costs for Pickering B is due to higher unit prices for new fuel loaded ($2.8M), partially offset by lower energy production ($-0.3M), and higher fuel utilization efficiency ($-0.5M).

Higher unit prices for new fuel loaded are mainly due to the impact of increases in uranium market prices on uranium supply contract prices as discussed in Ex. F2-T5-S1.

5.0 PERIOD-OVER-PERIOD CHANGES - HISTORICAL YEARS

2006 Actual versus 2006 Budget

Fuel costs for Darlington were on budget due to lower energy production (-$0.9M) being offset by higher unit prices for new fuel loaded ($0.8M) and lower fuel utilization efficiency ($0.1M).

The decrease in nuclear fuel costs for Pickering A is due to lower energy production (-$1.0M) partially offset by lower fuel utilization efficiency ($0.2M).

The decrease in nuclear fuel costs for Pickering B is due to lower energy production (-$2.6M) and higher fuel utilization efficiency (-$0.2M).

Higher unit prices for new fuel loaded are mainly due to the impact of increases in uranium market prices on uranium supply contract prices and an increase in fuel bundle manufacturing contract prices.

2006 Actual versus 2005 Actual

The increase in fuel costs for Darlington is due to higher fuel price ($2.0M) and lower fuel utilization efficiency ($0.1M) offset by lower energy production (-$1.1M).

The increase in fuel costs for Pickering A is due to higher energy production ($5.4M) and higher fuel price ($0.2M) partially offset by higher fuel utilization efficiency (-$1.2M).

The decrease in fuel costs for Pickering B is due to lower energy production (-$0.7M) and higher fuel utilization efficiency (-$0.3M) offset by higher fuel price ($0.5M).

2005 Actual vs. 2005 Budget

Fuel costs for Darlington were $0.2M under budget with lower energy production (-$0.7M) offset by lower fuel utilization efficiency ($0.5 M).

Fuel costs for Pickering A is $1.9M under budget due to lower energy production (-$2.3M) partially offset by lower fuel utilization efficiency ($0.4M).

Fuel costs for Pickering B were $0.2M over budget with higher energy production ($0.6M) offset by lower unit prices for new fuel loaded (-$0.1M) and higher fuel utilization efficiency (-$0.3M).

Numbers may not add due to rounding.

Table 1
Comparison of Nuclear Fuel Costs - Nuclear ($M)

Line No.	Prescribed Facility	2005 Budget	(c)-(a) Change	2005 Actual	(e)-(c) Change	2006 Actual	(e)-(g) Change	2006 Budget	(i)-(e) Change	2007 Actual
		(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)
	Uranium:									
1	**Darlington NGS**	50.0	(0.2)	49.8	1.0	50.8	(0.1)	50.9	6.7	57.5
2	**Pickering A NGS**	8.6	(1.9)	6.8	4.4	11.1	(0.7)	11.9	(4.3)	6.9
3	**Pickering B NGS**	26.4	0.2	26.6	(0.6)	26.0	(2.8)	28.8	2.0	27.9
4	**Total Uranium**	85.0	(1.9)	83.1	4.8	87.9	(3.7)	91.6	4.4	92.3
5	**Used Fuel Management**[1]	14.5	(0.4)	14.2	1.2	15.4	(0.9)	16.3	1.0	16.4
6	**Fuel Oil**	1.0	2.2	3.1	(1.6)	1.6	(0.2)	1.8	2.7	4.3
7	**Total**	100.5	(0.0)	100.5	4.4	104.9	(4.8)	109.7	8.1	113.0

Line No.	Prescribed Facility	2007 Budget	(c)-(a) Change	2007 Actual	(e)-(c) Change	2008 Plan	(g)-(e) Change	2009 Plan
		(a)	(b)	(c)	(d)	(e)	(f)	(g)
	Uranium:							
8	**Darlington NGS**	54.1	3.4	57.5	21.4	78.9	19.2	98.2
9	**Pickering A NGS**	14.2	(7.3)	6.9	10.2	17.0	6.6	23.7
10	**Pickering B NGS**	34.0	(6.1)	27.9	15.2	43.1	15.5	58.6
11	**Total Uranium**	102.3	(10.0)	92.3	46.8	139.1	41.4	180.4
12	**Used Fuel Management**[1]	17.5	(1.1)	16.4	4.2	20.6	0.3	20.9
13	**Fuel Oil**	2.1	2.2	4.3	(1.6)	2.7	0.1	2.8
14	**Total**	121.8	(8.8)	113.0	49.4	162.4	41.8	204.2

1 Used Fuel Management is discussed in Ex. H1-T1-S2. For 2007 Actual, Used Fuel Management costs include an amount deferred in the Nuclear Liability Deferral Account discussed in Ex. J1-T1-S1.

OM&A PURCHASED SERVICES – NUCLEAR

1.0 PURPOSE

The purpose this exhibit is to present the purchases of OM&A services and products by the nuclear facilities that meet the threshold of one percent of the OM&A expense before taxes consistent with the OEB filing guidelines for OPG's Application.

2.0 OVERVIEW

An overview of OPG's procurement process which is applicable to the nuclear facilities is presented in Ex. F3-T5-S1.

The nuclear OM&A expense before taxes is equal to the sum of the nuclear base, project and outage OM&A plus the nuclear fuel expense. This sum ranges from $1455.3M in 2005 to $1916.6M in 2009 as presented in Ex. F2-T1-S1 Table 1. For the nuclear facilities the threshold of one percent of the OM&A expense before taxes is approximately $15M.

Information on vendor contracts for OM&A purchased services within the nuclear business that are equal to or in excess of $15M threshold for any of the years 2005, 2006 and 2007 is presented in Chart 1.

Chart 1

Purchase of Services - Nuclear OM&A Contracts

Vendor Name	Description/Nature of Activities	Request for Proposal Process		Rationale if Single Source
		Multiple Source	Single Source	
Siemens Canada Ltd. Siemens Power Generation	Provider of maintenance and engineering services (Pickering turbines). Provider of materials for Pickering turbines.		✓	Sole source original equipment manufacturer of Pickering turbine generators.
Nuclear Safety Solutions Ltd.	Provider of engineering services. The majority of work was single sourced, however, a small proportion of the work was competitively bid.	✓	✓	Sole source of nuclear safety related engineering analysis.
Ian Martin Ltd.	Provider of augmented staff.		✓	Single sourced purchases, however, pricing is competitive within OPG specified rate guidelines.
Eastern Construction Company Ltd.	Provider of general construction services. This included project work on the Darlington and Pickering Security buildings, Used Fuel Dry Storage Facilities and Refurbishment Waste Storage Buildings at the Bruce site	✓		
Candu Owners Group	The CANDU Owners Group Inc. is a not-for-profit organization which provides programs for the		✓	

	support, development, operation and maintenance of CANDU reactor technology. All CANDU Operators in the world are members of the CANDU Owners Group Inc.			
Babcock & Wilcox Canada Ltd.	Provider of specialty steam generator maintenance and feeder replacement services.	✓	✓	Sole source for some steam generator work (original equipment manufacturer).
Black & McDonald Ltd.	Provider of general construction services.	✓		
Atomic Energy of Canada Ltd.	Provider of engineering services and original equipment manufacturer parts. Provider of feeder replacement services and tooling (in partnership with Babcock & Wilcox Canada Ltd.). Sourcing is a combination of competitive bid and single sourcing.	✓	✓	Original equipment manufacturer for significant number of Pickering systems.
Wardrop Engineering Inc.	Provider of engineering services. Majority of work competitively bid.	✓	✓	Occasionally single sourced for project continuity.
Bruce Power Limited Partnership	Provider of site services to OPG Nuclear Waste Management facilities at Bruce site.		✓	Sole source.
AREVA NP	Provider of engineering services, steam generator maintenance services and augmented staff.	✓		
Acuren Group	Provider of augmented staff services related to NDT and engineering testing.	✓		
Durham Regional Police	Provider of Nuclear security services.		✓	Sole source

AMEC Black & McDonald Joint Venture	Pickering Auxillary Power System EPC contractor.	✓		
Ellis Don Fox Joint Venture	Darlington Used Fuel Dry Storage Facility EPC contractor	✓		
Crossby Dewar Inc.	Provider of scaffolding services.		✓	In 2006, 151 purchase orders were issued single source (only qualified vendor). In 2007 a second vendor was added to approved supplier list
Duratek of Canada Ltd.	Service contract for resin liner remediation at Western Waste Management Facility.	✓		

Total 2005 Spend ($M) = 414.6

Total 2006 Spend ($M) = 436.1

Total 2007 Spend ($M) = 346.3

ALLOCATION OF CORPORATE COSTS

1.0 PURPOSE

The purpose of this evidence is to describe corporate support and centrally held costs assigned and allocated to the nuclear and the regulated hydroelectric businesses and the underpinning allocation methodology.

2.0 OVERVIEW

OPG's corporate support groups provide services and incur costs in support of the nuclear and regulated hydroelectric businesses. These groups provide services that are necessary to run the business, meet statutory reporting and other requirements, and ensure the operation of the production facilities in a safe, effective, and efficient manner that complies with regulatory requirements. Corporate support groups include the Chief Information Office ("CIO"), Finance, Human Resources, Corporate Affairs, Energy Markets, Real Estate, Executive Office, Corporate Secretary, and Law. In addition, OPG centrally holds certain costs for the regulated facilities such as certain pension and other post employment benefits ("OPEB") costs, insurance costs, and performance incentive plan costs.

Corporate support and centrally held costs are either directly assigned or allocated to the regulated businesses using OPG's established methodology as outlined in section 5.0. Approximately 70 percent of OPG's total corporate function and centrally held costs are either directly assigned or allocated to regulated operations. OPG directly assigns costs that are directly related to a business. For example, corporate support employees working at, and solely in support of, a generating facility would be directly assigned to that facility. Direct assignment of costs accounts for approximately 45 to 50 percent of the corporate support and centrally held costs charged to the regulated facilities. Allocated costs are those costs that are used by more than one business unit. These costs are allocated based on appropriate cost drivers, which reflect cost causation or benefits received by the facility. OPG's costs allocation methodology has been reviewed and endorsed by independent cost allocation experts, R.J. Rudden Associates. The R.J. Rudden study is presented in Ex. F4-

T1-S1. The percentages above represent assignment of costs as presented in the R.J. Rudden report.

In addition to considering the allocation methodology for assigning and allocating corporate support and centrally held costs, R.J. Rudden also reviewed and endorsed OPG's methodology for allocating common hydroelectric business unit costs between regulated and unregulated hydroelectric facilities. These costs are described in Ex. F1-T2-S1.

2.1 Rationale for Corporate Structure

OPG has chosen to provide certain services centrally to ensure efficient and effective use of common shared services and systems. Centralization has resulted in lower costs through improved reporting to support better decision making, and common use of specialized resources in providing support to all production facilities. The benefits for this centralized service model are as follows:

- Use of common information systems reduces the total number of systems required to support the production facilities and thereby reduces costs.
- Centralizing support functions reduces staff levels while allowing business units access to specialized expert resources (e.g., commodity tax).
- Policies and procedures are standardized resulting in a consistent policy and governance framework.
- Common services and systems simplify and improve the accessibility of information for decision making (e.g., general ledger and data warehouse).
- Economies of scale are achieved through the use of common processes (e.g., payroll, accounts payable, and procurement) which reduce the costs of systems and resources.
- Centralization allows outsourcing opportunities where costs savings can be achieved as demonstrated through the outsourcing of IT systems and services to New Horizon System Services.

2.2 Corporate Initiatives

In 2002, OPG initiated a corporate structure review to improve the cost competitiveness of its business and included a restructuring plan to reduce staff. As a result of this initiative, OPG reduced staff by 1,450 employees including reductions to corporate support staff of approximately 400 staff. OPG also completed the outsourcing of certain non-core activities, improved centralized processes, and reorganized corporate support services. The outsourcing of non-core activities included the outsourcing of information technology services, pension administration, management of pension and nuclear liability funds, sale of nuclear safety analysis and assessment services, and certain research and development activities.

During the five years since the corporate structure review, OPG's annual business planning process has included a rigorous review of all business units' OM&A costs with additional focus on spending by the corporate support groups. The corporate support groups are challenged by the generation business leaders to rationalize their costs and justify the level of support provided to the production units. The direct assignment and allocation of corporate support costs was formalized and is the basis for OPG's internal management and external reporting. External reporting requirements include reporting segment information in OPG's quarterly and annual audited financial statements and management's discussion and analysis.

Given that it has been five years since the previous large scale formal cost review process, OPG decided that it was appropriate to initiate a support function review in conjunction with the 2008 business planning process. The support function review focuses on the support functions across the company. This strategic initiative was launched by the President in 2007 and is led by the Chief Operating Officer and a team of senior executives who are tasked with reviewing the cost structure and work processes of the support functions. The objective of the review is to focus on how OPG can be more effective and efficient, especially in supporting its work priorities.

The support function review is being conducted in two phases. The first phase, which was completed in 2007, consisted of a review of both corporate and business unit support groups' cost structures and work programs. This phase focused on the identification of cost saving opportunities, an identification of risks, and an assessment of the difficulty of implementation of identified opportunities. Certain of these cost saving opportunities have been incorporated into OPG's business plan 2008 - 2010 business plan for 2008 and subsequent years. These opportunities are expected to continue to yield cost saving benefits to OPG on an ongoing basis in the future.

Specifically, nuclear incorporated approximately $23M in total cost savings over the period 2008 - 2009, as discussed in Ex. F2-T2-S1. Corporate support groups' budgets incorporated approximately $14M in total cost savings associated with the regulated operations over the period 2008 - 2009, as discussed below.[1] Total hydroelectric cost savings are expected to be less than $1M over the period 2008 - 2009.

For corporate support groups, approximately $4M and $10M of cost reductions are incorporated in OPG's 2008 and 2009 budgets, respectively.[1] Some of the major contributors to the savings in corporate support groups are: increased standardization of information technology systems and a move towards more standard vendor-supported products by the CIO in order to minimize the cost of maintaining systems, and increased leverage of contracts for telecommunications, hardware purchases, and software and hardware maintenance provided by third parties. Within the Finance function, savings are expected to be achieved through the implementation of enhanced automation, increased standardization, and system and process improvements to increase efficiency and improve workflow.

Phase two of the review will focus on assessing the remaining saving opportunities. These opportunities generally carry a higher risk, are more difficult to achieve and/or require a longer-term implementation approach.

3.0 CORPORATE COSTS – TOTAL OM&A

Exhibit F3-T1-S1 Table 1 summarizes OPG's total corporate support and centrally held OM&A before direct assignment and allocation to nuclear and regulated hydroelectric. Fluctuations in these costs over the 2005 - 2009 period, many of which also contribute to

[1] Amount of corporate support groups' cost savings related to regulated operations is estimated based on an overall allocation percentage of each groups' costs determined according to OPG's cost allocation methodology.

fluctuations in costs directly assigned and allocated to nuclear and regulated hydroelectric, are discussed in this section.

Corporate support groups and centrally held costs increased over the 2005 - 2007 period mainly due to increases in centrally held costs relating to pension and OPEB over the entire period and higher CIO costs in 2007. The fiscal calendar adjustment in 2006 was lower than in 2005 and 2007, and partially offset the trend of increasing costs. (The fiscal calendar adjustment is described in section 3.8.)

The increase in the centrally held pension and OPEB costs during 2005-2007 was mainly due to changes in assumptions, such as the discount and inflation rates, updated membership and claims data, and changes in pension fund asset values, partially offset by higher amounts of pension and OPEB costs charged via payroll burden (refer to Ex. F3-T4-S1 for a discussion of accounting for pension and OPEB plans and associated costs). OM&A costs in the CIO group increased in 2007 due to an increase in the materiality threshold for capitalization of certain expenditures to $25,000, starting in 2007, for items such as low-value computer and other IT equipment (refer to Ex. A2-T2-S1 for further discussion), higher project costs, and additional IT support as a result of business unit requirements for data storage and telecommunication growth. The change in policy to expense low value computer and other IT equipment was made to ensure OPG's policy is consistent with industry practice.

Finance and Human Resources costs also increased slightly over the 2005-2007 period. Finance costs increased due to additional costs related to the establishment of a dedicated controllership group to support the increasing demands of the hydroelectric business unit, internal audit and internal control programs, and tax advisory services. Human Resources costs increased slightly due to the implementation of leadership development initiatives across OPG as well as additional expenditures on health and safety initiatives. Real Estate costs decreased slightly over the 2005 - 2007 period mainly due to the reassignment of a portion of Real Estate costs related to centrally-held assets, beginning in 2006, as a component of asset service fees charged to business units (discussed in Ex. F3-T3-S1).

Costs during 2008 and 2009 increase as compared to 2007 mainly due to higher costs in the CIO and Corporate Affairs groups as well as higher IESO non-energy charges, which are partially offset by lower centrally held pension and OPEB costs. The higher CIO costs are mainly due to a series of special initiatives, such as the relocation of multiple data centres, annual cost escalation based on a Cost-of-Living Adjustment and the Consumer Price Index pursuant to the New Horizon System Solutions (“NHSS”) outsourcing agreement (discussed in section 3.3 and Appendix A), increased business demand for IT services including ongoing suppport for new systems, and a non-recurring reduction in 2007 costs as a result of credits received from NHSS related to prior years. Corporate Affairs costs increase in 2008 - 2009 mainly due to activities associated with the OEB payments amount hearing, community engagement initiatives, and initiatives related to water safety, community and sponsorship advertising.

Finance costs associated with the support of hydroelectric projects and programs, nuclear refurbishment and new nuclear development initiatives, and internal audit and internal control programs are also forecast to increase.

Pension and OPEB expenses decrease in 2008 and 2009 as compared to the 2005 - 2007 period mainly due to the net impact of changes in assumptions for discount and inflation rates, and net changes in the long term growth rate in the pension fund asset value being higher than the growth in the pension obligation, partially offset by 2007 year-end pension fund value being lower than expected.

The forecast of IESO non-energy charges increases in 2008 and 2009 mainly due to the inclusion of the Global Adjustment and the OPG Rebate, which were not included in the 2005 - 2007 budgets for centrally held costs and which are not presented as part 2005-2007 actual costs.

OPG's total other centrally held costs increase in 2008 and 2009 primarily as a result of higher costs which are directly assigned to unregulated operations and do no impact OPG's proposed revenue requirement.

3.1 Description of Corporate Costs and Allocation of Costs

Exhibit F3-T1-S1 Tables 2 and 3 present the corporate support and centrally held costs allocated to nuclear and regulated hydroelectric over the historic, bridge, and test years. Costs allocated to nuclear include costs related to Bruce facilities.

The variance explanations as discussed in section 3.0 for total OPG costs are also applicable for the year-over-year variances in Ex. F3-T1-S1 Tables 2 and 3 for nuclear and regulated hydroelectric costs. In addition to the total OPG costs explanations, the CIO costs increase in 2007 due to higher project costs relating to the project management system project to improve resource management and costs. As well, the overall allocation of OPG's other costs to nuclear in 2006 is lower when compared to 2005 and future years due to higher costs incurred related to OPG's unregulated business. The variance explanations as discussed in section 3.0 for total OPG costs are also applicable for the year-over-year variances in Ex. F3-T1-S1 Table 3 for regulated hydroelectric costs. Also contributing to the higher costs for corporate support in 2006 and 2007 is a higher cost allocation due to increase capital spending by regulated hydroelectric on the Niagara Tunnel project and higher Finance costs. The higher Finance costs result from a new-dedicated controllership group to support the hydroelectric business which includes the completion of the Niagara Tunnel project, and First Nations negotiations. As well, Real Estate costs directly assigned and allocated to regulated hydroelectric increase slightly in 2008 mainly as a result of hydroelectric property rights and boundaries project in support of programs for public and dam safety programs.

3.2 Finance

Finance provides strategic advice, services, and support in the areas of controllership, financial services, treasury, insurance, risk services, financial planning, and asset planning. On behalf of the company, it prepares financial statements and maintains accounting policies and procedures in accordance with Canadian Generally Accepted Accounting Principles. OPG is a reporting issuer under the *Securities Act*, and is subject to continuous disclosure provisions of the *Securities Act*, which includes the requirement to file annual and interim financial statements and certifications on internal control over financial reporting with the securities regulator.

Financial Services perform external reporting, accounting, corporate procurement services, income and commodity tax services, and financial processing services such as accounts receivable, accounts payable, and fixed assets transactions management. Corporate procurement/supply chain procures materials and services for head office/support groups and assists the business unit's supply chain organizations, and provides corporate governance related to procurement.

Risk Services includes internal audit, operational risk management, market risk management, and credit risk management. The services performed by these groups include: assessing the effectiveness of OPG's network of risk management, control, and governance processes; providing risk management consulting services to the businesses; providing independent assurance that market risk exposures are managed within a framework of policies and procedures that clarify accountabilities, approved market risk related activities and risk tolerances; and assuring that OPG's counterparty's creditworthiness is assessed, transactions/contracts are structured to appropriately manage credit risk, and that there is ongoing monitoring and reporting of credit risk on a daily basis.

Controllership provides accounting, reporting, budgeting, and internal controls policies to the business units. There are specific departments dedicated to nuclear and hydroelectric stations and their costs are directly assigned to these business units. As well, other controllership departments provide support to all OPG business units and their costs are allocated based on OPG's allocation model.

Financial Planning provides corporate level business planning, financial planning, forecasting and reporting, financial strategy and performance management, and property tax services.

Treasury is responsible for the management of cash, financial exposure, capital structure, Ontario Nuclear Funds Agreement funds, and insurance premiums.

Asset Planning performs financial evaluations of major investment initiatives and provides the corporation with tools and programs to assist business units in their own assessments and preparation of business cases.

Exhibit F3-T1-S1 Tables 4 and 5 summarize Finance costs allocated to nuclear and regulated hydroelectric over the historic, bridge and test years.

A high percentage of finance costs are directly assigned for controllership (44 percent), risk services (51 percent), and supply chain (58 percent). Allocations of the remaining costs are determined based on the appropriate costs drivers as defined by OPG's cost allocation methodology. These percentages represent assignments and allocations as presented in the Summary of Distributions found in the R.J. Rudden report (Ex. F4-T1-S1).

3.3 Corporate Affairs

Corporate Affairs is responsible for managing a number of key functions essential to OPG's operations, specifically, Regulatory Affairs and Corporate Strategy, Public Affairs, and CIO.

<u>Regulatory Affairs and Corporate Strategy</u>

Regulatory Affairs and Corporate Strategy division guides OPG's interactions with economic regulators. These include the OEB, IESO, the National Energy Board and other Canadian and U.S. regulators that play an important role in OPG's operations. Regulatory Affairs provides regulatory intelligence, strategy, and advice and also manages regulatory interactions to obtain approvals and outcomes that allow OPG to accomplish its business goals.

Specific activities include:

- Leading OPG's preparation of the OEB payment amount application.

- Managing OPG's participation in regulatory proceedings and consultations in Ontario and other Canadian and U.S. jurisdictions.
- Co-ordinating the development of OPG positions on market issues and advancing these issues through the IESO's stakeholding processes.
- Providing regulatory and strategic support, research, and advice within OPG to facilitate OPG's participation in the electricity industry and to support strategic decisions.
- Obtaining and maintaining all necessary regulatory approvals for OPG to participate in the Ontario electricity market and other markets as required.

Regulatory Affairs and Corporate Strategy costs are applied to the business units using direct assignment (38 percent), which represents specific costs and estimates for the use of services and allocations (62 percent), which are based on a blend of costs at the regulated facilities for OM&A and capital expenditures. These percentages represent assignments and allocations as presented in the Summary of Distributions found in the R.J. Rudden report (Ex. F4-T1-S1).

Public Affairs

Public Affairs is responsible for internal and external communications. At the corporate level this includes media relations, internet communications, publications, and speeches. At the site/community level there are community outreach programs which include meetings and events with local community groups, communications about station operations and performance, and participation in community events. Also at the site/community level, particularly for the hydroelectric facilities, there are extensive public water safety awareness programs which are geared to educate a broad range of audiences about the importance of public water safety in the vicinity of the hydroelectric facilities. Internal communications ensure that OPG employees are aware of the company's major goals and objectives, as well as performance.

Public Affairs costs are applied to the business units using direct assignment (65 percent) which represents specific costs and estimates for the use of services and allocations (35 percent), which are based on a blend of costs at the regulated facilities for OM&A and capital expenditures. These percentages represent assignments and allocations as presented in the Summary of Distributions found in the R.J. Rudden report (Ex. F4-T1-S1).

Chief Information Office

The CIO oversees OPG's information management and information technology needs. It is specifically accountable for the strategic planning, management and operations of all information systems, programs, initiatives, and resources across OPG. The CIO also administers, on behalf of OPG, the Freedom of Information office and OPG’s governing documents framework.

At a more detailed level, the CIO is involved in the planning and budgeting of IT activities at all production sites, oversight of OPG’s IT vendors and outsourced service providers, delivery of IT projects and on-going IT services, information technology security, customer relationship management, and establishing information technology strategies and architectures. The systems utilized by corporate support groups provide support for business processes at all OPG locations. These costs include operating, maintaining and upgrading financial, human resources, real estate, energy markets, and other corporate systems.

Services are provided using a combination of internal staff and an outsourcing contract. In 2001, OPG outsourced its information technology services to New Horizon System Solutions through a competitive bidding process. New Horizon System Solutions provides application management and infrastructure management services. The infrastructure management services include desk-side support, helpdesk/call centre, e-mail, Internet, remote access, disaster recovery, and data centre operations. New Horizon System Solutions manages third party contracts on OPG’s behalf including software licenses, hardware maintenance, and telecommunication services. A summary of the outsourcing agreement between OPG and New Horizon System Solutions is included in Appendix A.

Exhibit F3-T1-S1 Tables 6 and 7 present the CIO costs allocated to nuclear and regulated hydroelectric over the historic, bridge, and test years.

CIO costs are allocated to business units using direct assignment (37 percent) which represents specific costs and estimates for the use of services and allocations (63 percent) which are based on various cost drivers (i.e., full time equivalents, LAN ID's, expenditures planned at OPG's production facilities). These percentages represent assignments and allocations as presented in the Summary of Distributions found in the R.J. Rudden report (Ex. F4-T1-S1).

3.4 Corporate Centre

The corporate centre includes the Executive Office (Chairman, President and CEO offices), the Corporate Secretary function, and Law. The Executive Office is responsible for the overall management and strategy for the company. The Corporate Secretary function supports the Board of Directors and the Executive Offices, and interfaces between the Board, management and OPG's shareholder.

Law provides legal advice and legal services that encompass a wide range of areas so as to effectively and efficiently support all business units across OPG. Law provides key service as follows:

- Support for procurement activities for materials, fuel, equipment and services, CIO activities, corporate governance, and finance.
- Support for all corporate and commercial matters related to all business units and advice related to OPG's pension and nuclear funds.
- Provides advice on real estate, energy markets, Bruce lease and related agreements, and water resources.
- Provides advice on energy regulatory matters, including OEB payment amount application, environmental approvals and compliance, nuclear licensing, litigation, municipal approvals and land use planning, First Nations issues, freedom of information request, and occupational health and safety compliance.
- Advice and services in the areas of labour, employment and privacy law.

The costs of the Executive Office and Corporate Secretary are allocated to the production facilities by applying the appropriate cost drivers. All Executive Office and Corporate Secretary costs are allocated based on a blend of costs at the regulated facilities for OM&A and capital expenditures. Law costs are directly assigned to the production facilities they support through estimates of percentage of time spent in support of these facilities.

3.5 Energy Markets, Including Sustainable Development

Energy Markets coordinates the offering of OPG's regulated facilities into the IESO market. This includes outage planning and strategies to optimize production based on market price signals, and to manage generation risks. Energy Markets is also responsible for providing advice and analysis on regulatory issues, responding to proposed market rule changes, compliance and market monitoring, energy revenue planning and forecasting, and emergency preparedness.

The Sustainable Development group supports OPG's compliance with existing environmental laws, and helps ensure that the corporation is strategically aligned to address short-term and long-term environmental risks and opportunities. The Sustainable Development group also reports environmental performance and regulatory developments to the OPG Board and senior management to assist them in discharging their due diligence obligations. The Sustainable Development group develops the environmental policy direction for the company, supports the businesses in implementing environmental policies and programs and is responsible for the corporate environmental management system.

The regulated facilities benefit from these two groups as their services are necessary to offer energy into the IESO market, to meet regulatory and operating limits, to meet reporting commitments, and to arrange confirmation of timing of planned outages with the IESO, while operating efficiently and effectively.

Energy Markets costs are applied to the business units using direct assignment (82 percent) which represents specific costs and estimates for the use of services and allocations (18 percent) which are allocated based on the appropriate cost drivers. These percentages represent assignments and allocations as presented in the Summary of Distributions found in the R.J. Rudden report (Ex. F4-T1-S1).

3.6 Human Resources

Human Resources provides payroll services, recruitment, labour relations, employee safety, security and wellness, compensation and benefits, ethics and code of business conduct, human resource planning and reporting and generalist human resources services in the field. There are generalist human resources departments dedicated to nuclear, fossil, hydroelectric and corporate business units, as well as specialist human resources departments that serve all of OPG.

Compensation and Benefits provides comprehensive compensation services including compensation system design, management and administration, pension and benefits administration, and payroll processing. It also provides the employee wellness strategy and services including: employee family assistance program, nursing services, the chief physician's office, and the disability management program.

Site (nuclear and regulated hydroelectric) Human Resources and Employee Safety is provided directly at the production facilities. Site Human Resources provides human resources and employee safety strategy, services, programming, and governance in support of the business units. Support is provided in areas such as resource management, employee wellness, and human resources administration. The employee safety function assists the corporation in fulfilling their requirements as outlined in the *Occupational Health and Safety Act of Ontario*. Specifically they:

- Ensure health and safety policies are developed and maintained as per regulatory requirements.
- Help to develop and maintain a health and safety program, as required by the *Occupational Health and Safety Act*, as well as to manage and mitigate health and safety risks to employees, contractors, and members of the public.

- Develop and maintain the necessary standards and procedures to ensure that work is carried out safely (e.g., contractor management programs and musculoskeletal disorder prevention programs).
- Review performance internally and benchmark externally and provide advice and assistance to OPG on emerging health and safety risks, trends, and regulatory issues.
- Work with other partners such as safety associations, unions, and regulators to continually improve health and safety performance.

Labour Relations provides labour relations services to OPG regarding strategy, negotiations, governance oversight, and programming and support. Human Resources Strategy and Support provides workforce planning and human resources project management support.

The Senior Vice President's office holds the budget for all human resources consultants and purchased services requirements.

Exhibit F3-T1-S1 Tables 8 and 9 summarize human resources costs allocated to nuclear and regulated hydroelectric over the historic, bridge, and test years.

Human Resources has a high level of direct assignment of costs (61 percent). The remainder (39 percent) is allocated based on appropriate costs drivers as defined by OPG's cost methodology. These percentages represent assignments and allocations as presented in the Summary of Distributions found in the R.J. Rudden report (Ex. F4-T1-S1).

3.7 Real Estate

The Real Estate group manages OPG's real estate assets. It maintains property records, buys/sells/leases land and buildings, pays rent, provides corporate–wide administrative and office services, as well as fleet administration – buying, selling, licensing and insurance. There are four departments within Real Estate: Facility Services, Business Services, Real Estate Services, and Fleet Services.

Facility Services manages furniture, office moves, employee relocations, office ergonomics, office renovations, space planning, janitorial and recycling services, and 24 hour emergency services. Business Services provides services such as document processing, controlled documents, records management, clerical relief, training coordination and office equipment, library services, mail, courier, printing imaging, and graphics services. Real Estate Services manages all OPG real estate assets, maintains property records (maps, surveys, and documents), rationalizes and develops portfolio strategies, surveys properties, acquires land or buildings and dispose of surplus properties. Fleet Services provides fleet administration, technical advice, license and insurance renewals, and fleet acquisition.

In addition to the OM&A costs to support these services, OM&A costs of managing real estate assets held centrally (e.g., OPG Head Office) are held within Real Estate. Generation business units are charged an asset service fee related to the use of these centrally held assets (Ex. F3-T3-S1).

Exhibit F3-T1-S1 Tables 10 and 11 summarizes Real Estate costs allocated to nuclear and regulated hydroelectric over the historic, bridge, and test years.

Real estate has a high level of costs directly assigned to the production facilities for facility services (87 percent) and business services (48 percent). The remaining departments, Fleet Services, and the Vice President's office are allocated based on the appropriate cost drivers. These percentages represent assignments and allocations as presented in the Summary of Distributions found in the R.J. Rudden report (Ex. F4-T1-S1).

3.8 Centrally Held Costs

The centrally held costs are directly assigned or allocated to the regulated facilities.

Centrally held costs include the following:

- Certain pension and OPEB costs such as interest on the obligations, the expected return on pension plan assets, amortization of past service costs, amortization of actuarial gains and losses, and variances to current service costs. The costs are directly assigned and allocated based on the proportion of current service costs associated with the production facilities. For a further discussion of pension and OPEB refer to Ex. F3-T4-S1.

- OPG's insurance program, which includes commercial general liability, all risk property, boiler and machinery breakdown, including statutory boiler and pressure vessel inspections, and business interruption. OPG also maintains property insurance for damage to the nuclear portions of its generating stations which complements the conventional property insurance program.
- Performance incentives for management, goalsharing for Society of Energy Professionals ("Society") and Power Workers' Union ("PWU") members and performance recognition for Society employees. A description of incentive plans is provided in Ex. F3-T4-S1 Sections 6.2 and 6.4.
- IESO non-energy charges are charges applied to the withdrawals of energy by OPG generation facilities from the IESO controlled grid. The charges include such discrete elements as the debt retirement charges, the rural or remote electricity rate protection charge, charges associated with IESO administration fees, transmission fees, Ontario Power Authority uplift fees, the Global Adjustment, the OPG Rebate, etc. These charges are not discretionary and apply to all withdrawals from the IESO controlled grid. These charges are directly assigned to the specific regulated facilities.
- The fiscal calendar adjustment is a wage adjustment that reflects the difference in the number of days between the 52-week fiscal calendar used for payroll accounting and OPG's financial year ending on December 31. The adjustment is temporary by its nature.
- Other costs included in the centrally held costs are the ONFA guarantee fee (payable to the Province of Ontario to guarantee the unfunded nuclear liabilities as discussed in Ex. H1-T1-S1), vacation accruals for current year benefit increases and certain provincial sales tax costs as discussed in Ex. F3-T1-S1.

Exhibit F3-T1-S1 Tables 12 and 13 summarize the centrally held costs allocated to nuclear and regulated hydroelectric over the historic, bridge, and test years.

4.0 COST ALLOCATION METHODOLOGY REVIEW

OPG retained R.J. Rudden Associates ("Rudden") in 2006 to evaluate whether the methodology used to assign and allocate common costs to nuclear and regulated hydroelectric meets current best practices and is consistent with precedents on cost allocation established by the OEB. Rudden made recommendations to OPG for changes to address any perceived gaps. Rudden also reviewed the methodology used by OPG to derive the asset service fees charged for the use of certain assets held centrally to both the regulated and unregulated business units. Asset service fees are considered in Ex. F3-T3-S1.

R.J. Rudden, a unit of Enterprise Management Solutions, Black & Veatch Corporation, is a strategic, economic, and management consulting firm specializing in energy matters. Rudden provides assistance in areas such as economic analysis, strategy development, operational assessments, industry restructuring support, litigation and regulatory support, and technical analysis. Rudden has over 24 years of experience and has assisted dozens of electric, gas, water, and telecommunications clients. Rudden has completed cost of service and cost allocation studies for wires-only utilities, integrated utilities and Independent System Operators in many jurisdictions in Canada and the U.S.

R.J. Rudden's findings on OPG's cost allocation methodology as identified in its report are as follows:

- OPG's cost allocation process has the support of senior levels of management.
- OPG's cost allocation process uses the principles of direct assignment and cost drivers that are key components of current best practices and OEB precedents.
- OPG's process relies on the judgement of departmental managers and business units to support specific identification and time estimates. These are the people in the best position to determine how resources are used.
- Supporting analyses were prepared by many of the central support and administrative costs groups and departments, including detailed analyses of activities, identification of specific resources, interviews to determine time estimates and reviews of invoices to determine historical usage.

- The business units to which the central support and administrative costs are distributed are familiar with the cost allocation process, confirmed where appropriate that specific resources are used by them and confirmed that the functions and services for which they are allocated costs are actually being received by them.

Summary of Conclusions by R.J. Rudden

- The overall approach is appropriate for the business organization of OPG.
- Direct assignment of costs by specific identification and by estimation is based on sufficient information reasonably applied.
- Direct assignments are used wherever possible.
- The costs drivers selected by OPG for those instances where not all costs are directly assigned are appropriate.
- The methodology used by OPG to distribute the corporate and centrally held costs separates the costs between regulated and unregulated business units in a manner that meets current best practices and is consistent with cost allocation precedents established by the OEB.

4.1 OPG's Response to R.J. Rudden Report Recommendations

As part of the cost allocation review, R.J. Rudden made the following recommendations with respect to OPG's process:

1. OPG should consider a formal quarterly review process, which includes a review of results of allocations, a review of departmental resource distributions based on time estimates, a review of direct assignments and allocators, and a review of allocator values.

In response to this recommendation, OPG instituted a formal quarterly review process in 2006, in which the results of allocations are formally reviewed by the Corporate Controller and Business Unit Controllers. The review incorporates all of the items highlighted by R.J. Rudden.

2. Documentation of the methodology should be improved and the CIO allocation model should be made consistent with the general cost allocation model used throughout the company.

OPG has improved its documentation based on R.J. Rudden's recommendations. The documentation incorporates the purposes and principles underlying the methodology, as well as responsibilities and time schedules for preparing and reviewing allocations. In addition, templates were created that were that are used to document specific services provided by each corporate support group. OPG has not developed templates to document time estimates, as recommended by R.J. Rudden, but it is something we may consider in the future. The CIO model has been made consistent with the general cost model by focusing on cost causality.

3. Cost driver selection should be standardized.

OPG has implemented this recommendation by focusing on cost causality and ensuring the consistent cost drivers are used throughout the company for similar activities. For example, Finance activities that are not directly assigned are allocated based on financial cost drivers such as OM&A and capital expenditures of the business units. This cost driver is appropriate for Finance since the support provided to business units is related to business unit budgets and complexity.

A copy of the R.J. Rudden Report is provided in Ex. F4-T1-S1.

5.0 METHODS OF ALLOCATION

There are two methods to distribute shared costs among the business units – direct assignment and allocation.

Direct Assignment

Direct assignment is used when specific resources, both individual employees and specific cost items, used by a particular business unit can be reasonably established. There is specific identification of resources where there is a direct relationship between the costs incurred and the business unit that causes the costs. Estimation of the resources used by the business unit may be based on current time estimates or historical activity.

Allocation

Allocations are used when more than one business unit uses a resource, but the portions of the resource that each uses cannot be directly established. In these cases, a cost driver is assigned to allocate the costs of the resource. A cost driver is a formula for sharing the cost of a resource among those who caused the cost to be incurred. There are two types of cost drivers - external and internal drivers. External drivers are based on data that are external to the allocation process. For example, the Accounts Payable Department's costs are allocated to business units based on the number of transactions processed for each group. Internal drivers are based on values computed as part of the cost allocation process. For example, a supervisor's salary may be allocated in proportion to the salaries of the people being supervised.

OPG used three steps when allocating a department's costs:

Step One – Specific Identification of Resources

The costs of resources specifically identified to a business unit are assigned to it.

- Labour: Identifying individuals who support only one business unit.
- Non-labour: Identifying costs directly caused by one business unit.

Step Two – Estimation of Resources

The next step is to identify the resources in each department that directly support one or more business units and to estimate the resources attributable to each business unit. The costs of these resources are directly assigned to each business unit in proportion to the estimated time required by that business unit.

Step Three – Assign Cost Drivers

Where no direct relationship exists, a cost driver is assigned to each type of expense. Similar activities have similar or standardized cost drivers. Rudden has recommended standardized cost drivers and OPG has adopted these changes. A list of cost drivers used by business unit is provided in Exhibit B of the Rudden report (see Ex. F4-T1-S1).

OPG department managers and the business units were consulted and supporting analyses were prepared to support the specific identification/direct assignment, and in selecting cost drivers which improves the quality of the cost allocation process. The department managers are in the best position to determine how resources are used.

6.0 SUMMARY OF COST DRIVERS USED IN COST ALLOCATION PROCESS

Detail Listing OPG Cost Drivers

	Directly Assigned	Allocated
Regulatory Affairs	Specific & estimates	Capital & OM&A
Corporate Strategy	Specific & estimates	Capital & OM&A
Public Affairs	Specific & estimates	Capital & OM&A
CIO	Specific & estimates	Various
Corporate Centre	Time estimates	Capital & OM&A
Finance		
Financial Services	Specific assignment	Capital & OM&A
Risk Services	Time estimates	Capital & OM&A
Site Controllers	Direct	Capital & OM&A
Financial Planning	none	Capital & OM&A
Treasury	Specific assignment	Capital & OM&A
Asset Planning	none	Capital & OM&A
Energy Markets/SD	Time estimates	Capital & OM&A
Human Resources		
Compensation & Benefits	Assigned FTE's	FTE's
Site HR	Direct	none
Labour Relations	Assigned FTE's	FTE's
HR Strategy	none	FTE's
HR EVP	none	FTE's
Real Estate	Specific & estimates	FTE's
Centrally Held Costs		
Pension/OPEB	Direct	Various
Insurance	Technology by insurer	Various
Performance Incentives	Direct	Various
IESO Non-Energy Charges	Direct	none
Other	Direct	Various

LIST OF ATTACHMENTS

APPENDIX A

Summary of New Horizon System Solutions Outsourcing Agreement

Information Technology Outsourcing Service Summary

1.0 PURPOSE

The purpose of the summary is to provide an overview of the structure and the key components of the New Horizon System Solutions outsourcing agreement.

2.0 BACKGROUND

OPG was formed in 1999. Since then a number of initiatives have been implemented to drive efficiencies, reduce long term costs, and allow OPG to focus on its core business of generating electricity. These initiatives included the outsourcing of certain non-core activities including information technology services.

Although the initiative to outsource information technology services was implemented in the early years of OPG's existence and partially stemmed from the anticipated decontrol of Ontario's electricity marketplace, this initiative continues to yield benefits to OPG and the ratepayers in the current environment.

Following a competitive bidding process, OPG entered into a joint venture agreement with Business Transformation Services, a wholly owned subsidiary of Cap Gemini Ernst & Young ("CGEY") on November 21, 2000 to outsource OPG's information technology services.

The joint venture known as New Horizon System Solutions ("NHSS"), an Ontario limited partnership, entered into the Information Technology Services Agreement ("ITSA") on February 1, 2001 with OPG, and OPG transferred approximately 450 employees to the partnership. The ten year term of the ITSA expires on January 31, 2011.

On March 28, 2002, in accordance with the terms of the ITSA, CGEY purchased OPG's interest in the NHSS joint venture and an amended and restated ITSA was executed to reflect the change in ownership and revised structure of NHSS.

In July 2003, OPG executed the Energy Market Services Information Technology Services Agreement ("EMS ITSA") with NHSS with an effective date of August 1, 2003. The term of the EMS ITSA expires coterminous with the ITSA.

3.0 SUMMARY OF SIGNIFICANT FEATURES OF THE CONTRACT

3.1 Service Components

The information technology services provided by NHSS consist of OM&A Services and Project Services.

<u>OM&A Services</u>

The categories of OM&A Services are:

- Base Services
- Enhancement Hours
- Variable Demand

- Base Services consists of internal and external labour costs, third party contracts, and some consumables incurred by NHSS in providing the OM&A services.

  The types of Base Services provided are described as follows:
  - Systems Management consisting of backup recovery, IT infrastructure support, operations and data management, production scheduling and systems software management.
  - IT Security Management including general IT security, access control, virus control, firewall, data encryption, user administration, IT security reporting and incident response.

- Business Application Management including the support, maintenance and enhancement of IT applications, provision of associated documentation and training, and management of web content.
- Telecommunication and Network Services including power system services, business voice and data services, mail/file and print services, and internet services.
- Desktop Services including help desk, desktop break/fix, desktop software support, desktop hardware and software upgrades and desktop technical education.
- General Management consisting of IT strategy and architecture management, IT quality assurance service management, IT problem management, contract management, asset management, and change management.

- Enhancement Hours are labour services used to make minor modifications to existing infrastructure and software applications in addition to the support services delivered as part of Base Services. The Enhancement Hours are divided into pools based on application and infrastructure type. The number of hours required by OPG for each pool is assessed and confirmed with NHSS annually prior to the commencement of each calendar year.

- Variable Demand primarily consists of telecommunication (voice and data) charges from third parties.

Project Services Project Services consists of IT application development or infrastructure improvement projects. Project services may include the management and delivery responsibility for project services provided by of third parties.

OPG is committed to purchase a specified minimum amount of Project Services in each contract year. If OPG does not purchase the required Project Services annual commitment, NHSS has the right to bill OPG as if the Project Services had been delivered. Historically, OPG has either met or exceeded the minimum Project Services commitment and plans to continue utilizing the Project Services in excess of the minimum requirements.

3.2 PRICING

Pricing Structure

In the amended and restated ITSA, pricing was structured in the following three-phased approach:

- Shadow Joint Venture Phase (January 31, 2002 – December 31, 2002)
  Total costs in the Shadow Joint Venture Phase consisted of OM&A Services, Project Services and Overhead Fees. OM&A Services were comprised of Base Services, Enhancement Hours and Variable Demand.

- Gain-Sharing Phase (January 1, 2003 – December 31, 2004)
  Total costs in the Gain-Sharing Phase consisted of OM&A Services, Project Services and Overhead Fees. The Gain-Sharing Phase was designed to reduce costs prior to transitioning to a Fixed Price Phase.

- Fixed Price Phase (January 1, 2005 – January 31, 2011)
  Total costs in the Fixed Price Phase consist of OM&A Services, Project Services and Overhead Fees. The price for the Base Services portion of OM&A Services was set on January 1, 2005 and is reduced by Infrastructure cost savings as described in 5.0. New, decommissioned, upgraded software applications or changes in volumes may result in incremental/decremental changes to the fixed price. Project Services and OM&A Services other than Base Services continue to be priced on a cost-plus basis.

In addition to the OM&A Services and Project Services, OPG pays NHSS in respect of overhead costs incurred by NHSS in providing the services (the “Overhead Fees”). Overhead Fees include indirect costs for NHSS support functions including Human Resources, Finance and office space such as rent and utilities costs. The Overhead Fees are fixed for each contract year as set out in ITSA

Inflation Adjustments

All labour related costs and overhead are adjusted annually according to the Toronto Consumer Price Index (commencing on January 1, 2003).

4.0 BENEFITS OF OUTSOURCING

The successful implementation of the outsourcing agreement has provided significant benefits to OPG as listed below:

- Allows OPG to focus on core business which is the safe, efficient production of electricity in the Province of Ontario.
- OPG benefits from economies of scale achieved and maintained by NHSS such as purchasing power for IT related products and services.
- The leasing of the Bruce Generating Stations to a third party reduced OPG's IT requirements. The outsourcing arrangement allowed the lessee to contract IT services directly with NHSS for the use of OPG's excess capacity, saving OPG $8 million in IT costs annually.
- Continues to drive efficiencies in the form of a contracted 5% reduction in the cost of Base Services effective January 1, 2003 resulting in annual savings of $3 million, gain share savings of $4 million annually, and potential infrastructure cost savings of $1 million per year as discussed in 5.0.
- Transfers service delivery risk to NHSS, with financial penalties if specified service levels are not met.
- NHSS is responsible for all aspects of labour management, including collective bargaining and staff training.
- The outsourcing arrangement provides a ready source of highly trained staff with technical expertise.
- NHSS is able to manage and allocate the work force where needed.

5.0 COST SAVING INITIATIVES

Reliable and cost effective information technology services are critical to safe and efficient operation of OPG's generation facilities. The amended and restated ITSA contained a number of cost reduction which benefited OPG.

Guaranteed Price Reduction

Effective January 1, 2003, the price to OPG for the initial set of Base Services was reduced to a level below OPG's original cost for those same services. This price reduction was guaranteed to OPG and was implemented whether or not NHSS had found the required cost savings.

Gain-Sharing Phase (January 1, 2003 – December 31, 2004)

The Gain-Sharing Phase period was designed to reduce costs associated with the provision of the Base Services under the outsourcing arrangement. The initiative was structured to benefit both OPG and NHSS by sharing cost reductions achieved by NHSS during this period, although OPG's share of the reductions was significantly larger than NHSS' share. Gain Sharing savings resulted in a reduction of the price for Base Services of approximately $4 million annually, which continue to the end of the contract term.

Infrastructure Cost Savings (January 1, 2005 – End of Contract)

Infrastructure cost savings are based on the cost of third party contracts and materials, calculated annually, and shared on a 50/50 basis between OPG and NHSS during the remainder of the term of ITSA. The cost savings have been approximately $1M annually.

6.0 PERFORMANCE STANDARDS

Throughout the ten year term of the ITSA, NHSS is responsible for providing IT services to OPG in accordance with specified performance standards. NHSS is required to monitor, analyze and report to OPG the service levels achieved.

Three types of performance standards are specified within the agreement. They are:

- Availability Performance Standard - This is the percentage of time that a service element (e.g., an application) is available to the end user which is tracked and reported either on a 24/7 or prime time basis.
- Response Time Performance Standard - This is the time that it takes for an application to carry out a transaction.

- Problem Resolution Time - This is the time that it takes for NHSS to respond to and resolve an outage or satisfy a request which is traced and reported either on a 24/7 or prime time basis.

If service levels fall below the specified performance standards, OPG is entitled to a performance credit. NHSS is incented to earn back 50% of the credit by meeting or exceeding the applicable incentive performance standards for four consecutive months immediately following the month in which the service level failure occurred.

7.0 PERFORMANCE MONITORING

As operational efficiencies are integral to the success of OPG, OPG requires NHSS to keep complete and accurate logs of all service failures in accordance with a mutually agreed upon methodology.

- Each business day during the term, NHSS provides a report to OPG detailing the status of all existing service failures.
- On a weekly basis, NHSS provides to OPG a report detailing OPG's capacity utilization relating to computing and data storage requirements for essential service elements and network circuit utilization.
- On a monthly basis, NHSS provides OPG with a dashboard report detailing the performance of each service element, total outage time for each planned and unplanned outage, actual resolution time, total number of transactions, response time, call percentage and call resolution rate for Help Desk and others. OPG also reviews the status of all existing service failures and other operational issues with NHSS.

Numbers may not add due to rounding.

Table 1
Corporate Support Groups & Centrally Held Costs ($M)
OPG

Line No.	Corporate Costs	2005 Actual	2006 Actual	2007 Actual	2008 Plan	2009 Plan
		(a)	(b)	(c)	(d)	(e)
1	**Finance**	56.2	57.0	62.6	67.1	68.5
2	**Corporate Affairs**	16.5	16.7	19.8	31.0	31.0
3	**CIO**	149.5	146.4	168.2	192.3	190.3
4	**Corporate Centre**[1]	20.4	19.3	21.0	21.6	21.6
5	**Energy Markets**	23.1	21.0	20.6	26.1	26.6
6	**Human Resources**	42.7	45.7	47.7	48.9	50.7
7	**Real Estate**	47.2	37.6	42.2	43.2	42.9
8	**Sub-Total**	355.6	343.7	382.1	430.2	431.6
	Centrally Held Costs:					
9	**Pension/OPEB Related**	97.3	208.7	178.8	147.9	117.4
10	**Insurance**	26.7	26.6	26.7	26.5	27.5
11	**Performance Incentives**	33.6	40.9	40.8	41.8	42.7
12	**IESO Non-Energy Charges**	25.9	22.4	20.5	35.9	35.2
13	**Other**	28.0	17.2	31.1	42.6	37.7
14	**Sub-Total**	211.5	315.8	297.9	294.7	260.5
15	**Total**	567.1	659.5	680.0	724.9	692.1

1 Corporate Centre includes Executive Office, Corporate Secretary, and Law.

Numbers may not add due to rounding.

Table 2
Allocation of Corporate Support & Administrative Costs ($M)
Nuclear

Line No.	Corporate Group	2005 Actual	2006 Actual	2007 Actual	2008 Plan	2009 Plan
		(a)	(b)	(c)	(d)	(e)
1	**Finance**	31.3	32.6	34.3	37.9	37.9
2	**Corporate Affairs**	9.2	11.0	10.6	20.1	19.8
3	**CIO**	98.8	95.9	111.5	124.6	123.3
4	**Corporate Centre**[1]	11.9	10.2	11.8	12.0	11.6
5	**Energy Markets**	2.8	1.3	2.5	4.2	4.1
6	**Human Resources**	28.0	30.7	32.8	32.6	33.6
7	**Real Estate**	36.1	28.6	33.1	32.3	32.1
8	**Sub-Total**	218.1	210.3	236.6	263.7	262.4
	Centrally Held Costs:					
9	**Pension/OPEB Related**	72.8	157.9	134.8	111.4	88.5
10	**Insurance**	11.8	11.8	11.5	11.7	12.2
11	**Performance Incentives**	24.6	28.9	29.0	28.9	29.5
12	**IESO Non-Energy Charges**	10.8	10.1	9.8	18.5	18.5
13	**Other**	18.1	4.2	25.1	22.8	19.1
14	**Sub-Total**	138.1	212.9	210.2	193.3	167.8
15	**Total**	356.2	423.2	446.8	457.0	430.2

1 Corporate Centre includes Executive Office, Corporate Secretary, and Law.

Numbers may not add due to rounding.

Updated: 2008-03-14
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Exhibit F3
Tab 1
Schedule 1
Table 3

Table 3
Allocation of Corporate Support & Administrative Costs ($M)
Regulated Hydroelectric

Line No.	Corporate Group	2005 Actual	2006 Actual	2007 Actual	2008 Plan	2009 Plan
		(a)	(b)	(c)	(d)	(e)
1	**Finance**	2.3	4.0	5.1	5.7	6.1
2	**Corporate Affairs**	0.3	1.2	2.9	3.9	4.0
3	**CIO**	5.7	6.5	6.6	9.1	9.0
4	**Corporate Centre**[1]	1.9	2.5	2.1	2.1	2.3
5	**Energy Markets**	1.4	1.7	1.6	2.8	2.8
6	**Human Resources**	1.7	2.1	2.2	2.4	2.5
7	**Real Estate**	1.3	1.5	1.4	2.2	2.1
8	**Sub-Total**	14.6	19.5	21.9	28.2	28.8
	Centrally Held Costs:					
9	**Pension/OPEB Related**	3.3	7.7	6.1	5.2	4.1
10	**Insurance**	3.5	3.2	3.3	3.2	3.3
11	**Performance Incentives**	1.2	1.8	2.1	2.5	2.5
12	**IESO Non-Energy Charges**	4.5	4.4	3.4	6.1	6.1
13	**Other**	0.5	2.0	1.2	2.3	2.0
14	**Sub-Total**	13.0	19.1	16.1	19.3	18.0
15	**Total**	27.6	38.6	38.0	47.5	46.8

1 Corporate Centre includes Executive Office, Corporate Secretary, and Law.

Numbers may not add due to rounding.

Table 4
Allocation of Finance Costs - Nuclear ($M)

Line No.	Costs	2005 Actual	2006 Actual	2007 Actual	2008 Plan	2009 Plan
		(a)	(b)	(c)	(d)	(e)
1	**Financial Services**	12.9	12.9	13.5	15.3	15.0
2	**Risk Services**	3.0	4.5	4.9	5.7	5.7
3	**Controllership**	8.9	9.0	10.3	11.3	11.8
4	**Financial Planning**	1.9	1.8	1.8	1.7	1.7
5	**Treasury**	1.2	1.7	1.6	2.1	2.1
6	**Asset Planning**	1.1	1.2	1.3	1.6	1.6
7	**CFO Office**	2.3	1.5	0.9	0.2	0.0
8	**Total**	31.3	32.6	34.3	37.9	37.9

Numbers may not add due to rounding.

Table 5
Allocation of Finance Costs - Regulated Hydroelectric ($M)

Line No.	Costs	2005 Actual	2006 Actual	2007 Actual	2008 Plan	2009 Plan
		(a)	(b)	(c)	(d)	(e)
1	**Financial Services**	0.9	1.2	2.1	2.3	2.3
2	**Risk Services**	0.2	0.7	0.9	1.0	1.1
3	**Controllership**	0.8	1.5	1.4	1.6	1.7
4	**Financial Planning**	0.1	0.3	0.3	0.3	0.5
5	**Treasury**	0.1	0.1	0.2	0.2	0.2
6	**Asset Planning**	0.1	0.1	0.2	0.2	0.3
7	**CFO Office**	0.1	0.1	0.0	0.1	0.0
8	**Total**	2.3	4.0	5.1	5.7	6.1

Numbers may not add due to rounding.

Table 6
Allocation of CIO Costs - Nuclear ($M)

Line No.	Costs	2005 Actual	2006 Actual	2007 Actual	2008 Plan	2009 Plan
		(a)	(b)	(c)	(d)	(e)
1	**Infrastructure Management**	21.6	25.4	26.6	36.3	36.2
2	**Contracts**	14.5	17.0	17.8	24.3	24.3
3	**Application Maintenance**	6.0	7.0	7.4	10.0	10.1
4	**Enhancements and Variable Demand**	8.1	3.8	4.9	6.7	6.6
5	**NH Indirects and Miscellaneous**	7.9	7.1	6.8	9.4	9.3
6	**NHSS Base Costs**	58.1	60.3	63.5	86.7	86.5
7	**OM&A Project Costs**	5.2	4.5	6.7	7.4	7.3
8	**CIO Costs**	14.8	10.7	14.3	4.5	4.3
9	**Common Corporate**	20.7	20.4	27.0	26.0	25.2
10	**Total**	98.8	95.9	111.5	124.6	123.3

Numbers may not add due to rounding.

Table 7
Allocation of CIO Costs - Regulated Hydroelectric ($M)

Line No.	Costs	2005 Actual	2006 Actual	2007 Actual	2008 Plan	2009 Plan
		(a)	(b)	(c)	(d)	(e)
1	**Infrastructure Management**	0.5	0.6	0.6	0.8	0.8
2	**Contracts**	0.2	0.3	0.3	0.4	0.4
3	**Application Maintenance**	0.3	0.4	0.4	0.5	0.5
4	**Enhancements and Variable Demand**	0.7	0.6	0.7	0.9	0.9
5	**NH Indirects and Miscellaneous**	0.3	0.2	0.2	0.4	0.4
6	**NHSS Base Costs**	2.0	2.1	2.2	3.0	3.0
7	**OM&A Project Costs**	0.8	0.7	0.3	0.6	0.6
8	**CIO Costs**	1.1	0.9	1.2	0.9	0.9
9	**Common Corporate**	1.8	2.8	2.9	4.6	4.5
10	**Total**	5.7	6.5	6.6	9.1	9.0

Numbers may not add due to rounding.

Table 8
Allocation of Human Resources Costs - Nuclear ($M)

Line No.	Costs	2005 Actual	2006 Actual	2007 Actual	2008 Plan	2009 Plan
		(a)	(b)	(c)	(d)	(e)
1	**Compensation & Benefits**	3.4	5.8	5.9	6.0	6.2
2	**Corporate HR**	4.8	5.9	5.9	6.4	6.4
3	**Labour Relations**	1.2	1.6	1.8	2.0	2.1
4	**Strategy & Support**	1.7	1.8	1.5	1.6	1.7
5	**Site HR**	12.4	12.1	12.8	13.9	14.5
6	**SVP Office**	4.5	3.5	4.9	2.7	2.7
7	**Total**	28.0	30.7	32.8	32.6	33.6

Numbers may not add due to rounding.

Table 9
Allocation of Human Resources Costs - Regulated Hydroelectric ($M)

Line No.	Costs	2005 Actual	2006 Actual	2007 Actual	2008 Plan	2009 Plan
		(a)	(b)	(c)	(d)	(e)
1	**Compensation & Benefits**	0.2	0.3	0.3	0.4	0.4
2	**Corporate HR**	0.3	0.3	0.4	0.3	0.3
3	**Labour Relations**	0.1	0.1	0.1	0.1	0.1
4	**Strategy & Support**	0.1	0.1	0.1	0.1	0.1
5	**Site HR**	0.8	1.2	1.3	1.4	1.5
6	**SVP Office**	0.2	0.1	0.0	0.1	0.1
7	**Total**	1.7	2.1	2.2	2.4	2.5

Numbers may not add due to rounding.

Table 10
Allocation of Real Estate Costs - Nuclear ($M)

Line No.	Costs	2005 Actual	2006 Actual	2007 Actual	2008 Plan	2009 Plan
		(a)	(b)	(c)	(d)	(e)
1	**Real Estate Services**	11.7	9.3	9.9	10.5	10.3
2	**Business Services**	17.7	14.0	14.6	14.7	14.6
3	**Facility Services**	5.6	4.4	8.0	6.6	6.7
4	**VP Office & Fleet services**	1.1	0.9	0.6	0.5	0.5
5	**Total**	36.1	28.6	33.1	32.3	32.1

Numbers may not add due to rounding.

Table 11

Allocation of Real Estate Costs - Regulated Hydroelectric ($M)

Line No.	Costs	2005 Actual	2006 Actual	2007 Actual	2008 Plan	2009 Plan
		(a)	(b)	(c)	(d)	(e)
1	**Real Estate Services**	0.9	1.0	0.8	1.6	1.5
2	**Business Services**	0.3	0.4	0.5	0.5	0.5
3	**Facility Services**	0.0	0.0	0.1	0.1	0.1
4	**VP Office & Fleet services**	0.1	0.1	0.0	0.0	0.0
5	**Total**	1.3	1.5	1.4	2.2	2.1

Numbers may not add due to rounding.

Table 12

Allocation of Centrally Held Costs - Nuclear ($M)

Line No.	Costs	2005 Actual	2006 Actual	2007 Actual	2008 Plan	2009 Plan
		(a)	(b)	(c)	(d)	(e)
1	**Pension/OPEB Related**	72.8	157.9	134.8	111.4	88.5
2	**Insurance**	11.8	11.8	11.5	11.7	12.2
3	**Performance Incentives**	24.6	28.9	29.0	28.9	29.5
4	**IESO Non-Energy Charges**	10.8	10.1	9.8	18.5	18.5
5	**Fiscal Calendar Adjustment**	0.5	(17.7)	3.4	6.9	3.4
6	**ONFA Guarantee Fee**	7.3	7.6	7.5	4.0	4.0
7	**OEFC Indemnity Fee**	3.5	0.5	0.0	0.0	0.0
8	**PST**	2.6	1.0	1.9	2.6	2.6
9	**OEB Related Costs**	0.0	0.4	0.4	0.0	0.0
10	**Vacation Accrual**	4.5	5.7	3.8	5.9	6.1
11	**Other**	(0.3)	6.7	8.1	3.4	3.0
12	**Total**	138.1	212.9	210.2	193.3	167.8

Numbers may not add due to rounding.

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Schedule 1
Table 13

Table 13

Allocation of Centrally Held Costs - Regulated Hydroelectric ($M)

Line No.	Costs	2005 Actual	2006 Actual	2007 Actual	2008 Plan	2009 Plan
		(a)	(b)	(c)	(d)	(e)
1	**Pension/OPEB Related**	3.3	7.7	6.1	5.2	4.1
2	**Insurance**	3.5	3.2	3.3	3.2	3.3
3	**Performance Incentives**	1.2	1.8	2.1	2.5	2.5
4	**IESO Non-Energy Charges**	4.5	4.4	3.4	6.1	6.1
5	**Fiscal Calendar Adjustment**	0.0	(0.8)	0.2	0.5	0.2
6	**OEFC Indemnity Fee**	0.2	0.7	0.0	0.0	0.0
7	**PST**	0.1	0.0	0.1	0.2	0.2
8	**OEB Related Costs**	0.0	0.1	0.1	0.0	0.0
9	**Vacation Accrual**	0.2	0.3	0.3	0.4	0.4
10	**Other Centrally Held Costs**	0.0	1.7	0.5	1.2	1.2
11	**Total**	13.0	19.1	16.1	19.3	18.0

Numbers may not add due to rounding.

Table 1a
Comparison of Allocation of Corporate Support & Administrative Costs ($M)
Regulated Hydroelectric

Line No.	Corporate Group	2005 Budget	(c)-(a) Change	2005 Actual	(e)-(c) Change	2006 Actual	(e)-(g) Change	2006 Budget	(i)-(e) Change	2007 Actual
		(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)
1	**Finance**	2.6	(0.3)	2.3	1.7	4.0	0.1	3.9	1.1	5.1
2	**Corporate Affairs**	0.4	(0.1)	0.3	0.9	1.2	(0.1)	1.3	1.7	2.9
3	**CIO**	6.3	(0.6)	5.7	0.8	6.5	(0.9)	7.4	0.1	6.6
4	**Corporate Centre**[1]	2.5	(0.6)	1.9	0.6	2.5	(0.6)	3.1	(0.4)	2.1
5	**Energy Markets**	1.4	0.0	1.4	0.3	1.7	(0.2)	1.9	(0.1)	1.6
6	**Human Resources**	1.9	(0.2)	1.7	0.4	2.1	0.0	2.1	0.1	2.2
7	**Real Estate**	1.3	0.0	1.3	0.2	1.5	(0.2)	1.7	(0.1)	1.4
8	**Sub-Total**	16.4	(1.8)	14.6	4.9	19.5	(1.9)	21.4	2.4	21.9
	Centrally Held Costs:									
9	**Pension/OPEB Related**	3.4	(0.1)	3.3	4.4	7.7	1.8	5.9	(1.6)	6.1
10	**Insurance**	4.3	(0.8)	3.5	(0.3)	3.2	(0.6)	3.8	0.1	3.3
11	**Performance Incentives**	1.2	0.0	1.2	0.6	1.8	0.3	1.5	0.3	2.1
12	**IESO Non-Energy Charges**	5.0	(0.5)	4.5	(0.1)	4.4	(1.1)	5.5	(1.0)	3.4
13	**Other**	1.2	(0.7)	0.5	1.5	2.0	(3.1)	5.1	(0.8)	1.2
14	**Sub-Total**	15.1	(2.1)	13.0	6.1	19.1	(2.7)	21.8	(3.0)	16.1
15	**Total**	31.5	(3.9)	27.6	11.0	38.6	(4.6)	43.2	(0.6)	38.0

1 Corporate Centre includes Executive Office, Corporate Secretary, and Law.

Numbers may not add due to rounding.

Table 1b
Comparison of Allocation of Corporate Support & Administrative Costs ($M)
Regulated Hydroelectric

Line No.	Corporate Group	2007 Budget	(c)-(a) Change	2007 Actual	(e)-(c) Change	2008 Plan	(g)-(e) Change	2009 Plan
		(a)	(b)	(c)	(d)	(e)	(f)	(g)
1	**Finance**	5.2	(0.1)	5.1	0.6	5.7	0.4	6.1
2	**Corporate Affairs**	3.1	(0.2)	2.9	1.0	3.9	0.1	4.0
3	**CIO**	6.9	(0.3)	6.6	2.5	9.1	(0.1)	9.0
4	**Corporate Centre**[1]	2.4	(0.3)	2.1	0.0	2.1	0.2	2.3
5	**Energy Markets**	1.9	(0.3)	1.6	1.2	2.8	0.0	2.8
6	**Human Resources**	2.4	(0.2)	2.2	0.2	2.4	0.1	2.5
7	**Real Estate**	1.4	0.0	1.4	0.8	2.2	(0.1)	2.1
8	**Sub-Total**	23.3	(1.4)	21.9	6.3	28.2	0.6	28.8
	Centrally Held Costs:							
9	**Pension/OPEB Related**	8.3	(2.2)	6.1	(0.9)	5.2	(1.1)	4.1
10	**Insurance**	3.6	(0.3)	3.3	(0.1)	3.2	0.1	3.3
11	**Performance Incentives**	2.1	0.0	2.1	0.4	2.5	0.0	2.5
12	**IESO Non-Energy Charges**	5.5	(2.1)	3.4	2.7	6.1	0.0	6.1
13	**Other**	3.3	(2.1)	1.2	1.1	2.3	(0.3)	2.0
14	**Sub-Total**	22.8	(6.7)	16.1	3.2	19.3	(1.3)	18.0
15	**Total**	46.1	(8.1)	38.0	9.5	47.5	(0.7)	46.8

1 Corporate Centre includes Executive Office, Corporate Secretary, and Law.

Numbers may not add due to rounding.

Table 2a
Comparison of Allocation of Corporate Support & Administrative Costs ($M)
Nuclear

Line No.	Corporate Group	2005 Budget	(c)-(a) Change	2005 Actual	(e)-(c) Change	2006 Actual	(e)-(g) Change	2006 Budget	(i)-(e) Change	2007 Actual
		(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)
1	**Finance**	34.3	(3.0)	31.3	1.3	32.6	(1.0)	33.6	1.7	34.3
2	**Corporate Affairs**	10.7	(1.5)	9.2	1.8	11.0	(1.0)	12.0	(0.4)	10.6
3	**CIO**	109.6	(10.8)	98.8	(2.9)	95.9	(13.3)	109.2	15.6	111.5
4	**Corporate Centre**[1]	16.9	(5.0)	11.9	(1.7)	10.2	(2.7)	12.9	1.6	11.8
5	**Energy Markets**	2.8	0.0	2.8	(1.5)	1.3	(0.1)	1.4	1.2	2.5
6	**Human Resources**	27.3	0.7	28.0	2.7	30.7	(1.8)	32.5	2.1	32.8
7	**Real Estate**	35.7	0.4	36.1	(7.5)	28.6	(3.9)	32.5	4.5	33.1
8	**Sub-Total**	237.3	(19.2)	218.1	(7.8)	210.3	(23.8)	234.1	26.3	236.6
	Centrally Held Costs:									
9	**Pension/OPEB Related**	73.6	(0.8)	72.8	85.1	157.9	40.9	117.0	(23.1)	134.8
10	**Insurance**	14.3	(2.5)	11.8	0.0	11.8	(1.4)	13.2	(0.3)	11.5
11	**Performance Incentives**	24.6	0.0	24.6	4.3	28.9	4.2	24.7	0.1	29.0
12	**IESO Non-Energy Charges**	11.5	(0.7)	10.8	(0.7)	10.1	(2.7)	12.8	(0.3)	9.8
13	**Other**	35.6	(17.5)	18.1	(13.9)	4.2	(7.5)	11.7	20.9	25.1
14	**Sub-Total**	159.6	(21.5)	138.1	74.8	212.9	33.5	179.4	(2.7)	210.2
15	**Total**	396.9	(40.7)	356.2	67.0	423.2	9.7	413.5	23.6	446.8

1 Corporate Centre includes Executive Office, Corporate Secretary, and Law.

Numbers may not add due to rounding.

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Tab 1
Schedule 2
Table 2b

Table 2b
Comparison of Allocation of Corporate Support & Administrative Costs ($M)
Nuclear

Line No.	Corporate Group	2007 Budget	(c)-(a) Change	2007 Actual	(e)-(c) Change	2008 Plan	(g)-(e) Change	2009 Plan
		(a)	(b)	(c)	(d)	(e)	(f)	(g)
1	**Finance**	34.4	(0.1)	34.3	3.6	37.9	0.0	37.9
2	**Corporate Affairs**	11.1	(0.5)	10.6	9.5	20.1	(0.3)	19.8
3	**CIO**	115.4	(3.9)	111.5	13.1	124.6	(1.3)	123.3
4	**Corporate Centre[1]**	13.0	(1.2)	11.8	0.2	12.0	(0.4)	11.6
5	**Energy Markets**	3.2	(0.7)	2.5	1.7	4.2	(0.1)	4.1
6	**Human Resources**	35.3	(2.5)	32.8	(0.2)	32.6	1.0	33.6
7	**Real Estate**	33.8	(0.7)	33.1	(0.8)	32.3	(0.2)	32.1
8	**Sub-Total**	246.2	(9.6)	236.6	27.1	263.7	(1.3)	262.4
	Centrally Held Costs:							
9	**Pension/OPEB Related**	170.7	(35.9)	134.8	(23.4)	111.4	(22.9)	88.5
10	**Insurance**	12.4	(0.9)	11.5	0.2	11.7	0.5	12.2
11	**Performance Incentives**	29.2	(0.2)	29.0	(0.1)	28.9	0.6	29.5
12	**IESO Non-Energy Charges**	14.2	(4.4)	9.8	8.7	18.5	0.0	18.5
13	**Other**	36.1	(11.0)	25.1	(2.3)	22.8	(3.7)	19.1
14	**Sub-Total**	262.6	(52.4)	210.2	(16.9)	193.3	(25.5)	167.8
15	**Total**	508.8	(62.0)	446.8	10.2	457.0	(26.8)	430.2

1 Corporate Centre includes Executive Office, Corporate Secretary, and Law.

COMPARISON OF ALLOCATION OF CORPORATE COSTS

1.0 PURPOSE

The purpose of this evidence is to describe period-over-period changes in the corporate support and centrally held costs that are assigned and allocated to the regulated hydroelectric and nuclear businesses.

2.0 PERIOD-OVER-PERIOD CHANGES - BRIDGE AND TEST PERIOD REGULATED HYDROELECTRIC OM&A

Exhibit F3-T1-S2 Tables 1a and 1b provide details on period-over-period changes for the bridge and test period.

2009 Plan versus 2008 Plan Regulated Hydroelectric

Corporate support and centrally held costs decrease by $0.7M for 2009 plan versus 2008 plan, primarily due to decreases in pension and other post-employment benefits (“OPEB”) expenses and other centrally held costs. Pension and OPEB expenses decrease mainly due to the net impact of changes in pension fund asset values and OPG’s pension obligation. Other centrally held costs decrease due to a lower fiscal calendar adjustment.

2008 Plan versus 2007 Actual Regulated Hydroelectric

Corporate support and centrally held costs increase by $9.5M in 2008 as compared to 2007 mainly due to increases in corporate support costs, IESO non-energy charges and other centrally held costs, partially offset by lower pension and OPEB expenses.

Expected cost increases in the corporate support groups are primarily due to the following:

- CIO costs increase mainly due to a series of special initiatives, such as the relocation of multiple data centres, annual cost escalation based on a cost-of-living adjustment and the consumer price index pursuant to the New Horizon System Solutions (“NHSS”) outsourcing agreement (discussed in Ex. F3-T1-S1), increased business demand for IT services including ongoing suppport for new systems, and a non-recurring reduction in 2007 costs as a result of credits received from NHSS related to prior years.

- Corporate Affairs costs increase mainly due to activities associated with the OEB payment amounts hearing and initiatives related to water safety, community and sponsorship advertising. Finance costs increase mainly for support of hydroelectric projects and programs and activities related to internal audit and internal control programs.
- Real Estate costs increase mainly due to the hydroelectric property rights and boundaries project in support of public and dam safety programs.
- Energy Markets costs increase mainly due to the organizational transfer of the Sustainable Development group from Corporate Centre and activities in support of pandemic planning.
- Corporate Centre costs remain constant overall; however, higher legal costs associated with the OEB payment amounts hearing are offset by the transfer of the Sustainable Development group to Energy Markets.

The forecast of IESO non-energy charges increases in 2008 mainly due to the inclusion of a forecast of the Global Adjustment and the OPG Rebate, which were not included in the 2005 - 2007 budgets for centrally held costs and which are not presented as part of 2005 - 2007 actual costs.

The expected increase in other centrally held costs include a higher fiscal calendar adjustment.

Pension and OPEB expenses decrease mainly due to the net impact of changes in assumptions for the discount rate from 5.25 percent to 5.6 percent and for the inflation rate, and net changes in the long term growth rate in the pension fund asset value being higher than the growth in the pension obligation, partially offset by 2007 year-end pension fund value being lower than expected. The discount rate change is based on changes in representative AA corporate bond yields used in establishing the discount rate, as discussed in Ex. F3-T4-S1.

2007 Actual versus 2007 Budget Regulated Hydroelectric

Corporate support and centrally held costs were lower than budget by $8.1M in 2007. The lower costs were mainly due to lower pension and OPEB costs reflecting a change in the discount rate from 5.0 percent to 5.25 percent, lower IESO non-energy charges, and a largely unspent centrally held contingency for unforeseen events and OEB related activities. Centrally held costs assigned and allocated to the regulated business do not include any contingencies in the 2008 and 2009 budgets.

IESO non-energy charges were lower than budget due to changes in the volume of load consumption and changes in the amount and types of settlement charges that apply to these loads.

2007 Actual versus 2006 Actual Regulated Hydroelectric

Corporate support and centrally held costs were lower by $0.6M in 2007 than in 2006, with lower centrally held costs being offset by higher corporate support costs.

Corporate support costs increased by $2.4M in 2007 mainly due to the following:

- Finance costs increased due to the establishment of a dedicated controllership group to support the increasing demands of the hydroelectric business (i.e., Niagara Tunnel project and First Nations negotiations) and costs for tax advisory services.
- Corporate Affairs costs increased mainly due to activities associated with the OEB payment amounts hearing and initiatives related to water safety, community and sponsorship advertising.
- All corporate support groups' costs increased in part due to economic increases, including labour cost escalation (discussed in Ex. F3-T4-S1).

Centrally held costs for pension and OPEB were lower due to changes in assumptions in the discount rate from 5.0 percent to 5.25 percent and an increase in the amounts charged the business units via the payroll burden. IESO non-energy charges were lower as a result of changes in the volume of load consumption and changes in the amount and types of settlement charges that apply to these loads.

3.0 PERIOD-OVER-PERIOD CHANGES - HISTORICAL PERIOD REGULATED HYDROELECTRIC OM&A

Exhibit F3-T1-S2 Table 1a provides details on period-over-period changes for the historical period.

2006 Actual versus 2006 Budget Regulated Hydroelectric

Corporate support and centrally held costs decreased by $4.6M for 2006 actual versus 2006–budget, primarily due to lower costs for corporate support, insurance, and other centrally held costs offset by higher pension and OPEB expenses.

The lower costs incurred by corporate support during 2006 compared to budget are due to the following:

- CIO costs decreased due to lower New Horizon System Solutions costs, deferral of OM&A projects, reduced telecommunications costs, and lower software and applications costs.

Insurance was lower due to lower than planned premiums. IESO non-energy charges were lower than planned due to changes in the volume of load consumption and changes in the amount and types of settlement charges that apply to these loads.

Other centrally held costs decreased due to lower than planned costs for OEB preparation.

Pension and OPEB expenses increased for 2006 actual versus 2006 budget mainly due to changes in assumptions in the discount rate from 5.4 percent to 5.0 percent, partially offset by the 2005 year end pension fund asset value being higher than budget value.

2006 Actual versus 2005 Actual Regulated Hydroelectric

Corporate support and centrally held costs increased by $11.0M for 2006 actual versus 2005 actual, primarily due to higher pension and OPEB expenses, overall higher corporate support and other centrally held costs.

Pension and OPEB expenses increased for 2006 actual costs versus 2005 actual mainly due to changes in assumptions in the discount rate from 6.0 percent to 5.0 percent and inflation rate from 2.25 percent to 2.0 percent, normal growth, and claims experienced, partially offset by the impact of the 2005 year end pension fund asset value being higher than the 2004 year end value.

Corporate support and other centrally held costs increased due to increased allocations from corporate support groups to regulated hydroelectric. The increase in costs allocated to the regulated hydroelectric facilities was due to an increase in expenditures and effort in support of the Niagara Tunnel project. As well, costs for Finance, Executive Office, and Law increased, due to a new dedicated controllership group and support for the Niagara Tunnel project, and First Nations negotiations.

<u>2005 Actual versus 2005 Budget Regulated Hydroelectric</u>

Corporate support and centrally held costs decreased by $3.9M primarily due to lower costs in corporate support, lower than planned insurance costs, and lower other centrally held costs related to other corporate costs.

The lower costs incurred by corporate support during 2005 compared to budget are due to the following:

- CIO costs decreased due to OPG’s share of cost reductions achieved by NHSS, lower license costs, and reduced spending on enhancement work from NHSS.
- Finance costs were lower due to lower staff levels.

Insurance was lower due to lower than planned premiums and amounts received for prior years’ claims.

4.0 PERIOD-OVER-PERIOD CHANGES - BRIDGE AND TEST PERIOD NUCLEAR OM&A

Exhibit F3-T1-S2 Tables 2a and 2b provide details on period-over-period changes for the bridge and test period.

<u>2009 Plan versus 2008 Plan Nuclear</u>

Corporate support and centrally held costs decrease by $26.8M for 2009 plan versus 2008 plan, primarily due to decreases in pension and OPEB expenses and other centrally held costs. Pension and OPEB expenses decrease mainly due to the net impact of changes in pension asset value and pension obligation. Other centrally held costs decreased due to a lower fiscal calendar adjustment.

<u>2008 Plan versus 2007 Actual Nuclear</u>

Corporate support and centrally held costs increase by $10.2M in 2008 compared to 2007 due to higher corporate support costs and IESO non-energy charges, partially offset by lower centrally held pension and OPEB expenses and other centrally held costs.

Expected cost increases in the corporate support groups are primarily due to the following:

- CIO costs increase mainly due to a series of special initiatives, such as the relocation of multiple data centres, annual cost escalation based on a cost-of-living adjustment and the consumer price index pursuant to the New Horizon System Solutions ("NHSS") outsourcing agreement (discussed in Ex. F3-T1-S1), increased business demand for IT services including ongoing suppport for new systems, and a non-recurring reduction in 2007 costs as a result of credits received from NHSS related to prior years.
- Corporate Affairs costs increase mainly due to activities associated with the OEB payment amounts hearing, community engagement initiatives, and initiatives related to community and sponsorship advertising.

- Finance costs increase mainly for support of new nuclear development and nuclear refurbishment initiatives and activities related to internal audit and internal control programs.
- Energy Markets costs increase due to the organizational transfer of the Sustainable Development group from Corporate Centre and activities in support of pandemic planning.
- Corporate Centre costs remain constant overall; however, higher legal costs associated with the OEB payment amounts hearing are offset by the transfer of the Sustainable Development group to Energy Markets.

The forecast of IESO non-energy charges increases in 2008 due to the inclusion of a forecast of the Global Adjustment and the OPG Rebate, which were not included in the 2005-2007 budgets for centrally held costs and which are not presented as part of 2005-2007 actual costs.

Pension and OPEB expenses decrease mainly due to the net impact of changes in assumptions for the discount rate from 5.25 percent to 5.6 percent and for the inflation rate, and net changes in the long term growth rate in the pension fund asset value being higher than the growth in the pension obligation, partially offset by 2007 year-end pension fund value being lower than expected. The discount rate change is based on changes in representative AA corporate bond yields used in establishing the discount rate, as discussed in Ex. F3-T4-S1.

Other centrally held costs decrease mainly as a result of a lower Ontario Nuclear Funds Agreement guarantee fee in 2008 and non-recurring environmental charges incurred in 2007, partially offset by a higher fiscal calendar adjustment in 2008.

<u>2007 Actual versus 2007 Budget Nuclear</u>

Corporate support and centrally held costs were lower than budget by $62.0M for 2007. The lower costs were mainly due to lower pension and OPEB costs reflecting a change in the discount rate from 5.0 percent to 5.25, lower IESO non-energy charges, and a largely unspent centrally held contingency for unforeseen events and OEB related activities. Centrally held costs assigned and allocated to the regulated business do not include any contingencies in the 2008 and 2009 budgets.

IESO non-energy charges were lower than budget due to changes in the volume of load consumption and changes in the amount and types of settlement charges that apply to these loads.

<u>2007 Actual versus 2006 Actual Nuclear</u>

Corporate support and centrally held costs were higher by $23.6M in 2007 than in 2006, primarily due to increases in corporate support costs and a higher fiscal calendar adjustment, partially offset by a decrease in centrally held pension and OPEB expenses.

The increases in costs by the corporate support groups are due to the following:

- CIO costs increase due to an increase in the materiality threshold for capitalization of certain expenditures, such as low-value computer and other IT equipment, incurred starting in 2007 to $25,000 (refer to Ex. A2-T2-S1 for further discussion), additional IT support as a result of business unit requirements for data storage and telecommunication growth, and higher project costs relating to the nuclear project management system project to improve resource management and costs. The nuclear project management system project includes the purchase, integration, and implementation of software, processes, and organization changes to improve Nuclear's ability to manage nuclear projects.
- Real Estate costs increase due to additional support for nuclear training, and purchases of furniture and office equipment.
- Energy markets costs increase due to costs incurred for emergency preparedness.
- All corporate support groups costs increased in part due to economic increases, including labour cost escalation discussed in Ex. F3-T4-S1.

Other centrally held costs increased due to a higher fiscal calendar adjustment.

The higher corporate support and other centrally held costs were partially offset by lower pension and OPEB expenses reflecting a change in the discount from 5.0 percent to 5.25 percent and an increase in the amounts charged to the business units via the payroll burden.

5.0 PERIOD-OVER-PERIOD CHANGES - HISTORICAL PERIOD NUCLEAR OM&A

Exhibit F3-T1-S2 Table 2a provides details on period-over-period changes for the historical period.

<u>2006 Actual versus 2006 Budget Nuclear</u>

Corporate support and centrally held costs increased by $9.7M for 2006 actual versus 2006 budget, primarily due to higher pension and OPEB expenses partially offset by lower costs for the corporate support, insurance, and other centrally held costs.

Pension and OPEB expenses increased for 2006 actual versus 2006 budget mainly due to changes in assumptions in the discount rate from 5.4 percent to 5.0 percent partially offset by the 2005 year -end pension fund asset value being higher than budget value.

The lower costs incurred by corporate support during 2006 compared to budget are due to the following:

- CIO costs decreased due to lower NHSS costs, deferral of projects, reduced telecommunications costs, and lower software and applications costs.

Insurance was lower due to lower than planned premiums.

Other centrally held costs decreased due to lower than planned OEB related costs.

<u>2006 Actual versus 2005 Actual Nuclear</u>

Corporate support and centrally held costs increased by $67.0M for 2006 actual versus 2005 actual primarily due to higher pension and OPEB expenses, partially offset by lower other centrally held costs.

Pension and OPEB expenses increased for 2006 actual costs versus 2005 actual mainly due to, changes in assumptions in the discount rate from 6.0 percent to 5.0 percent and inflation rate from 2.25 percent to 2.0 percent, normal growth, and claims experience, partially offset by 2005 year end pension fund asset value being higher than the 2004 year end value.

Corporate support and other centrally held costs decreased due to a decrease in allocations from corporate support groups to Nuclear. The decrease in costs allocated to the nuclear facilities was due to an increase in expenditures and effort in support of the hydroelectric business as a result of the Niagara Tunnel project. Real Estate costs allocated to Nuclear also decreased mainly due to the reassignment of a portion of Real Estate costs related to the asset service fees charged to the business units (discussed in Ex. F3-T3-S1). Other centrally held costs also decreased due to lower costs resulting from the fiscal calendar adjustment partially offset by higher performance incentives paid to staff.

<u>2005 Actual versus 2005 Budget Nuclear</u>

Corporate support and centrally held costs decreased by $40.7M for 2005 actual versus 2005 budget, primarily due to lower costs in corporate support, lower than planned insurance costs, and lower other centrally held costs.

The lower costs incurred by corporate support during 2005 compared to budget are due to the following:

- CIO costs decreased due to OPG’s share of cost reductions achieved by NHSS, lower license costs, and reduced spending on enhancement work from NHSS.
- Finance costs were lower due to lower staff levels.

Insurance was lower due to lower than planned premiums and amounts received for prior years claims.

Table 1
Other Operating Cost Items - Regulated Hydroelectric ($M)

Line No.	Cost Item	2005 Actual	2006 Actual	2007 Actual	2008 Plan	2009 Plan
		(a)	(b)	(c)	(d)	(e)
	Depreciation:					
1	**Niagara Plant Group**	47.1	41.5	41.9	41.9	42.3
2	**Saunders GS**	21.1	20.8	20.8	20.9	21.0
3	**Other[1]**	(1.1)	3.9	5.8	0.0	0.0
4	**Sub-total**	67.1	66.2	68.5	62.7	63.2
5	**Income Tax**	7.0	0.0	0.0	0.0	0.0
6	**Capital Tax**	12.0	11.9	8.8	8.7	8.7
	Property Tax:					
7	**Niagara Plant Group**	0.0	0.0	0.0	0.0	0.0
8	**Saunders GS**	0.0	0.0	0.0	0.0	0.0
9	**Sub-total**	0.0	0.0	0.0	0.0	0.0
10	**Total**	86.1	78.0	77.3	71.4	71.9

1 Includes losses on retirements, gains on sales, asset removal costs and other related charges.

Numbers may not add due to rounding.

Table 2
Calculation of Ontario Capital Tax - Regulated Hydroelectric ($M)
Years Ending December 31, 2005, 2006, 2007, 2008, 2009

Line No.	Particulars	2005 Actual	2006 Actual	2007 Budget	2007 Actual	2008 Plan	2009 Plan
		(a)	(b)	(c)	(d)	(e)	(f)
1	**Rate Base**	4,001.3	3,957.3	3,907.6	3,911.1	3,885.5	3,869.9
2	**Less: Provincial Exemption**	4.1	5.3	5.7	5.7	6.8	6.9
3	**Net Taxable Capital**	3,997.2	3,952.0	3,902.0	3,905.4	3,878.6	3,863.0
4	**Ontario Capital Tax Rate**	0.300%	0.300%	0.285%	0.225%	0.225%	0.225%
5	**Total Capital Tax**	12.0	11.9	11.1	8.8	8.7	8.7

Numbers may not add due to rounding.

Table 3
Calculation of Large Corporations Tax - Regulated Hydroelectric ($M)
Year Ending December 31, 2005 and Year Ending December 31, 2006

Line No.	Particulars	2005 Actual	2006 Actual
		(a)	(b)
1	**Rate Base**	4,001.3	
2	**Less: Federal Exemption**	27.0	
3	**Net Taxable Capital**	3,974.3	
4	**LCT Rate**	0.175%	
5	**Large Corporations Tax (Eliminated in 2006)**	7.0	N/A

Numbers may not add due to rounding.

Table 4

Other Operating Cost Items - Nuclear ($M)

Line No.	Cost Item	2005 Actual	2006 Actual	2007 Actual	2008 Plan	2009 Plan
		(a)	(b)	(c)	(d)	(e)
	Depreciation[1]:					
1	**Darlington NGS**	93.2	99.4	114.5	98.6	106.3
2	**Pickering NGS**	118.3	96.9	141.0	156.6	162.5
3	**Nuclear Support Divisions**	29.9	23.3	23.8	24.1	30.0
4	**IMS**	6.9	8.1	9.6	9.8	10.8
5	**Other[2]**	11.3	15.1	11.8	5.3	6.8
6	**Sub-total**	259.6	242.8	300.7	294.4	316.4
7	**Income Tax**	5.7	0.0	0.0	0.0	0.0
8	**Capital Tax[1]**	8.6	9.0	7.9	7.9	7.8
	Property Tax:					
9	**Darlington NGS**	0.2	9.9	8.6	9.1	9.3
10	**Pickering NGS**	7.3	6.9	(0.4)	4.8	4.9
11	**Sub-total**	7.5	16.8	8.2	13.9	14.2
12	**Total**	281.5	268.6	316.8	316.2	338.5

1 For 2007 Actual, includes amounts deferred in the Nuclear Liability Deferral Account discussed in Ex. J1-T1-S1.

2 Includes losses on retirements, gains on sales, asset removal costs and other related charges.
Includes nuclear waste management variable expenses (2005 Actual - $4.0M, 2006 Actual - $3.6M, 2007 Actual - $1.6M, 2008 Plan - $1.7M, 2009 Plan - $1.8M)

Numbers may not add due to rounding.

Table 5
Calculation of Ontario Capital Tax - Nuclear ($M)
Years Ending December 31, 2005, 2006, 2007, 2008, 2009

Line No.	Particulars	2005 Actual	2006 Actual	2007 Budget	2007 Actual	2008 Plan	2009 Plan
		(a)	(b)	(c)	(d)	(e)	(f)
1	**Rate Base**	2,865.5	3,005.7	3,442.4	3,500.1	3,515.4	3,483.8
2	**Less: Provincial Exemption**	2.9	4.1	5.0	5.1	6.2	6.2
3	**Net Taxable Capital**	2,862.5	3,001.6	3,437.4	3,495.0	3,509.2	3,477.7
4	**Ontario Capital Tax Rate**	0.300%	0.300%	0.285%	0.225%	0.225%	0.225%
5	**Total Capital Tax**	8.6	9.0	9.8	7.9	7.9	7.8

Numbers may not add due to rounding.

Table 6

Calculation of Large Corporations Tax - Nuclear[1] ($M)

Year Ending December 31, 2005 and Year Ending December 31, 2006

Line No.	Particulars	2005 Actual	2006 Actual
		(a)	(b)
1	**Rate Base[2]**	3,307.6	
2	**Less: Federal Exemption**	23.0	
3	**Net Rate Base**	3,284.6	
4	**LCT Rate**	0.175%	
5	**Large Corporations Tax (Eliminated in 2006)**	5.7	N/A

1 Large Corporations Tax for Nuclear includes amounts related to the Bruce facilities
2 Includes average fixed asset amount related to the Bruce facilities

Numbers may not add due to rounding.

Table 7
Calculation of Regulatory Income Taxes ($M)
Years Ending December 31, 2007, 2008 and 2009

Line No.	Particulars	2007 Actual	2008 Plan	2009 Plan
		(a)	(b)	(c)
	Determination of Regulatory Taxable Income			
1	**Regulatory Earnings Before Tax**[1]	(84.0)	472.0	504.0
2	**Additions for Tax Purposes:**			
3	**Depreciation**	387.0	408.0	443.0
4	**Nuclear Waste Management Expenses**	79.0	48.0	39.0
5	**Receipts from Nuclear Segregated Funds**	119.0	49.0	54.0
6	**Pension and OPEB/SPP Accrual**	384.0	353.0	337.0
7	**Regulatory Asset Amortization - PARTS Deferred Costs**	95.0	39.0	16.0
8	**Regulatory Asset Amortization - Nuclear Development Deferral Account and Capacity Refurbishment Variance Account**	N/A	8.0	10.0
9	**Regulatory Asset Amortization - Nuclear Liability Deferral Account**	N/A	36.0	48.0
10	**First Nations' Past Grievances Provision**	27.0	0.0	0.0
11	**Adjustment Related to Duplicate Interest Deduction**	34.0	56.0	54.0
12	**Other**	22.0	11.0	12.0
13	**Total Additions**	1,147.0	1,008.0	1,013.0
	Deductions for Tax Purposes:			
14	**CCA**	316.0	311.0	314.0
15	**Cash Expenditures for Nuclear Waste & Decommissioning**	198.0	226.0	193.0
16	**Contributions to Nuclear Segregated Funds**	788.0	454.0	350.0
17	**Pension Plan Contributions**	211.0	233.0	239.0
18	**OPEB/SPP Payments**	58.0	68.0	73.0
19	**Regulatory Asset Amortization - Nuclear Development Deferral Account and Capacity Refurbishment Variance Account**	N/A	7.0	10.0
20	**Regulatory Asset Deduction - Nuclear Liability Deferral Account**	N/A	1.0	1.0
21	**Other**	45.0	17.0	13.0
22	**Total Deductions**	1,616.0	1,317.0	1,193.0
23	**Regulatory Taxable Income/(Loss) Before Loss Carry-Over**	(553.0)	163.0	324.0
24	**Tax Loss Carry-Over to Future Years / (from Prior Years)**[2]	553.0	(163.0)	(324.0)
25	**Regulatory Taxable Income After Loss Carry-Over**	0.0	0.0	0.0
26	**Income Tax Rate**	34.12%	31.50%	31.00%
27	**Total Regulatory Income Taxes**	0.0	0.0	0.0
	Tax Rates:			
28	**Federal Tax**	21.00%	19.50%	19.00%
29	**Federal Surtax**	1.12%	0.00%	0.00%
30	**Provincial Tax**	14.00%	14.00%	14.00%
31	**Manufacturing & Processing Profits Deduction**	-2.00%	-2.00%	-2.00%
32	**Total Income Tax Rate**	34.12%	31.50%	31.00%

1 Reconciliation of regulatory EBT for 2007 to the audited financial statements is presented in Exhibit C1-T2-S1.
2 Refer to Ex. F3-T2-S1 Table 9 for a continuity schedule of regulatory tax losses.

Numbers may not add due to rounding.

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Tab 2
Schedule 1
Table 8

Table 8
Calculation of Regulatory Income Taxes ($M)
Year Ending December 31, 2005 and Year Ending December 31, 2006

Line No.	Particulars	2005 Actual	2006 Actual
		(a)	(b)
	Determination of Regulatory Taxable Income		
1	**Regulatory Earnings Before Tax**[1]	106.0	193.8
2	**Additions for Tax Purposes:**		
3	**Depreciation**	421.0	404.0
4	**Nuclear Waste Management Expenses**	34.0	38.0
5	**Receipts from Nuclear Segregated Funds**	23.0	19.0
6	**Pension and OPEB/SPP Accrual**	234.0	374.0
7	**One-Time Adjustment: P2P3 Inventory Write-offs**	49.0	N/A
8	**One-Time Adjustment: P2P3 CIP Write-offs**	38.0	N/A
9	**Regulatory Asset Amortization - PARTS Deferred Costs**	4.0	25.0
10	**Adjustment Related to Duplicate Interest Deduction**	45.0	38.0
11	**Other**	48.0	20.0
12	**Total Additions**	896.0	918.0
	Deductions for Tax Purposes:		
13	**CCA**	317.0	318.0
14	**Cash Expenditures for Nuclear Waste & Decommissioning**	84.0	153.0
15	**Contributions to Nuclear Segregated Funds**	454.0	454.0
16	**Pension Plan Contributions**	197.9	207.0
17	**OPEB/SPP Payments**	38.0	55.0
18	**Regulatory Asset Deduction - PARTS Deferred Costs**	258.0	13.0
19	**Other**	17.5	13.0
20	**Total Deductions**	1,366.4	1,213.0
21	**Regulatory Taxable Income/(Loss) Before Loss Carry-Over**	(364.4)	(101.2)
22	**Tax Loss Carry-Over to Future Years / (from Prior Years)**[2]	364.4	101.2
23	**Regulatory Taxable Income After Loss Carry-Over**	0.0	0.0
24	**Income Tax Rate**	34.12%	34.12%
25	**Regulatory Income Taxes**	0.0	0.0
	Calculation of Regulatory Income Taxes		
26	**Regulatory Income Taxes** (line 25)	0.0	0.0
27	**Large Corporations Tax - Nuclear** (Ex. F3-T2-S1 Table 6)	5.7	0.0
28	**Large Corporations Tax - Reg. Hydro.** (Ex. F3-T2-S1 Table 3)	7.0	0.0
29	**Total Regulatory Income Taxes**	12.7	0.0
	Tax Rates:		
30	**Federal Tax**	21.00%	21.00%
31	**Federal Surtax**	1.12%	1.12%
32	**Provincial Tax**	14.00%	14.00%
33	**Manufacturing & Processing Profits Deduction**	-2.00%	-2.00%
34	**Total Income Tax Rate**	34.12%	34.12%

1 Reconciliation of regulatory EBT to the audited financial statements is presented in Exhibit C1-T2-S1.
2 Refer to Ex. F3-T2-S1 Table 9 for a continuity schedule of regulatory tax losses.

Numbers may not add due to rounding.

Table 9
Summary of Regulatory Tax Losses ($M)
Years Ending December 31, 2005, 2006, 2007, 2008, 2009

Line No.	Particulars	2005 Actual	2006 Actual	2007 Actual	2008 Plan	2009 Plan
		(a)	(b)	(c)	(d)	(e)
1	**Loss Brought Forward**	N/A	(336.0)	(437.2)	(990.2)	(827.2)
2	**Income/(Loss) for the Year**	(364.4)	(101.2)	(553.0)	163.0	324.0
3	**Allocation to Period Prior to Regulation**[1]	28.4				
4	**Loss Carried Forward**	(336.0)	(437.2)	(990.2)	(827.2)	(503.2)

1 See Ex. F3-T2-S1 for discussion of allocation of 2005 loss to period prior to regulation.

OTHER OPERATING COST ITEMS

1.0 PURPOSE

The purpose of this evidence is to present OPG's other operating cost items. Other operating costs include depreciation expense, income tax, capital tax, commodity tax, and property tax.

2.0 OVERVIEW

Exhibit F3-T2-S1 Tables below present other operating expenses for the prescribed facilities, which are considered separately below.

3.0 DEPRECIATION EXPENSE

Once a constructed or purchased asset is classified as in-service, the related capital expenditures are recorded in an appropriate asset class with an established service life. Capital project expenditures are recorded as fixed assets in the construction in progress account until they are classified as in-service, and are not depreciated. Each asset is assigned a unique asset number.

Approximately 90 percent of OPG's in-service fixed assets are directly associated with specific generation facilities. The net book value of the nuclear and Bruce assets includes costs relating to OPG's fixed asset removal and nuclear waste management liability, as discussed in Ex. H1-T1-S2.

The remaining in-service fixed assets are either directly associated with a business unit, or are held centrally and are used by both regulated and unregulated generation business units. The assets held centrally are not allocated to prescribed facilities; instead the business units (both regulated and unregulated) are charged a service fee for the use of these assets. This charge is reported as an OM&A cost. The explanation of the service fee methodology is provided in Ex. F3-T3-S1.

Depreciation of an asset commences once it is declared to be in-service. OPG uses the group depreciation method where each class of assets is depreciated at an established rate.

This method is typically used by regulated utilities in Ontario. Under this method, ordinarily when an asset within a class is retired, the gross asset value is removed from both the cost of the asset and the related accumulated depreciation. 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.

The assumption underlying the group depreciation method is that assets retired in the normal course are fully depreciated. In the asset group, some assets are retired before the end of their estimated service life, while others are retired after the end of their estimated service lives. Consequently, on average, the entire asset class is assumed to be fully depreciated at retirement.

The depreciation expense also includes expenses relating to nuclear low-level and intermediate-level waste management, as discussed in Ex. H1-T1-S2. Further, any asset removal costs incurred as a result of replacing existing equipment that have not been previously provided for are included in depreciation expense in the period of removal. Removal costs include costs associated with disassembling a component of an asset to gain access to a subcomponent to be repaired or replaced and the cost to reinstall the removed component.

It should be noted that depreciation expense amounts presented in tables accompanying this exhibit, as well as tables accompanying Ex. F3-T2-S2, do not include amortization amounts related to OPG's variance and deferral accounts. Historical and proposed amortization/recovery amounts are presented and discussed in Exhibit J.

Depreciation rates for the various classes of in-service fixed assets are based on their estimated service lives. Service lives are established by the technical and engineering personnel of the business unit that manage the fixed assets. The business units rely primarily on technical assessments based on their operating experience. Fixed assets are depreciated on a straight-line basis except for computers and transport and work equipment, which are depreciated on a declining balance basis due to the nature of these assets. The service life of an asset class is limited by the service life of the station(s) to which it relates. The following provides a summary of the average service lives and depreciation rates of the fixed assets of OPG's regulated business, which are used to determine the depreciation expense for OPG's proposed test period revenue requirement:

Nuclear generating stations and major components[1]	15 to 49 years
Hydroelectric generating stations and major components	25 to 100 years
Administration and service facilities	10 to 50 years
Computers, and transport and work equipment assets – declining balance	9% to 40% per year
Major application software	5 years
Service equipment	5 to 10 years

[1] Excludes the Bruce Generating Stations

The depreciation expense associated with the Bruce facilities is presented separately in Ex. G2-T2-S1.

As part of its due diligence on the service lives of fixed assets and ultimately the calculation of depreciation expense, OPG convenes an internal Depreciation Review Committee ("DRC"). The DRC is accountable for providing a formal engineering, technical, and financial review of fixed asset service lives. The DRC conducts a review of the service lives of generating stations and a selection of asset classes every year, with the objective of reviewing all significant asset classes over a five-year cycle.

The DRC is comprised of representatives from each of the business units with operational expertise as well as staff from finance and regulatory affairs functions. The engineering and technical review of the service lives is based on a variety of sources (depending on the asset class or facility in question), including operational experience of the business units, lifecycle planning and condition assessment data for major facilities, as well as benchmarking data (where available). In addition to the engineering and technical review of the fixed assets, the DRC is also accountable for assessing the impact of other external factors on station service lives, such as the impact of government policy or legislation. The Committee's scope and recommendations are submitted for approval to the Chief Operating Officer, Chief Financial

Officer, Executive Vice Presidents of Nuclear, Hydroelectric, and Fossil business units and the Senior Vice President, Corporate Affairs (the "Approvals Committee") for approval. Approved DRC recommendations on depreciation are implemented on January 1 of the year following the year of review unless otherwise required.

The focus of the 2007 DRC review was the overall life of each station. This review was to be completed by assessing the service lives of the asset classes that have a significant impact on each station's end of life date, as well as other factors that may affect station lives. These significant asset classes are referred to as the "life limiting components".

The 2007 DRC recommended extensions to the estimated service lives of the Bruce A and B Generating Stations to 2014 from 2012 and to 2035 from 2030, respectively. These changes have been incorporated into OPG's proposed revenue requirement and for accounting purposes effective January 1, 2008. The extension of the Bruce A service life was based on information contained in the Ontario Power Authority's 2007 Integrated Power System Plan and Bruce Power L.P.'s public announcement in August 2007 of its intention to refurbish Unit 4 of the station. The extension of the Bruce B service life was similarly based on data from the Integrated Power System Plan and OPG's earlier technical knowledge of the state of life-limiting components of the station. The 2007 DRC also recommended the extension of the estimated service life of the Darlington Generating Station to 2019 from 2017 based on an engineering assessment of the expected lives of pressure tubes at the station and planned capability factors. The extensions to the lives of the Bruce A, Bruce B and Darlington Generating Stations decreases OPG's annual depreciation expense by approximately $8M for Bruce A, $7M for Bruce B and $18M for Darlington.

The 2007 DRC concluded that the current estimated service lives of regulated hydroelectric stations are appropriate based on a technical assessment of their dams, which are the relevant life limiting components. The recommendations of the 2007 DRC were accepted by the Approvals Committee. A copy of the 2007 Depreciation Review Committee report is provided in Appendix B.

Previously, in 2006, the DRC recommended the extension of the estimated service life of the Bruce B Generating Station to 2012 from 2010, which was implemented for accounting purposes effective January 1, 2007. The DRC recommended the life extension based on then-current discussion papers released by the Ontario Power Authority relating to the integrated power system plan. This change decreased OPG's depreciation expense related to the Bruce facilities by approximately $14M/year. The impact of other recommendations by the 2006 DRC on depreciation expense associated with regulated operations was not material. A redacted copy of the 2006 Depreciation Review Committee report is provided in Appendix A. OPG has redacted information with respect to OPG's unregulated fossil operations. The report was approved by OPG's business unit leaders and the Chief Financial Officer.

Prior to the DRC convening in 2006, the estimated service life of the Pickering B Generating Station was extended to 2014 from 2009 effective January 1, 2006, following an engineering assessment of the major components of the station and taking into account recent station capacity factors. This change resulted in an annual decrease in depreciation expense of approximately $36M. OPG also extended the life of Pickering A Unit 4 to 2021 from 2017 in the fourth quarter in 2005, following the return to service of Pickering A Unit 1. The extension was largely based on the fact that Pickering A would be operating as a two-unit station following the return to service of the refurbished Unit 1 and the decision by OPG's Board of Directors not to proceed with the planned refurbishments of Units 2 and 3. The impact of this change was a decrease in depreciation expense of approximately $16M annually.

In anticipation of regulation by the OEB, OPG retained Gannett Fleming Inc. ("Gannett Fleming"), an external consultant with in-depth experience in the area of depreciation for rate regulation purposes, to review the adequacy of OPG's depreciation review process based on the 2006 DRC process. See Exhibit F4-T2-S1 for a copy of the full report. In its report, Gannett Fleming concluded that the

> "processes, procedures and methods used by the DRC as part of OPG's Depreciation Review Process are sufficient to address generally accepted depreciation objectives for rate regulated companies. Additionally, OPG's current practices should result in a reasonable determination of average service lives and a reasonable and appropriate

amount of depreciation expense to be included in OPG's revenue requirement request." (Part I, page 2)

In assessing OPG's depreciation review process, Gannett Fleming developed a set of six generally accepted regulatory objectives related to depreciation. These objectives are based on their experience with North American utilities and consist of: effectiveness, efficiency, transparency and understandability, intergenerational equity, capital attraction, and independence from bias. Based on a review of OPG's policies and procedures related to depreciation, a review of working papers supporting service life estimates, and interviews with OPG staff involved in depreciation accounting and estimating service lives, Gannett Fleming concluded that OPG's processes meet the required regulatory objectives. As part of this engagement, OPG also requested that Gannett Fleming provide recommendations for improvements. Recommendations were provided in the following two areas: (1) independence from bias and (2) transparency and understandability. OPG has addressed aspects of these recommendations in the 2007 DRC process, as explained below, and will address the remaining recommendations as part of the 2008 DRC process.

Gannett Fleming noted that they did not observe any bias in OPG's existing process. However, in order to eliminate any potential perception of bias in a regulatory forum, Gannett Fleming recommended that OPG implement a Depreciation Approvals Committee or a similar internal governance structure that would oversee and approve the work of the DRC. Essentially, such a structure already exists within OPG, as the DRC's recommendations are approved by the heads of each OPG business unit. In order to fully address this recommendation, in 2007 OPG expanded the role of the heads of the business units from approving the service life estimates developed by the DRC to also approving the process and methods that are used by the DRC to select assets for review and to assess their service life indicators. As well, starting in 2007, the business unit leaders have become responsible for formally nominating representatives from their business units to the DRC. This expanded role incorporates Gannett Fleming's recommendations relating to approving asset selection criteria and providing direction to the DRC regarding the type of work that should be performed to estimate service lives.

Gannett Fleming also recommended increased use of benchmarking of certain asset service lives as an additional means of ensuring the impartiality of the DRC process. In 2008, OPG will consider benchmarking the service lives of its hydroelectric assets and certain components of its nuclear facilities for which meaningful comparison data can be obtained.

The second recommendation relates to transparency and understandability of the DRC report in a regulatory forum. The 2006 DRC report that Gannett Fleming reviewed focused on documenting the results of the DRC and provided limited information on asset selection criteria or depreciation policies and procedures. In order to address Gannett Fleming's recommendation in this area, OPG intends to document the asset selection criteria in its subsequent DRC reports in greater detail and has also documented relevant depreciation policies and procedures as part of this exhibit.

4.0 REGULATORY INCOME TAXES

General Requirements

Under the *Electricity Act, 1998,* OPG is required to make payments in lieu of corporate income and capital taxes to the Ontario Electricity Financial Corporation and to file federal and provincial income tax returns with the Ontario Ministry of Finance. The tax payments are calculated in accordance with the *Income Tax Act* (Canada) and the *Corporations Tax Act* (Ontario), and are modified by the *Electricity Act, 1998* and related regulations. This effectively results in OPG paying taxes similar to what would be imposed under federal and Ontario tax legislation.

Accounting Methodology

Prior to rate regulation, OPG utilized the liability method of accounting for income taxes and recorded both current and future income tax expense in accordance with Generally Accepted Accounting Principles. When OPG became subject to rate regulation on April 1, 2005, the taxes payable method of accounting for income taxes was adopted for the regulated operations in accordance with Generally Accepted Accounting Principles. This method was adopted because it is the method approved by the OEB for determining the tax allowance in the rates for regulated gas utilities and is specified in the Electricity Distributors Rate Handbook. Under the taxes payable method of accounting for income tax, only the current tax expense is recorded in the financial statements; future taxes are not recorded to the extent that they are recovered or refunded through regulated payment amounts.

In late 2007, the Canadian Institute of Chartered Accountants introduced certain changes to Generally Accepted Accounting Principles that will be effective on January 1, 2009. These changes will require all rate regulated entities to use the liability method of accounting for income taxes and, therefore, record future tax expense in the financial statements. In accordance with these changes to Generally Accepted Accounting Principles, OPG expects to record a regulatory asset or liability for the amount of future income taxes expected to be recovered or refunded through regulated payment amounts. Consistent with the use of the taxes payable method approved by the OEB for other regulated utilities (as noted above), OPG has not incorporated future tax expense into its revenue requirement.

Regulatory Income Taxes – Current Tax Expense

For purposes of establishing regulated payment amounts, OPG seeks recovery of current income tax expense only. The regulatory income taxes are determined by applying the statutory tax rate to regulatory taxable income of the combined nuclear and regulated hydroelectric operations as well as taxable income associated with the Bruce facilities. These income taxes are then allocated to nuclear (including the Bruce facilities) and regulated hydroelectric operations based on each business's regulatory taxable income. This approach reduces the total taxes included in the revenue requirement because if there is a tax loss in one regulated business unit, it reduces the tax expense in the other regulated business unit.

Regulatory taxable income is computed by making adjustments to the regulatory earnings before tax for items with different accounting and tax treatment, applying the same principles as used for the calculation of actual income taxes under applicable legislation as well as regulatory principles. The most significant adjustments, as detailed in the calculation of taxable income/loss for the period 2005 - 2009 in Tables 7 and 8 accompanying this exhibit, are as follows:

1. Depreciation/Capital Cost Allowance– Accounting depreciation expense is not deductible for tax purposes, however tax depreciation (i.e., capital cost allowance) is deductible. The capital cost allowance deduction for 2005 and subsequent years has been reduced to reflect the impact of adjustments resulting from an ongoing income tax audit of OPG by the Provincial Tax Auditors (the "Tax Auditors").
2. Nuclear Waste Management Expenses – OPG is responsible for decommissioning its nuclear stations and nuclear used fuel and low-level and intermediate-level waste management (collectively, the "Nuclear Liabilities") as described in Ex. H1-T1-S1. Expenses accrued relating to this obligation are not deductible for tax purposes.
3. Cash Expenditures for Nuclear Waste and Decommissioning – Cash expenditures incurred and charged against the Nuclear Liabilities are deductible for tax purposes.
4. Segregated Fund Contributions and Receipts – OPG is required under the Ontario Nuclear Fuel Act to make contributions to segregated funds to enable it to meet its obligations for the Nuclear Liabilities, as described in Ex. H1-T1-S1. *The Electricity Act, 1998* allows OPG a tax deduction when the contributions are made. When OPG receives monies from the funds for reimbursement of eligible expenditures, the amount received is taxable.
5. Adjustment Related to Duplicate Interest Deduction – This adjustment removes a portion of interest related to OPG's Nuclear Liabilities since this interest is included in both OPG's tax deduction for segregated nuclear fund contributions and the tax deduction associated with the deemed interest expenses financing OPG's rate base. The adjustment is determined based on the debt ratio and cost of debt from Ex. C1-T2-S1, and an assessment of the portion of OPG's rate base related to the Nuclear Liabilities.
6. Pension/Other Post-Employment Benefits – Pension and other post-employment benefits expenses recorded by OPG for accounting purposes (as discussed in Ex. F3-S4-T1) are not deductible for tax purposes. However, cash contributions to the registered pension plan, as well as OPEB and the supplementary pension plan payments are deductible for tax purposes.
7. Regulatory Assets and Liabilities – Certain expenditures recorded by OPG as regulatory assets for accounting purposes are considered to be operating expenses for tax

purposes and can be deducted in the year incurred. These expenses are recovered from ratepayers in future test periods in accordance with the direction provided by the OEB and the benefit of the tax deduction is recognized in the year these expenses are recovered (and recorded as amortization expense for accounting purposes). For instance, tax deductible costs incurred to increase the output of, refurbish or add operating capacity to a generation facility are recorded as a regulatory asset for accounting purposes and are not deducted as an operating expense as part of the calculation of the regulatory taxable income during the historical and bridge periods. Amounts recorded in the Nuclear Development Deferral Account and the Capacity Refurbishment Variance Account will be deducted for regulatory taxable income purposes during the test period based on the recovery amount/methodology approved by the OEB.

As an exception to the above principle, Pickering A return to service ("PARTS") expenses recorded by OPG as a regulatory asset in the PARTS deferral account described in Ex. J1-T1-S1 were deducted as an operating expense in the calculation of the regulatory taxable income in the year the expenses were actually incurred. Therefore, the amortization of the PARTS regulatory asset is added back for the purposes of calculating the regulatory taxable income, as the ratepayers will receive the tax benefit associated with these deferred costs through the application of the tax loss carry forward balance (discussed below) during the test period.

8. First Nations' Past Grievances Provision – Expenses recorded by OPG for accounting purposes as provisions for anticipated future expenditures are not deductible for tax purposes. Refer to Ex. F1-T2-S2 for a discussion of the First Nations' Past Grievances Provision.
9. Other – This category includes various miscellaneous tax adjustments such as the accrual for materials obsolescence, capital items that are expensed for accounting purposes, and meals and entertainment expenses that are subject to the 50 percent tax deduction limitation.
10. One Time Adjustments – Costs representing the impairment of inventory and construction in progress assets in 2005 as a result of OPG's decision not to proceed with

the return to service of Pickering A Units 2 and 3 were not recovered from the ratepayers. Consequently, the related amount deductible by OPG for tax purposes is added back in order to calculate the regulatory taxable income in 2005.

The regulatory taxable income calculation for the years 2005 - 2007 results in tax losses for those years, as shown in Ex. F3-T2-S1 Tables 7, 8 and 9. The actual cumulative tax losses at the end of 2007 that are available to be carried forward are $990.2M. These tax losses were generated mainly due to OPG's contributions to segregated funds, which are deductible for tax purposes under the *Electricity Act, 1998* and regulations there-under. OPG made annual contributions of $454M in 2005 - 2007 as well as a one-time additional payment of $334M in 2007 in accordance with the Ontario Nuclear Funds Agreement. This one-time payment was previously forecast to occur in the first quarter of 2008. (Refer to Ex. G2-T2-S1 for further detail on this payment.) In 2005, the $258M in PARTS expenses recorded as a regulatory asset were also deducted for tax purposes, as allowed under the *Income Tax Act* (Canada) contributing to a tax loss in that year. In 2007, OPG's negative earnings before taxes contributed to the tax loss in that year. OPG has forecasted higher regulatory earnings before tax for the test period and, accordingly, taxable income of $163.0M and $324.0M in 2008 and 2009, respectively. Table 9 accompanying this exhibit presents a continuity schedule of OPG's regulatory taxable income/losses.

Since OPG became subject to regulation on April 1, 2005, the annual regulatory tax loss for 2005 calculated as $364.4M in Ex. F3-T2-S1 Table 8 should be adjusted to remove the portion of the loss attributable to the period prior to regulation. The adjustment is based on a straight-line pro-ration with the exception of the loss resulting from the PARTS deferred costs deduction. The ratepayers receive the benefit of the full PARTS deferred costs deduction as O. Reg. 53/05 requires OPG to recover the full amount of these costs. The amount of the adjustment is a reduction to the loss of $28.4M, as reflected in Ex. F3-T2-S1 Table 9.

Typically, if a net tax loss arises in a particular year, it is carried forward to reduce regulatory taxable income in future years. OPG has applied its projected total cumulative tax losses at the end of 2007 to reduce the projected regulatory taxable income in 2008 and 2009 of

$163.0M and $324.0M, respectively, to nil. In this application, the projected tax losses are also used to mitigate the customer bill impact of OPG's payment amount and deferral/variance account recovery proposals. This mitigation proposal is described in Exhibit K.

Income Tax Audit

OPG is currently being audited by the Tax Auditors for the 1999 taxation year. In 2006 and 2008, OPG received preliminary communications from the Tax Auditors with respect to their initial findings from their audit of OPG's 1999 taxation year. Many of the issues raised through the audit are unique to OPG and relate either to start-up matters and positions taken on April 1, 1999 upon commencement of OPG's operations, or matters that were not addressed through the *Electricity Act, 1998*. Although OPG has resolved some of these issues, there is uncertainty as to the resolution of the remaining issues. OPG expects to receive a reassessment for its 1999 taxation year. Although this reassessment would relate to the 1999 taxation year, the potential impact of the reassessment could be to materially increase income taxes for the 2005 - 2009 period and subsequent years, and therefore reduce tax losses.

Regulatory Income Taxes – Large Corporations Tax

OPG was subject to the large corporations tax until it was eliminated by the federal government effective 2006. For the historical year 2005, large corporations tax was calculated by applying the applicable rate to the rate base in excess of the full large corporations tax exemption. The full exemption was attributed to regulated operations as part of the calculation, consistent with the determination of regulatory income taxes on a stand-alone basis. The calculation of large corporations tax presented in Tables 3 and 6 accompanying this exhibit includes an amount related to the Bruce facilities.

Ontario Corporate Minimum Tax

Ontario corporate minimum tax ("OCMT") is designed to impose a minimum tax based on financial statement income calculated without most tax adjustments. The OCMT paid in a year can be applied to reduce taxes payable in future years. The OCMT rate is substantially lower than the general Ontario corporate tax rate and is only payable when there are little or no Ontario taxes payable. Generally, OCMT is calculated as four percent of accounting income less 12 percent of taxable income. To the extent OPG forecasts a tax loss for a particular test year, OPG determines an OCMT amount for its regulated operations. OPG expects that it will be able to apply OCMT determined for its regulated operations to reduce regulatory income taxes in the near future. To mitigate the customer impact of OPG's proposed revenue requirement and to provide a measure of payment stability, OPG does not propose to recover OCMT in its revenue requirement. OPG notes that excluding OCMT from the revenue requirement is consistent with the guidance provided by the OEB in the Electricity Distributors Rate Handbook.

5.0 ONTARIO CAPITAL TAX

OPG is subject to the Ontario capital tax at the applicable rate on its taxable capital subject to the general capital tax deduction. For regulatory purposes, the rate base in excess of the general capital tax deduction is used as a proxy for the taxable capital used as the base for calculating Ontario capital tax. The full capital tax deduction was attributed to regulated operations, consistent with the determination of regulatory income taxes on a stand-alone basis. The applicable Ontario capital tax rates are scheduled to decrease from 0.300 percent to 0.225 percent in 2007, 2008 and 2009. The amount of Ontario capital tax included in the revenue requirement may therefore vary year-over-year as a result of changes in rate base and applicable rates. The Ontario capital tax is currently scheduled to be eliminated effective July 1, 2010.

The calculation of Ontario capital tax associated with nuclear and regulated hydroelectric business units is presented in Tables 2 and 5 accompanying this exhibit, respectively. Ontario capital tax associated with the Bruce facilities is presented separately in Ex. G2-T2-S1.

6.0 COMMODITY TAX

Goods purchased by OPG are subject to the eight percent retail sales tax (provincial sales tax) levied under the *Retail Sales Tax Act* (Ontario), except for purchases of machinery and equipment used directly in the generation of electricity which are exempt under section 7 (1) (40) of the Act. Provincial sales tax is also payable on certain information technology services, printing and parking, and OPG is required to self assess the tax and remit it. Provincial sales tax forms part of the expenditure of the underlying item (OM&A, capital, inventory, etc.) except for the self-assessment amounts which are primarily recorded as a centrally-held cost, as discussed in Ex. F3-T1-S1.

OPG is subject to the five percent goods and services tax levied under Part IX of the *Excise Tax Act* (Canada) on all goods and services purchased. While the goods and services tax is recoverable by claiming input tax credits on returns filed monthly, goods and services tax is included in the cash working capital component of the rate base, as noted in the Lead/Lag Study in Ex. B4-T1-S1.

Where applicable, OPG pays duty under the *Customs Act (*Canada) on goods imported into Canada; however, currently most of these imports are either exempt or have duty free status through the North American Free Trade Agreement. For supply and installation contracts, the contractor's price includes duty, if applicable, on the goods imported to perform the work. Any duty paid forms part of the expenditure on the underlying item (OM&A, capital, inventory, etc.).

7.0 PROPERTY TAX

OPG is responsible for both the payment of municipal property taxes and a payment in lieu of property tax to the Province of Ontario. The total of these two property tax payments is intended to represent what a commercial generating company would pay as property tax on OPG's assets based on full current value assessment, and represents OPG's property tax expense.

<u>Municipal Property Taxes</u>

Municipal property taxes are regulated under the *Assessment Act, 1990* and are levied on OPG owned generation lands and buildings. For certain generating assets the *Act* prescribes the basis for assessment of the municipal property taxes. Municipal property taxes are made to about 100 municipalities each year by OPG. This rate application presents municipal property taxes for prescribed nuclear and hydroelectric lands and buildings owned and operated by OPG.

The Municipal Property Assessment Corporation issues notices of assessments annually, which are reviewed by OPG staff for accurate valuation and tax classification issues. Any incorrect classes and under/overvaluations are appealed through the Assessment Review Board.

OPG pays municipal property tax related to certain properties, which are not directly associated with specific generation business units and are held centrally. These properties primarily include OPG's Head Office and certain other properties located in the vicinity of Toronto, Ontario. Regulated generation business units are charged a service fee for the use of assets that are centrally held. Municipal property taxes incurred by OPG for the centrally held properties form part of that fee as discussed in Ex. F3-T3-S1.

<u>Payment in Lieu of Property Tax</u>

Payment in lieu of property tax is regulated through O. Reg. 224/00 under the *Electricity Act, 1998* and is paid to the Province of Ontario through the Ontario Electricity Financial Corporation. According to O. Reg. 224/00 the payment in lieu of property tax represents taxes based on the difference between current value assessment and the prescribed municipal assessment for certain generating assets.

The assessment basis under O. Reg. 224/00 has not been updated since 1999. Consequently, the current value assessment amounts used for payment in lieu calculations and the payments in lieu amounts themselves are out of date. The Province has indicated that they intend at some point to update the assessment values in O. Reg. 224/00 and make it retroactive to 1999. This would result in retroactive increases in the payments in lieu of property tax for OPG.

Property Taxes on Nuclear and Bruce Assets

For property assessment/taxation purposes, nuclear generating stations (including Bruce facilities) lands contain buildings that are classified as "generating" (e.g., buildings that are used in, or auxiliary to, the generating process, such as power house, water treatment plant, pump houses, etc) and "non-generating" (e.g., administration/office buildings). Municipal property tax payments to municipalities are paid based on a statutory assessment rate of \$86.11 per square meter, per the *Assessment Act, 1990* for "generating" buildings, and at current value assessment, which is the valuation method used for other property owners in the province, for "non-generating" buildings. For "generating" buildings, OPG is also subject to making payments in lieu of property tax, as described above, based on the difference between current value assessment and the prescribed municipal assessment rate of \$86.11 per square meter.

In establishing its budgets for the historical and bridge years OPG assumed that the update to O. Reg. 224/00 will occur in the budget year, resulting in the budgeting of higher payments in lieu than have actually occurred. The budgets for the test period (2008 and 2009) for nuclear generation stations (including Bruce facilities) do not assume that the regulation will be updated during the test period. OPG proposes to record the financial impact of property tax changes for OPG's regulated facilities resulting from an update to O. Reg. 224/00 or related regulations in its proposed Changes in Tax Rates, Rules, and Assessments variance account as described in Ex. J1-T3-S1. Property taxes associated with the Bruce facilities are presented in separately Ex. G2-T2-S1.

Property Taxes on Hydroelectric Assets

OPG does not make payments in lieu of property tax on hydroelectric facility stations, dams and upstream/downstream properties; instead, OPG pays a gross revenue charge under section 92.1 of the *Electricity Act, 1998*. Refer to Ex. F1-T4-S1 for discussion of the gross revenue charge. For those hydroelectric properties that are not associated with a generating station or dam site, OPG pays municipal property tax under the *Assessment Act, 1990* at current value assessment. For the prescribed hydroelectric facilities, municipal property taxes are only payable for its district office at DeCew. DeCew municipal property taxes are approximately $19,000/year.

LIST OF ATTACHMENTS

ONTARIOPOWER GENERATION

DEPRECIATION REVIEW COMMITTEE RECOMMENDATIONS

December 2006

Depreciation Review Committee Recommendations
EXECUTIVE SUMMARY

In 2006, the Depreciation Review Committee (DRC) was mandated to assess asset service lives and quantify the financial impacts of any proposed changes.

Scope of Review:

1. The DRC makes recommendations with respect to estimated service lives for major fixed assets. The recommendations in this report have been reviewed and endorsed by Senior Management having custody of the assets. The recommendations contained herein are proposed for implementation on January 1, 2007, except as noted.

2. The 2006 DRC selected asset classes which covered approximately $4.2 billion or 42 percent of the total net book value of OPG's major fixed assets as at February 1, 2006.

Summary of DRC Asset Coverage	Net Book Value M$
Nuclear	1,200
Hydroelectric	2,800
Fossil	-
Corporate – Administration and Service Communications	200
Subtotal	4,200
Less: Asset Classes Deferred to Next DRC Review	(80)
Total	**4,120**

3. The review of average service lives for major fixed assets is based mainly on operating experience and engineering judgment. This review resulted in no change to average service lives, except as noted below.

4. The depreciation service life of the Darlington generating station remains at 25 years.

5. Bruce B service life has been extended by 2 years to 2012.

6. Recent developments with respect to the service lives of OPG's nuclear and fossil stations have resulted in changes to depreciation service lives and are documented below and included in this report.

7. A review of minor fixed assets was not performed at this time but will be considered for the next review cycle.

Developments Occurring Outside the DRC Process:

Nuclear:

The service lives of the nuclear stations were established on April 1, 1999 based on the known predicted life limiting component at each plant. The predicted service lives resulted in establishing the depreciation life at Pickering B and Darlington units at 25 years and Pickering A at 40 years. Pickering A extended life was primarily a result of replacement of the pressure tubes on all four units in the early 1990's.

As a result of the work to return Pickering A to service and assessment work on the condition of Pickering B units, changes to the service lives of these stations were approved by senior management. The DRC convened after these decisions were approved and the changes are documented in this report. The changes made to the service lives of the nuclear stations are as follows:

- Pickering A Unit 4 was refurbished and returned to service in 2003. The depreciation service life was extended to 2017, effective January 1, 2004, based on the assumption of the unit running as a one unit station. With the completion of the return to service of Unit 1 in November 2005, the service lives of the two units at Pickering A were revised to 2021. The impact for 2006 was an increase in depreciation of $6M. This is made up of an increase in depreciation of $22M from the in service of Pickering A Unit 1, offset by a decrease in depreciation of $16M from the life extension of Pickering A Unit 4 from 2017 to 2021.

- Based on a recent assessment at of the condition of the major components at Pickering B the service life was extended to 2014 for depreciation purposes effective January 1, 2006. The depreciation impact of this change is a decrease of $37M annually.

Fossil:
The service lives of the coal-fired plants, of 2007 and 2008, for first half of 2006 was based on [redacted]

<u>Summary of Station Life Changes Occurring Outside the DRC Process</u>

Stations	Service Life at April 1, 1999	Effective Date of Depreciation Change	Revised Average End of Life (December)	Estimated Annual Impacts $M increase/ (decrease)
Pickering A Unit 1	Dec 2012	Nov 2005*	2021	22
Pickering A Unit 4	Dec 2012	Jan 2004** Nov 2005**	2017 2021	(20) (16)
Pickering B	Sept 2009	Jan 2006	2014 ***	(37)
Coal-fired Generating Stations	See Table 3.2.1	[redacted]	[redacted]	[redacted]

* From 1999 until November 2005, Pickering A Unit 1 was out of service
** From 1999 until October 2003, Pickering A Unit 4 was out of service
*** September

<u>2006 DRC Recommendations:</u>

Nuclear Facilities

- Bruce B service life has been extended by 2 years to 2012.
- More in depth review of nuclear process systems asset class to be conducted in next DRC;
- More in depth review of major fixed asset classes that will last for the life of the plant, such as process systems, fuel channel assemblies, calandria tubes, moderator heat exchange, etc., to be conducted in the next DRC; and
- For asset classes relating to the Pickering plant with individual service lives less than the current service life of 2021, do not extend the service life to the current date. This recommendation is made on the basis of an immaterial dollar impact, and as such not making the change will save administrative time and effort.

Hydroelectric Facilities

- Service life for public safety booms asset class should be decreased to 15 years from 75 years. The dollar impact on depreciation expense is minimal.

Corporate Administrative and Services Assets

- On reviewing the service life of 700 University Avenue and administrative system software, no change in service life is required.

<u>Recommendations for future DRC includes:</u>

General

- Obtain input from line of business asset management and condition assessment groups through existing members of DRC;
- Investigate possibility of benchmarking of OPG's DRC process against similar processes followed by other companies;
- Provide advance notice of future DRC schedule;
- Consider findings from depreciation process review performed by Gannett Fleming Inc; and
- Review minor fixed assets

Nuclear

- Review plant condition assessment reports and ensure recommendations are consistent;
- Review nuclear assets intended to last the life of the plant such as process systems, to assess if assumptions are still valid;
- Consider reassessment of Darlington; and

Hydroelectric

- Review specific asset class recommendations which relate to how these assets are organized in the fixed asset sub-ledger.

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1.0 INTRODUCTION

1.1 Work of the Depreciation Review Committee

The Depreciation Review Committee (DRC) is accountable for providing a formal engineering, technical and financial review of major and minor fixed asset service lives. The DRC periodically reviews the service lives of all major facilities and a selection of asset classes, with the objective of reviewing significant and new asset classes over a regular cycle.

In order to fulfill its objective of providing an engineering and technical review of the service lives of OPG fixed assets, it is important for the DRC to have representatives of the various lines of business who have good knowledge and expertise of the day to day operations of each of the various OPG plants. As such, senior management of each of the lines of business are consulted to ensure that the appropriate technical and engineering staff are selected for the DRC. In addition to the technical and engineering review of the fixed assets, the DRC is also accountable for assessing the financial impact of any changes to service lives that it recommends. This is particularly important in the area of depreciation expense and its impact on OPG's corporate financial statements, as well as budgets and forecasts. As such, financial staff is required for the DRC, particularly those involved with the calculation and analysis of depreciation expense and those involved in the preparation and analysis of OPG's financial statements, budgets and forecasts.

The 2006 DRC included representatives from Nuclear, Hydroelectric, and Corporate Functions who have custody of major fixed assets and understand and have experience related to how the assets are operated, as well as representatives from finance. In addition, since a portion of OPG's business is now regulated, representatives from Regulatory Affairs and Regulatory Finance were on the 2006 DRC.

DRC recommendations are documented in the DRC report, which is reviewed by DRC representatives and receives the concurrence of Senior Management. The goal, functions and structure of the Committee are outlined in detail in Appendix A.

The Committee's recommendations are submitted to the Chief Financial Officer for approval and implementation. Approved DRC recommendations are generally implemented on January 1st of the year following the year of review.

1.2 Scope of the Review for 2006

The Depreciation Review Committee's deliberations for 2006 focused primarily on the review of the following:

- The DRC makes recommendations with respect to estimated service lives for major fixed assets. The recommendations in this report have been reviewed and endorsed by Senior Management having custody of the assets. The recommendations contained herein are proposed for implementation on January 1, 2007, except as noted.

- The 2006 DRC selected asset classes which covered approximately $4.2 billion or 42 percent of the total net book value of OPG's major fixed assets as at February 1, 2006.

A summary of the DRC Asset Coverage is shown in the Table below 1.2 below.

Table 1.2
Summary of DRC Asset Coverage

	Net Book Value M $
Nuclear	1,200
Hydroelectric	2,800
Fossil	-
Corporate - Admin & Service and Communications	200
Sub-total	4,200
Less: Asset Classes Deferred to Next DRC Review	(80)
Total	**4,120**

- The review of average service lives for all major fixed assets is based mainly on operating experience and engineering judgment. This review resulted in no change to average service lives, except as noted below;

- The depreciation service life of the Darlington generating station remains at 25 years;

- Bruce B service life has been extended to 2012. The two year extension was the result of discussion papers released by the Ontario Power Authority and is consistent with the assumptions used by Nuclear Waste Management Division in the estimate of the future costs of retiring Bruce B assets; and

- Recent developments with respect to the service lives of OPG's nuclear and fossil stations have resulted in changes to depreciation service lives and are documented below and included in this report.

1.2.1 Developments Occurring Outside the DRC Process and Background Information

Nuclear:
The service lives of the nuclear stations were established on April 1, 1999 based on the known predicted life limiting component at each plant. The predicted service lives resulted in establishing the depreciation life at Pickering B and Darlington Units at 25 years and Pickering A at 40 years. Pickering A extended life was primarily a result of replacement of the pressure tubes on all four Units in the early 1990's.

As a result of the work to return Pickering A to service and assessment work on the condition of Pickering B units, changes to the service lives of these stations were approved by senior management. The DRC convened after these decisions were approved. The changes made to the service lives of the nuclear stations are as follows:

- Pickering A Unit 4 was refurbished and returned to service in 2003. The depreciation service life was extended to 2017 based on the assumption of the unit running as a one unit station. With the completion of the return to service of unit 1 in November 2005, the service lives of the two units at Pickering A was revised to 2021. The impact for 2006 was an increase in depreciation of $6M. This is made up of an increase in depreciation of $22M from the in service of Pickering A Unit 1, offset by a decrease in depreciation of $16M from the life extension of Pickering A Unit 4 from 2017 to 2021;

- In 2006, nuclear senior management approved a change to the Pickering B station's service life from 2009 to 2014, based on an assessment last year on the condition of major components. This is expected to reduce depreciation expense by approximately $37M per year;

- A reassessment of Darlington has not been completed as part of this DRC, and will be considered at a future date; and

Fossil:
The service lives of the coal-fired plants of 2007 and 2008 for first half of 2006 was based on [redacted]

A summary of the station life changes due to developments occurring outside the DRC process is shown in the Table below 1.2.1 below.

Table 1.2.1
Summary of Station Life Changes
Developments Occurring Outside the DRC Process

Stations	Revised Average End of Life (December)	Estimated Annual Impacts $M increase/ (decrease)
Pickering A Unit 1	2021	22
Pickering A Unit 4	2021	(36)
Pickering B	2014*	(37)
Coal-fired Generating Stations	[redacted]	[redacted]

* September

1.3 ASSET CLASS SELECTION CRITERIA

The DRC's process for the selection of assets for service life review is as follows:

1. Corporate Accounting members of the DRC made an initial selection based on high dollar value asset classes and asset classes that have undergone changes in their business environment;

2. The initial asset selection by Corporate Accounting was reviewed by all DRC members at the first meeting;

3. Business unit members of the DRC were asked to identify additional selections based on their knowledge of plant operating experience;

4. The assets selected for review were finalized and approved by all members of the DRC based on the Corporate Accounting's initial recommendations and input from business unit members; and

5. Not all components were covered from the classes selected. Some classes were noted for further assessment as part of future DRC.

1.3.1 Results of Initial Asset Class Selection

- The results of the initial asset class selection based on dollar value are summarized in Table 1.3.1 below.

Table 1.3.1
Results of Initial Asset Class Selection

Asset Class #	Asset Class Description	NBV $M	Life
15200	Buildings and Structures	376	50
15340	Process Systems	350	40
15450	Condenser Tubing Pickering	104	30
15600	Instrumentation and Control	301	30
10200	Substructures and Super-substructures	1,434	100
10301	Lining of Tunnels and Permanent Shafts	244	75
10318	Gates, Stoplogs and Operating Mechanisms	346	50
10501	Main Rotating Electrical Plant – Mach less Windings	256	75
16210	Permanent Buildings, Roads and Site Improvements	137	50
16560	Administrative System Software	84	5

- Two Corporate asset classes selected for review have undergone changes in their business environment. In September 2005, the super asset in asset class 16210 (700 University Ave. building), was transferred from a capital lease to OPG owned. Asset class 16560 (Systems software – Energy Markets) was selected because market structure changes have meant that OPG has substantially reduced its electricity trading business. As such, it was felt that the changed business circumstances surrounding both these asset classes, warranted DRC review.

- A review of minor fixed assets was not done at this time but will be considered for the next review cycle.

1.3.2 Results of Final Asset Class Selection

- The initial asset classes recommended by Corporate Accounting were accepted by the DRC.
- Nuclear members of the DRC did not recommend any additional asset classes for review.
- Hydroelectric members of the DRC recommended the additional asset classes for review which are summarized in Table 1.3.2 below.

Table 1.3.1
Results of Additional Asset Class Selection

Asset Class #	Asset Class Description	NBV $M	Life
10302	Spillways, Sluices, Flumes	95	75
10502	Bus, Switching and Power Cable	89	45
10503	High Voltage Switching	20	40
10504	Control Boards & Switchboards	84	25
10505	Station Service Electrical Equipment	55	50
10510	Main Power and Station Service – Transformers	142	50
10531	Circuit Breakers	6	50
10700	Auxiliary Systems	106	30

For a more detailed list of final asset selections which includes, net book values and service lives, see Appendix C.

2.0 FINANCIAL IMPACT ON DEPRECIATION EXPENSE

A change of $1M pertaining to Hydroelectric was recommended see section 3.3 for details.

3.0 RECOMMENDATIONS AND SUPPORTING RATIONALE

3.1 Nuclear Facilities

The DRC reviewed service lives assigned to various asset classes selected. Bruce B service life has been extended to 2012.

3.1.1 Average Service Lives of Nuclear Generating Stations

The previously assigned average service life to nuclear generating stations was 40 years Pickering A and 25 years for Bruce A & B, Pickering B, and Darlington, based on respective assumed capacity usage.

One of the major life limiting components is pressure tubes. Replacement of these components is taken into account in the determination of the service life.

The remaining service lives of OPG's nuclear generating stations as of January 2006 are shown in Table 3.1.1.

Table 3.1.1
Remaining Service Lives for
Nuclear Generating Stations

Station	Estimated Retirement Date (Dec. 31)	Remaining Service Life as at Jan. 1, 2007
Pickering A Unit 1	2021	15
Pickering A Units 2 & 3*	n/a	n/a
Pickering A Unit 4	2021	15
Pickering B	2014	8
Darlington	2017	11
Bruce A**	2003	-
Bruce B**	2012	6

* Assets written off in 2005 as a result of the decision no to proceed with the refurbishment of the units.

** Assets are on lease to Bruce Power for 17 year term (commenced May 1, 2001) 11 years remaining in lease term.

3.1.2 Average Service Lives of Nuclear Generating Station Asset Classes (excl. Bruce)

The DRC reviewed four nuclear generating station asset classes (excluding Bruce) and no revisions to average service lives are recommended at this time.

As a result of feasibility studies being undertaken regarding the potential to refurbish and extend the life of Pickering B station, detailed plant condition assessments are being completed over the next two years. Nuclear generating station asset class lives will be revisited following the completion of the plant condition assessments.

15340 – Process Systems

This asset class (Nuclear process systems) is rather broad, encompasses a significant amount of varied systems, and represents the infrastructure inherent in a nuclear plant outside of the major life limiting components (i.e. pressure tubes / steam generators). The current 40 year life reflects the expectation that these process systems would be able to last for the extended ten years past original design capability.

The process systems are aging, but are expected to remain operational to the current end-of-life dates (EOL) predicted for Pickering A and B and Darlington. Detailed station condition assessments will be performed as part of the Pickering B Plant Life Extension Project (PLEP) to determine whether these assets can continue to operate for an additional 20 – 30 years past their current end of life (EOL) dates.

Recommendation:

Due to the large number of significant systems in this asset class, it is recommended that all components in this asset class be reviewed by the next DRC, before making a final service life recommendation.

3.2 Fossil Facilities

3.2.1 Average Service Lives of Fossil Generating Stations

The average service life assigned to Ontario Power Generation's fossil generating stations is summarized in table 3.2.1 and reflects [redacted]

The end station life for the coal-fired generating stations is [redacted]

The remaining stations service lives of the OPG's fossil generating stations as of January 2007 are shown in Table 3.2.1 below.

Table 3.2.1
Remaining Service Lives at Fossil Generating Stations

Station	Estimated Retirement Date July 1, 2006	Remaining Service Life as at Jan. 1, 2007
[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]

[redacted]

3.3 Hydroelectric Facilities

OPG has 64 hydroelectric generating stations, and 238 associated dams. Implementation of the recommendations arising from this review will increase the annual charges to operations for Hydroelectric by $1M in the first year and approximately $500K annually thereafter.

3.3.1 Average Service Lives of Hydroelectric Generating Stations

The hydroelectric long life components which include the dams and civil structures for the hydroelectric facilities, were designed to last 50 and 100 years respectively. The April 1, 1999 revaluation of OPG's assets reset the operating life assumption on these assets to 100 years. The revaluation also assigned approximately 80% of the hydroelectric fixed assets value has been assigned to dams and civil structures.

The hydroelectric medium life components, which include, the mechanical and electric systems, in the hydroelectric facilities, have been retained at their existing service life assumptions (30-40 years). The remaining lives of these assets as at April 1, 1999, are used as a basis to calculate depreciation expense. Senior management have reviewed and determined that the remaining lives of these assets are representative of their current useful and technical lives.

3.3.2 Average Service Lives of Hydroelectric Generating Station Asset Classes

The DRC reviewed the service lives assigned to selected hydroelectric asset classes. Based on the review, the DRC recommends retaining the average service lives of twelve asset classes and the splitting of asset class 10300 into two classes in order to separate public safety booms from spillways, sluices, and flumes.

The implementation of these recommendations will increase annual depreciation expense by $1M.

The rationale for the revision of the service life is:

1030200 – Spillways, Sluices, Flumes (Public Safety Booms only)

The previous service life review noted that these assets are all long-lived assets that are in place for long periods of time with only periodic maintenance. Only under extreme conditions, the conveyance systems are replaced or re-lined.

Given that these assets are subject to more extreme conditions due to water flow friction and abrasion, and damage due to debris in the conveyance structure, it is reasonable that they carry a service life less than power dams which currently have a service life of 100 years. The approach is consistent with other Canadian Utilities as previously surveyed by Hydro Quebec.

It is recommended that the asset class for public safety booms be split from the asset class for spillways, sluices and flumes and the public boom asset class be decreased to 15 years from 75 years.

The current net book value of OPG's public safety booms is approximately $8M. The recommended change will increase annual depreciation expense by $1M.

Bus, Switching and Power Cable and Control Boards and Switch Boards (Asset Classes 10502 & 10504).

A proposal was made to consider putting new additions pertaining to this class into a separate class with a shorter life. Further work will be undertaken as part of the next DRC review to confirm, and if necessary, establish a new estimated service life for additions on a going forward basis.

3.4 Administrative and Service Facilities

3.4.1 Average Service Lives of Administrative and Service Facilities Asset Classes

The DRC reviewed the average services lives of two service facility components. Based on various benchmarking studies and analysis for buildings and administrative system software, the DRC recommends retaining the average service lives of the two components reviewed.

3.5 Recommendations for the next DRC

Several recommendations have been identified for consideration for future DRC process, and they are as follows:

Recommendations for future DRC includes:

General

- Obtain input from the line of business, asset management and condition assessment groups through existing members of DRC;
- Investigate possibility of benchmarking OPG's DRC process against similar processes followed by other companies;
- Provide advance notice of future DRC schedule; and
- Consider findings from the depreciation process review performed by Gannett Fleming Inc.

Nuclear

- Review plant condition assessment reports to ensure recommendations are consistent;
- Review nuclear assets intended to last the life of the plant such as process systems, to assess if assumptions are still valid;
- Reassessment of Darlington; and

Hydroelectric

- Review specific asset class recommendations raised which relate to how these assets are organized in the fixed asset sub-ledger such as:

    1. Split auxiliary systems asset class into smaller categories including security systems;
    2. Split fences from land and improvement asset class;
    3. Consider splitting bus, switching and power cable and control boards and switchboards into separate categories; and
    4. Consider distinguishing transformers between dry and oil type.

THE DEPRECIATION REVIEW COMMITTEE

Purpose

The mandate of the Depreciation Review Committee (DRC) is to review and make recommendations concerning service lives of major and minor fixed assets to the Senior Vice President and Chief Financial Officer for approval.

Timing

As the recommendations are finalized throughout the deliberation period, DRC members forward documentation supporting the resolution of items to the Chairperson of the DRC. Both the engineering and the financial/accounting aspects of the issues are addressed in the documentation.

Structure

The DRC includes a representative from each Business Unit having custody of major fixed assets as well as representatives having experience in financial and strategic planning.

The Committee is organized into two sub-committees Major Fixed Asset Committee and a Minor Fixed Asset Committee with the chairperson chairing both sub-committees

Representatives on the DRC's major fixed assets committee are shown in the following section.

Major Fixed Asset Committee

Corporate Accounting:
Tom Staines (Chairperson)
Dave Bell
Lubna Ladak
Vicki Teti
John Tipold

Regulatory Affairs:
Randy Pugh

Finance - Asset Management:
Eleen Louie
Fred Leschinsky

Finance - Investment and Business Planning:
Stephen Rogers

Business Unit Representatives:
Don Brazier – Finance Hydroelectric
Terry Karaim – Nuclear Engineering
Connie Leclair – Finance Support Services
Mike Martelli – Hydroelectric Engineering
John Mauti – Finance Nuclear
Ken Ryfa – Finance Energy Markets
Debi Short – Finance CIO
Robert Tsin – Finance Support Services

In addition to the Committee, other staff members provided support to the DRC's work in 2006:

Corporate – Operational and Technical:
Lindy Civiero
Chris Hubbard
Stephen Mills

Hydroelectric - Operational and Technical:
Stefano Bomben
Pius Ko
Gord Haines
Bruce Hogg
Ian Munro

ONTARIO POWER GENERATION'S FIXED ASSETS

Ontario Power Generation categorizes its fixed assets as follows:

- major fixed assets under construction;
- major fixed assets in service;
- minor fixed assets

Major fixed assets under construction are comprised of land, buildings, plant, and equipment in the process of being acquired or constructed. The ultimate economic benefit of acquiring and constructing these assets is considered to relate to future periods.

Major fixed assets in-service consist of land, buildings, plant and equipment that have been declared in-service.

Minor fixed assets are comprised of transport and work equipment, service equipment, office furniture and equipment, computers other than those directly supporting the bulk electricity system and railway equipment. These assets are accounted for on a more detailed unit basis for control reasons.

OPG maintains extensive accounting records of the costs of its fixed assets. Their accumulated depreciation and retirements provide a history of the assets constructed or acquired by OPG. Consistent with the other major electrical utilities in North America, OPG maintains its fixed asset accounting records on the basis of asset classes.

For depreciation purposes, plant components having compatible service lives are aggregated into the standardized asset class accounts established for each of the following major fixed asset classifications:

- generation facilities
  - Nuclear
  - Fossil
  - Hydroelectric
- communications and system control facilities
- administration and service facilities

Aggregate of the values recorded in the asset classes form a property record for accounting purposes. A property record establishes a physical entity such as a generating station.

DRC 2006 ASSET CLASS SELECTION
As of February 1, 2006

Appendix C

# OF Assets	BU	Class #	Description	Note	Acquisition Value	Accumulated Depreciation	Net Book Value	Life
1	HE	10200	Substructures and Super-structures		1,539	(105)	1,434	100
2	HE	10301	Lining of Tunnel and Permanent Shafts		269	(25)	244	075
3	HE	10302	Spillways, Sluices and Flumes	1	105	(10)	95	075
4	HE	10318	Gates Stoplogs and Operating Mechanisms		395	(49)	346	050
5	HE	10501	Main Rotating Electrical Plant Mach less Windings		300	(44)	256	075
6	HE	10502	Bus, Switching and Power Cable	2	115	(26)	89	045
7	HE	10503	High Voltage Switching	2	25	(5)	20	040
8	HE	10504	Control Boards and Switchboards	2	131	(47)	84	025
9	HE	10505	Station Service Electrical Equipment		85	(30)	55	050
10	HE	10510	Main Power and Station Service Transformers	2	181	(39)	142	050
11	HE	10531	Circuit Breakers	2	7	(1)	6	050
12	HE	10700	Auxiliary Systems	3	140	(34)	106	030
1	NUC	15200	Buildings and Structures		577	(201)	376	050
2	NUC	15340	Process Systems	2	484	(134)	350	040
3	NUC	15450	Condenser Tubing Pickering		116	(12)	104	030
4	NUC	15600	Instrumentation and Control		417	(116)	301	030
1	CORP A&S	16210	Buildings and Site Improvements		179	(42)	137	050
2	CORP A&S	16560	Administration and System Software		296	(212)	84	005
18	Total							
			TOTAL MAJOR FIXED ASSETS TO BE Reviewed in 2006		**5,361**	**(1,132)**	**4,229**	
			TOTAL MAJOR FIXED ASSETS		**13,000**	**(2,963)**	**10,037**	

2006 - % coverage based on NBV of assets	0.42
2006 - % coverage based on # asset classes	0.13

Note 1 – Recommended service life change
Note 2 – Further investigation recommended at next DRC
Note 3 – Partially deferred to next DRC

DEPRECIATION REVIEW COMMITTEE RECOMMENDATIONS

Regulated Business

December 2007

<u>Regulated Business - Depreciation Review Committee (DRC) Recommendations</u>

EXECUTIVE SUMMARY

Background and Scope of 2007 Review

The Depreciation Review Committee (DRC) annually reviews the service lives of all major facilities and a selection of asset classes, with the objective of reviewing all significant asset classes over a five year period. The facilities and assets of the regulated business are selected for review by the Approval Committee, which is comprised of the Chief Operating Officer, Chief Financial Officer, Chief Nuclear Officer, EVP Hydroelectric and Senior Vice President, Corporate Affairs. The Approval Committee also approves the recommendations of the DRC.

The scope of the 2007 DRC review focused on the end of life for all regulated facilities as approved by the Approval Committee. Based on input from the technical and engineering members of the DRC, who represent the business units, certain fixed assets were identified in both Nuclear and Regulated Hydroelectric stations that have significant impact in determining each station's overall end of life date. Accordingly the DRC's sample selection of assets reviewed were those that had a major impact on determining station end of life dates.

The technical and engineering review of the Nuclear line of business, for Pickering and Darlington facilities, indicated the expected service life of the pressure tubes is the predominant factor determining station end of life dates.

The DRC's method of assessing the lives of major components to establish an end of life date of the Bruce facilities for depreciation review purposes had to be altered, mainly due to OPG's limited access to technical data for the Bruce facilities. As such, for Bruce B, the DRC considered earlier knowledge of the life limits on the pressure tubes in relation to an assessment of Bruce Power's operating intentions to develop a view on the expected lives of the units. Assumptions around operating intentions were derived based on reviewing future capacity plans filed with the Ontario Power Authority (OPA) and the term of the Bruce lease. For Bruce A, developments and related impacts are summarized based on plans filed with the OPA and recent 2007 publicly available information.

For the Regulated Hydroelectric line of business, the condition of the dams is the determining factor for estimating station end of life dates. Accordingly, the DRC has focused its review on the major asset classes related to the station dams.

Recommendations from 2007 Review

Based on its review of the evidence submitted, the DRC recommends the following:

Nuclear*:*

- The average service lives of Pickering A and B stations remain the same as in the 2006 review;
- The average service life of Darlington units should be extended by two years and revised from 2017 to 2019 effective January 1, 2008. This will also align the service lives with end of life dates of the major life limiting component and also align depreciation dates with those used to establish the decommissioning liability used by the Nuclear Waste Management Division (NWMD). The impact on depreciation for 2008 is a reduction of $18 million;
- The average service life of Bruce B should be extended by two years and revised from 2012 to 2014. The impact on depreciation for 2008 is a reduction of $7 million.

- The average service life of Bruce A should be extended by five years from 2030 to 2035. This revision is based on information made publicly available by Bruce Power and is consistent with analysis of the 2007 Integrated Power System Plan (IPSP) prepared by the OPA. On August 29, 2007, Bruce Power issued a press release that indicated that Bruce A unit 4 will be extended from 2017 to 2036.

Regulated Hydroelectric*:*

- The service lives of hydroelectric assets remain unchanged.

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1.0 INTRODUCTION

1.1 Work of the Depreciation Review Committee

The Depreciation Review Committee (DRC) is accountable for providing a formal engineering, technical and financial review of major and minor fixed asset service lives. The DRC annually reviews the service lives of all major facilities and a selection of asset classes, with the objective of reviewing all significant asset classes over a five year period. The Approval Committee, which includes the Chief Operating Officer, Chief Financial Officer, Chief Nuclear Officer, EVP Hydroelectric and the Senior Vice President, Corporate Affairs, approved the review of the end of life dates of all generating facilities for the 2007 DRC (Appendix C).

In order to fulfill its objective of providing an engineering and technical review of the service lives of OPG fixed assets, it is important for the DRC to have representatives of the various lines of business who have substantial knowledge and expertise of the day to day operations of each of the various plants operated by OPG. As such, the Approval Committee is consulted to ensure that the appropriate technical and engineering staff are selected for the DRC. In addition to the technical and engineering review of the fixed assets, the DRC is also accountable for assessing the financial impact of any changes to service lives that it recommends. This is particularly important in the area of depreciation expense and its impact on OPG's corporate financial statements, as well as budgets, forecasts and the rate application to the Ontario Energy Board. As such, financial staff are required for the DRC, particularly those involved with the calculation and analysis of depreciation expense and those involved in the preparation and analysis of OPG's financial statements, budgets forecasts and rate regulated processes.

The 2007 DRC included representatives from Nuclear and Regulated Hydroelectric who have custody of major fixed assets and understand and have experience related to how the assets are operated, as well as representatives from finance. In addition, since a portion of OPG's business is now regulated, representatives from Regulatory Affairs and Regulatory Finance were on the 2007 DRC.

DRC recommendations are documented in the DRC report, which is reviewed by DRC representatives and receives the concurrence of the Approval Committee. The goal, functions and structure of the Committee are outlined in detail in Appendix A.

The Committee's recommendations are submitted to the Approval Committee for approval and implementation. Approved DRC recommendations are implemented on January 1st of the year following the year of review.

1.2 Scope of the Review for 2007

The Depreciation Review Committee's deliberations for 2007 focused on the review of asset classes that have a direct impact on the end of life assumptions for Nuclear and Regulated Hydroelectric stations operated by OPG. As such, the assets selected for review were those that had a major impact on the station end of life dates. The scope also included the Bruce facilities service lives based on consideration of OPG's past operating experience in conjunction with plans filed with the OPA.

2.0 Review of Station End-of Life - Nuclear

2.0.1 Overview

In conducting its 2007 review of Nuclear station end of life dates, the DRC has focused on different sources of evidence, depending on the site. For Pickering and Darlington, the review focused on the life limiting components (see section 2.1). For Bruce sites however, since access to detailed technical information on these plants by OPG personnel is limited, the DRC relied on other methods. For Bruce B, the DRC relied on published information regarding capacity factors (see section 2.2) and previous available information regarding the service lives of major life limiting components. For Bruce A, OPG relied on publicly available information released by Bruce Power during 2007 and assessment of the IPSP filed with the OPA.

2.1.0 Pickering and Darlington

In conducting its 2007 review of Pickering and Darlington facilities, the DRC has relied extensively on assessments performed by site technical staff and approved by Nuclear senior management in estimating unit end of life. These assessments were based on detailed reviews of plant components at Pickering and Darlington stations as documented in various condition assessments, life cycle plans and monitoring of unit performance. The end of life as estimated by senior management at Pickering and Darlington sites is based on the performance of four major components: feeders, steam generators, pressure tubes and reactor components. In each of these facilities, pressure tubes have been assessed as the life limiting components. Thus estimated end of life is based on the remaining life of each unit's pressure tubes.

2.1.1 Pickering A, Units 1 and 4

Estimated end of life dates for Pickering A, Units 1 and 4 were based on plant reviews, assessments and inspections conducted throughout 2006. Based on this documentation, the DRC has noted the following:

- Most likely end of life dates are based on the remaining lives of the pressure tubes and are as follows in Equivalent Full Power Years (EFPY which is defined as the life of a station based on running at full capacity):

Unit 1   21.0 EFPY or Q1 2022
Unit 4   23.3 EFPY or Q1 2028

- The Pickering A units were retubed in the late 1980's to early 1990's.
- The above estimated operating life dates are based on future capability factors consistent with the 2008-2012 Business Plan;
- The Pickering A unit lives will be revisited in the next DRC process as greater clarity is obtained around the refurbishment of the Pickering B units and potential impacts on Pickering A.

2.1.2 Pickering B

Estimated technical end of life dates for Pickering B units were assessed and documented by Nuclear management. Based on this documentation, the DRC has noted the following:

- Pressure tubes are expected to be the limiting component for all units and the service life limit for pressure tubes is predicted to occur at 24 Equivalent Full Power Years (EFPY);
- Based on future capability factors consistent with the 2008-2012 Business Plan, the estimated end of life dates are as follows:

Units 5 to 7	Q1 2014
Unit 8	Q1 2016

- The above estimated end of life dates do not factor in the potential to refurbish and life extend Pickering B;
- Degradation of the steam generators for all units has been identified as a risk that could impact on the reliability of the units to the current end of life; however, pressure tubes have been determined as the primary life limiting factor at this time.

2.1.3 Darlington

Estimated end of life dates for Darlington units were assessed and documented by Nuclear management. Based on this documentation, the DRC has noted the following:

- Pressure tubes are expected to be the limiting component for predicting service lives for all units and the nominal life limit for pressure tubes is 24 Equivalent Full Power Years (EFPY).
- The following estimated end of life dates are based on future capability factors consistent with the 2008 – 2012 Business Plan:

Units 1 and 2	Q1 2019
Unit 3	Q4 2019
Unit 4	Q1 2020

Based on inspection results, there is a high degree of confidence that feeders and steam generators for all units will not become the life limiting components.

2.2.0 Bruce Facilities

In gathering evidence to substantiate end of life dates for the Bruce facilities, since access to detailed technical data on life limiting components of the Bruce facilities by OPG personnel is limited, the DRC relied on other methods to estimate unit lives.

2.2.1 Bruce B

With regards to Bruce B, the following two factors were considered:

- On August 29, 2007, the OPA filed the Integrated Power System Plan (IPSP) - a proposed 20-year plan for Ontario's Electricity System - with the Ontario Energy Board (OEB). Analysis of the 2007 IPSP indicates that, if Bruce B were to be refurbished, the refurbishment outages of the four Bruce B units would start between 2015 and 2019. Until the Bruce B units are taken out it is reasonable to assume that steps would be taken to keep the units available to the system. Hence, the implied service lives of these units are year end 2014, year-end 2015, year-end 2017 and year-end 2018 based on analysis of the IPSP.

- Based on historical information of life limits of pressure tubes for Bruce B units, the known in-service dates of the units and a conservative prediction of performance for the remainder of the units' lives OPG calculated that , the units will achieve 24 EFPY as follows: B5 –2014, B6 –2014, B7 –2015 and B8 –2017. Using "average" unit nominal ends-of-life, the service life for the station would be set at year-end 2014 (i.e. the year-end prior to average unit nominal end of life of mid-2015).

2.2.2 Bruce A

With regards to Bruce A, on August 29, 2007 a Bruce Power press release indicated that Bruce A Unit 4 will be refurbished and that the estimated service life will be extended from December 2017 to 2036. This information is also consistent with analysis of the 2007 IPSP prepared by the OPA. This extension to the life of Bruce Unit 4 impacts on the amortization of the asset value associated with the Asset Retirement Obligation (ARO) of Bruce A, which is currently being amortized based on average end of life of 2030. This change results in a revised average end of life for the Bruce A units of 2035. Based on an average end of life date of 2035 the annual impact on depreciation effective January 1, 2008 is a reduction of $8million.

2.3.0 DRC Recommendations – Nuclear End of Life Dates

Based on the review of the documentation submitted and discussions with Nuclear technical personnel, the DRC recommends the following with regards to Nuclear stations end of life dates:

A) Pickering A, Units 1 and 4 End of Life remains at 2021

Although the estimated technical end of life date for Unit 4 is 2028, it is considered appropriate to estimate the entire Pickering A station end of life is co-incident with Pickering Unit 1, as it is uncertain whether Pickering A Unit 4 would be economically viable operating as a single unit. There are also potential impacts on the viability of Pickering A depending on decisions made around the refurbishment and life extension of Pickering B. Given these uncertainties, the DRC is recommending that Pickering A unit's end of life remain unchanged for both units and revisited in the next DRC process as greater clarity is obtained about the future of the Pickering B units.

B) Pickering B Units End of Life remains at 2014

This recommendation is consistent with the technical analysis of the end of life dates for life limiting components prepared by Nuclear senior management.

C) Darlington Units End of Life revised from 2017 to 2019

This recommendation is consistent with technical analysis of the end of life dates for life limiting components prepared by Nuclear senior management.

With regards to the implementation date for accounting purposes, the DRC proposes an effective date of January 1, 2008. ***Such a revision on that effective date will reduce depreciation for accounting purposes by $18 million per annum.***

D) Bruce B units End of Life revised from 2012 to 2014

A conservative average end-of life date for Bruce B is December 2014 based on running each unit to 24 EFPY. This is supported by OPG's past operating experience and in line with OPA planning. ***Such a revision on that effective date will reduce depreciation for accounting purposes by $7 million per annum.***

E) Bruce A Units End of Life revised from 2030 to 2035

Based on a recent announcement by Bruce Power relating to refurbishment of Bruce A, Unit 4 and the resulting extension of its life to 2036, the DRC recommends extension of the Bruce A station estimated end of life date to 2035. ***Such a revision will reduce depreciation for accounting purposes by $8 million per annum.***

Table 2.3.1
Summary of End of Life Dates - Nuclear

Station	**Current End of Life Date (Dec. 31, unless otherwise stated)**	**End of Life Date Proposed by 2007 DRC effective Jan. 1, 2008**
Pickering A Unit 1	2021	2021
Pickering A Units 2 & 3*	n/a	n/a
Pickering A Unit 4	2021	2021
Pickering B	2014***	2014
Darlington	2017	2019
Bruce A**	2030	2035
Bruce B**	2012	2014

* Assets written off in 2005 as a result of the decision no to proceed with the refurbishment of the units.
** Assets are on lease to Bruce Power for 17 year term (commenced May 1, 2001).
***End of life occurs on September 30, 2014.

3.0 Review of Station End of Life - Regulated - Hydroelectric Facilities

3.0.1 Overview

Hydroelectric facilities have 6 regulated stations (Sir Adam Beck One, Sir Adam Beck Two, Sir Adam Beck Pump Generating Station, DeCew Falls One, DeCew Falls Two and Saunders). OPG has twenty-seven dams that are associated with stations in the Niagara Plant Group stations and three dams are associated with the R.H. Saunders Generating Station.

In conducting its 2007 review of Niagara Plant Group and R.H. Saunders stations, the DRC has relied extensively on recent assessments performed by site technical staff and approved by Hydroelectric senior management. As concrete dams are the life limiting component of any hydroelectric generating station, these assessments have been based primarily on detailed reviews of the condition of the dams at various Niagara Plant Group and R.H. Saunders sites.

3.0.2 Niagara Plant Group and R.H. Saunders Service Life Dates

The major asset classes associated with the dams of all Regulated Hydroelectric facilities were selected for review. The asset classes selected for review were #10101 (Excavating and Dredging), asset #10311 (Earth and Rock) and #10312 (Concrete) and comprise almost 50% of the current net book value of Regulated Hydroelectric fixed assets in service.

The review of these three asset classes for both Niagara Plant Group and R.H. Saunders sites was conducted by senior Hydroelectric engineering personnel. Based on this review which considered the performance records of these dams, the findings of ongoing regular inspection, monitoring, and maintenance programs, the findings of dam safety periodic reviews and plant condition assessments, there is no evidence to support a change in asset service life. The results of this review have been approved by Hydroelectric senior management and have been documented in reports submitted to the DRC.

3.1.0 DRC Recommendations – Hydroelectric End of Life Dates

Based on the evidence submitted and discussions with engineering staff concerning the dams, the DRC is recommending that no change in end of life is required for all Regulated Hydroelectric facilities.

APPENDIX A

THE DEPRECIATION REVIEW COMMITTEE

Purpose

The mandate of the Depreciation Review Committee (DRC) is to review and make recommendations concerning service lives of fixed assets to the Approval Committee.

Timing

As the recommendations are finalized throughout the deliberation period, DRC members forward documentation supporting the resolution of items to the Chairperson of the DRC. Both the engineering and the financial/accounting aspects of the issues are addressed in the documentation.

Structure

The DRC includes a representatives from each operating business unit, as nominated by the business unit representatives of the Approval Committee, as well as representatives having experience in finance, investment planning and rate regulation.

Representatives on the DRC are shown in the following section.

DRC members

Accounting:
Tom Staines (Chairperson)
Dave Bell
Lubna Ladak
John Tipold
Vicki Teti

Regulatory Affairs:
Randy Pugh

Finance - Asset Management:
Eleen Louie

Finance – Corporate Investment Planning:
Stephen Rogers
Jack Fong

Business Unit Representatives:
Don Brazier – Hydroelectric Finance
Fred Dermarkar - Nuclear Engineering
Peter Chan and Pius Ko – Hydroelectric Engineering
John Mauti – Nuclear Finance

APPENDIX B

ONTARIO POWER GENERATION'S FIXED ASSETS

Ontario Power Generation categorizes its fixed assets as follows:

- major fixed assets under construction;
- major fixed assets in service; and
- minor fixed assets

Major fixed assets under construction are comprised of land, buildings, plant, and equipment in the process of being acquired or constructed. The ultimate economic benefit of acquiring and constructing these assets is considered to relate to future periods.

Major fixed assets in-service consist of land, buildings, plant and equipment that have been declared in-service.

Minor fixed assets are comprised of transport and work equipment, service equipment, office furniture and equipment, computers other than those directly supporting the bulk electricity system and railway equipment. These assets are accounted for on a more detailed unit basis for control reasons.

OPG maintains accounting records of the costs of its fixed assets. Their accumulated depreciation and retirements provide a history of the assets constructed or acquired by OPG. Consistent with the other major electrical utilities in North America, OPG maintains its fixed asset accounting records on the basis of asset classes.

For depreciation purposes, plant components having compatible service lives are aggregated into the standardized asset class accounts established for each of the following major fixed asset classifications:

- generation facilities
  - Nuclear
  - Hydroelectric
  - Fossil
- communications and system control facilities
- administration and service facilities

Aggregates of the values recorded in the asset classes form a property record for accounting purposes. A property record establishes a physical entity such as a generating station.

APPENDIX C

History of Changes to Nuclear Station End of Life Dates

Prior to this year's DRC review, the table below summarizes end of life dates for nuclear stations:

Stations	Service Life at April 1, 1999	Effective Date of Depreciation Change	Revised Average End of Life (December)	Estimated Annual Depreciation Impacts $M increase/ (decrease)	2007 DRC Proposed Revised Life	Estimated Annual Impact of 2007 Review $M increase/decrease
Pickering A Unit 1	Dec 2012	Nov 2005*	2021	22	n/a	n/a
Pickering A Unit 4	Dec 2012	Jan 2004** Nov 2005**	2017 2021	(20) (16)	n/a	n/a
Pickering B	Sept 2009	Jan 2006	2014 ***	(37)	n/a	n/a
Darlington	**Dec 2017**	**n/a**	**n/a**	**n/a**	**2019**	**(18)**
Bruce A	**Dec 2003**	**2006**	**2030**	**46********	**2035**	**(8)**
Bruce B	**Dec 2010**	**2006**	**2012**	**(14)**	**2014**	**(7)**

* From 1999 until November 2005, Pickering A Unit 1 was out of service
** From 1999 until October 2003, Pickering A Unit 4 was out of service
***End of life date is September 2014
****Prior to 2006 there was no asset value associated with the Bruce A Asset Retirement Obligation. as the station was fully depreciated. An asset value was assigned subsequently on December 31, 2006 following a change in estimate of the ARO related to Bruce A on that date.

Prior to this report the DRC has reviewed specific asset classes representing approximately $4 billion or approximately 40 percent of the total net book value of OPG's major fixed assets.

Summary of DRC Asset Coverage	Net Book Value M$
Nuclear	1,200
Hydroelectric	2,800
Total	4,000

COMPARISON OF OTHER OPERATING COST ITEMS

1.0 DEPRECIATION

With the exception of OPG's 2007 budget to actual variance explained below, OPG's hydroelectric budgeted and actual depreciation expense has been stable over the 2005 - 2007 period, and is expected to remain relatively stable throughout the test period. As a result, this section explains the main factors contributing to depreciation expense variances in OPG's nuclear operations and only the 2007 hydroelectric depreciation expense variance.

<u>2009 Plan versus 2008 Plan</u>

Planned depreciation for 2009 is expected to be higher than the 2008 planned depreciation for OPG's nuclear operations due to in-service additions in 2009 and a full year of depreciation related to additions in 2008.

The main in-service additions in 2009 relate to the following nuclear projects (discussed in Ex. D2-T1-S2): security fence project, auxiliary heating system at Darlington, second Darlington full scope simulator, and controlled area improvements. The main in-service additions in 2008 relate to the following projects (discussed in Ex. D2-T1-S2): used fuel dry storage in station modifications at Darlington, calandria vault inspection tooling at Pickering A, security monitoring room, and security fence project.

<u>2008 Plan versus 2007 Actual</u>

Nuclear depreciation is expected to be slightly lower in 2008 than in 2007 mainly due to an $18M decrease due to the extension of the estimated service life, for accounting purposes, of the Darlington Generating Station to 2019 from the previous estimated end-of-service life date of 2017, which is effective January 1, 2008 (as discussed in Ex. F3-T2-S1), offset by a $13M increase due to a full year effect of the expected depreciation expense related to the portion of the auxiliary power system installation project at Pickering B that came into service toward the end of 2007.

<u>2007 Actual versus 2007 Budget</u>

Nuclear depreciation remained relatively stable when compared to budget.

Actual hydroelectric depreciation was higher than the budgeted amount in 2007 primarily due to removal costs of approximately $4.6M charged to depreciation in accordance with OPG's policy to include removal costs in depreciation expense (as described in Ex. F3-T2-S1, Section 3.0). These costs, which were not in the budget, related mainly to the removal of the old accelerator wall as part of the Niagara Tunnel project.

<u>2007 Actual versus 2006 Actual</u>

Nuclear depreciation was significantly higher in 2007 than in 2006. The increase was primarily the result of approximately $48M of additional depreciation due to the increase in nuclear fixed asset values related to the increase in the nuclear liabilities that occurred on December 31, 2006 (refer to Ex. H1-T1-S1 for the discussion of the increase in nuclear liabilities and Ex. H1-T1-S2 for the discussion of the relationship between nuclear liabilities and fixed asset values). In-service additions during 2007, the largest being the auxiliary power system installation at the Pickering B Generating Station, as well as a full year of depreciation related to 2006 in-service additions (described above) also contributed approximately $11M to the increase in nuclear depreciation year-over-year.

<u>2006 Actual versus 2005 Actual</u>

Actual nuclear depreciation was lower in 2006 primarily as a net result of the following factors:

1. $36M decrease due to the extension of the estimated service life, for accounting purposes, of the Pickering B generating station to 2014 from the previous estimated end-of-service life date of 2009, which was effective January 1, 2006 (as discussed in Ex. F3-T2-S1).
2. $13M decrease due to the extension of the estimated service life of Pickering A, Unit 4 from 2017 to 2021 during the fourth quarter of 2005 (as discussed in Ex. F3-T2-S1).
3. $18M increase due to the coming into service of the refurbished Pickering A, Unit 1 in November of 2005, which resulted in a full year of depreciation expense related to this unit during 2006 as compared to 2005.

4. $18M increase due to in-service additions of several nuclear projects during 2006, including Darlington and Pickering security optimization, Darlington fire protection and feeder integrity.

2006 Actual versus 2006 Budget

Nuclear depreciation is lower than budget in 2006 mainly as a result of the extension of the estimated service lives of the Pickering B Generating Station and Pickering A, Unit 4 for accounting purposes (as noted above), the impact of which was partially offset by higher than planned in-service additions related to nuclear projects. The extensions of the service lives contributed $36M and $13M, respectively, to the difference between actual and budgeted amounts of nuclear depreciation.

2005 Actual versus 2005 Budget

Actual nuclear depreciation remained relatively stable when compared to budget.

2.0 REGULATORY INCOME TAXES

For the 2005 - 2009 period inclusive, OPG's budgeted and actual income taxes are nil with the exception of the large corporations tax in 2005 and 2006. OPG's budgeted and actual regulatory income taxes reflect tax losses for 2005 - 2007. OPG expects to carry forward sufficient tax losses to offset the forecast regulatory taxable income budgeted for 2008 and 2009. As a result there are no variances in: 2009 plan versus 2008 plan, 2008 plan versus 2007 actual, 2007 actual versus 2007 budget, and 2007 actual versus 2006 actual.

2006 Actual versus 2006 Budget

Actual 2006 tax expense was lower than budget due to the fact that the 2006 budget included a provision for large corporations tax whereas the 2006 actual income tax amount reflects the elimination of large corporations tax by the federal government effective in 2006.

2005 Actual versus 2006 Actual

Actual 2006 tax expense was lower than in 2005 due to the elimination of the large corporations tax effective in 2006 by the federal government.

2005 Actual versus 2005 Budget

The income tax expense in the 2005 budget is higher than the 2005 actual due to the different methodology used in calculating the large corporations tax. The actual amount is calculated using the rate base, as described in Ex. F3-T2-S1, whereas the budgeted amount was calculated using the forecasted taxable capital as determined in accordance with appropriate tax legislation.

3.0 ONTARIO CAPITAL TAX

2009 Plan versus 2008 Plan

The Ontario capital tax for 2009 is expected to remain relatively stable when compared to 2008.

2008 Plan versus 2007 Actual

The Ontario capital tax for 2008 is expected to remain relatively stable when compared to 2007.

2007 Actual versus 2007 Budget

The decrease in actual Ontario capital tax in 2007 when compared to budget is primarily due to the rate reduction announced late in 2007 from the budgeted rate of 0.285 percent to 0.225 percent.

2007 Actual versus 2006 Actual

The decrease in the Ontario capital tax for 2007 compared to 2006 is primarily due to the rate reduction from 0.300 percent in 2006 to 0.225 percent in 2007, partially offset by the increase in rate base for nuclear as discussed in Ex. B1-T1-S1.

2006 Actual versus 2006 Budget

The budgeted amount for 2006 is higher than actual due to the different methodology used in calculating Ontario capital tax for budget and actual purposes. The actual amount is calculated using the rate base, as described in Ex. F3-T2-S1, whereas the budgeted amount is calculated using the forecasted taxable capital as determined in accordance with appropriate tax legislation.

<u>2005 Actual versus 2006 Actual</u>

The year-over-year variance is not material.

<u>2005 Actual versus 2005 Budget</u>

Ontario capital tax in the 2005 budget is higher than the 2005 actual mainly due to the different methodology used in calculating the Ontario capital tax as discussed above.

4.0 PROPERTY TAX

As discussed Ex. F3-T2-S1, OPG's property tax expense related to the regulated hydroelectric facilities is immaterial. OPG has provided variance explanations related to its nuclear operations below:

<u>2009 Plan versus 2008 Plan</u>

Nuclear property taxes are expected to remain stable over the period 2008 - 2009.

<u>2008 Plan versus 2007 Actual</u>

The budgeted property tax expense for nuclear in 2008 is expected to be higher than the 2007 actual expense primarily because the 2007 actual expense includes a refund to OPG of $6.6M associated with the successful resolution of municipal tax appeals with the City of Pickering.

<u>2007 Actual versus 2007 Budget</u>

The 2007 budgeted amount for property tax expense is higher than the 2007 actual expense because the budget assumed an amount of $6.9M related to an amendment to O. Reg. 224/00 described in Ex. F3-T2-S1 (the "expected amendment") and because the budget did not reflect the refund to OPG of $6.6M associated with the resolution of the municipal tax appeals with the City of Pickering.

2007 Actual versus 2006 Actual

The actual nuclear property tax expense for 2007 is lower than the expense in 2006 primarily due to the refund to OPG of $6.6M in 2007 associated with the resolution of the municipal tax appeals with the City of Pickering.

2006 Actual versus 2006 Budget

The actual nuclear property tax expense for 2006 is lower compared to the 2006 budgeted amount primarily due to a budgeted cost of $6.8M for the expected amendment.

2006 Actual versus 2005 Actual

The increase in the property tax expense for Nuclear in 2006 compared to 2005 is due primarily to the tax recovery of $8.8M realized in 2005 resulting from the settlement of municipal tax appeals for the 1999 to 2002 taxation years.

2005 Actual versus 2005 Budget

The higher 2005 budgeted property tax expense for Nuclear compared to 2005 actual expense is due primarily to two factors. Approximately $11.1M was budgeted for the expected amendment and the actual tax refund for the settlement of municipal tax appeals was $3.4M higher than budgeted.

Numbers may not add due to rounding.

Table 1
Comparison of Other Operating Cost Items - Regulated Hydroelectric ($M)

Line No.	Cost Item	2005 Budget	(c)-(a) Change	2005 Actual	(e)-(c) Change	2006 Actual	(e)-(g) Change	2006 Budget	(i)-(e) Change	2007 Actual
		(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)
	Depreciation:									
1	**Niagara Plant Group**	49.0	(1.9)	47.1	(5.6)	41.5	0.1	41.4	0.4	41.9
2	**Saunders GS**	21.0	0.1	21.1	(0.3)	20.8	0.0	20.8	0.0	20.8
3	**Other**[1]	1.1	(2.1)	(1.1)	4.9	3.9	3.7	0.2	1.9	5.8
4	**Sub-total**	71.1	(3.9)	67.1	(1.0)	66.2	3.8	62.4	2.3	68.5
5	**Income Tax**	10.1	(3.1)	7.0	(7.0)	0.0	(6.3)	6.3	0.0	0.0
6	**Capital Tax**	18.2	(6.2)	12.0	(0.1)	11.9	(6.0)	17.9	(3.1)	8.8
	Property Tax:									
7	**Niagara Plant Group**	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
8	**Saunders GS**	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
9	**Sub-total**	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
10	**Total**	99.4	(13.3)	86.1	(8.1)	78.0	(8.6)	86.6	(0.8)	77.3

Line No.	Cost Item	2007 Budget	(c)-(a) Change	2007 Actual	(e)-(c) Change	2008 Plan	(g)-(e) Change	2009 Plan
		(a)	(b)	(c)	(d)	(e)	(f)	(g)
	Depreciation:							
11	**Niagara Plant Group**	41.5	0.4	41.9	(0.0)	41.9	0.4	42.3
12	**Saunders GS**	20.8	(0.0)	20.8	0.1	20.9	0.1	21.0
13	**Other**[1]	0.0	5.8	5.8	(5.8)	0.0	0.0	0.0
14	**Sub-total**	62.3	6.2	68.5	(5.8)	62.7	0.5	63.2
15	**Income Tax**	0.0	0.0	0.0	0.0	0.0	0.0	0.0
16	**Capital Tax**	11.1	(2.3)	8.8	(0.1)	8.7	(0.0)	8.7
	Property Tax:							
17	**Niagara Plant Group**	0.0	0.0	0.0	0.0	0.0	0.0	0.0
18	**Saunders GS**	0.0	0.0	0.0	0.0	0.0	0.0	0.0
19	**Sub-total**	0.0	0.0	0.0	0.0	0.0	0.0	0.0
20	**Total**	73.4	3.8	77.3	(5.8)	71.4	0.5	71.9

1 Includes losses on retirements, gains on sales, asset removal costs and other related charges.

Numbers may not add due to rounding.

Table 2a

Comparison of Other Operating Cost Items - Nuclear ($M)

Line No.	Cost Item	2005 Budget	(c)-(a) Change	2005 Actual	(e)-(c) Change	2006 Actual	(e)-(g) Change	2006 Budget	(i)-(e) Change	2007 Actual
		(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)
	Depreciation:									
1	**Darlington NGS**	85.9	7.3	93.2	6.2	99.4	(18.4)	117.8	15.1	114.5
2	**Pickering NGS**	109.0	9.3	118.3	(21.4)	96.9	(17.9)	114.8	44.1	141.0
3	**Nuclear Support Divisions**	30.0	(0.1)	29.9	(6.6)	23.3	(5.7)	29.0	0.5	23.8
4	**IMS**	6.4	0.5	6.9	1.2	8.1	(1.5)	9.6	1.5	9.6
5	**Other[1]**	17.3	(5.9)	11.3	3.8	15.1	3.6	11.5	(3.3)	11.8
6	**Sub-total**	248.5	11.1	259.6	(16.8)	242.8	(39.9)	282.7	57.9	300.7
7	**Income Tax**	5.7	0.0	5.7	(5.7)	0.0	(3.5)	3.5	0.0	0.0
8	**Capital Tax**	10.2	(1.6)	8.6	0.4	9.0	(0.8)	9.8	(1.1)	7.9
	Property Tax:									
9	**Darlington NGS**	11.6	(11.4)	0.2	9.7	9.9	(3.8)	13.7	(1.3)	8.6
10	**Pickering NGS**	10.0	(2.7)	7.3	(0.4)	6.9	(0.2)	7.1	(7.3)	(0.4)
11	**Sub-total**	21.6	(14.1)	7.5	9.3	16.8	(4.0)	20.8	(8.6)	8.2
12	**Total**	286.0	(4.5)	281.5	(12.9)	268.6	(48.2)	316.8	48.1	316.8

1 Includes losses on retirements, gains on sales, asset removal costs and other related charges.
Includes nuclear waste management variable expenses (2005 Budget - $4.0M, 2005 Actual - $4.0M, 2006 Actual - $3.6M, 2006 Budget - $3.6M, 2007 Actual - $1.6M)

Numbers may not add due to rounding.

Table 2b

Comparison of Other Operating Cost Items - Nuclear ($M)

Line No.	Cost Item	2007 Budget	(c)-(a) Change	2007 Actual	(e)-(c) Change	2008 Plan	(g)-(e) Change	2009 Plan
		(a)	(b)	(c)	(d)	(e)	(f)	(g)
	Depreciation:							
1	**Darlington NGS**	109.1	5.4	114.5	(15.9)	98.6	7.7	106.3
2	**Pickering NGS**	138.7	2.3	141.0	15.6	156.6	5.9	162.5
3	**Nuclear Support Divisions**	24.4	(0.6)	23.8	0.3	24.1	5.9	30.0
4	**IMS**	12.3	(2.7)	9.6	0.2	9.8	1.0	10.8
5	**Other[1]**	9.0	2.8	11.8	(6.5)	5.3	1.5	6.8
6	**Sub-total**	293.5	7.2	300.7	(6.3)	294.4	22.0	316.4
7	**Income Tax**	0.0	0.0	0.0	0.0	0.0	0.0	0.0
8	**Capital Tax**	9.8	(1.9)	7.9	0.0	7.9	(0.1)	7.8
	Property Tax:							
9	**Darlington NGS**	13.5	(4.9)	8.6	0.5	9.1	0.2	9.3
10	**Pickering NGS**	7.2	(7.6)	(0.4)	5.2	4.8	0.1	4.9
11	**Sub-total**	20.7	(12.5)	8.2	5.7	13.9	0.3	14.2
12	**Total**	324.0	(7.2)	316.8	(0.6)	316.2	22.3	338.5

1 Includes losses on retirements, gains on sales, asset removal costs and other related charges.
Includes nuclear waste management variable expenses (2007 Budget - $3.6M, 2007 Actual - $1.6M, 2008 Plan - $1.7M, 2009 Plan - $1.8M)

ASSET SERVICE FEES

1.0 PURPOSE

The purpose of this exhibit is to explain the service fee methodology used by OPG and to explain the year-over-year changes in the service fees charged to each of the nuclear and regulated hydroelectric businesses.

2.0 BACKGROUND

Approximately 90 percent of OPG's in-service fixed assets are directly associated with specific generation facilities. The remaining assets are either directly associated with a business unit, or are held centrally and are used by both regulated and unregulated generation business units. The assets held centrally are not included in rate base, and the depreciation and amortization expense in this rate submission does not include any depreciation or amortization related to these assets. Instead, the regulated business units (as well as unregulated business units) are charged a service fee for the use of these assets, which is included in their respective OM&A expenses in this Application. The basis for the apportionment of the service fee to the regulated business units is described below for each type of centrally-held asset. Exhibit F3-T3-S1 Tables 1 and 2 present asset service fee amounts charged or expected to be charged to nuclear and regulated hydroelectric business units for years 2005 – 2009.

3.0 SERVICE FEE METHODOLOGY

Service fees are computed in a cost-based manner. Costs included in the computation of service fees comprise depreciation expense, certain operating costs, such as property taxes, and a tax-adjusted return earned on these assets. It should be noted that OPG's methodology for computing service fees has been reviewed by R.J. Rudden in conjunction with the external study of OPG's corporate cost allocation methodology. Rudden concluded that "the assets for which Service Fees are charged are required and used by OPG's generation business units" and that "the methodology for determining the usage of the asset by the generation business units for the purposes of allocating the Service Fee is based on cost causation and consistent with the Centralized Support and Administrative Cost methodology" (pg. 24 of R.J. Rudden study in Ex. F4-T1-S1). Reference is made to Ex. F4-T1-S1 for a full copy of the consultant's report.

The regulated generation business units are charged a service fee for the use of the following assets, which are further discussed below:

1. OPG Head Office (located in Toronto, Ontario)
2. Kipling Site Building Complex (located in Toronto, Ontario)
3. Certain Shared CIO and Energy Markets Assets (together, "IT Assets")

The charts below provide budgeted service fee amounts by asset and by regulated business unit for the years ending December 31, 2008 and 2009.

Chart 1

Asset Service Fee Amounts – 2008 and 2009

2008 $M	**OPG Head Office**	**Kipling Building Complex**	**IT Assets**	**Total**
Nuclear	8.2	3.3	18.4	29.9
Regulated Hydroelectric	1.2	0.3	1.0	2.5
Total	9.4	3.6	19.4	32.4

2009 $M	**OPG Head Office**	**Kipling Building Complex**	**IT Assets**	**Total**
Nuclear	8.3	3.5	13.7	25.5
Regulated Hydroelectric	1.1	0.3	0.7	2.1
Total	9.4	3.8	14.4	27.6

<u>OPG Head Office</u>

OPG's Head Office is partially used by personnel from the regulated business units and corporate functions that support them. The service fee for the use of OPG's Head Office building by the nuclear and regulated hydroelectric operations is computed based on an allocation of depreciation expense, operating costs related to maintaining the building, property taxes, and a tax-adjusted return on the capital invested in these assets. The costs calculated for the purposes of establishing the service fee for each of the regulated business units is based on the principles of OPG's corporate cost allocation methodology discussed in Ex. F3-T1-S1. Depreciation expense and property tax expense, as per OPG's budget for the year, are apportioned using the relative square footage used by the regulated operations and the portion of corporate functions supporting them. Operating costs are incurred by the facilities services group of the Real Estate function. These costs, as per OPG's budget for the year, are also apportioned based on relative square footage used by the regulated operations and the portion of corporate functions supporting them.

The return amounts for 2005 - 2007 are computed using an after-tax rate of return of 5.55 percent, which approximates the actual historic weighted average cost of capital for the regulated operations as per Exhibit C. The return amounts for 2008 and 2009 are computed using after-tax rates of return which are consistent with the proposed weighted average cost of capital rates for the regulated operations as per Exhibit C. The return on equity component of the above weighted average cost of capital rates is grossed-up by OPG's budgeted statutory tax rate for the year in question. The tax-adjusted rate of return is applied to the average budgeted net book value of the building for the year, and then apportioned to each of the regulated business units using relative square footage. In the future, OPG will use the weighted average cost of capital approved by the OEB for the regulated facilities as the rate of return.

The components used to establish the projected service fee for OPG's Head Office for the years ending December 31, 2008 and 2009, respectively, are presented below:

Chart 2

Components of Asset Service Fee for OPG's Head Office – 2008 and 2009

2008 *$M*	**Nuclear**	**Regulated Hydroelectric**	**Total**
Depreciation Expense	1.4	0.2	1.6
Property Tax	1.4	0.2	1.6
Operating Costs	2.7	0.4	3.1
Tax-adjusted Return	2.7	0.4	3.1
Total	8.2	1.2	9.4

2009 *$M*	**Nuclear**	**Regulated Hydroelectric**	**Total**
Depreciation Expense	1.4	0.2	1.6
Property Tax	1.5	0.2	1.7
Operating Costs	2.6	0.3	2.9
Tax-adjusted Return	2.8	0.4	3.2
Total	8.3	1.1	9.4

Kipling Building Complex

OPG's Kipling Building Complex is partially used by personnel from the regulated business units and corporate functions that support them. The Kipling Complex is also used by the Nuclear Inspection and Maintenance Services Division, and is currently undergoing renovations to house a training centre for non-nuclear generation business units. The service fee for the use of the Kipling Building Complex by the nuclear and regulated hydroelectric operations is computed in the same manner as that used for the OPG Head Office. The same components (i.e., depreciation, property tax, operating costs, and the tax-adjusted return) are apportioned based on relative square footage.

The components used to establish the projected service fee for the Kipling Building Complex for the years ending December 31, 2008 and 2009, respectively, are presented below:

Chart 3

Components of Asset Service Fee for Kipling Building Complex – 2008 and 2009

2008 *$M*	**Nuclear**	**Regulated Hydroelectric**	**Total**
Depreciation Expense	0.1	0.0	0.1
Property Tax	0.3	0.0	0.3
Operating Costs	2.5	0.3	2.8
Tax-adjusted Return	0.4	0.0	0.4
Total	3.3	0.3	3.6

2009 *$M*	**Nuclear**	**Regulated Hydroelectric**	**Total**
Depreciation Expense	0.1	0.0	0.1
Property Tax	0.3	0.0	0.3
Operating Costs	2.6	0.3	2.9
Tax-adjusted Return	00.5	0.0	0.5
Total	3.5	0.3	3.8

<u>IT Assets</u>

IT assets include computer systems and applications utilized throughout OPG, such as SAP and other enterprise resource planning systems, document management and archiving systems, computer network hardware and the remote access system, as well as information technology systems, applications and infrastructure related to OPG's generation portfolio management, trading and origination activities, and related administrative functions such as transaction settlements. These assets are used by personnel from the regulated business units and corporate functions that support them. The service fee for the use of IT assets by the nuclear and regulated hydroelectric operations is computed based on an appropriate portion of depreciation expense and a tax-adjusted return. The portion of the costs calculated for the purposes of establishing the service fee for each of the regulated business units is based on the principles of OPG's corporate cost allocation methodology discussed in Ex. F3-T1-S1. For the majority of IT assets, depreciation expense, as per OPG's budget for the year, is apportioned using the relative number of business workstations used by the regulated operations and the portion of corporate functions supporting them.

The return amounts for 2005 - 2007 are computed using an after-tax rate of return of 5.55 percent, which approximates the actual historic weighted average cost of capital for the regulated operations as per Exhibit C. The return amounts for 2008 and 2009 are computed using after-tax rates of return which are consistent with the proposed weighted average cost of capital rates for the regulated operations as per Exhibit C. The return on equity component of the above weighted average cost of capital rates is grossed-up by OPG's budgeted statutory tax rate for the year in question. The tax-adjusted rate of return is applied to the average budgeted net book value of the assets for the year, and, for the majority of IT assets, then apportioned to each of the regulated business units using the relative number of business workstations.

The components used to establish the service fee for IT Assets for the years ending December 31, 2008 and 2009, respectively, are presented below:

Chart 4

Components of Asset Service Fee for IT Assets – 2008 and 2009

2008 $M	**Nuclear**	**Regulated Hydroelectric**	**Total**
Depreciation Expense	15.9	0.9	16.8
Tax-adjusted Return	2.5	0.1	2.6
Total	18.4	1.0	19.4

2009 $M	**Nuclear**	**Regulated Hydroelectric**	**Total**
Depreciation Expense	11.2	0.6	11.8
Tax-adjusted Return	2.5	0.1	2.6
Total	13.7	0.7	14.4

Numbers may not add due to rounding.

Table 1
Asset Service Fees - Regulated Hydroelectric ($M)

Line No.	Business Unit	2005 Actual	2006 Actual	2007 Actual	2008 Plan	2009 Plan
		(a)	(b)	(c)	(d)	(e)
1	**Regulated Hydroelectric**	1.2	2.5	2.3	2.5	2.1

Numbers may not add due to rounding.

Table 2
Asset Service Fees - Nuclear ($M)

Line No.	Business Unit	2005 Actual	2006 Actual	2007 Actual	2008 Plan	2009 Plan
		(a)	(b)	(c)	(d)	(e)
1	**Nuclear**	14.7	30.8	33.2	29.9	25.5

COMPARISON OF ASSET SERVICE FEES

1.0 PURPOSE

The purpose of this evidence is to present the period-over-period changes in the asset service fees charged to the regulated hydroelectric and nuclear businesses.

2.0 OVERVIEW

As shown in Ex. F3-T3-S2 Tables 1 and 2, asset service fees charged to regulated hydroelectric are not material. The fee for nuclear decreases in 2008 and 2009. The decreases in the fee for nuclear in 2008 and 2009 as compared to 2007 primarily reflect lower expected purchases of IT assets as compared to prior years, partially offset by a higher rate of return applied to the asset values. The fee charged to nuclear in 2006 and 2007 is relatively consistent. The increase in the asset service fee in 2006 as compared to 2005 is largely due to refinements in the fee calculation methodology described below.

3.0 PERIOD-OVER-PERIOD CHANGES

<u>2009 Plan versus 2008 Plan</u>

The asset service fee for the nuclear business unit in 2009 is expected to be lower by $4.4M than the 2008 fee. The decrease is primarily due to the declining net book value of IT Assets, resulting from ongoing depreciation and fewer expected capital additions than in years prior to 2008. The asset service fee charged to the regulated hydroelectric business unit remains relatively stable and is not material.

<u>2008 Plan versus 2007 Actual</u>

The asset service fee charged to the nuclear business unit is expected to be lower by $3.3M in 2008 as compared to 2007 actual. Budgeted depreciation expense for all of OPG's IT Assets is expected to be lower by $4.0M in 2008 as compared to 2007. This is due to the decreasing net book value of IT assets, resulting from ongoing depreciation and fewer expected capital additions. The lower net book value of the assets also results in a lower tax-adjusted return component in the service fee. However, the impact of the decrease in the net book value on the return component is more than offset by the increase in the after-tax rate of return from 5.55 percent in 2007 to a rate that is consistent with the proposed weighted average cost of capital rate for the regulated operations in 2008 as per Exhibit C. Overall, the tax adjusted return component for OPG's centrally-held assets increases from $15.9M in 2007 to $18.7M in 2008. Although the asset service fee charged to the regulated hydroelectric business unit is also impacted by the above factors, its magnitude remains immaterial year-over-year.

4.0 PERIOD-OVER-PERIOD CHANGES

2007 Actual versus 2007 Budget

The actual asset service fee charged to the regulated operations was $4.1M greater than budget due to higher IT asset depreciation expense of $4.9M, partially offset by lower than planned operating expenses of $0.8M resulting from favourable utility costs and reduced furniture expenditures at OPG's Head Office. The higher IT asset depreciation expense was a result of an increase in assets placed in service during 2007.

2007 Actual versus 2006 Actual

The actual asset service fee charged to the regulated operations in 2007 was relatively consistent with the actual amount charged in 2006.

2006 Actual versus 2006 Budget

The actual asset service fee charged to the regulated operations was consistent with budgeted amounts.

2006 Actual versus 2005 Actual

The increase in the actual service fee charged in 2006 for both nuclear and regulated hydroelectric is primarily attributable to the refinement of the calculation of the fee that took place in conjunction with the review of the asset service fee methodology by R.J. Rudden. The refinements included (1) the expansion of the scope of the service fee concept to all centrally held assets used by generation segments in order to achieve consistent treatment;

and (2) the inclusion of an apportionment of operating costs incurred by the Real Estate corporate function.

2005 Actual versus 2005 Budget

The actual asset service fee charged to the regulated operations was consistent with budgeted amounts.

Numbers may not add due to rounding.

Table 1

Comparison of Asset Service Fee - Regulated Hydroelectric ($M)

Line No.	Business Unit	2005 Budget	(c)-(a) Change	2005 Actual	(e)-(c) Change	2006 Actual	(e)-(g) Change	2006 Budget	(i)-(e) Change	2007 Actual
		(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)
1	**Regulated Hydroelectric**	1.1	0.1	1.2	1.2	2.5	(0.0)	2.5	(0.1)	2.3

Line No.	Business Unit	2007 Budget	(c)-(a) Change	2007 Actual	(e)-(c) Change	2008 Plan	(g)-(e) Change	2009 Plan
		(a)	(b)	(c)	(d)	(e)	(f)	(g)
2	**Regulated Hydroelectric**	2.4	(0.0)	2.3	0.1	2.5	(0.4)	2.1

Numbers may not add due to rounding.

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Table 2

Comparison of Asset Service Fee - Nuclear ($M)

Line No.	Business Unit	2005 Budget	(c)-(a) Change	2005 Actual	(e)-(c) Change	2006 Actual	(e)-(g) Change	2006 Budget	(i)-(e) Change	2007 Actual
		(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)
1	**Nuclear**	13.4	1.3	14.7	16.1	30.8	0.2	30.6	2.4	33.2

Line No.	Business Unit	2007 Budget	(c)-(a) Change	2007 Actual	(e)-(c) Change	2008 Plan	(g)-(e) Change	2009 Plan
		(a)	(b)	(c)	(d)	(e)	(f)	(g)
2	**Nuclear**	29.1	4.1	33.2	(3.3)	29.9	(4.5)	25.5

COMPENSATION AND BENEFITS

1.0 PURPOSE

The purpose of this evidence is to present the compensation and benefits framework associated with OPG's regulated facilities. This evidence provides context for other parts of the Application which address operational costs.

2.0 OVERVIEW

OPG manages its compensation and benefits costs within the complex context of a business that requires highly skilled employees that are generally trained in-house, a 90 percent unionized environment, a changing external environment in the electricity sector and a high level of transparency. OPG will be facing significant demographic challenges in the next five to ten years that will increase compensation cost pressures. OPG is committed to ensuring that compensation and benefits will continue to attract, retain, and engage employees as required by the business.

3.0 BACKGROUND

OPG was formed in 1999, after the demerger of Ontario Hydro. Since that time OPG has implemented a number of structural improvements in response to changes in the Ontario electricity marketplace and OPG's role within it. These improvements have been implemented to achieve process and performance efficiencies, focus on our core business of generating electricity and reduce long-term costs, including compensation costs. These changes have included:

- 2000 - Outsourcing of the IT business to an external service provider which involved the transfer of approximately 450 staff.
- 2000 - Selling of assets such as the Research Division.
- 2001 - Leasing of the Bruce Nuclear site.
- 2002 - Transfer of approximately 150 staff performing nuclear safety analysis and assessments to an outside company.

- 2002 - Outsourcing of the management of the pension and nuclear liability funds to professional money managers thereby avoiding IT investments, improving governance and enabling independent reviews and performance assessments.
- 2002 - Outsourcing of pension administration including existing staff.
- 2002 and 2006 - Restructuring of the terms and conditions of the collective agreements to provide increased flexibility and cost savings.

In addition to these changes, OPG has also undergone significant restructuring programs resulting in the departure of approximately 1,450 staff over a two year period from 2002 - 2003. The payroll savings from this downsizing were approximately $200M per year. In addition, in 2004 nine Vice-President positions were eliminated, and the training and functional support roles within Nuclear were amalgamated, resulting in a reduction of eight executive positions.

4.0 CURRENT DEMOGRAPHICS AND HUMAN RESOURCES ENVIRONMENT

As a result of the initiatives outlined above, at the end of 2006, there were 11,667 regular staff in three categories at OPG.[1] Regular staff are those employees who are not temporary or on contract. Non-regular staff refers to temporary employees. The breakdown of regular staff is as follows:

- Skilled Technical/Trades/Clerical -
  7,055 staff who are represented by the Power Workers' Union ("PWU")
- Engineering, Finance and other Professional staff
  3,419 staff represented by the Society of Energy Professionals ("Society")
- Management Staff
  1,193 executive/professional/administrative staff who are not represented by a union

The proportions of staff representation are similar for the regulated operations as to proportions in the company as a whole. As the above numbers show, approximately 90 percent of the workforce is unionized and covered by the collective agreements that were in place at the time of demerger from Ontario Hydro, with some modifications as mentioned

[1] All staff numbers quoted throughout the Exhibit refer to regular staff unless otherwise indicated.

below. Since items such as wages, pension, and benefits form part of the collective agreements, any changes to these can only be made through the collective bargaining process. Since the formation of OPG, there have been three rounds of negotiations with the PWU and four with the Society. Many of the terms and conditions of employment have been adjusted to reflect the different business needs of OPG.

Within the regulated portion of the business the staff numbers for each jurisdiction are as follows:

Chart 1

Staff Numbers By Representation - Regulated Business - Year End 2006

	# of Employees[1]				
Representation	Nuclear[2]		Regulated Hydro[2]		
	Regular	Non-Regular	Regular	Non-Regular	TOTALS
Power Workers Union	4920	425	263	3	5611
Society of Energy Professionals	2759	19	91	2	2871
Management Group	834	20	52	1	907
TOTALS	8513	464	406	6	9389

[1] Based on 2006 year end payroll data for employees in their home-base positions
[2] Includes allocations of corporate support functions staff to both regulated businesses as well as allocations of Hydroelectric Central Support staff to the Regulated Hydroelectric business.

As the above data indicates, the regulated portion of the business is 90 percent unionized.

In order to support the diverse mix of generation capabilities within OPG, staff must be highly skilled, and must possess a wider array of skills than employees in many other utilities across the province or country. OPG's workforce is comprised of engineers, scientists, other professional staff, and skilled trades people. Approximately 8,500 employees (73 percent of the OPG population) require post secondary education to perform their jobs. For the majority of these, two or more years of community college or a university degree are required, and this education ranges from skilled technician or technologist training, to advanced university degrees in fields such as engineering and finance. These highly skilled staff are in high demand across the country, and OPG must compete for these employees with Bruce Power and other private generators and energy service organizations as well as the general marketplace.

The average age of OPG employees is currently 45.4 years. Approximately 58 percent of all OPG staff have more than 15 years of service, and 37 percent have more than 20 years of service. As a result, OPG's planning assumptions indicate that the company will be facing significant resourcing gaps over the next five years. Between 2007 and 2011, it is estimated that the following percentages of staff will need to be replaced because of retirements and terminations:

Chart 2

2007 – 2011

% Of Staff To Be Replaced

Management	40%
Trades Supervisors, First Line Managers	47%
Maintainers	26%
Operators	22%
Engineering	30%
Technical Support	38%
Other (admin support, business analysts, lawyers, human resources consultants, real estate services staff, emergency response, security)	27%
TOTAL	30%

The replacement percentages are similar for the regulated businesses as they are for all of OPG.

OPG projects through its workforce planning programs that by the year 2020 the company will experience a shortfall of approximately 8,200 employees as a result of retirements and regular turnover. This number assumes a steady state for the number of employees through each year. As a result, the analysis is highly conservative. OPG is expecting that its staff numbers will grow to accommodate potential rehabilitation and new generation in Nuclear. The impact of the decisions in this area on staff requirements will be significant.

In response to these challenges, OPG is focusing on the following three areas:

4.1 Recruitment and Talent Management

The nature of the work performed at OPG means that many positions cannot be filled from normal external sources. The demand for highly-skilled and industry-specific trades and engineering knowledge requires OPG to recruit carefully and train extensively. In order to facilitate this process, OPG has implemented a rigorous succession management process that has identified replacement candidates for critical positions that may be vacated in the short-term through retirements.

OPG has renewed its hiring programs over the last five years, and has made an effort, through such initiatives as career fairs, to establish a brand presence on campuses of post-secondary institutions across Ontario. Approximately 286 new employees have been hired through this program over the last five years. A substantial increase to this number is required in the next five years. In order to facilitate future hiring and to further strengthen its relationships with colleges and universities, OPG partners with them to ensure that the necessary programs are in place. For example, OPG has created a strategic partnership with University of Ontario Institute of Technology. OPG has also worked with other organizations in the industry to establish and fund industrial research chairs in support of research and development in nuclear engineering. OPG also provides more than 250 youth student awards and scholarships. In addition, OPG has partnered with companies who are downsizing to redeploy their mid-career individuals that have skills that can be used at OPG. Finally, OPG has renewed its apprenticeship program to bring in a regular stream of entry-level skilled tradespersons to address the demographics issue with its skilled trades workforce.

4.2 Skills Development

OPG invests considerable resources to provide technical training to its employees ensuring that they are prepared to take on the roles essential to the organization. In addition, OPG has focused on development initiatives to prepare employees for promotion to supervisory and management positions as incumbents retire. Examples of development initiatives are the training programs for new supervisors and for middle managers.

4.3 Retaining and Managing Potential Retirees

In addition to the succession management process outlined above, OPG is also making use of retirees as a source of contingent labour for project related work.

4.4 Demographics Summary

OPG employs mostly unionized staff who are highly skilled and have many years of experience. It is anticipated that OPG will experience a significant staff shortfall by the year 2020 and, as a result, labour rates must be maintained at a level that can retain existing highly skilled staff, attract replacement staff in advance of anticipated shortfalls, and provide sufficient time to train new staff in order that the business can continue to operate safely and effectively.

5.0 LABOUR AGREEMENTS

Pursuant to the Ontario *Labour Relations Act*, OPG was required, as a successor employer to Ontario Hydro, to adopt collective agreements covering the employees transferred to OPG from Ontario Hydro on April 1, 1999. The majority of employees within OPG are unionized and, as a result, items such as wages, pensions, and benefits can only be changed through the collective bargaining process. In OPG’s environment, it is necessary to balance the business requirements and long-term company interests related to working in a competitive, unionized environment with unions who, in most cases (e.g., the PWU), have the right to strike.

Since OPG was created, new collective agreements have been negotiated by OPG with both the PWU and the Society. The following are the agreements currently in place:

- Collective agreement between OPG and the PWU respecting general working conditions, wages and pension for nuclear employees (April 1, 2006 - March 31, 2009).
- Collective agreement between OPG and the PWU respecting general working conditions, wages and pension for non-nuclear employees (April 1, 2006 - March 31, 2009).
- Collective agreement between OPG and the Society respecting general working conditions, wages, and pensions (January 1, 2006 - December 31, 2010).

The favourable comparisons in labour rates between OPG and other successors to Ontario Hydro and major competitors is found in section 9.0 - Benchmarking.

6.0 CURRENT COMPENSATION

The highly skilled nature of the work, coupled with the aging workforce, means that OPG needs to compensate its employees appropriately in order to retain and attract a consistent supply of employees with the high standards of skills required by OPG.

The following provides the 2006 average compensation and benefits levels for the major categories of OPG employees in the regulated businesses:

Chart 3

Average Employee Costs ($K) For Regulated Business – Year End 2006

		PWU		Society		Management Group	
		Regular	Non-Regular[5]	Regular	Non-Regular[5]	Regular	Non-Regular[5]
Nuclear	Base Salary[1]	72.2	32.7	90.6	36.5	117.6	25.8
	Over Time[1]	14.5	10.1	14.3	3.6	0.9	0.0
	Incentives[1,2]	1.5	0.0	2.4	0.0	18.9	0.0
	Other[1,3]	6.1	6.6	2.3	2.3	8.5	0.5
	Benefits[4]	4.1	0.0	5.0	0.0	6.4	0.0
Regulated Hydro	Base Salary[1]	77.7	13.9	92.9	6.9	122.6	45.1
	Over Time[1]	8.7	1.1	4.7	0.0	0.3	0.0
	Incentives[1,2]	1.2	0.0	2.4	0.0	21.1	0.0
	Other[1,3]	3.8	0.0	1.7	0.0	10.8	0.9
	Benefits[4]	4.6	0.0	5.6	0.0	9.2	0.0
Corporate Support Functions	Base Salary[1]	59.5	20.1	90.5	54.0	105.3	55.5
	Over Time[1]	1.6	0.8	2.3	0.9	0.1	0.0
	Incentives[1,2]	1.1	0.0	2.0	0.4	20.0	4.3
	Other[1,3]	1.7	0.9	1.3	3.1	5.4	6.9
	Benefits[4]	4.2	0.0	5.7	0.0	6.2	0.0

[1] Based on 2006 year end payroll data for employees in their home-base positions
[2] Includes Goalsharing and Authorization Bonuses for PWU; Goalsharing, Performance Recognition Plan and Authorization Bonuses for the Society, and Annual Incentive Plan and Leadership Allowances for Management Group
[3] Includes travel time, unused vacation days paid out, standby allowance and shift allowance
[4] Includes group life Insurance and health and dental benefits coverage while employed
[5] Includes temporary employees for "peak" periods

Towers Perrin, Mercer, Watson Wyatt, and Hay conduct yearly surveys of their clients to determine overall salary increases, and these are made available to the public. Chart 12 provides a summary of median 2006 actual salary increases. A comparison between this chart and the wage increases provided at OPG shows that OPG is in line with the external market. Charts 13 and 14 also provide charts comparing annual wage adjustments for other employers for the PWU and the Society. These charts demonstrate that OPG has been successful in negotiating general wage increases that are below those of most of the successor companies of former Ontario Hydro and OPG's current competitors.

6.1 Power Workers Union

Seeking to contain labour rates, OPG negotiated a new compensation system with the PWU in 2002. The former system inherited from Ontario Hydro contained over 600 positions and approximately 2200 rates of pay. The new system has a simple and comprehensive banding structure where all positions are grouped and placed in one of three salary bands. There are 22 rates of pay under the new system. In tandem with the new compensation system, the concept of skill broadening was introduced.

Skill broadening was designed to improve productivity. Under this approach, traditional job family silos were removed and employees are trained and directed to perform a variety of related tasks. As a result, the jobs have become more varied which allows employees more flexibility for work assignments. This approach also allows trained employees to work together to complete assignments without undue regard to specialization. The changes created a working environment where there are far fewer situations of additional payments being made as one person relieves for another person. During the term of the 2002 – 2005 PWU collective agreement, the overall target for productivity gains and cost savings from skill broadening was $290M. The target for 2002 was $36M, and this target was exceeded with a result of $44.4M in value being realized. The target for 2003 of $59M was also achieved. At this point skill broadening became part of the standard operating practice of the company.

As a result of collective bargaining, the general wage increases for the PWU have been between two percent and three percent for the past number of years, and this trend continues for the years 2006 - 2008.

Goalsharing, the incentive program applicable to PWU staff, is discussed in section 6.4.

6.2 The Society of Energy Professionals

A major element of the most recent set of negotiations with the Society was the development and implementation of a new compensation structure designed to contain labour rates and simplify administrative systems. The structure, implemented in 2006, simplifies the pay administration for the employees represented by the Society and puts a focus on performance recognition through the introduction of a new performance recognition system. The program recognizes superior individual performance by paying a lump sum award to the top 30 percent of performers based on an annual individual performance score. Within the plan there are two types of awards – one for non-supervisors (up to four percent - six percent) and one for supervisors (six - ten percent).

As a result of collective bargaining, the general wage increases for the Society have been between two percent and three percent for the past number of years, and this trend continues for the years 2006 - 2010.

Goalsharing, the other incentive program applicable to Society staff, is discussed in section 6.4.

6.3 Management Group

In 1998, Mercer was retained to assist in the development of a compensation strategy for non-represented staff in the context of the company's evolution towards a competitive marketplace. Key objectives of the compensation plan included:

1. Being able to attract and retain executive personnel who would operate in a de-regulated north-east North American marketplace.
2. Recruiting senior nuclear executives to mange the generating assets.

3. Facilitation of cultural change towards a commercial orientation.

In anticipation of the commercialization of Ontario's electricity market, OPG adopted a compensation philosophy of targeting total compensation for all non-unionized employees at the median of the Canadian market. The Canadian market was defined to be a cross-section of Canadian organizations of comparable size, operating in a competitive market. OPG's salaries at the time were below the median, and implementation of the new philosophy was staged such that fully competitive pay levels would not be achieved until the electricity market was fully opened.

Implementing market-based compensation required changes to increase the performance focus of OPG's compensation architecture, with a greater proportion of overall pay at-risk. The system had the following features:

- Base salaries
  - Administered based on the assessment of scope of the job demands, individual competencies, and performance
- Annual incentive plan ("AIP")
  - Target incentive levels were increased, and tied to performance
  - Performance evaluated against corporate, business unit and personal goals
- Long-Term incentive plan
  - Introduced for a limited number of senior executives
  - Awards determined based on assessment of corporate performance measured over a three-year rolling period

These elements were designed to be helpful in building an employee population that would allow OPG to compete in an open electricity marketplace.

In late 2003, the Province indicated that it would not continue with the privatization of OPG's assets and started restructuring the competitive marketplace. In 2004, OPG responded by making the following changes in its compensation approach in order to signal a return to a more public sector employment situation:

- Reduced the target incentive levels under the AIP
- Reduced the maximum available AIP award by 50 percent
- Eliminated the long term incentive plan
- Froze base salaries for Vice Presidents and above
- Froze the salary structure at 2002 levels
- Reduced the executive population

In 2005, OPG continued with the freeze in salary structure and the salaries of Senior Vice Presidents and above. The Company also kept the reduced incentive levels but did allow for the recognition of achievement of stretch performance goals. In 2006 the Company allowed for performance-based salary changes for executives but kept the salary structure frozen. This means that performance-based salary changes were allowed but the overall salary band structure did not change.

Management Group Compensation Philosophy

OPG follows best practices when dealing with Management Group compensation. There is a Compensation and Human Resources Committee of the Board of Directors, which is comprised of independent directors. The Committee meets at least four times per year, has full access to management and company data, and has hired an advisor from Mercer to provide them with advice. The Compensation and Human Resources Committee is responsible for overseeing all significant compensation matters and make recommendations to the full Board of Directors for approval.

When reviewing executive compensation, OPG gathers information on the executive market. OPG looks at two comparator groups of utilities (Canadian owned energy companies) and non-utilities (Canadian owned public and private large manufacturing and high tech firms). In 2006, OPG's philosophy was to position OPG's Management Group compensation at the 75th percentile against other utilities and around the median or 50th percentile of comparable non-utility sector companies. The reason that the 75th percentile in the utility market was used is due to OPG having unique and diverse assets that are not found in other utilities in

Canada. Using 75^{th} percentile compensation to compare against other power utility players, while remaining competitive against the general executive market, was an appropriate compensation philosophy for OPG. OPG has reviewed its philosophy in late 2007 and now also plans to conduct a comparison using the 50^{th} percentile for the public and utility markets going forward.

While it is impossible to have a perfect fit with two moving benchmarks, figure 3 on page 35 presents OPG's current market position. In practice, in recruiting and retaining quality executives OPG often finds that the norms of the general industrial sector, with which OPG most often competes for talent, drive the levels of compensation. This has been particularly the case when recruiting senior nuclear operating executives. OPG has needed to look to the United States because an executive market for the nuclear industry is limited in Canada.

The OPG Management Group salary structure is very detailed and is rigorously maintained, with base salaries defined by job responsibilities and salary ranges defined for each job level. The base salary and AIP award structure (discussed in the next section – Incentive Programs) is found in Chart 4.

Chart 4

2007 Base Salary and AIP Award Structure

Band Level	Position Examples	Base Salary Ranges Min.	Base Salary Ranges Mid.	Base Salary Ranges Max.	AIP Threshold	AIP Target	AIP Max.	AIP Perf Split Corp/BU/Ind
A	President & CEO	$580,000	$720,000	$860,000	25.0%	50.0%	75.0%	50/0/50
B	COO & Fossil/Hydro Business Unit Leaders	$315,000	$390,000	$465,000	22.5%	45.0%	67.5%	50/0/50
C	Executive Vice-Presidents, CNO	$265,000	$330,000	$395,000	22.5%	45.0%	67.5%	50/0/50
D	Sr Vice-Presidents & Vice-Presidents, e.g. VP-Risk	$190,000	$235,000	$280,000	12.5%	25.0%	37.5%	25/50/25
E	Vice-Presidents, e.g. VP-Finance, VP-Nuclear HR, VP-Nuclear Trng	$160,000	$200,000	$240,000	12.5%	25.0%	37.5%	25/50/25
F	Directors, Managers e.g. Dir-Compensation, Hydro Station Manager	$120,000	$150,000	$180,000	10.0%	20.0%	30.0%	25/50/25
G	Directors, Managers, e.g. Dir-Fund Mgmt, Mgr-Chemistry	$90,000	$110,000	$150,000	7.5%	15.0%	22.5%	25/50/25
H	Managers, e.g. Section Mgr-Scheduling, Mgr-Tax, Outage Mgr	$65,000	$90,000	$130,000	7.5%	15.0%	22.5%	25/50/25
I	Journey Level Professionals eg Sr Human Resources Consultant, Sr. Financial Analyst	$55,000	$80,000	$105,000	5.0%	10.0%	15.0%	25/50/25
J	Entry Level/Junior Professional eg Human Resources Consultant, Financial Analyst	$50,000	$65,000	$80,000	4.0%	8.0%	12.0%	25/50/25
K	Exec Administrative Assts./Sr Tech Clerks	$40,000	$50,000	$60,000	4.0%	8.0%	12.0%	25/50/25
L	Mgr/ Dir Administrative Assts / Tech Clerks	$35,000	$45,000	$55,000	4.0%	8.0%	12.0%	25/50/25
M	Entry Level Clerical	$25,000	$35,000	$45,000	4.0%	8.0%	12.0%	25/50/25

6.4 Incentive Programs

6.4.1 Goalsharing

Goalsharing is an annual incentive plan for unionized staff to share in the gains realized when OPG meets or exceeds its business targets. This program does not operate like a profit sharing plan but rather is based on achieving business unit objectives such as decreased costs, increased productivity and reliability and environmental and safety targets. The objectives of the goalsharing program are:

- To contribute to OPG's business success.
- To share OPG's business success with all represented employees.
- To engage employees in OPG's business.
- To enhance employees' understanding of OPG's business.
- To foster a productive relationship and sense of partnership between OPG Management, the Society and the PWU.

Awards are distributed following the end of the calendar year (typically within the first quarter of the following year). Goalsharing payments are considered to be income and are subject to statutory deductions; however, they are non-pensionable and do not form part of base salary for any other purpose. Management establishes the mandatory performance measures and target performance levels for the site scorecards, and determines the year-end results and performance score. Measures and targets may be adjusted by OPG during the year if there are significant changes to the business direction or priorities. Goalsharing results and awards are audited internally and are approved by the Board of Directors. Refer to Chart 3 for information on recent award levels.

6.4.2 Management Group Annual Incentive Plan

Incentives are a key and normal component of the compensation payable to executives and non-union employees. The AIP was adopted in 1999 to encourage and reward performance, based on the achievement of defined objectives. The plan has evolved over the years and has been adapted in response to changing business requirements. In 2007, the plan was revised to improve the alignment of the measures of the production units and the awards given to the corporate support functions as well as to simplify the plan. The intent of the plan is to deliver a portion of total compensation paid to Management Group employees on a pay-at-risk basis. Under the plan, eligible employees can earn annual cash awards if key cost control and operational objectives of the Corporation, Business Unit and individual are met during the plan year. Refer to Chart 3 for information on recent award levels.

As with other aspects of Management Group compensation previously discussed, the AIP also undergoes a rigorous review process. After the CEO approves the targets, the scorecards are reviewed and approved by the Compensation and Human Resources Committee. AIP is made up of three components: a corporate scorecard, business unit scorecards, and personal objectives for individual performance. For each performance objective, there are threshold, target, and maximum levels of performance. Once the overall score is established, AIP awards are calculated based on a weighting of the corporate, business unit, and individual elements. There are different weightings for the corporate and business unit elements depending on whether the job functions are production-based or focused on providing corporate support. Awards also vary depending on an employee's level of contribution and salary band level. Refer to Chart 4 for information on target award percentages for each salary band for production-based employees. Once performance levels are assessed, the CEO and the Compensation and Human Resources Committee complete a final review and approval of the payout for the AIP. Results and payouts undergo an internal audit each year.

6.4.3 Authorization Bonuses and Leadership Allowances

Employees in Nuclear who are authorized by the Canadian Nuclear Safety Commission, such as Control Room Shift Supervisors and Control Room Shift Operating Supervisors, and who are required to maintain their licenses as a requirement of their job, receive a license retention bonus between 14 percent - 20 percent of their base salary. The bonus is pensionable. In addition, Authorized Training Supervisors are eligible to receive 50 percent of the Control Room Shift Supervisors and Control Room Shift Operating Supervisors authorization bonus.

Management Group employees who are required to work shifts are paid a leadership allowance. This allowance is in lieu of provisions such as shift premiums and on-call payments which are afforded to represented employees who work shifts. The leadership allowance provides for up to 30 percent - 40 percent of base salary, of which 10 percent is pensionable. In addition, Management Group employees who are on call 24 hours a day, seven days a week, are licensed and hold the license authority for plant operations receive the same bonus.

These allowances and bonuses are necessary to attract and retain staff for the applicable positions and to provide appropriate incentives to staff to keep their licenses current. The staff licensing process is set out by the Canadian Nuclear Safety Commission and represents a challenging and time-consuming task. Not every employee is prepared to devote personal time and effort necessary to obtain and maintain a license. In addition, Management Group employees in these organizational units are significantly more likely to experience salary compression with their unionized subordinates.

6.5 Compensation Summary

Operating within a unionized environment can pose significant challenges in terms of cost containment. This challenge becomes even greater when coupled with the requirement for highly skilled workers and an anticipated staff shortfall. Despite all of the above, OPG has made progress toward containing labour costs through the implementation of a number of initiatives, including skill broadening, a new Society compensation plan, and maintaining management salaries at the 75th percentile of the Utility market. Details on compensation benchmarking and wage competitiveness are found in section 9.0.

7.0 PENSION AND BENEFITS

OPG's pension and benefit programs consist of post employment benefits as well as health, dental, and other benefits for current employees and their dependants. Post employment benefits programs consist of a registered pension plan ("RPP") and supplementary pension plans, and other post employment benefits ("OPEB"), which include post-retirement benefits, such as group life insurance and health and dental care for pensioners and their dependants, as well as long-term disability benefits for current employees.

Pension and benefits levels at OPG are determined in two ways. Approximately 90 percent of the employee population is covered by collective agreements that contain pension and benefits clauses. Pension and benefits levels for Management Group employees are determined by the Board of Directors. At Ontario Hydro, all pension plan details and most health and dental benefit items were the same for all employees. In contrast, OPG views pension and benefits as part of the total compensation package that should vary according to the overall compensation for each employee group. As a result, there are differences between the pension and benefits levels for PWU and Society-represented staff and those for the Management Group. These differences also contribute to the ability of OPG to attract, retain, and motivate employees.

As a successor from the Ontario Hydro pension plan, OPG has a contributory, defined benefit RPP, which follows closely the model used by most public sector pension plans. All OPG employees earn and contribute towards an ample pension package, although the benefit levels are slightly less for non-unionized employees than for union members. In addition, all employees are eligible to receive benefits from the defined benefit supplementary pension plans should their pension promise exceed the limits under the *Income Tax Act* for payment from the RPP. The health and dental benefits have also moved away from a “one size fits all” approach and these now show differences between the unionized and non-unionized groups of employees. OPG monitors benefit payments associated with both pension and health and dental benefits plans closely to ensure that the plans are being administered appropriately.

7.1 Pension

The RPP is funded. The fund assets include equity securities and corporate and government debt securities, real estate, and other investments which are managed by professional investment managers. The fund does not invest in equity or debt securities issued by OPG. Independent actuarial valuations are performed at least once every three years to determine the funded status of the RPP and, in turn, OPG's contributions. The valuation is filed with the Financial Services Commission of Ontario, as required by the *Pension Benefits Act* (Ontario). Deficits are funded over a period of time in accordance with the *Pension Benefits Act* (Ontario) (five - fifteen years depending on the nature of the deficit). If the plan is in a surplus position, OPG may reduce or suspend its contributions to the extent permitted under the *Pension Benefits Act* (Ontario). The most recently filed actuarial valuation was as at January 1, 2005 and showed that the pension fund was in a deficit position. The next funding valuation will be performed as at January 1, 2008 and is expected to be carried out during 2008.

The supplementary pension plans are not funded but are secured by letters of credit.

A number of changes have been made to the pension promise over the past few years. These include:

- In 2001, all new employees hired into manager positions or higher took on a different set of pension benefits including reduced indexing levels, inclusion of incentive amounts in pensionable earnings and undiscounted retirement at age 60.
- In 2003, employee contribution rates increased for all groups from 4 percent of base earnings up to the year's maximum pensionable earnings and 6 percent of base earnings in excess of year's maximum pensionable earnings to 4.5 percent and 6.5 percent respectively.
- In 2006, employee contribution rates further increased to 7 percent of base earnings for the Society and Management Group members.

A defined benefit RPP has long been a part of the public service compensation package. It is designed to be retentive and to reward long service. In an industry where skills are generally made and not bought on the outside market, this type of pension plan is desirable.

Historical and planned pension costs for the regulated businesses are presented in Chart 6.

7.2 Benefits

All employees and pensioners at OPG have health and dental benefits designed to protect them from undue costs associated with illness and to encourage them to take steps to maintain good health. The benefits plan has experienced some pressure recently as fewer services are covered by the provincial government. OPG has been taking steps to both monitor and control benefits and has implemented a number of changes to stabilize costs and to better align benefit provisions with those of the external market. Changes for the employees represented by the Society and the PWU are achieved only through the collective bargaining process and are, therefore, tied to the timelines of the agreements. OPG outsources its claims management to Great West Life and, in addition, has put in place a number of mechanisms to control benefits costs. These include the mandatory use of generic drugs, the use of a drug card at pharmacies, and a requirement for prior approval for uncommon and expensive drug and treatment therapies.

Recent benefits changes for each employee group to help control costs include the following:

<u>Management Group</u>

- In 2000:
  - Stopped automatically applying benefit provisions realized through Union negotiations to Management Group employees.
  - Introduced the Millennium Health & Dental Plan for new external hires, which provides benefits that are more in line with those generally provided in the external market.
  - Reduced vacation entitlement for new external hires.
  - Froze levels of benefit coverage for existing employees under the Heritage Health & Dental Plan at 2000 levels.
- In 2006:
  - Changed coverage for chiropractic and physiotherapy services to ensure costs incurred by OPG remained at the same levels as previously experienced when these services were covered by OHIP. The coverage is subject to a cap and a co-insurance payment.
  - Eliminated coverage for non life-sustaining over-the-counter drugs.

  - Capped drug dispensing fees at $5.00.

The Society

- In 2006:
  - Eliminated coverage for all non life-sustaining over-the-counter drugs.
  - Capped drug dispensing fees at $5.00.

PWU

- In 2000:
  - Changed yearly coverage maximums for services such as chiropractor and paramedical services and instituted co-payments for certain services.
  - Drug card use became compulsory for all prescriptions.
  - Dispensing fees for over-the-counter drugs capped at $6.11.
  - Instituted reasonable and customary limits for virtually all types of eligible claims.
- In 2002:
  - Instituted further maximums on a variety of items such as chiropractor services.
- In 2006:
  - Terminated coverage for future family members of surviving spouses.

As a result of these changes, OPG is experiencing less escalation in the costs of health and dental benefits than other employers. In 2007, OPG's benefit payments rose an average of 3.1 percent against an industry average figure of approximately 17 percent based on information provided by Great West Life. Great West Life, like all other group insurance carriers, keeps track of changes taking place in the healthcare industry, specifically with respect to trends in overall utilization, inflation, and cost shifting between the public and private sectors.

One area in which OPG incurred additional costs relates to the Ontario health premium. OPG was directed, through an arbitration award, to provide the Ontario health premium to all PWU-represented employees and pensioners. This resulted in an additional payment of approximately $6M annually, in addition to the expenditures incurred with a one-time pay system change to allow tracking and payment of these amounts.

OPG is large enough to warrant being self-insured, and over one million claims are processed annually. The payment amount of claims processed in 2007 associated with health and dental benefits and life insurance for both current employees and pensioners across the Company was approximately $98M.

Historical and forecasted OPEB costs for the regulated businesses are presented in Chart 6.

7.3 Pension and Benefits Costs

OPG is seeking recovery of pension and benefits costs associated with the regulated operations based on the amount of pension and benefits costs determined in accordance with Generally Accepted Accounting Principles ("GAAP").

7.3.1 Accounting Treatment of Pension and OPEB Plans

OPG's accounting for its pension and OPEB plans is in accordance with GAAP as set out in Canadian Institute of Chartered Accountants Handbook Section 3461. In accordance with GAAP, pension, and OPEB costs for the current year are based on the measurement of RPP fund assets and benefit obligations at the end of the previous year.

The obligations for pension and other post retirement benefit costs are determined using the projected benefit method pro-rated on service. Under this method, an equal portion of the total estimated future benefit is attributed to each year of service until the date the plan participant would be entitled to the full benefit. The obligation at a particular date is the actuarial present value of the benefits attributed to service rendered up to that date.

The obligation for long-term disability benefits is determined using the projected benefit method on a terminal basis. Under this method, the total estimated future benefit is attributed to the year of service in which a disability actually occurs.

Pension and OPEB costs and obligations are determined annually by independent actuaries using management's best estimate assumptions, both economic (inflation, salary escalation, health care cost trends, etc) and demographic (mortality, termination rates, retirement rates, etc). The discount rates used in determining projected benefit obligations and the costs for pension and OPEB are based on representative AA corporate bond yields in accordance with GAAP.

For purposes of determining pension costs, RPP fund assets are valued using a market-related value of assets. The market-related value used by OPG recognizes gains and losses on equity assets relative to a six per cent assumed real return over a five-year period.

Pension and OPEB costs are made up of a number of components, including current service costs, interest costs on the obligations at the appropriate discount rate, the expected return on RPP fund assets using an estimated long-term rate of return, amortization of past service costs (arising from plan amendments) and amortization of actuarial gains or losses. Actuarial gains and losses consist of experience gains and losses, which arise because actual experience differs from that assumed (e.g., investment experience different than expected, fewer deaths or higher inflation), and adjustments for changes in assumptions (e.g., discount rate or a new mortality table).

In accordance with GAAP, actuarial gains and losses are generally amortized over future periods and, therefore, affect recognized costs and the recorded obligation over a period of time. In accordance with GAAP, OPG's policy for accounting for pension and OPEB is to amortize the net cumulative unamortized gain or loss in excess of 10 percent of the greater of the benefit obligation and the market-related value of the plan assets over the expected remaining service life of the employees. This is known as the "corridor approach". Past service costs are amortized on a straight-line basis over the expected average remaining service life of the employees covered by the plan, and therefore also affect recognized costs and the recorded obligation over a period of time.

Thus, as a result of the use of a market-related asset value, the corridor approach, and the amortization of actuarial gains and losses and past service costs, certain components of the actuarial gains and losses and past service costs are not being immediately charged to pension and OPEB costs and, therefore, are not immediately reflected in OPG's financial statements.

7.3.2 Assumptions and Budget Setting for Pension and OPEB Costs

In order to project OPG's total pension and OPEB costs for business planning purposes it is necessary to estimate the value of the obligations and the pension fund assets at the end of each year preceding each of the years in the forecast period. This requires making projections of the actual fund performance and of the assumptions that will be used to determine the costs. The following are the main projected assumptions used in determining the forecasted pension and OPEB costs for 2008 - 2009 and actual assumptions used in determining actual costs for 2005 - 2007:

Chart 5

Pension and OPEB Cost Assumptions

	2005 Actual	**2006 Actual**	**2007 Actual**	**2008 Plan**	**2009 Plan**
Discount rate	6.0% per annum; (5.25% for long term disability benefits)	5.0% per annum; (4.75% for long term disability benefits)	5.25% per annum; (5.0% for long term disability benefits)	5.6% per annum; (5.35% for long term disability benefits)	5.6% per annum; (5.35%for long term disability benefits)
Inflation rate	2.25% per annum	2.0% per annum	2.0% per annum	2.25% per annum	2.25% per annum
Salary schedule escalation rate	3.25% per annum	3.0% per annum	3.0% per annum	3.25% per annum	3.25% per annum
Expected long-term rate of return on pension fund assets	7.0% per annum	7.0% per annum	7.0% per annum	7.0% per annum	7.0% per annum

Actual rate of return on pension fund assets in the prior year(s)[1]	N/A	N/A	N/A	0.8% in 2007	0.8% in 2007 and 7.0% in 2008

[1] No assumption for actual rate of return on pension fund assets in prior year(s) is required for the calculation of actual pension costs because the actual prior year-end pension fund asset values are known.

As a result of OPG being required to make assumptions in forecasting pension and OPEB costs, significant variances may occur between the forecast and the actual pension and OPEB costs to the extent that the actual assumptions are adjusted to reflect various changes, such as those in economic conditions and demographics, between the forecast date and the beginning of the forecast year. Similarly, significant variances may occur between the forecast and actual pension and OPEB costs to the extent that actual experience, such as the return on pension funds assets, to the beginning of the forecast year differs from that assumed at the time the forecast is prepared. OPG proposes a variance account to capture the above differences, as discussed in Ex. J1-T3-S1.

7.3.3 Pension and OPEB Cost Distribution

A portion of OPG's total pension and OPEB costs is charged directly to business areas via payroll burden charged through the pay system as part of the standard labour rate (discussed in section 8). The portion of pension and OPEB costs included in the standard labour rate is based on the budgeted current service cost. The remainder of pension and OPEB costs, which includes interest costs on the obligations, the expected return on pension plan assets, amortization of past service costs, amortization of actuarial gains and losses, and any current service cost variance from budget, is recorded as a centrally-held cost (presented in Ex. F3-T1-S1).

The payroll burden component of the current service costs that is reflected in the regulated business units' OM&A is largely presented as part of labour costs in Ex. F2-T2-S1 and Ex. F2-T4-S1 for Nuclear and Ex. F1-T2-S1 for Regulated Hydroelectric. The current service costs charged via payroll burden to corporate support groups are embedded in the OM&A

costs of these groups. Corporate support groups' OM&A costs are assigned or allocated to the regulated business units in accordance with OPG's cost allocation methodology, as described in Ex. F3-T1-S1.

The centrally-held costs for pension and OPEB are allocated to the regulated business units in proportion to the pension and OPEB costs that are charged to the regulated business units based on direct charges via payroll burden plus the costs assigned and allocated from the corporate support groups. This methodology was reviewed as part of OPG's external cost allocation study presented in Ex. F2 and discussed in Ex. F3-T1-S1. The centrally-held costs for pension and OPEB allocated to the regulated businesses are recorded as OM&A costs.

7.3.4 Comparison of Pension and OPEB Costs

The following chart presents pension and OPEB costs attributed to regulated operations for the period 2005 - 2009:

Chart 6

Pension and OPEB Costs[1,2] ($M)

	Nuclear					**Regulated Hydro**				
	2005 Actual	**2006 Actual**	**2007 Actual**	**2008 Plan**	**2009 Plan**	**2005 Actual**	**2006 Actual**	**2007 Actual**	**2008 Plan**	**2009 Plan**
Pension – Burden Component	109.2	145.6	170.4	165.4	170.8	4.8	7.1	7.8	7.7	7.9
Pension – Centrally Held Component	(20.7)	18.8	13.3	(10.7)	(35.7)	(1.0)	0.9	0.6	(0.5)	(1.6)
Total Pension Cost	**88.5**	**164.4**	**183.7**	**154.7**	**135.1**	**3.8**	**8.0**	**8.4**	**7.2**	**6.3**
OPEB –	42.7	53.3	62.2	60.3	62.8	1.9	2.6	2.8	2.7	2.9

Burden Component										
OPEB – Centrally Held Component	93.5	139.1	121.5	122.1	124.2	4.3	6.8	5.6	5.7	5.7
Total OPEB Cost	**136.2**	**192.4**	**183.7**	**182.4**	**187.0**	**6.2**	**9.4**	**8.4**	**8.4**	**8.6**

[1] Pension and OPEB costs include allocations of costs related to corporate support functions

[2] Supplementary pension plans costs are included with OPEB costs

Pension and OPEB costs charged directly to regulated business units via payroll burden increase significantly over the 2005 - 2007 period. The increases are due mainly to the net impact of successive decreases in the projected discount rate assumption from 6.5 percent in 2005 to 5.4 percent in 2006 and to 5.0 percent in 2007, a decrease in the inflation rate assumption from 2.25 percent in 2005 to 2.0 percent in 2006 and 2007, and updated membership and claims data. A change in the mortality assumption also contributes to the increase in the payroll burden charged in 2007 as compared to 2006. The payroll burden amounts are expected to remain relatively stable in 2008 and 2009.

Pension and OPEB costs recorded as centrally-held costs allocated to the regulated business units increase significantly in 2006 as compared to 2005. Main drivers of the net increase are: the change in assumptions in the discount and inflation rates, updated membership and claims data, and year-over-year variances in RPP fund asset values. The net increases are partially offset by higher amounts of pension and OPEB costs being charged to the business units via payroll burden. Centrally-held pension and OPEB costs decreased in 2007 as compared to 2006 mainly due to the higher amounts of pension and OPEB costs being charged to the business units via payroll burden. The decrease was partially offset by the same main drivers, other than the inflation rate, contributing to the net increase in the costs in 2006 as compared to 2005 identified above, and a change in the mortality assumption. Centrally-held pension costs are expected to decrease further in 2008 and 2009 mainly due to expected changes in RPP fund asset values and pension benefit obligation, and the change in assumptions in the discount and inflation rates. Centrally-held OPEB costs are expected to remain relatively stable over the 2008 - 2009 period as compared to 2007. Specific period-over-period comparison of the centrally-held pension and OPEB costs is presented as part of the analysis of corporate support and centrally-held costs in Ex. F3-T1-S2.

7.3.5 Accounting Treatment of Benefit Plans for Current Employees

Costs associated with benefit plans for current employees are recorded for accounting purposes on the basis of actual benefit payments made by OPG to, or on behalf of the employees. Costs are charged to regulated business units via the burden component of the standard labour rate (discussed in section 8). The component of these costs reflected in the regulated business units' OM&A is largely presented as part of labour costs in Ex. F2-T2-S1 and Ex. F2-T4-S1 for Nuclear and Ex. F1-T2-S1 for Regulated Hydroelectric. Costs are also charged via payroll burden to corporate support groups and are embedded in the OM&A costs of these groups. Corporate support groups' OM&A costs are assigned or allocated to the regulated business units in accordance with OPG's cost allocation methodology, as described Ex. F3-T1-S1.

7.4 Pension and Benefits Summary

OPG has taken a number of steps to control pension and benefits costs. A less generous benefits plan now exists for newly hired Management Group employees and some of the previous benefits enjoyed by existing Management employees are no longer available. In bargaining with both the PWU and the Society, OPG has been successful in placing maximums on a variety of benefits items and in eliminating coverage for others.

8.0 STANDARD LABOUR RATE

As part of its business planning process, OPG develops a standard hourly labour rate for each functional group within the company by job category (e.g., one labour rate is established for all nuclear operators). This rate is uploaded into the time reporting systems and is used to track and record costs for accounting and cost management purposes during the year. Separate standard labour rates are developed for job categories within Nuclear, the Niagara Plant Group and R.H. Saunders. Separate labour rates are also developed for job categories within each corporate support group.

The labour rate is based on actual historical base salary information for each job category, adjusted for escalation rates and increased by the burden component, with the largest component being pension and benefits costs, and other entitlements. A standard overtime hourly labour rate is also developed for represented staff by including an overtime premium, as a percentage of base salary, based on actual historical information. Regular and overtime (where applicable) standard labour rates are determined separately for each of the representations: PWU, the Society, and Management Group.

The escalation rates used in developing labour rates for PWU and the Society represented staff are based on the general wage increases under applicable collective agreements (as discussed in sections 6.1 and 6.2 of this exhibit) and the anticipated staff movement, progressions and promotions. The escalation rates are approximately three percent to four percent annually for PWU and approximately four percent annually for the Society during the 2005 - 2009 period. The escalation rates for Management Group are three percent for each of the years during 2007 - 2009. Escalation rates for Management Group for the period 2005 - 2006 were based on consumer price index increases and were in the one percent to two percent range per year. Escalation rates used in the calculation of standard labour rates are consistent across all functional groups within OPG.

The burden component of the labour rate primarily reflects an estimate of the costs of pension and OPEB as well as costs for health, dental and other benefits for employees while they are employed. The rate is applied as a percentage of base salary in calculating the standard labour rates. The change in the burden percentage over the period 2005 - 2007 is driven largely by increases in total pension and OPEB costs. The reasons for the increases in the burden component of total pension and OPEB costs over the 2005-2007 period are described in section 7.3.4 of this exhibit. The burden component of total pension and OPEB costs is expected to remain relatively stable over the 2007-2009 period. However, higher planned regular staff levels, primarily in Nuclear, in 2008 and 2009 as compared to 2007 result in a lower burden percentage included in the standard labour rate. Staff levels for Nuclear are discussed in Ex. F2-T2-S1. The burden percentages used for developing standard labour rates are the same across all functional groups within OPG.

9.0 BENCHMARKING

OPG conducts benchmarking each year to ensure that data is available to make decisions about the management salary structure and to support the negotiation processes with the unions. The challenge with finding appropriate benchmarks for OPG results from the unique nature of the technology and the business model. There are no utilities in Canada that deals with nuclear, fossil, and hydro technologies to the same extent as OPG. Looking to other heavily unionized manufacturers is also not a complete match because of the ownership structure of the company. These factors make it difficult to find appropriate comparators for the whole company and, as a result, OPG uses several different benchmarks for different segments of the employee population. It should be noted that OPG uses the standard compensation convention of stating that a position is considered at “market” if the comparison is within five to ten percent of the market level.

For management positions, OPG engages Mercer to conduct a market benchmarking review comparing both the structure and the actual compensation elements. The Mercer study uses 37 companies that are similar in size, function or revenue to OPG as well as public and private energy/utility companies. Chart 7 provides a list of comparator groups for the non-utilities sector market and Chart 8 provides the list of comparator groups for the utilities sector market.

Figure 1 (see attachments at the back) shows the market compensation analysis for the non-utilities market. The findings from this analysis indicate that, when compared with the 50th percentile level of the non-utilities market, the executives at OPG are paid below market, the middle management positions are generally at market and the lower level management positions are generally slightly above market. The relationship between the private market and OPG are similar to other public sector employers, in that the executives are generally paid less, middle management is at the average market level and the lower level positions, which are closely linked to unionized employees elsewhere in the company, are higher. Some of the salary levels in the middle management positions also reflect the fact that OPG is carefully managing the issue of wage pressures and compression from the unionized wages of their subordinates.

Figure 2 (see attachments at the back) presents the market compensation analysis for the utilities market. In 2006, OPG compared itself to the 75th percentile of this market because of the additional complexity in OPG that does not exist in other utilities. There were several instances here where no matches between OPG positions and positions in the utilities market could be found. Where matches were found, OPG is above market for more senior-level positions and at market for middle- and lower-level salary bands.

Figure 3 (see attachments at the back) provides a summary of the Mercer results for total remuneration comparison market position for OPG as compared to both the non-utility and utility markets.

In addition, OPG participates in a study of the Power Services Industry conducted by Towers Perrin. This study compares data across Canada where job matches are sufficiently strong. Figure 4 (see attachments at the back) provides a list of comparator organizations. Chart 9 provides a range of positions throughout OPG and compares them to the 75th percentile of market data. This chart indicates that while some positions are paid above market and some are below market, OPG is slightly above the 75th percentile of market on an overall basis.

OPG also tracks the differences between its unions and other employers as much as possible. The primary competitor for nuclear jobs represented by the PWU is Bruce Power LP. A wage comparison, conducted following the last round of negotiations between the PWU and Bruce Power LP is attached at Chart 10. Overall OPG wages are generally lower than those at Bruce Power LP.

Chart 11 provides a comparison of the salaries for Society-represented employees at OPG, Hydro One, and Bruce Power LP. OPG and Bruce Power LP are similar in their pay ranges while Hydro One is slightly higher.

OPG also monitors the general external market to determine the appropriate level of wage adjustments that are required to maintain wage competitiveness. Each year, data is gathered from numerous sources on the projected salary increases for the coming year. Generally, the projections are conservative when compared to the actual increased provided.

Charts 15 and 16 provide a comparison between the general wage increases provided to the Society and the PWU through collective bargaining with OPG and other Ontario Hydro successor and related organizations. Both charts illustrate that OPG has been able to negotiate agreements that provide reasonable wage increases. (It should be noted that the cumulative column provides a compounded total for the increases over the period.)

Chart 7

Market Compensation Review 2006 - Ontario Power Generation

Comparator Group - Non-Utilities Sector Market

Abitibi Consolidated Inc	Finning International
ACE Aviation Holdings	Gerdau Ameristeel
Agrium Inc	Husky Energy
Atco Ltd	Inco Ltd.
CN Rail	Industrial-Alliance Life Ins.
Canadian Natural Resources	Nexen Inc.
Canadian Pacific Railway Ltd.	Nortel Networks Corp.
Canadian Utilities	Nova Chemicals Corp.
Canfor Corp	Potash Corp. of Saskatchewan
Cascades Inc.	Quebecor World Inc.
Celestica	Rogers Communications
CGI (Groupe) Inc.	Shell Canada Ltd
Dofasco Inc.	SNC Lavalin Group Inc.
Domtar Inc.	Suncor Energy Inc.
Enbridge Inc.	Teck Cominco Ltd.
Fairfax Financial Hldg.	Telus Corp.
Falconbridge Ltd.	TransCanada Corp.

Chart 8

Market Compensation Review 2006 - Ontario Power Generation

Comparator Group - Utilities Sector Market

Alberta Electric System Operator
British Columbia Hydro and Power Authority
British Columbia Transmission Corporation
City of Medicine Hat
ENMAX Corporation
EPCOR Utilities Inc.
Hydro One Inc.
Hydro-Quebec
Manitoba Hydro Electric Board
New Brunswick Power Holding Corporation
Newfoundland & Labrador Hydro Electric Corporation
Northwest Territories Power Corporation
Ontario Power Generation Inc.
Saskatchewan Power Corporation
Yukon Energy Corporation

Chart 9

Findings – OPG Salary Variance from the 75th Percentile of Market Data Based on Analysis by Towers Perrin

Salary % Variance from the 75th Percentile	
Position	**Total Sample**
Operating Technician – Senior	1%
Operating Technician – Junior	9%
Operating Technician – Entry	-13%
Senior Business Developer	-7%
Project Financial Analyst – Fully Qualified	5%
Project Engineer – Fully Qualified	13%
Engineer – Specialist	13%
Engineer – Fully Qualified	19%
Engineer – Developmental	22%
Engineer – Entry	13%
Technologist – Advanced Specialist	15%
Technologist – Fully Qualified	17%
Technologist – Developmental	-12%
Technologist – Entry	5%
Senior Daily Trader/Power Trader	26%
Environment – Advanced Specialist	5%
Environment – Fully Qualified	28%
Industrial Nurse	10%
Safety – Advanced Specialist	5%
Safety – Specialist	11%
Purchasing Supervisor	14%
Senior Buyer	8%
Buyer	11%
Junior Buyer	5%
Fleet Manager	-7%
Vehicle Tradesperson	18%
Regulatory Analyst – Specialist	20%
Regulatory Analyst – Fully Qualified	0%
Warehouse Supervisor	21%
Maintenance Supervisor	14%
Maintenance Technician – Senior	-9%
Maintenance Technician – Journeyman	15%
Maintenance Planner	15%
Labourer	24%

Chart 10

2006 - Wage Comparison Between PWU Positions In Bruce Power and OPG

Position	OPG 2006	Bruce Power 2006	2006 Difference BP to OPG		2008 Difference BP to OPG	
			$/Hour	%		
Civil Maintainer I	$31.84	$42.37	-10.53	-33%	-$11.37	-34%
Emergency Response Maintainer	$31.84	$38.20	-6.36	-20%	-$6.92	-20%
Civil Maintainer II	$31.84	$39.70	-7.86	-25%	-$8.52	-25%
Nuclear Operator	$40.93	$47.21	-6.28	-15%	-$6.88	-16%
Shift Control Technician	$40.93	$46.36	-5.43	-13%	-$5.98	-14%
Mechanical Maintainer	$40.93	$46.23	-5.30	-13%	-$5.84	-13%
Nuclear Security Officer	$31.84	$30.94	0.90	3%	$0.81	2%
Clerk II Admin	$26.14	$28.81	-2.67	-10%	-$2.97	-11%
Supervising Nuclear Operator	$45.02	$49.15	-4.13	-9%	-$4.61	-10%
Clerk I Admin	$31.84	$34.50	-2.66	-8%	-$2.98	-9%
Project Tech II – E&C	$40.93	$43.41	-2.48	-6%	-$2.83	-7%
Chemical Technician	$40.93	$41.25	-0.32	-1%	-$0.53	-1%
Cost & Scheduling Technician	$40.93	$43.41	-2.48	-6%	-$2.83	-7%
Mechanical Maintainer UTS	$45.02	$46.23	-1.21	-3%	-$1.50	-3%
Sr. Shift Control Technician	$45.02	$46.36	-1.34	-3%	-$1.64	-3%
Control Maintenance Assessor	$40.93	$46.36	-5.43	-13%	-$5.98	-14%
Finance Clerk	$31.84	$34.50	-2.66	-8%	-$2.98	-9%
FLMa Civil II	$35.02	$42.37	-7.35	-21%	-$7.99	-22%
Maintenance Assessor (Nuclear)	$40.93	$42.37	-1.44	-4%	-$1.72	-4%
Clerk III Admin	$26.14	$24.06	2.08	8%	$2.09	8%

Note that Bruce Power wage information is contained in the collective agreement between Bruce Power and the PWU. The above classifications account for the majority of Bruce Power classifications. Some classifications in OPG do not exist at Bruce Power (e.g., Fossil and Hydro classifications). The above analysis was provided based on a sample group large enough to provide an estimate as to the overall difference in pay rates for all employees represented by the PWU at each of Bruce Power and OPG.

On a weighted average basis the differential between OPG and Bruce Power wages was 12.8 percent in 2006 and will grow to 13.3 percent in 2008.

Chart 11

2007 - Wage Comparison Between Society Positions In Bruce Power, Hydro One and OPG

Salary Band	Range	OPG	Bruce Power	Hydro One
MP6	Min	$96,597	$99,348	$77,329
	Max	$112,097	$110,462	$110,462
MP5	Min	$89,621	$93,191	$72,528
	Max	$105,122	$103,627	$103,627
MP4	Min	$57,449	$58,127	$67,989
	Max	$98,589	$97,156	$97,156
MP3	Min	$57,449	$58,127	$63,815
	Max	$92,500	$91,156	$91,156
MP2	Min	$57,449	$58,127	$59,849
	Max	$86,721	$85,468	$85,468

.

Chart 12

2006 Actual Salary Increases (%) At Median

	Towers Perrin	Mercer	Watson Wyatt	Hay	OPG
Executives	**3.5**	**3.6***	**4.1**	**3.4***	**3.5**
Professional	**3.5**	**3.4***	**3.6**	**3.4***	**3.0**
Trades	**3.2**	**3.3***	**3.3**	**2.8***	**3.0**

***Projected 2006 Averages**

Chart 13

Society General Wage Increases (%)

	2001	2002	2003	2004	2005	2006	2007	Cumulative
IESO	4.5	1	3	3	3	3	3	**26**
Bruce Power	3	2.5	3	4	3.25	3.25	3	**24**
ESA	3	2.5	2.5	3	3	3	4.5	**24**
New Horizons	3	2.5	2.5	3	3	3	3	**22**
Hydro One	3	2	3	3	3	3	3	**22**
OPG	3	2.5	2	3	3	3	3	**21**
NSS	3	2.5	2	3	2.75	3	3	**21**
Inergi	3	2	3	3	2	3	3	**21**
Kinectrics	1	2	2	2	3	3	3	**16**

Chart 14

PWU General Wage Increases (%)

	2001	2002	2003	2004	2005	2006	2007	Cumulative
Kinectrics	3	5	3	2.5	3	3	3	**25**
Bruce Power	3	3.1	4	3	3	3	3.25	**25**
Hydro One	3	3	3	3	3	3.5	3	**24**
New Horizons	3	3	3	3.25	3	3	3	**24**
NSS	3	2	3	2.5	2.5	3	3	**21**
OPG	3	2	3	2.5	2.5	3	3	**21**
ESA	2	2	3	3	3	3	3	**21**
IESO	2	2.	3	3	2.5	3	3	**20**
Inergi	3	3	3	3	3	2.75	n/a	

9.1 Benchmarking Summary

The Mercer Benchmarking study showed that when management positions are compared with those in the non-utilities market, some OPG positions are above market with some at or below market. When the same study compared OPG positions with the utilities market, some positions were above market while most were at market.

OPG also participates in a Power Services industry study with Towers Perrin. This study determined that while some OPG positions are paid above market and some below, on an overall basis, OPG is slightly above the 75th percentile of market.

When comparing OPG PWU positions with those in Bruce Power, the Bruce Power positions are paid significantly more than similar positions within OPG, while Society-represented positions are paid similarly to Bruce Power.

LIST OF ATTACHMENTS

Market Compensation Analysis (cont'd)

Table 1: Non-Utilities Sector Market

2006 Direct Compensation

Band	Data Source	Base Salary (1)		Annual Incentive (2)		Total Cash Compensation (3)	Total Cash Compensation Position to Market	Long-Term Incentive (4)		Total Direct Compensation (5)	Total Direct Compensation Position to Market
		Midpoint	Actual Average	(% of Base)	($ Value)			(% of Base)	($ Value)		
A	OPG	$720,000	$830,400	100%	$830,400	$1,660,800	0.95	-	-	$1,660,800	0.464
	Market	$963,000		81%	$780,030	$1,743,030		191%	$1,839,330	$3,582,360	
B	OPG	$390,000	$490,000	45%	$220,500	$710,500	0.79	-	-	$710,500	0.476
	Market	$485,000		86%	$417,100	$902,100		122%	$591,700	$1,493,800	
C	OPG	$330,000	$325,000	45%	$146,250	$471,250	0.82	-	-	$471,250	0.487
	Market	$371,976		55%	$204,587	$576,563		105%	$391,505	$968,068	
D	OPG	$235,000	$270,000	25%	$67,500	$337,500	1.42	-	-	$337,500	0.983
	Market	$184,878		29%	$52,731	$237,609		57%	$105,581	$343,190	
E	OPG	$200,000	$188,400	25%	$47,100	$235,500	1.08	-	-	$235,500	0.792
	Market	$171,364		28%	$47,573	$218,937		46%	$78,349	$297,286	
F	OPG	$150,000	$155,184	20%	$31,037	$186,221	1.12	-	-	$186,221	0.911
	Market	$137,128		21%	$28,742	$165,870		28%	$38,531	$204,401	
G	OPG	$110,000	$127,416	15%	$19,112	$146,528	1.24	-	-	$146,528	1.033
	Market	$102,000		16%	$16,255	$118,255		23%	$23,596	$141,851	
H	OPG	$90,000	$110,976	15%	$16,646	$127,622	1.21	-	-	$127,622	1.061
	Market	$93,646		13%	$12,107	$105,753		16%	$14,574	$120,327	
I	OPG	$80,000	$83,959	10%	$8,396	$92,355	1.15	-	-	$92,355	1.043
	Market	$72,737		11%	$7,910	$80,647		11%	$7,867	$88,514	
J	OPG	$65,000	$62,448	8%	$4,996	$67,444	0.96	-	-	$67,444	0.956
	Market	$64,138		10%	$6,414	$70,552		-	-	$70,552	
K	OPG	$50,000	$59,048	8%	$4,724	$63,772	1.03	-	-	$63,772	1.027
	Market	$57,612		8%	$4,513	$62,125		-	-	$62,125	
L	OPG	$45,000	$50,966	8%	$4,077	$55,043	1.10	-	-	$55,043	1.098
	Market	$46,849		7%	$3,279	$50,128		-	-	$50,128	
M	OPG	$35,000	$39,591	8%	$3,167	$42,758	1.13	-	-	$42,758	1.131
	Market	$35,596		6%	$2,225	$37,821		-	-	$37,821	

2006 Non-Cash Compensation / **2006 Total**

Band	Data Source	Perquisites (6)				Benefits Pre '01 (7)	PowerFlex Credits (8)	Pension (9)	Total Non-Cash Compensation (10)	Total Non-Cash Compensation Position to Market	Total Remuneration (11)	Total Remuneration Position to Market
		Car Allowance	Club Membership	Financial Counseling	Annual Medical							
A	OPG	$24,000			-	$27,752	$50,000	$365,635	$467,387	1.307	$2,128,187	0.540
	Market	$24,000	$7,000	$4,000	$1,200	$34,423	-	$287,062	$357,685		$3,940,045	
B	OPG	$30,000	-	-	-	$16,436	$48,259	$134,704	$229,399	1.241	$939,899	0.560
	Market	$18,000	$3,500	$3,500	$1,200	$18,728	-	$139,854	$184,782		$1,678,582	
C	OPG	$30,000	-	-	-	$14,378	$35,022	$111,730	$191,130	1.352	$662,380	0.597
	Market	$12,000	$3,500	$3,500	$1,200	$16,313	-	$104,886	$141,399		$1,109,467	
D	OPG	$20,000	-	-	-	$11,121	$22,634	$62,943	$116,698	1.788	$454,198	1.112
	Market	$12,000	$3,500	$3,500	$1,200	$8,618	-	$36,459	$65,277		$408,467	
E	OPG	$12,000	-	-	-	$9,920	$14,095	$51,390	$87,405	1.529	$322,905	0.911
	Market	$9,000	$3,500	$2,000	$1,200	$8,134	-	$33,337	$57,171		$354,457	
F	OPG	-	-	-	-	$8,206	$12,241	$35,207	$55,654	1.154	$241,875	0.957
	Market	$9,000	$3,500	$2,000	$1,200	$6,789	-	$25,737	$48,226		$252,627	
G	OPG	-	-	-	-	$6,834	$9,487	$24,556	$40,877	1.031	$187,405	1.033
	Market	$9,000	$3,500	$2,000	$1,200	$5,578	-	$18,365	$39,643		$181,494	
H	OPG	-	-	-	-	$6,148	$7,514	$19,978	$33,640	1.539	$161,263	1.134
	Market	-	-	-	-	$5,347	-	$16,506	$21,853		$142,180	
I	OPG	-	-	-	-	$5,805	$4,561	$19,226	$29,592	1.763	$121,947	1.158
	Market	-	-	-	-	$4,591	-	$12,198	$16,789		$105,303	
J	OPG	-	-	-	-	$5,291	$2,414	$15,166	$22,871	1.560	$90,315	1.060
	Market	-	-	-	-	$4,279	-	$10,377	$14,656		$85,208	
K	OPG	-	-	-	-	$4,777	$2,809	$11,245	$18,831	1.450	$82,603	1.100
	Market	-	-	-	-	$4,043	-	$8,948	$12,991		$75,116	
L	OPG	-	-	-	-	$4,605	$1,797	$9,858	$16,260	1.540	$71,303	1.175
	Market	-	-	-	-	$3,652	-	$6,903	$10,555		$60,683	
M	OPG	-	-	-	-	$4,262	$897	$7,274	$12,433	1.529	$55,191	1.201
	Market	-	-	-	-	$3,237	-	$4,893	$8,130		$45,951	

Notes:

(1) For OPG, Base Salary Midpoint is the salary midpoint for each band. Actual Average Salary represents the average salary of positions matched for each band.
All other OPG compensation components are derived from the Base Salary Midpoint value, where applicable. For market data, Base Salary represents the average salary of position matches at the 50th percentile.
(2) Represents target annual incentive for OPG and for Bands A-M market data. Bands A-C market data actual annual incentive is used.
(3) Total Cash Compensation equals Base Salary plus Annual Incentive and PowerFlex Credits.
(4) OPG does not currently have a Long-Term Incentive Plan. For market data, reflects actual long-term incentive value.
(5) Total Direct Compensation equals Total Cash Compensation plus Long-Term Incentive.
(6) Perquisite market data figures are based on previous analysis, as summarized in Mercer letter to Tony Marr, "Industry Perquisite Information - Additional Details", dated December 21, 1999. This data was adjusted to reflect current markets levels today.
(7) Benefits include value of Life, Accident, Disability, Health and Dental Benefits paid by the company. Values for LTD, Health and Dental include inflationary/utilization adjustments over the prior year's values for costing changes seen in today's marketplace.
Benefit value is based on the Heritage program and applied to employees hired prior to July 1, 2001. Figures reflect relative values of the benefit programs and not true costs.
(8) For OPG, PowerFlex Credits are as provided by OPG. This benefit was discontinued in 2001. Not all employees are eligible.
(9) For Pension, values for Bands A-H are based on ESPS plan and values for Bands I-M are based on SPS plan.
For market data, Pension amounts are based on base salary plus annual incentive target for Bands A-M.
(10) Total Non-Cash Compensation is the sum of Perquisites, 2006 Benefits, and Pension.
(11) Total Remuneration is the sum of Total Direct Compensation and Total Non-Cash Compensation. Total Remuneration does not include any amount in respect of non-pension post-retirement benefits.

Market Compensation Analysis (cont'd)

Table 2: Utilities Sector Market

2006 Direct Compensation

Band	Data Source	Base Salary (1) Midpoint	Base Salary (1) Actual Average	Annual Incentive (2) (% of Base)	Annual Incentive (2) ($ Value)	Total Cash Compensation (3)	Total Cash Compensation Position to Market	Long-Term Incentive (5) (% of Base)	Long-Term Incentive (5) ($ Value)	Total Direct Compensation (6) (7)	Total Direct Compensation Position to Market
A	OPG	$720,000	$830,400	100%	$830,400	$1,660,800	3.75	-	-	$1,660,800	3.75
	Market	**$305,097**		**45%**	**$137,294**	**$442,391**		-	-	**$442,391**	
B	OPG	$390,000	$490,000	45%	$220,500	$710,500	-	-	-	$710,500	-
	Market	-		-	-	-		-	-	-	
C	OPG	$330,000	$325,000	45%	$146,250	$471,250	-	-	-	$471,250	-
	Market	-		-	-	-		-	-	-	
D	OPG	$235,000	$270,000	25%	$67,500	$337,500	-	-	-	$337,500	-
	Market	-		-	-	-		-	-	-	
E	OPG	$200,000	$188,400	25%	$47,100	$235,500	1.25	-	-	$235,500	1.25
	Market	**$150,443**		-	-	**$150,443**		-	-	**$150,443**	
F	OPG	$150,000	$155,184	20%	$31,037	$186,221	1.00	-	-	$186,221	1.00
	Market	**$151,733**		**23%**	**$34,899**	**$186,632**		-	-	**$186,632**	
G	OPG	$110,000	$127,416	15%	$19,112	$146,528	1.03	-	-	$146,528	1.03
	Market	**$123,108**		-	-	**$123,108**		-	-	**$123,108**	
H	OPG	$90,000	$110,976	15%	$16,646	$127,622	0.95	-	-	$127,622	0.95
	Market	**$112,287**		**20%**	**$22,457**	**$134,744**		-	-	**$134,744**	
I	OPG	$80,000	$83,959	10%	$8,396	$92,355	0.92	-	-	$92,355	0.92
	Market	**$91,542**		-	-	**$91,542**		-	-	**$91,542**	
J	OPG	$65,000	$62,448	8%	$4,996	$67,444	-	-	-	$67,444	-
	Market(14)	-		-	-	-		-	-	-	
K	OPG	$50,000	$59,048	8%	$4,724	$63,772	-	-	-	$63,772	-
	Market(14)	-		-	-	-		-	-	-	
L	OPG	$45,000	$50,966	8%	$4,077	$55,043	-	-	-	$55,043	-
	Market(14)	-		-	-	-		-	-	-	
M	OPG	$35,000	$39,591	8%	$3,167	$42,758	-	-	-	$42,758	-
	Market(14)	-		-	-	-		-	-	-	

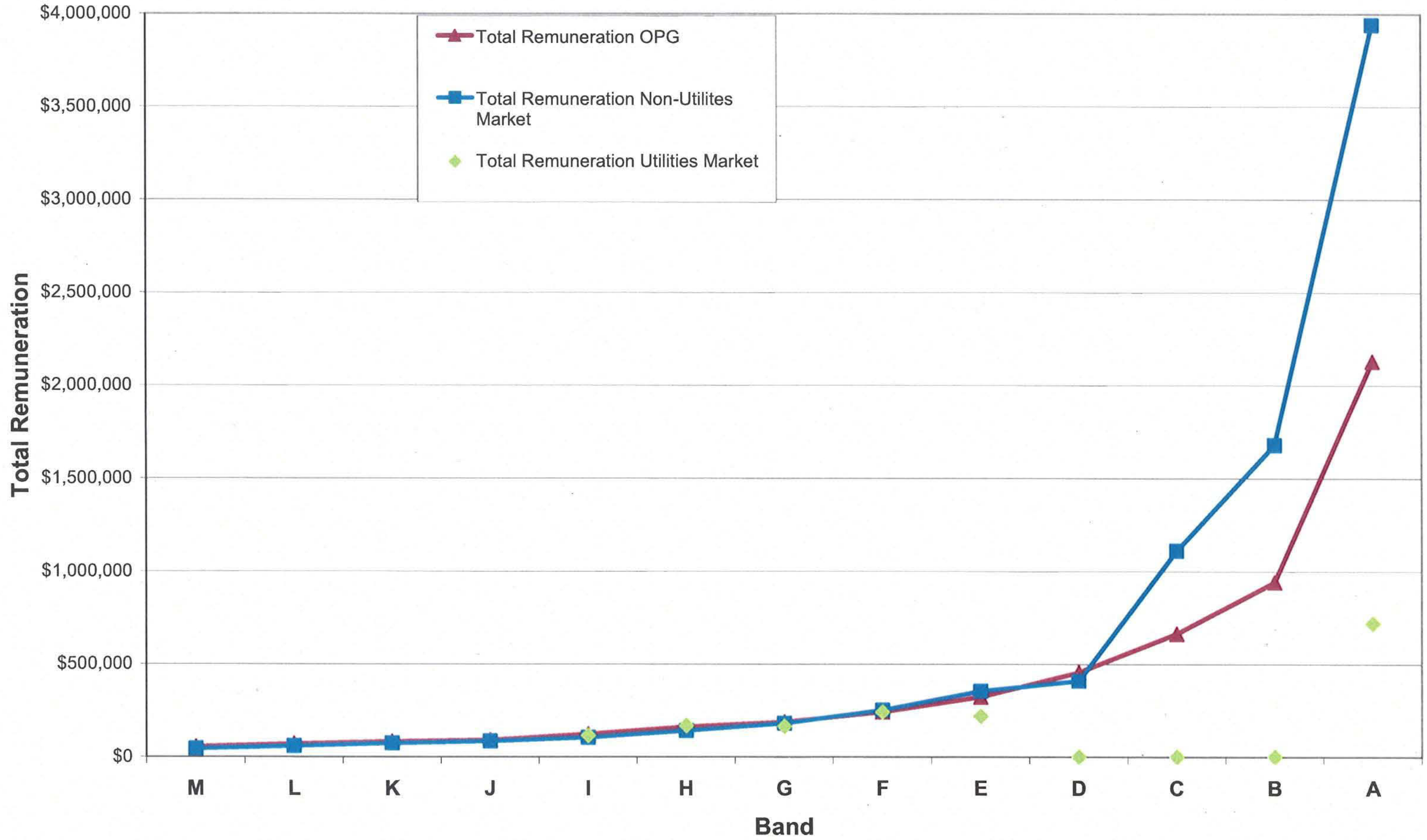
2006 Non-Cash Compensation / **2006 Total**

Band	Data Source	Total Perquisites: Perquisites (13)	Total Perquisites: Annual Medical	Benefits Pre '01 (8)	PowerFlex Credits (9)	Pension (10)	Total Non-Cash Compensation (11)	Total Non-Cash Compensation Position to Market	Total Remuneration (12)	Total Remuneration Position to Market
A	OPG	$24,000	-	$27,752	$50,000	$365,635	$467,387	1.69	$2,128,187	2.96
	Market	**$31,000**	**$1,200**	**$23,221**	-	**$221,243**	**$276,664**		**$719,055**	
B	OPG	$30,000	-	$16,436	$48,259	$134,704	$229,399	-	$939,899	-
	Market	-	-	-	-	-	-		-	
C	OPG	$30,000	-	$14,378	$35,022	$111,730	$191,130	-	$662,380	-
	Market	-	-	-	-	-	-		-	
D	OPG	$20,000	-	$11,121	$22,634	$62,943	$116,698	-	$454,198	-
	Market	-	-	-	-	-	-		-	
E	OPG	$12,000	-	$9,920	$14,095	$51,390	$87,405	1.27	$322,905	1.47
	Market	**$14,000**	**$1,200**	**$8,284**	-	**$45,301**	**$68,785**		**$219,228**	
F	OPG	-	-	$8,206	$12,241	$35,207	$55,654	1.01	$241,875	1.00
	Market	**$8,000**	**$1,200**	**$7,561**	-	**$38,530**	**$55,291**		**$241,923**	
G	OPG	-	-	$6,834	$9,487	$24,556	$40,877	0.97	$187,405	1.13
	Market	**$6,000**	**$1,200**	**$6,320**	-	**$28,688**	**$42,208**		**$165,316**	
H	OPG	-	-	$6,148	$7,514	$19,978	$33,640	0.99	$161,263	0.96
	Market	**$3,000**	-	**$5,854**	-	**$25,199**	**$34,053**		**$168,797**	
I	OPG	-	-	$5,805	$4,561	$19,226	$29,592	1.21	$121,947	1.05
	Market	-	-	**$5,328**	-	**$19,140**	**$24,468**		**$116,010**	
J	OPG	-	-	$5,291	$2,414	$15,166	$22,871	-	$90,315	-
	Market(14)	-	-	-	-	-	-		-	
K	OPG	-	-	$4,777	$2,809	$11,245	$18,831	-	$82,603	-
	Market(14)	-	-	-	-	-	-		-	
L	OPG	-	-	$4,605	$1,797	$9,858	$16,260	-	$71,303	-
	Market(14)	-	-	-	-	-	-		-	
M	OPG	-	-	$4,262	$897	$7,274	$12,433	-	$55,191	-
	Market(14)	-	-	-	-	-	-		-	

Notes:
In the case where there was insufficient data "-" will appear.
(1) For OPG, Base Salary Midpoint is the salary midpoint for each band. For OPG, Actual Average Salary of represents the average salary of positions matched for each band. All other OPG compensation components are derived from the Base Salary Midpoint value, where applicable. For market data, Base Salary represents actual salary value.
(2) Represents target annual incentive for OPG and for Bands A-M market data.
(3) Total Cash Compensation equals Base Salary plus Annual Incentive.
(4) Total Cash Compensation Position to Market for Bands E,G and I reflect Base Salary Compensation Positon to Market.
(5) OPG does not currently have a Long-Term Incentive Plan. For market data, reflects actual long-term incentive value.
(6) Total Direct Compensation equals Total Cash Compensation plus Long-Term Incentive.
(7) Total Direct Compensation Position to Market for Bands E,G and I reflect Base Salary Compensation Positon to Market.
(8) Benefits include value of Life, Accident, Disability, Health and Dental Benefits paid by the company. Values for LTD, Health and Dental include inflationary/utilization adjustments over the prior year's values for costing changes seen in today's marketplace. Benefit value is based on the Heritage prgram and applied to employees hired prior to July 1, 2001. Figures reflect relative values of the benefit programs and not true costs.
(9) For OPG, PowerFlex Credits are as provided by OPG. This benefit was discontinued in 2001. Not all employees are eligible.
(10) For Pension, values for Bands A-H are based on ESPS plan and values for Bands I-M are based on SPS plan. For market data, Pension amounts are based on base salary plus annual incentive target for Bands A-M.
(11) Total Non-Cash is the sum of Perquisites, 2006 Benefits, and Pension.
(12) Total Remuneration is the sum of Total Direct Compensation and Total Non-Cash Compensation. Total Remuneration does not include any amount in respect of non-pension post-retirement benefits.
(13) Perquisites include car allowance, club membership and financial counselling. Market data is based on estimate from industry survey.
(14) Public utilites market data not available for grades J to M.

Market Compensation Analysis (cont'd)

Summary of Findings – Total Remuneration Comparison



*Insufficient market data to display compensation data for Bands B, C and D, and incentive data for bands E, G and I

Comparator Organizations

Investor Owned

- AltaLink Management Ltd.
- ATCO Electric Ltd.
- ATCO Power Ltd.
- Bruce Power
- Enbridge Gas Distribution
- FortisAlberta Inc.
- Maxim Power Corp.
- Nexen Inc.
- Nova Scotia Power Inc./Emera Inc.
- TransAlta Corporation
- TransCanada Pipelines Limited
- Whitecourt Power LP

Government Owned

- Alberta Electric System Operator
- British Columbia Hydro and Power Authority
- British Columbia Transmission Corporation
- ENMAX Corporation
- EPCOR Utilities Inc.
- Hydro One Inc.
- Hydro-Quebec
- New Brunswick Power Holding Corporation
- Newfoundland & Labrador Hydro Electric Corporation
- Saskatchewan Power Corporation

OPG PROCURMENT PROCESS

1.0 PURPOSE

The purpose of this exhibit is to provide an overview of OPG's procurement process which is applicable to the regulated hydroelectric and nuclear businesses as well as OPG corporate. This information is provided in support of the OM&A purchased services information presented for each of Regulated Hydroelectric (Ex. F1-T5-S1), Nuclear (Ex. F2-T6-S1), and Corporate (Ex. F3-T5-S2).

2.0 OVERVIEW OF PROCUREMENT PROCESS

OPG's procurement process is conducted as follows[1]:

- Need for a service or item is identified and a requisition is created and approved by the appropriate requisitioning authority per OPG's Organizational Authority Register.
- If no existing agreement is in place which can satisfy the need for a service or item, the procurement business units of nuclear, hydroelectric or corporate, as applicable (collectively referred to as Supply Chain), in consultation with the requisitioner, seeks quotations[2] or proposals[3] from at least two competitive sources. The exception to this is when a single source strategy is used.
- Single source strategy is used when it is not possible and/or is impractical to obtain the required items or service through normal competitive procurement methods. Approval by the appropriate purchasing authority (according to OPG's Organizational Authority Register) must be sought when single source strategy is used.

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[1] This process applies to the acquisition of services or items above a threshold value of $10,000. Below this threshold value, purchasing authority is delegated to the businesses through the use of a purchasing card.

[2] An request for quotation ("RFQ") is a request for price and availability of items/services based on specified technical, quality, and commercial requirements where the value is estimated up to $100K.

[3] An request for proposal ("RFP") is a formal request for price and availability of an item and/or service based on specified technical and commercial requirements where the value is estimated to be greater than $100K.

- When soliciting competitive quotations or proposals, Supply Chain prepares a list of selection criteria, against which proposals/quotations are evaluated for awarding of the contract.
- For services performed on OPG premises, potential suppliers are pre-qualified with respect to safety performance.
- To ensure the integrity of the procurement process, Supply Chain acts as the single point of contact with potential suppliers until evaluation of proposals or quotations is complete and a supplier has been selected. The requisitioner is responsible for technical evaluation and Supply Chain for commercial evaluation of quotations and proposals. Cost is one of the criteria used in evaluating proposals or quotations; however, the relative weighting of the selection criteria varies and there may be instances when the lowest cost supplier is not selected on the basis of other criteria (e.g., delivery) being more important given the nature of the work to be undertaken. Evaluation of the selection criteria is properly documented and the selection of a supplier that is not the lowest cost supplier would be appropriately documented as well.
- Purchasing authority has been delegated to Supply Chain.
- Negotiation and finalization of the purchase order and/or agreement terms is performed jointly by Supply Chain and the requisitioner. A purchase order and/or agreement will be issued upon Supply Chain receiving a requisition approved by the appropriate organizational authority register authority. In some areas, master agreements have been developed with certain suppliers to shorten the procurement cycle time for services and items through pre-negotiated terms, conditions and rates. In other areas, OPG has established master agreements with more than one supplier for the same type of service under similar terms and conditions to create a competitive environment whereby the suppliers under the master agreement competitively bid thus ensuring OPG receives the best value.
- Once the supplier is awarded business, an OPG Contract Administrator monitors the contract to ensure the supplier meets all contractual obligations. The performance of the supplier is assessed by the Contract Administrator and Supply Chain and consideration is given to this when selecting proponents for future work. Supply Chain manages data on the performance of suppliers, including supplier scorecards. Any observations regarding

the supplier's unsatisfactory execution of their obligations by the requisitioner is recorded and communicated to Supply Chain for appropriate action.

- The requisitioner notifies Supply Chain once the contract requirements are complete and final payment has been made. The purchase order is subsequently closed out by Supply Chain.
- This process is broadly applicable to both the Nuclear and Hydroelectric businesses, as well as Corporate; however, there are additional quality assurance requirements which are part of the Nuclear procurement process.

OM&A PURCHASED SERVICES – CORPORATE

1.0 PURPOSE

The purpose this exhibit is to present the purchases of OM&A services and products by the corporate support groups within OPG that meet the threshold of one percent of the OM&A expense before taxes consistent with the OEB filing guidelines for OPG's Application.

2.0 OVERVIEW

An overview of OPG's procurement process which is applicable to the corporate groups is presented in Ex. F3-T5-S1.

The corporate OM&A expense before taxes is equal to the sum of the corporate support groups and centrally-held costs. This sum ranges from $567.1M to $719.0M over the 2005 - 2009 period as presented in Ex. F3-T1-S1 Table 1. For the corporate groups, the threshold of one percent of the OM&A expense before taxes is approximately $5M.

Information on vendor contracts for OM&A purchased services by the corporate groups that are equal to or in excess of $5M for any of the years 2005, 2006 or 2007 is presented in Chart 1. The information in Chart 1 provides the total value of the contracts for the corporate group and not an allocation to the regulated facilities.

Chart 1

Purchase of Services - Corporate OM&A Contracts

Vendor Name	**Description/Nature of Activities**	**Tendering Process**	
		Competitive	Single Source
New Horizons System Solution	Provide OPG with information technology services as specified in F3-T1-S1 Appendix A.	✓	
Marsh Canada Limited	Insurance premiums.	✓[1]	
CCSI Technology Solutions Corporation/ GE Capital Information Technology	Servers, laptops, personal computers and peripherals purchases.	✓	
Kolter Property Management	Manage 700 University Avenue building.	✓	
PHH Vehicle Management Services	Transport and work equipment leasing.	✓	
ARI Financial Services Inc.	Transport and work equipment leasing.	✓	
Partners and Edell	Reputation building, community outreach and communication services and water safety.	✓	

Total 2005 Spend ($M) = 158.0
Total 2006 Spend ($M) = 160.7
Total 2007 Spend ($M) = 164.3

[1] Marsh Canada is the broker for OPG's insurance purchases. Total spend amount included for Marsh Canada predominantly represents insurance premiums distributed among a large number of individual insurance providers pursuant to applicable insurance policies. The use of broker services to obtain insurance coverage provides for a competitive tendering process.

Report to

Ontario Power Generation Inc.

Regarding

Corporate Allocation Methodology Review

April 30, 2006

R·J·Rudden
ASSOCIATES
A Black & Veatch Company

TABLE OF CONTENTS

EXHIBITS

I. SUMMARY

A. Background and Purpose

R. J. Rudden Associates ("Rudden" or "we") is pleased to submit this Report to Ontario Power Generation Inc. ("OPG") on our Cost Allocation Methodology Review ("Review"). Rudden was engaged by OPG to perform this Review for the purpose of evaluating whether the methodology employed by OPG to distribute Centralized Support and Administrative Costs ("CSA Costs") separates the CSA Costs between regulated nuclear, regulated hydroelectric and unregulated operations in a manner that meets current best practices and is consistent with precedents on cost allocation established by the Ontario Energy Board ("OEB"), and to make appropriate recommendations to OPG. In this Report "regulated" and "unregulated" refer only to regulation by the OEB with respect to the payment amounts that OPG receives for the output from its generating stations.

Rudden was also asked to review the methodology used by OPG to compute Service Fees related to assets that are held by OPG's Other Business unit and used by both the regulated and unregulated generation operations.

Rudden was also asked to review OPG's methodology regarding distributing the CSA Costs between energy output and Ancillary Services.

Rudden, a unit of Enterprise Management Solutions, Black & Veatch Corporation, is a strategic, economic and management consulting firm specializing in energy matters. We provide assistance in areas such as economic analysis, strategy development, operational assessment, industry restructuring support, litigation and regulatory support and technical analysis. The firm has more than 24 years of experience providing the services necessary to develop regulatory and case-specific strategies, make the decisions about whether or not to file, and execute the work. Rudden has assisted many dozens of electric, gas, water and telecommunications clients in hundreds of proceedings. Rudden has completed cost of service and cost allocation studies for "wires-only" utilities, integrated utilities and Independent System Operators in many jurisdictions in Canada and the U. S.

B. Ontario Power Generation Inc.- Business, Organization and the CSA Costs

Ontario Power Generation Inc. is wholly owned by the Province of Ontario. Its principal business is the generation and sale of electricity in Ontario and to interconnected markets.

OPG is primarily organized by generation technology, with separate Business Units for Nuclear, Hydroelectric, Fossil, and Other Business (non-generation). All the stations in the Nuclear Business Unit are regulated, all the stations in the Fossil Business Unit are unregulated, and the Hydroelectric Business Unit includes both regulated and unregulated stations. Other Business includes the Energy Markets group, which supports the generation businesses of OPG and also engages in other activities. Table 5 provides additional information on the Business Units.

The costs for the regulated Nuclear and regulated Hydroelectric generating operations, including the CSA Costs distributed to them, may be considered in future proceedings before the OEB in determining revenue requirements and payment amounts that OPG receives for regulated Nuclear and regulated Hydroelectric generating operations.

Many of the functions and services necessary to support the Business Units are performed by centralized employee groups within OPG. The employee groups that provide the Centralized Support and Administrative functions and services are listed in . Table 1 also includes a non-employee group- Centrally Held Costs. Centrally Held Costs are included because they also must be distributed among the Business Units.

TABLE 1 GROUPS PROVIDING CSA FUNCTIONS AND SERVICES	
Human Resources	CIO
Corporate Center	Energy Markets
Nuclear Waste Management	Real Estate
Finance	Hydroelectric Common
Corporate Affairs	Centrally Held Costs (not a group)

Each group is organized into departments, as shown in Table 6. Exhibit A describes the functions and services provided by each of the departments within each group.

Some departments support only one Business Unit. Most departments support more than one Business Unit, and for those departments, it is necessary to distribute the costs of their resources (employees' time and other costs) among the Business Units they support. In many cases, specific resources can be identified to particular Business Units. In those cases, although the costs are incurred by a centralized department, there is a direct relationship between the costs incurred and the Business Units that cause the costs.

In other cases, the portions of resources (employees' time and other costs) that the department spends on each Business Unit can be estimated.

In cases where neither specific identification nor estimates are possible, it is necessary to allocate the costs of the resources to Business Units using cost drivers.

These methods of distributing costs are discussed in more detail in Section II.

C. Summary of Approach

Our Review comprised the tasks listed in Table 2.

TABLE 2 TASKS		
TASK	**DESCRIPTION**	**Section**
Task 1	Identified the business of OPG and its overall organization.	III.A.
Task 2	Identified how OPG is organized to meet the operating and administrative needs of the Business Units and the Stations. Identified the departments included in the CSA Costs.	III.B.
Task 3	Reviewed methodology currently used by OPG to distribute CSA Costs.	III.C.
Task 4	Interviewed OPG personnel responsible to obtain information used to distribute CSA Costs. Interviewed service recipients.	III.D.
Task 5A	Evaluated OPG's methodology including design, use of direct assignment, selection of cost drivers and documentation.	IV.A.
Task 5B	Prepared recommendations.	IV.B.

A cost driver is a formula for sharing the cost of a resource among those who cause the cost to be incurred. The use of cost drivers conforms to many regulatory precedents. Rudden applies the following guiding principles in evaluating cost drivers:

> *Economics*- Cost drivers should be selected based on cost causation, which means there is a causal relationship between the cost driver and the costs incurred in performing the activity. Where cost causation cannot be easily implemented or established, selecting cost drivers based on benefits received is a fair and consistent treatment.
>
> *Implementation*- Other factors considered in assigning cost drivers include practicality, stability and materiality.

D. Scope

Consistent with standard practice for consulting assignments, we relied on the genuineness and completeness of all documents presented to us by OPG and we accepted factual statements made to us by OPG (e.g., budget dollars; specific time assignments), subject only to overall reasonableness considerations and actual contrary knowledge, but without independent confirmation.

The total CSA Costs for 2006 are estimated to be C$729 million (including Hydroelectric Common as described in Exhibit A). In making judgments based on materiality, and in developing statistics for this Report, we used a budget provided by OPG that OPG expects will be reasonably close to actual departmental costs for 2006.

Rudden did not review the models used by OPG to implement the methodology.

E. Summary of Conclusions

Rudden's conclusions regarding OPG's allocation methodology for CSA Costs follow:

- ✓ The overall approach is appropriate for the business organization of OPG.
- ✓ Direct assignments of costs by specific identification and by estimation are based on sufficient information reasonably applied.
- ✓ Direct assignments are used wherever possible.
- ✓ The cost drivers selected by OPG for those instances where less than all costs could be distributed by direct assignments, are appropriate. The cost drivers reflect recommendations from Rudden, and are identified in Exhibit B, which is discussed in Section IV.C.
- ✓ Documentation for the process should be improved as discussed in Section IV.A.
- ✓ The methodology used by OPG to distribute the CSA Costs separates the CSA Costs between regulated and unregulated Business Units in a manner that meets current best practices and is consistent with cost allocation precedents established by the OEB.

Our conclusions are further discussed in Section IV.A.

Rudden has also recommended several refinements to OPG's methodology, including separating the CSA Costs between labor and non-labor, analyzing the CSA Costs in more detail for the purpose of assigning cost drivers and improving the selection of cost drivers. Rudden also recommended improvements to documentation and increasing the scope and frequency of OPG's review process. Our recommendations are further discussed in Section IV.B.

Regarding Service Fees, Rudden reviewed the methodology that OPG uses to determine the Service Fees and determined that it is reasonable. Our findings are discussed in Section V.

Regarding Ancillary Services, Rudden reviewed OPG's methodology not to distribute CSA Costs to Ancillary Services, and we believe it is reasonable. Our findings are discussed in Section VI.

II. Principles of Cost Distribution

A. Overview

The primary purpose of our Cost Allocation Methodology Review was:

> Evaluate whether the methodology employed by OPG to distribute CSA Costs separates the CSA Costs between regulated and unregulated operations in a manner that meets current best practices and is consistent with precedents on cost allocation established by the OEB, and make appropriate recommendations to OPG.

The purpose of OPG's cost distribution methodology is to distribute the CSA Costs among the Business Units. First, the costs are distributed among the Business Units and in some cases, to other CSA groups. Then, the costs that were distributed to other CSA groups must be redistributed to the Business Units.

B. Direct Assignment and Allocation

There are two methods to distribute shared costs among Business Units – Direct Assignment and Allocation.

Direct Assignment is used when the resources used by a particular Business Unit can be reasonably established. Direct Assignment includes:

- *Specific identification* of resources (individual employees and specific cost items) to a particular Business Unit. Although in OPG's organizational structure the costs are incurred by a centralized department, in many instances there is a direct relationship between the costs and the Business Unit (and sometimes a particular Station) that causes the costs. For example, in many cases specific employees within a centralized department support a particular Business Unit or Station.

- *Estimation* of the resources (portions of employees' time and other costs) utilized by a Business Unit. Estimates may be based on current time estimates or actual historical activity.

- *Service Fees* charged by OPG's Other Business unit for the use of assets held by Other Business and used by both the regulated and unregulated generation operations, as discussed in Section V.

Approximately 46.7% of CSA Costs (reflecting 51.5% of CSA Functions and 39.1% of Centrally Held Costs) were directly assigned to Business Units by specific identification or by estimation, excluding the Hydroelectric Common Cost group which is 100%

specific to the Hydroelectric Business Unit and is distributed between its regulated and unregulated operations.

Allocation is used when more than one Business Unit uses a resource, but the portions of the resource that each uses cannot be directly established. In these cases, cost drivers must be assigned to allocate the costs of the resource. A cost driver is a formula for allocating the cost of a resource among those who cause the cost to be incurred. The principles that Rudden applies in evaluating the appropriateness of cost drivers are discussed in Section II.C. below.

Direct assignment is preferable to Allocation because it is based on a more direct relationship.

As an example of the different methods to distribute costs, consider two departments: Human Resources- Nuclear HR & Employee Safety and Human Resources- Compensation & Benefits. Nuclear HR & Employee Safety is devoted exclusively to the Nuclear Business Unit, and its costs are *directly assigned* to that Business Unit.

Some of the labor resources in the Compensation & Benefits department are also devoted exclusively to specific Business Units, and those costs are also *directly assigned* to those Business Units. The balance of the resources in the Compensation & Benefits department support all Business Units. The costs of these resources are *allocated* among the Business Units based on the number of full-time equivalent employees within the Business Unit.

C. Cost Drivers

As stated above, a cost driver is a formula for sharing the cost of a resource among those who cause the cost to be incurred. Rudden uses the following guiding principles in evaluating cost drivers:

> *Economics*- Cost drivers should be selected based on cost causation, which means there is a causal relationship between the cost driver and the costs incurred in performing the activity. Where cost causation cannot be easily implemented or established, selecting cost drivers based on benefits received is a fair and consistent treatment.
>
> *Implementation*- Other factors considered in assigning cost drivers include:
>
> - Practicality – The cost driver should be understandable, obtainable at reasonable cost and objectively verifiable.
> - Stability – When estimates are used, the cost driver should be able to be estimated with reasonable accuracy, and estimates should be unbiased.

- o Materiality – When choosing between cost drivers, small differences can often be ignored in favor of Practicality and Stability (see above).

D. Types of Cost Drivers

Cost drivers can be classified as External or Internal. External drivers are based on data that are external to the cost allocation process, such as physical units or dollar amounts.

Internal drivers are based on values computed as part of the cost allocation process. For example, the cost of a supervisor's salary might be allocated in proportion to the salaries of the people being supervised, and general departmental costs might be allocated in proportion to directly assigned departmental costs.

Table 3 further describes different types of cost drivers.

TABLE 3 DESCRIPTION OF TYPES OF COST DRIVERS

TYPE	DESCRIPTION	EXAMPLES
External Drivers		
Physical	Physical units; usually objectively determinate but often require estimates	FTEs (Full-Time Equivalent Employees), Number of Business Workstations, LAN IDs, SAP User Counts, Number of Transactions
Financial	Financial information from accounting or management reports including budgets and projections	Revenue, OM&A, Net Assets, Value of Transactions, Pension / OPEB Costs, Labor Costs
Blended	Weighted combinations of other cost drivers, used when more than one is applicable and none is clearly preferable; weights determined by judgment	Blend- OM&A / Capital Expenditures with 50% weight for OM&A and 50% for Capital Expenditures
Internal Cost Drivers		
All Internal Cost Drivers	Use the result of previous allocations as the basis for further allocations	General departmental costs might be allocated in same proportion as directly assigned departmental costs

The values for the cost drivers for a Business Unit are the sum of the values for the generating stations in the Business Unit, plus any Business Unit support activities.

Table 4 summarizes the types of costs drivers used to distribute CSA Costs (excluding Hydroelectric Common) to Business Units; the percentages use estimated 2006 Budget amounts.

TABLE 4 DIRECT ASSIGNMENTS AND COST DRIVERS USED FOR DISTRIBUTION OF CSA COSTS TO BUSINESS UNITS

Direct Assignment or Type of Cost Driver	Centralized Support & Administrative Functions	Centrally Held Costs	CSA Costs (A)
Direct Assignment- Specific	31.1%	26.2%	29.2%
Direct Assignment- Historical	18.8%	12.9%	16.5%
Direct Assignment- Service Fees	2.6%		1.6%
Physical Cost Drivers	16.6%		10.2%
Financial Cost Drivers	2.0%	60.9%	24.9%
Blended Cost Drivers	9.4%		5.7%
Internal Cost Drivers	19.5%		11.9%
Total	**100.0%**	**100.0%**	**100.0%**

(A) Excludes Hydroelectric Common which is 100% directly assigned to the Hydroelectric business unit.

III. OPG'S CURRENT METHODOLOGY

This section includes a discussion of Tasks 1-4 identified in Table 2, including the purpose of each task, the source of the information and the detailed steps performed.

A. Task 1: Identified the Business of OPG and its Overall Organization

The purpose of this task was to identify how OPG is organized. This information was obtained from OPG public and internal documents and discussions with OPG personnel.

Ontario Power Generation Inc. is wholly owned by the Province of Ontario. Its principal business is the generation and sale of electricity in Ontario and to interconnected markets.

OPG is primarily organized by generation technology, with separate Business Units for Nuclear, Fossil, Hydroelectric, and Other Business. Other Business includes the Energy Markets group, which supports the generation businesses of OPG and also engages in other activities. The cost of activities that support the generation businesses are distributed among Business Units. Table 5 lists each Business Unit of OPG, together with the number of Stations in the Business Unit and their generating capacity at December 31, 2005, and identifies whether it is regulated or unregulated.

TABLE 5 SUMMARY OF BUSINESS UNITS

Business Unit- Status	Stations	No. of Stations	Capacity MW
Nuclear- Regulated	• All stations	3	6,606
Hydroelectric- Regulated	• Niagara plant group • R. H. Saunders station	6	3,383
Hydroelectric- Unregulated	• All other, including wind	61	3,606
Fossil- Unregulated	• All stations	5	8,578
Other Business- Unregulated			
Total		75	22,173

The payment amounts that OPG began to receive effective April 1, 2005 is based on output from generation facilities as prescribed in Ontario Regulation 53/05. OPG receives different payments for the output from its regulated Nuclear facilities and its regulated Hydroelectric facilities. The costs associated with OPG's regulated operations, including the CSA Costs distributed to them, may be considered in future proceedings before the OEB.

The payment amounts received by OPG for energy and other services provided by its unregulated Stations are determined by market-based transactions or other arrangements, and are not subject to rate regulation by the OEB.

B. Task 2: Identified Departments That Provide CSA Functions and Services

The purpose of this task was to identify how OPG is organized to meet the operating and administrative needs of the Business Units, and to identify the departments providing Centralized Support and Administrative functions and services. This information was obtained in discussions with OPG personnel.

Many of the functions and services necessary to support the Business Units and Stations are performed by centralized departments within OPG. The groups and departments that provide the Centralized Support and Administrative functions and services are listed in Table 6. Exhibit A describes the functions and services provided by each department. CSA Costs also include Centrally Held Costs that must be distributed among the Business Units.

TABLE 6 DEPARTMENTS PROVIDING CSA FUNCTIONS AND SERVICES

Group	Departments
Human Resources	• Nuclear HR & Employee Safety • Hydro / Fossil HR & Employee Safety • Corporate HR • Compensation & Benefits • HR External Purchase Services • HR Strategy & Reporting • Corporate Wellness • Labour Relations • Corporate Safety • HR Executive Vice President’s Office
Corporate Center	• Executive Office • Law • Sustainable Development • Corporate Secretariat
Nuclear Waste Management	• Nuclear Waste Management

TABLE 6 DEPARTMENTS PROVIDING CSA FUNCTIONS AND SERVICES	
Finance	• Controllership • Treasury • Risk Services • Supply Chain • Financial Planning & Taxation • CFO's Office
Corporate Affairs	• Public Affairs • Regulatory Affairs / Strategic Planning • Corporate Affairs Senior Vice President's Office
CIO	• New Horizon Infrastructure Management • New Horizon Third Party Contracts • New Horizon Application Maintenance • New Horizon Other • CIO Work Programs • Non-Capital Projects
Energy Markets	• Portfolio Management • Trading • Planning & Analysis • Energy Markets Support • Fuels Procurement • Energy Markets Programming • Energy Markets Senior Vice President's Office
Real Estate	• Real Estate Services • Business Services • Facility Services • Fleet Services • Real Estate Vice President's Office
Centrally Held Costs (not a group)	• Wage & Salary Related • Cost of Goods Sold • Subsidiaries and Joint Ventures • Other
Hydroelectric Common	• Hydroelectric Business Unit Common Support Costs • Ottawa-St. Lawrence Common Support Costs

Some of these departments, such as Controllership, Compensation & Benefits, and Real Estate Services, support more than one Business Unit. Other departments, such as

Human Resources- Nuclear HR & Employee Safety and Nuclear Waste Management, support only one Business Unit.

For departments that support more than one Business Unit, it is necessary to distribute the costs of the department's resources among the Business Units. In many cases, specific resources (individual employees and specific cost items) can be identified to particular Business Units. In these cases, although the costs are incurred by a centralized department, there is a direct relationship between the costs and the Business Units that cause the costs.

In other cases, the portions of resources (employees' time and other costs) that the department spends on each Business Unit can be estimated.

In cases where neither specific identification nor estimation are possible, it is necessary to allocate the costs of the resources to the Business Units using cost drivers.

These methods of distributing costs (direct assignment by specific identification and by estimation, and allocation) are discussed in Section II of this Report.

C. Task 3: Reviewed Methodology Currently Used by OPG to Distribute CSA Costs

The purpose of OPG's cost distribution methodology is to distribute the CSA Costs among the Business Units, and in the case of Hydroelectric, between the regulated and unregulated stations. This information was obtained from discussion with OPG personnel and review of OPG documentation for its cost allocation methodology.

- First, the costs are distributed among the Business Units, and in the case of Hydroelectric, between the regulated and unregulated stations, and in some cases to other CSA groups. This step is discussed in this Section under Distribution of CSA Costs to Business Units.

- Costs that were distributed to other CSA groups must be redistributed to the Business Units, and in the case of Hydroelectric, between the regulated and unregulated stations. Costs distributed between CSA groups are not significant relative to total CSA Costs. This step is discussed in this Section under Redistribution of CSA Costs Initially Distributed to CSA Groups.

Distribution of CSA Costs to Business Units

For each department identified in Table 6, OPG personnel obtained the estimated 2006 Budget, detailed as to labor and non-labor resources, and then discussed the distribution of departmental resources among Business Units, and in the case of Hydroelectric, between the regulated and unregulated stations, with the responsible managers.

Direct Assignment

Direct assignment includes specific identification and estimation (of employees' time and other costs), which may be based on current time estimates or historical activity.

The first step in OPG's methodology was *specific identification* of resources. For labor resources, this meant identifying individuals who support only one Business Unit. For non-labor resources, it meant identifying costs directly caused by one Business Unit. The costs of resources specifically identified to a Business Unit were directly assigned to it.

For example, Human Resources- Nuclear HR & Employee Safety department supports only the Nuclear Business Unit; therefore the costs of this department were directly assigned to the Nuclear Business Unit. Also, some of the activities in Human Resources-Compensation & Benefits support only specific Business Units, and those costs are also directly assigned to those Business Units.

The next step was to identify the resources in each department that directly support one or more Business Units and to *estimate* the portions of these resources, which are mostly labor, attributable to each Business Unit. The estimates, which are mostly time estimates, were provided by departmental managers. Some managers based their estimations on concurrent time records, some conducted interviews with their personnel, and some used their informed judgment. The costs of these resources are directly assigned to each Business Unit in proportion to the estimated time required by that Business Unit.

For example, the Risk Services department supports all Business Units. Based on employee interviews the departmental manager estimated the portion of time spent on each Business Unit. The costs of these resources are directly assigned to the Business Units based on their shares of the estimated time.

Some non-labor resources are directly assigned using estimates based on actual historical values. For example, historical data transmission and telecommunication costs can be directly assigned among the Business Units. The actual historical Business Unit percentages are used as an estimate to directly assign the 2006 costs.

Allocation

When less than all of a department's resources can be distributed by direct assignment (either by specific identification or by estimation), a cost driver must be assigned to allocate the cost of the remaining resources among the Business Units, and in the case of

Hydroelectric, between regulated and unregulated station. A cost driver is a formula for sharing the cost of a resource among those who cause the cost to be incurred. The principles that Rudden applies in evaluating the appropriateness of cost drivers are discussed in Section II.

For example, a portion of the costs in Human Resources- Compensation & Benefits were directly assigned to specific Business Units. The balance of the department's resources support all of the employees of OPG. The costs of these resources are *allocated* among the Business Units using the cost driver FTEs (number of full-time equivalent employees) in each Business Unit. Table 3 describes the different types of cost drivers.

Redistribution of CSA Costs Initially Distributed to CSA Groups

In distributing costs to the Business Units, some costs initially were allocated to other CSA groups. These costs must be redistributed to the Business Units.

For example, portions of several CIO applications support the Finance group. The costs of these applications must be redistributed from Finance to the Business Units. As another example, some CIO activities are allocated using the cost driver Business Workstations, which allocates portions of the costs to the Finance, Human Resources and other CSA groups. These costs also must be redistributed from the CSA groups to the Business Units.

These costs are considered to be incurred in support of the group to which they are initially distributed, and are redistributed in the same ratio as that group's total CSA Costs. For example, the CIO costs initially distributed to the Finance group are redistributed to the Business Units in the same ratio as the total Finance group CSA Costs were distributed.

D. Task 4: Interviewed OPG Personnel

The purposes of this task were to assess the resources, level of support and understanding of the cost allocation methodology within OPG, and to ascertain that the Business Units to which the CSA Costs are distributed receive the CSA functions and services.

This task included interviews and meetings with the following OPG personnel:

- Those responsible for design and execution of the cost allocation process.
- CSA group and departmental managers responsible for providing activity descriptions, specific identification of resources and estimates and information for use in selecting cost drivers.

- Representatives of the Business Units to which the CSA Costs are distributed.

Based on our meetings and interviews and on working with OPG personnel on this Review, we found the following:

- ✓ OPG's cost allocation process has the support of senior levels of management.
- ✓ OPG's cost allocation process uses the principles of direct assignment and cost drivers that are key components of current best practices and OEB precedents.
- ✓ Many people throughout OPG participate in the cost allocation process and they believe that achieving an appropriate result is important.
- ✓ OPG's process relies on the judgments of departmental managers and Business Units to support specific identification and time estimation. These are the people in the best position to determine how resources are used.
- ✓ Supporting analyses were prepared by many of the CSA groups and departments, including detailed analyses of activities, identification of specific resources, interviews to determine time estimates and reviews of invoices to determine historical usage.
- ✓ In selecting cost drivers, OPG departmental managers and also Business Unit users were consulted. Obtaining input from the people closest to the management and use of resources improves the quality of the cost allocation process.
- ✓ OPG has documented significant portions of its cost allocation methodology. However, the completeness and understandability of the documentation varies considerably among the CSA groups and sometimes among departments within the groups.
- ✓ The Business Units to which the CSA Costs are distributed are familiar with the cost allocation process, confirmed where appropriate that specific resources are used by them and confirmed that the functions and services for which they are allocated costs are actually being received by them.

IV. CONCLUSIONS AND RECOMMENDATIONS

A. Task 5A: Evaluation of OPG' s Methodology

This task presents our evaluation of OPG's methodology including design, use of direct assignment, selection of cost drivers and documentation. The information was obtained based on our understanding of the business, review of OPG's methodology and discussions with OPG personnel.

Design

In evaluating the design of OPG's methodology, we applied the following criteria:

- Does it reflect how the business is organized and operated?

  Evaluation: OPG's methodology follows its organizational structure, in which Business Units receive many of their necessary support functions and services from centralized departments rather than on-site resources.

  The use of internal allocators for costs initially distributed to CSA groups is also appropriate given the centralized support structure.

  In addition, the methodology reflects that many of the functions and services provided by centralized departments support only one Business Unit, and allows for direct assignment of resources.

  Conclusion: OPG's methodology reflects how OPG is organized and operated.

- Are sufficient resources devoted to the cost allocation process?

  Evaluation: OPG's cost allocation process has the support of senior levels of management. In addition, there is participation by many people in the organization, and they believe that achieving an appropriate result is important. Detailed analyses of activities were prepared by many of the groups we interviewed.

  Conclusion: OPG has devoted sufficient resources to the cost allocation process.

- Is sufficient information gathered from reliable sources to support specific identification, time estimation and selection of appropriate cost drivers?

Evaluation: The methodology relies on the judgments of departmental managers and Business Units to support specific identification and time estimation. These are the people in the best position to determine how resources are used. We understand that the results of the cost allocation are reviewed quarterly. However, recognizing the OEB trend toward more formal reviews, OPG should consider a more formal quarterly review process. See Section IV.B. Task 5B: Recommendations.

In selecting cost drivers, departmental manages and also users were consulted. Obtaining input from the people closest to the resources improves the quality of decisions as to cost drivers.

Conclusion: Sufficient information is gathered from reliable sources to support specific identification, time estimation and selection of appropriate cost drivers.

Use of Direct Assignment

Evaluation: Direct assignment is preferable to allocation because it is means there is a direct relationship between the costs incurred and the Business Unit or Station causing it to be incurred.

Conclusion: The OPG methodology uses direct assignment wherever possible.

Selection of Cost Drivers

Evaluation: Exhibit B lists the cost drivers selected by OPG for those instances where less than all costs could be distributed by direct assignments. OPG's selections reflect discussion and input from Rudden, based on our review of the functions and services provided by the CSA departments, and application of the principles identified in Section II. Our recommendations for cost drivers included the following:

- Use of greater detail in activity reporting
- Separation of Labor and Non-labor costs
- In many cases where direct assignment was not used, OPG had used FTEs as the cost driver. Based on Rudden's recommendations, OPG is now using a variety of appropriate drivers, typical of those used by other utilities.

See Section IV.C. for a discussion of Exhibit B.

Conclusion: The cost drivers listed in Exhibit B are appropriate based on the principles identified in Section II.

Documentation

Evaluation: OPG has a large volume of documentation to support its methodology. However, the completeness and understandability of the documentation varies considerably among the CSA groups and sometimes among departments within the groups. Possibly, this reflects the diverse nature of the CSA groups and the Business Units, and also the participation of many people in the allocation process.

While having many people participate can lead to a better result, the lack of consistency should be addressed. Lack of consistency:

- Makes it more difficult to explain the process to OPG personnel and to the OEB and intervenors.
- Can lead to inconsistency in application of principles and other errors.
- Makes it more difficult to adapt the methodology as the business changes.

Conclusion: See Section IV.B. for specific recommendations on improving the documentation.

B. Task 5B: Recommendations

The following are Rudden's recommendations arising from the Review:

1. OPG should consider a formal quarterly review process, including:
   - Review of results of allocation (this is currently done).
   - Review of departmental resource distributions based on time estimates.
   - Review of direct assignments and allocators.
   - Review of allocator values.
2. Documentation of the OPG methodology should be improved. OPG has documented significant portions of its cost allocation methodology. However, several areas should be improved. Improvement in these areas is typically required after initial adoption and implementation of a cost allocation methodology.

- The purpose and principles that underlie the methodology should be documented and presented to all participants.

- Responsibilities and time schedules should be distributed, including the responsibility for making decisions.

- A template should be used to document specific identification and time estimation. Exhibit C has a proposed template.

- Due to its complexity, the CIO allocation is performed using a separate, parallel cost allocation model. OPG should continue to devote the resources to ensure that this model is consistent with the general model.

3. Cost driver selection should be standardized. In assigning cost drivers, similar activities should have similar cost drivers. The current cost drivers, recommended by Rudden and adopted by OPG, are standardized. The general rationale for selecting cost drivers should be explained and documented, and applied to new cost items as appropriate. See Section IV.D. for a discussion of the standardized cost drivers recommended in this Review.

C. Cost Drivers Selected- Exhibit B

This Section describes Exhibit B, which summarizes the Distributions of the CSA Costs, indicates costs that are distributed by direct assignment, and identifies the cost drivers selected by OPG for those instances where less than all costs could be distributed by direct assignments.

Column A lists each department that provides the CSA functions and services and the group to which the department belongs, and lists the activities within each department.

Column B shows each activity's percentage of the departmental budget for 2006. Each department sums to 100%.

Columns C-G show how departmental costs are distributed to the Business Units, and in the case of the Hydroelectric Business Unit, among regulated and unregulated generating stations. If a portion of costs are Direct Assigned to one or more Business Units, the Direct Assignment method is shown in Column C and the amount, shown as a percentage of the departmental budget for 2006, is shown in Column D. The Direct Assignment methods listed in Column C include Specific, Estimate and Historic.

For the portion of costs to be allocated to the Business Units, Column E shows the cost driver and Column F shows the amount as a percentage of the departmental budget for

2006. For each activity, the percentages in Columns D and F total the percentage in Column B.

All of OPG's nuclear plants are in the Nuclear Business Unit, which is regulated, all of its fossil plants are in the Fossil Business Unit, which is unregulated, and all Other Business (which includes the Energy Markets group and other activities) is unregulated. Therefore costs that are distributed to Nuclear, Fossil or Other Business are already determined to be either regulated or unregulated.

However, some plants within the Hydroelectric Business Unit are regulated and some are unregulated. Therefore, Column G shows how the cost of each activity is distributed between Hydroelectric Regulated and Hydroelectric Unregulated. The entries in Column G apply to costs that are Direct Assigned. For Direct Assigned costs, Column G shows either:

- If it was possible to Direct Assign between Hydroelectric Regulated and Hydroelectric Unregulated, Column G shows "Specific to Stations"; "Estimates to Stations"; or "Historical to Stations"; depending on the type of Direct Assignment.

- If it was not possible to Direct Assign between Hydroelectric Regulated and Hydroelectric Unregulated, Column G shows the cost driver used to allocate between Hydroelectric Regulated and Hydroelectric Unregulated.

- If no costs were Direct Assigned to Hydroelectric, Column G shows "N/A".

For Allocated costs, there are no entries in Column G because all of the cost drivers in Column E separate costs between Hydroelectric Regulated and Hydroelectric Unregulated.

D. Standardized Cost Drivers

Following is the general rationale used in recommending cost drivers for OPG:

- Direct assignment, by specific identification, time estimation or historical, is recommended whenever possible.

- For activities that support another CSA group, the recommendation is to allocate the costs in the same ratios as the supported groups, not the groups that incur the costs. For example, CIO costs allocated to Finance would be allocated to Business Units in the same ratio as all other Finance costs.

- For supervisory costs, the recommendation is to allocate the costs in the same ratio as the department or group that is supervised. For general departmental expenses, depending on their nature, the recommendation is to allocate the costs in the same ratio as the total costs or the labor costs for the department.

- For Human Resources related-activities, the recommended cost driver is FTEs.

- For Wage & Salary-driven costs, the recommended cost driver is Labor Costs or Pension / OPEB Costs.

- For activities that are causally related to the Business Units across several areas (e.g., activities such as Corporate Accounting, Financial Planning, Risk and Assurance, Public Affairs) the recommended cost drivers are usually a blend of two or more financial drivers, including OM&A, Capital Expenditures or Revenue.

  The book values for OPG's Assets reflect amounts established upon formation of the company in 1999 and are not necessarily representative of historical cost or replacement cost. OPG management believes the Asset book values do not reflect the level of effort required to operate or support the plants. Therefore, for activities for which we considered a blended cost driver that included Assets, instead we used factors that reflect levels of effort required such as Capital Expenditures.

  In computing Capital Expenditures, a two or three year average was used in order to provide stability in the cost driver shares.

- For activities related to procurement, the recommended cost driver is the number of transactions or value of purchases that is reasonably closely related to the items procured.

- For CIO hardware and software activities closely related to the users (e.g., Microsoft Wintel Operating Systems, Software Licenses) the recommended cost driver is Business Workstations. For CIO infrastructure-related activities (e.g., Deskside Support, Helpdesk, E-mail, Internet) the recommended cost driver is LAN IDs.

V. SERVICE FEES

OPG's Other Business unit holds assets that are used by both the regulated and unregulated generation operations. These assets comprise:

- OPG head office building (700 University Avenue building)
- Kipling Avenue property site
- CIO assets / computer systems
- Energy Markets assets / computer systems

OPG's Methodology

OPG's Other Business unit charges a Service Fee to the generation business units for the use of these assets. The methodology for calculating the services fee is based on the depreciation expense, return component and applicable operating costs (i.e., costs not already charged to the user, such as property taxes).

> Depreciation expense for each asset is computed using the same basis as for financial accounting purposes, and the same methodology that was used in the setting of the payment amounts that OPG currently receives from the output of its regulated operations.
>
> The return component is computed using a rate of return of 5.55% applied to the average budgeted Net Book Value of the assets. The average budgeted Net Book Value is adjusted annually. The rate of return was used in the setting of the payment amounts that OPG currently receives from the output of its regulated operations.
>
> The return component also includes an income tax gross-up on the return on equity component, computed at OPG's statutory tax rate for the year.
>
> Income taxes used in the setting of the payment amounts that OPG currently receives from the output of its regulated operations are based on OPG's tax payment liability, thus the regulatory book basis is the same as the regulatory tax basis and there is no adjustment to Net Book Value for Future Income Taxes (i.e., accumulated deferred income taxes).

To determine the Service Fee charged to each of the generation business units, OPG:

- *Computes* the total annual budgeted amounts of depreciation expense, return and applicable operating costs for each asset

- *Determines* the portion of the annual total allocated to each generation business unit based on its usage of the assets

- *Reallocates* amounts that were allocated to Corporate and to Energy Markets to other business units based on appropriate cost drivers

Conclusion

Rudden reviewed the methodology that OPG uses to determine the Service Fee and determined that it is reasonable. Our determination is based on the following findings:

- The assets for which Service Fees are charged are required and used by OPG's generation business units.

- The fees are computed using a methodology that is cost-based.

- Costs are determined on a basis consistent with similar costs included in the setting of the payment amounts that OPG currently receives from the output of its regulated operations.

- The methodology for determining the usage of the assets by the generation business units for the purpose of allocating the Service Fee is based on cost causation and is appropriate and consistent with the Centralized Support and Administrative Costs methodology.

- OPG has informed us that the Service Fees have been compared to market rates, where market rates are available, and were found to be reasonably consistent.

VI. Ancillary Services

In addition to the sale of electric energy output, OPG's Business Units receive revenue from the sale of Ancillary Services. As part of this engagement, Rudden was also asked to review OPG's methodology regarding distributing the CSA Costs between energy output and Ancillary Services.

OPG's Methodology

Ancillary Services revenue for 2006 is budgeted at $76 million. Table 7 lists the specific Ancillary Services sold by the regulated and unregulated Business Units, and their shares of revenue.

TABLE 7 ANCILLARY SERVICES SOLD BY OPG'S BUSINESS UNITS

Ancillary Service	% of Ancillary Regulated Services Revenue	% of Ancillary Unregulated Services Revenue
Automatic Generation Control (AGC)	61%	23%
Operating Reserve	19%	16%
Reactive Power	19%	61%
Black Start	1%	0%
Total	**100%**	**100%**

OPG's methodology is not to distribute CSA Costs to Ancillary Services, because the provision of Ancillary Services is inextricably linked to the operation of the generating stations for the purpose of producing electricity.

An examination of Table 7 indicates that the Ancillary Services that OPG's Business Units provide are inextricably linked to the operation of the generating stations for the purpose of producing electricity. The AGC Ancillary Service illustrates this relationship, because the AGC service is to permit the system operator to adjust the generation output of the AGC stations.

Further, the same operators are responsible for activities related to the generation of electricity and activities related to providing Ancillary Services; it is not possible to have two sets of employees.

The CSA that are the primary subject of this report relate to Business Units where costs are shared, but could be incurred separately. For example, Human Resource group costs are shared, but it would be possible for each Business Unit to have its own Human Resource group.

This is not the case for Ancillary Services, which is inextricably linked to the operation of the generating stations for the purpose of producing electricity.

Rudden concurs that Ancillary Services are inextricably linked to the operation of the generating stations. We also reviewed the potential for costs that could be directly assigned or allocated to Ancillary Services.

Direct Assignment of Costs to Ancillary Services

Based on discussions with OPG personnel, the following CSA Cost areas were considered for direct assignment of costs to Ancillary Services:

- Energy Markets- estimated time for activities such as learning and implementing market rules, preparing contracts for services that are contracted, and Ancillary Services operations and support. This effort was estimated at approximately $250,000 per year.

- Regulatory Affairs- estimated time for activities such as ensuring compliance with market rules and developing the regulatory treatment for Ancillary Services. This effort was determined to be minimal at approximately 20% of a full-time person on an ongoing basis.

It should be noted that the potentially directly assignable costs identified above are included in the total CSA costs that are detailed in Exhibit D.

Based on our review, the amount of costs that could be directly assigned, that would be or allocated based on direct assignment of assets or operating and maintenance costs, to Ancillary Services is minimal.

Allocation of Costs to Ancillary Services

After costs have been directly assigned, the basis for allocating CSA Costs is cost causation or, where cost causation cannot be easily implemented or established, benefits received.

The Ancillary Services-related asset costs, and the related operating and maintenance costs, minimal compared to total Assets and OM&A. Therefore, the portion of CSA costs that would be allocated to Ancillary Services based on their shares of communication and control assets, for activities having Assets or Capital Expenditures as cost drivers, and their shares of costs of operating and maintenance costs, for activities having OM&A as cost drivers, would be very small.

Conclusion

Rudden reviewed OPG's methodology not to distribute CSA Costs to Ancillary Services, and we believe it is reasonable. Our determination is based on the following findings:

- The provision of Ancillary Services is inextricably linked to the operation of the generating stations for the purpose of producing electricity.
- The amount of costs that could be directly assigned costs to Ancillary Services is minimal.
- The portion of CSA costs that would be allocated to Ancillary Services based on their shares of cost drivers would be very small.
- The effort required to track direct CSA Costs and to track the information needed to allocate CSA Costs would be considerable, especially when compared to the likely costs.

GLOSSARY

Ancillary Services means the services provided by generating units for Operating Reserves, Automatic Generation Control (AGC), Black Start and Reactive Power

CIO means Chief Information Officer, the name of OPG's information technology group

CSA Costs means Centralized Operating and Administrative Costs

FTEs means full-time equivalent employees

GRC means the Gross Revenue Charge payable to the Province of Ontario

M&S means materials and supplies

Net Assets means Net book value of property, plant and equipment and other fixed assets

New Horizon means New Horizon System Solutions LP, which provides CIO services to OPG on an outsourced basis

OEB means the Ontario Energy Board

OM&A means Operating, Maintenance and Administrative (expenses)

ONFA means Ontario Nuclear Funds Agreement

OPEB means Other Post-Employment Benefits

OPG means Ontario Power Generation Inc.

Regulated means the payment amounts received by OPG for the energy output from the generating stations in a Business Units **are** regulated by the OEB

Report means this Report

Review means Rudden's review of OPG's Cost Allocation Methodology for CSA Costs, the subject of this Report

Rudden means R. J. Rudden Associates, A Unit of Enterprise Management Solutions, Black & Veatch Corporation

Unregulated means the payment amounts received by OPG for the energy output from the generating stations in a Business Units **are not** regulated by the OEB

EXHIBIT A – FUNCTIONS AND SERVICES PROVIDED BY CENTRALIZED SUPPORT AND ADMINISTRATIVE DEPARTMENTS

DEPARTMENT	FUNCTIONS AND SERVICES
Human Resources Group	
Nuclear HR & Employee Safety	• Support HR function at Nuclear sites including pay services, hiring and safety
Hydroelectric / Fossil HR & Employee Safety	• Support HR function at Hydroelectric / Fossil sites including pay services, hiring and safety
Corporate HR	• Provide HR support to Corporate Function groups including employee services, hiring and safety • Provide security services to Head Office and other non-station locations
Compensation & Benefits	• Provide pension and pay services • Develop and implement compensation strategy and design • Manage and support benefit plans • Provide relocation services
HR External Purchase Services	• Represent third-party contracts relating to family assistances for employees, security operations, medical staff, employee satisfaction surveys and others
HR Strategy & Reporting	• Provide HR reporting services
Corporate Wellness	• Manage health-related benefits programs • Provide health services • Manage LTD, Rehab and WSIB programs
Labour Relations	• Manage bargaining unit strategy and relations
Corporate Safety	• Develop, implement, oversee and monitor safety targets
HR Executive Vice President's Office	• Manage Human Resources group
Corporate Center Group	
Executive Office	• Provide overall OPG vision and strategy
Law	• Provide solutions to legal issues at OPG • Review OPG's contractual obligations

EXHIBIT A – FUNCTIONS AND SERVICES PROVIDED BY CENTRALIZED SUPPORT AND ADMINISTRATIVE DEPARTMENTS	
Sustainable Development	• Minimize environmental risk to OPG; establish corporate environmental management system & policy framework • Provide advice on pending and future environmental risks and opportunities
Corporate Secretariat	• Support corporate policies and government relations • Provide support for the Board of Directors and Executive Office
Nuclear Waste Management Group	
Nuclear Waste Management	• Manage all OPG's nuclear waste, including Bruce Power • Plan for decommissioning of nuclear stations
Finance Group	
Controllership	• Financial Processing Services- Accounts Payable; Accounts Receivable and Fixed Assets, including transactions and business support • Financial accounting, reporting, budgeting • Regulatory accounting and reporting • Business Unit / Site support for transactions, accounting, reporting, budgeting • Investment planning
Treasury	• Manage short-term liquidity • Manage capital structure and investor relations • Cost of insurance premiums and management of insurance programs • Manage ONFA funds
Risk Services	• Develop and implement overall corporate risk management framework • Monitor and establish business rules for market risk management, and develop and evaluate risk models • Measure, monitor and mitigate credit risk at OPG • Conduct risk-based process audits • Facilitate OPG's Internal Controls Certification
Supply Chain	• Manage contractor safety, procurement governance and performance reporting for all of OPG • Provide procurement solutions to Corporate groups

EXHIBIT A – FUNCTIONS AND SERVICES PROVIDED BY CENTRALIZED SUPPORT AND ADMINISTRATIVE DEPARTMENTS	
Financial Planning / Taxation	• Engage in financial planning • Provide tax planning and compliance services
CFO's Office	• Manage Finance group
Corporate Affairs Group	
Public Affairs	• Manage corporate communication, Corporate Citizenship Program and media and stakeholder relations
Regulatory Affairs / Strategic Planning	<u>Regulatory Affairs</u> • Markets and Research Regulatory Affairs- Support commercial activities in the Ontario market • Ontario Regulatory Affairs- Represent OPG to economic regulators in Ontario <u>Strategic Planning</u> • Provide strategic support to senior executives and Board of Directors. Inform staff of strategic developments; provide strategic plan and responses to strategic inquiries • Maintain knowledge of the energy industry and business environment; optimize use of external strategic services
Corporate Affairs Senior Vice President's Office	• Manage Corporate Affairs group
CIO Group	
New Horizon Infrastructure Management	Support infrastructure hardware and software, including: • Deskside Support, Helpdesk, Microsoft Wintel, Storage, E-mail, Internet • Data Transmission and Telecommunication backbones • UNIX, MVS platforms • Remote access
New Horizon Third Party Contracts	• Manage Third Party contracts including MVS; Microsoft Wintel; Storage; UNIX; SAP; Disaster Recovery

EXHIBIT A – FUNCTIONS AND SERVICES PROVIDED BY CENTRALIZED SUPPORT AND ADMINISTRATIVE DEPARTMENTS	
New Horizon Application Maintenance	Maintain applications and functions, including: • SAP- Finance; Human Resources • SAP application development • SAP Data Warehousing and Reporting; SAP Work Management and Supply Chain • Passport • IT Architecture • IT Purchasing functions
New Horizon Other	• Cost of New Horizon overhead charges • Cost of Variable Data Transmission and Telecommunication charges • Cost of PST expense
CIO Work Programs	Maintain applications, including: • Business Unit specific; Site specific; Function specific • CIO overhead and management costs; Document management; Freedom of information • Workstation purchases; Software licenses
Non-capital Projects	• Non-capital costs of new applications and projects
Energy Markets Group	
Portfolio Management	• Optimize assets over real time (offer) out to Business Plan timeframe
Trading	• Execute trading and hedging for Portfolio
Fuels Procurement	• Manage contractual buying of coal, oil, transportation and emission credits • Contract for byproducts of coal production
Planning & Analysis	• Prepare analytical studies for execution and strategic direction, and spot and forward curves for commodities
Energy Markets Programming	• Define requirements for all fuels and emission allowance/credits • Integrate strategies across Energy Markets departments and with other Corporate groups
Energy Markets Support	• Implement and monitor compliance with market rules; Perform after-the-fact analysis; Perform training
Energy Markets Senior Vice President's Office	• Manage Energy Markets group
Real Estate Group	

EXHIBIT A – FUNCTIONS AND SERVICES PROVIDED BY CENTRALIZED SUPPORT AND ADMINISTRATIVE DEPARTMENTS	
Real Estate Services	• Manage all Corporate, Nuclear, Hydroelectric and Fossil real estate assets • Maintain property records • Rationalize and develop portfolio strategies • Acquire / lease / dispose of land or buildings
Business Services	• Provide OPG-wide administrative and office services
Facility Services	• Provides all facility related services for properties managed by OPG
Fleet Services	• Provide OPG wide fleet administration, including acquisition, disposition, licensing and insurance
Real Estate Vice President's Office	• Manage Real Estate Services group
Centrally Held Costs (not a group)	
Wage & Salary Related	• Pension / OPEB- amortization of deferred costs • Employee incentives and vacation accrual • Labor Costs escalation provision • Fiscal Calendar Payroll Adjustment
Cost of Goods Sold	• Cost of Goods Sold- Other Business (e.g., Real Estate) • Cost of Services Provided to Bruce Power
Subsidiaries and Joint Ventures	• Impact of consolidating results of OPG's joint ventures and subsidiaries such as Brighton Beach Power LP
Other	• Other Centrally Held Costs such as Rate Regulation Expenses, CNSC Provincial Fee, PST-Self Assessment
Hydroelectric Common Costs	
Hydroelectric Business Unit Common Support Costs	• Manage and support Hydroelectric stations • Provide centralized services to Hydroelectric stations, including Engineering, Water Resources Management, Environmental and other technical and business support • Manage and fund Hydroelectric development projects
Ottawa-St. Lawrence Common Support Costs	• Manage and support 10 Hydroelectric stations within the Ottawa-St. Lawrence plant group with stations on the St. Lawrence, Ottawa and Madawaska rivers, including the regulated R.H. Saunders station

OPG CENTRALIZED SUPPORT AND ADMINISTRATIVE COSTS
COST ALLOCATION METHODOLOGY REVIEW
SUMMARY OF DISTRIBUTIONS

-		DISTRIBUTION TO BUSINESS UNITS				HYDROELECTRIC
		Direct Assignment		Allocation		Regulated / Unregulated
DEPARTMENT / Activities	Activity % of Dept.	Method	BU Direct Assign %	Cost Driver	BU Allocation %	Applies to Direct Assignment
(A)	(B)	(C)	(D)	(E)	(F)	(G)
HUMAN RESOURCES GROUP						
Nuclear HR & Employee Safety	27.9%	Specific	27.9%			N/A
Hydro / Fossil HR & Employee Safety	15.9%	Specific	14.7%	FTEs	1.2%	Specific to Stations
Corporate HR	15.4%	Specific / Estimates	3.2%	FTEs	12.2%	FTEs
Compensation & Benefits	12.8%	Specific / Estimates	2.9%	FTEs	9.9%	FTEs
HR External Purchase Services	10.1%	Specific / Estimates	3.4%	FTEs	6.7%	FTEs
HR Strategy & Reporting	5.3%	Specific / Estimates	1.3%	FTEs	4.0%	FTEs
Corporate Wellness	4.2%	Specific / Estimates	2.2%	FTEs	2.0%	FTEs
Labour Relations	4.2%	Specific / Estimates	3.8%	FTEs	0.4%	FTEs
Corporate Safety	3.4%	Specific / Estimates	1.6%	FTEs	1.8%	FTEs
Executive Vice President's Office	0.8%			Internal- HR Total	0.8%	
	100.0%		61.0%		39.0%	
CORPORATE CENTER GROUP- EXECUTIVE OFFICE						
Executive Office	100.0%			Blend- OM&A / CapEx	100.0%	
	100.0%		0.0%		100.0%	
CORPORATE CENTER GROUP- LAW						
Law- In-house	55.0%	Estimates	55.0%			> Blend- OM&A / CapEx > Internal- Energy Markets Total > Estimates to Hydro Regulated / Hydro Unregulated
Law- External, General	25.0%	Estimates	25.0%			> Blend- OM&A / CapEx > Internal- Energy Markets Total > Estimates to Hydro Regulated / Hydro Unregulated
Law- External, Specific	20.0%	Specific	20.0%			Specific to Stations
	100.0%		100.0%		0.0%	

OPG CENTRALIZED SUPPORT AND ADMINISTRATIVE COSTS
COST ALLOCATION METHODOLOGY REVIEW
SUMMARY OF DISTRIBUTIONS

-		DISTRIBUTION TO BUSINESS UNITS				HYDROELECTRIC
		Direct Assignment		Allocation		Regulated / Unregulated
DEPARTMENT / Activities	Activity % of Dept.	Method	BU Direct Assign %	Cost Driver	BU Alloc-ation %	Applies to Direct Assignment
CORPORATE CENTER GROUP- SUSTAINABLE DEVELOPMENT						
Sustainable Development Labor Costs	56.8%	Estimates	56.8%			Blend- OM&A / CapEx
Reforestation Program	19.8%			Blend- OM&A / CapEx	19.8%	
University Chair Sponsorship	12.5%	Specific	12.5%			N/A
E7 Scholarship Program	10.8%			Blend- OM&A / CapEx	10.8%	
	100.0%		69.3%		30.7%	
CORPORATE CENTER GROUP- CORPORATE SECRETARIAT						
Corporate Secretariat	58.9%			Blend- OM&A / CapEx	58.9%	
Board of Directors	41.1%			Blend- OM&A / CapEx	41.1%	
	100.0%		0.0%		100.0%	
NUCLEAR WASTE MANAGEMENT GROUP						
Nuclear Waste Management	100.0%	Specific	100.0%			N/A
	100.0%		100.0%		0.0%	

OPG CENTRALIZED SUPPORT AND ADMINISTRATIVE COSTS
COST ALLOCATION METHODOLOGY REVIEW
SUMMARY OF DISTRIBUTIONS

		DISTRIBUTION TO BUSINESS UNITS				HYDROELECTRIC
-		Direct Assignment		Allocation		Regulated / Unregulated
DEPARTMENT / Activities	Activity % of Dept.	Method	BU Direct Assign %	Cost Driver	BU Alloc-ation %	Applies to Direct Assignment
FINANCE GROUP- CONTROLLERSHIP						
Controllership- Nuclear Accounting, Planning and Support	29.3%	Specific	29.3%			N/A
Controllership- Energy Markets	16.5%			Internal- Energy Markets Total	16.5%	
Corporate Accounting	11.0%			Blend- OM&A / CapEx	11.0%	
Controllership- Fossil	10.9%	Specific	10.9%			N/A
Controllership- Hydro	4.0%	Specific	4.0%			Estimates to Stations
Financial Processing Services- Accounts Payable	10.2%			> Transactions- Accounts Payable > Blend- OM&A / CapEx	10.2%	
Financial Processing Services- Office	4.8%			Blend- OM&A / CapEx	4.8%	
Controllership- External Purchase Services	4.1%			Blend- OM&A / CapEx	4.1%	
Investment Planning	4.1%			Blend- OM&A / CapEx	4.1%	Blend- OM&A / CapEx
Financial Processing Services- Accounts Receivable and Asset Management	2.1%			Transactions- AR / Asset Management	2.1%	
Regulatory Accounting	2.0%			Regulated Revenue Requirement	2.0%	
Vice President, Financial Services Office	1.0%			Blend- OM&A / CapEx	1.0%	
	100.0%		44.2%		55.8%	
FINANCE GROUP- TREASURY						
Treasury Operations	5.1%			Blend- OM&A / CapEx	5.1%	
Investor Relations	1.3%			Blend- OM&A / CapEx	1.3%	
Insurance Premiums	92.0%	Specific	76.1%	Insurance Company / Management Estimates	15.9%	> Specific to Stations > Insured Replacement Value
Ontario Nuclear Funds Management	1.6%	Specific	1.6%			N/A
	100.0%		77.7%		22.3%	

OPG CENTRALIZED SUPPORT AND ADMINISTRATIVE COSTS
COST ALLOCATION METHODOLOGY REVIEW
SUMMARY OF DISTRIBUTIONS

-		DISTRIBUTION TO BUSINESS UNITS				HYDROELECTRIC
		Direct Assignment		Allocation		Regulated / Unregulated
DEPARTMENT / Activities	Activity % of Dept.	Method	BU Direct Assign %	Cost Driver	BU Alloc- ation %	Applies to Direct Assignment
FINANCE GROUP- RISK SERVICES						
Risk and Assurance	32.6%	Estimates	20.2%	Blend- OM&A / CapEx	12.4%	> Blend- OM&A / CapEx > Internal- Energy Markets Total > Estimates to Hydro Regulated / Hydro Unregulated
Credit Risk	15.4%	Estimates	11.4%	Blend- OM&A / CapEx	4.0%	> Blend- Revenue / Fuel (excl. Hydro GRC) > Internal- Energy Markets Total > Estimates to Hydro Regulated / Hydro Unregulated
Market Risk	14.6%	Estimates	11.8%	Blend- Revenue / Fuel (excl. Hydro GRC)	2.8%	> Blend- OM&A / CapEx > Internal- Energy Markets Total > Estimates to Hydro Regulated / Hydro Unregulated
Enterprise Risk	11.4%	Estimates	8.0%	Blend- OM&A / CapEx	3.4%	> Blend- OM&A / CapEx > Internal- Energy Markets Total > Estimates to Hydro Regulated / Hydro Unregulated
Internal Controls Certification Costs	8.7%			Blend- OM&A / CapEx	8.7%	
Risk Services Office	17.3%			Internal- Risk Services Total	17.3%	
	100.0%		51.4%		48.6%	
FINANCE GROUP- SUPPLY CHAIN						
Supply Chain Management	100.0%	Estimates	58.0%	M&S / External Purchase Services Expenditures	42.0%	M&S / External Purchase Services Expenditures
	100.0%		58.0%		42.0%	
FINANCE GROUP- FINANCIAL PLANNING / TAXATION						
Financial Planning	47.7%			Blend- OM&A / CapEx	47.7%	
Taxation- Income, Other	24.4%			Blend- OM&A / CapEx	24.4%	
Taxation- Commodity Tax	17.0%			M&S / External Purchase Services Expenditures	17.0%	
Taxation- Property	9.6%			Net Assets	9.6%	
Taxation- Labor	1.3%			FTEs	1.3%	
	100.0%		0.0%		100.0%	

OPG CENTRALIZED SUPPORT AND ADMINISTRATIVE COSTS
COST ALLOCATION METHODOLOGY REVIEW
SUMMARY OF DISTRIBUTIONS

-		DISTRIBUTION TO BUSINESS UNITS				HYDROELECTRIC
		Direct Assignment		Allocation		Regulated / Unregulated
DEPARTMENT / Activities	Activity % of Dept.	Method	BU Direct Assign %	Cost Driver	BU Alloc-ation %	Applies to Direct Assignment
FINANCE GROUP- CFO OFFICE						
CFO Office	63.4%			Internal- Finance Total	63.4%	
Pension Fund Reviews External Purchase Service	36.6%			FTEs	36.6%	
	100.0%		0.0%		100.0%	
CORPORATE AFFAIRS GROUP- PUBLIC AFFAIRS						
Public Affairs Labor Costs	40.5%	Estimates	40.5%			Estimates to Stations
Public Awareness	25.6%			Blend- OM&A / CapEx	25.6%	
Canadian Nuclear Association	11.1%	Specific	11.1%			N/A
Corporate Citizenship Program- Site Specific Initiatives	10.4%	Specific	10.4%			Specific to Stations
Corporate Citizenship Program- Corporate-Wide Initiatives	6.7%			Blend- OM&A / CapEx	6.7%	
Community Research Programs	2.3%			Blend- OM&A / CapEx	2.3%	
Advertising- Nuclear	1.7%	Specific	1.7%			N/A
Water Safety Awareness	1.7%	Specific	1.7%			MWh Generation
	100.0%		65.4%		34.6%	
CORPORATE AFFAIRS GROUP- REGULATORY AFFAIRS / STRATEGIC PLANNING						
Regulatory Affairs- Labor Costs	51.4%	Specific / Estimates	25.1%	Blend- OM&A / CapEx	26.3%	Blend- OM&A / CapEx
Strategic Planning	29.2%	Specific	1.8%	Blend- OM&A / CapEx	27.4%	N/A
Regulatory Affairs- Membership Fees	10.6%	Specific / Estimates	6.0%	Blend- OM&A / CapEx	4.6%	Blend- OM&A / CapEx
Regulatory Affairs- External Purchase Services	8.8%	Specific / Estimates	5.2%	Blend- OM&A / CapEx	3.6%	Blend- OM&A / CapEx
	100.0%		38.1%		61.9%	
CORPORATE AFFAIRS GROUP- SVP OFFICE						
Corporate Affairs Senior Vice President's Office	100.0%			Internal- Corporate Affairs Total	100.0%	
	100.0%		0.0%		100.0%	

OPG CENTRALIZED SUPPORT AND ADMINISTRATIVE COSTS
COST ALLOCATION METHODOLOGY REVIEW
SUMMARY OF DISTRIBUTIONS

-		DISTRIBUTION TO BUSINESS UNITS				HYDROELECTRIC
		Direct Assignment		Allocation		Regulated / Unregulated
DEPARTMENT / Activities	Activity % of Dept.	Method	BU Direct Assign %	Cost Driver	BU Alloc-ation %	Applies to Direct Assignment
CIO GROUP- NEW HORIZON INFRASTRUCTURE MANAGEMENT						
Deskside Support; Helpdesk; E-mail; Internet	11.2%			LAN IDs	11.2%	
Microsoft Wintel Operating Systems	2.8%			Business Workstations	2.8%	
Data Transmission and Telecommunication	2.6%			Business Workstations (for supported sites)	2.6%	
UNIX Operating System	1.8%			Unix Applications Support	1.8%	
MVS Operating System	1.3%	Specific	1.3%			N/A
Storage	1.2%	Specific	0.3%	Internal- Functional Estimates	0.9%	N/A
Remote Access	0.4%			Security Fobs Count	0.4%	
CIO GROUP- NEW HORIZON THIRD PARTY CONTRACTS						
MVS Operating System	5.1%	Specific	5.1%			N/A
Microsoft Wintel Operating Systems	3.2%			Business Workstations	3.2%	
UNIX Operating System	2.3%			Unix Applications Support	2.3%	
SAP	2.0%			SAP User Count	2.0%	
Storage	0.9%	Specific	0.2%	Internal- Functional Estimates	0.7%	N/A
Disaster Recovery; Security	0.5%			Business Workstations	0.5%	
Technical Computing Services	0.4%	Specific	0.3%	LAN IDs	0.1%	N/A

OPG CENTRALIZED SUPPORT AND ADMINISTRATIVE COSTS
COST ALLOCATION METHODOLOGY REVIEW
SUMMARY OF DISTRIBUTIONS

-		DISTRIBUTION TO BUSINESS UNITS				HYDROELECTRIC
		Direct Assignment		Allocation		Regulated / Unregulated
DEPARTMENT / Activities	Activity % of Dept.	Method	BU Direct Assign %	Cost Driver	BU Allocation %	Applies to Direct Assignment
CIO GROUP- NEW HORIZON APPLICATION MAINTENANCE						
Passport; Nuclear Custom Applications	2.8%	Specific	2.8%			N/A
SAP Data Warehousing and Reporting; SAP Work Management and Supply	2.7%	Specific	0.2%	Internal- Functional Estimates	2.5%	N/A
SAP Application Development and Authorization / Basis	1.8%			Internal- SAP Functional Cost Total	1.8%	
SAP HR Modules; HR Custom Applications	1.4%			Internal- HR Total	1.4%	
SAP Finance Modules; Finance Custom Applications	0.9%			Internal- Finance Total	0.9%	
Web Custom Applications; IT Architecture	0.8%			LAN IDs	0.8%	
IT Purchasing	0.6%			Business Workstations	0.6%	
CIO GROUP- NEW HORIZON OTHER						
New Horizon Overhead Charges	7.2%			Internal- New Horizon Total	7.2%	
Data Transmission and Telecommunication- Variable Costs	5.5%	Historical	5.5%			Historical to Stations
Enhancement Hours	3.1%			Internal- Applicable Applications / Services	3.1%	
PST Expense	1.5%			Internal- Applicable New Horizon Costs Total	1.5%	
Miscellaneous Services	0.8%	Historical	0.8%			Historical to Stations
Microsoft User Licenses	0.2%			Business Workstations	0.2%	

OPG CENTRALIZED SUPPORT AND ADMINISTRATIVE COSTS
COST ALLOCATION METHODOLOGY REVIEW
SUMMARY OF DISTRIBUTIONS

-		DISTRIBUTION TO BUSINESS UNITS				HYDROELECTRIC
		Direct Assignment		Allocation		Regulated / Unregulated
DEPARTMENT / Activities	Activity % of Dept.	Method	BU Direct Assign %	Cost Driver	BU Allocation %	Applies to Direct Assignment
CIO GROUP- CIO WORK PROGRAMS						
Site-Specific Work Programs	7.1%	Specific	7.1%			Specific to Stations
Energy Markets Work Programs	4.3%			Internal- Energy Markets Various	4.3%	
CIO Overhead Costs	4.0%			Internal- CIO Various	4.0%	
Passport; Other Nuclear IT Support Work Programs	2.5%	Specific	2.5%			N/A
Workstation Purchasing	2.4%			FTEs	2.4%	
Real Time Systems Support	1.0%	Estimates	1.0%			Estimates to Stations
Hydro / Fossil CIO Support Work Programs	0.9%			Internal- Hydro / Fossil Support Totals	0.9%	
HR Support Work Program	0.8%			Internal- HR Total	0.8%	
Document Management	0.7%	Estimates	0.7%			Internal- Various
Supply Chain Support Work Program	0.6%	Estimates	0.6%			Internal- Various
Telecom- Project Support	0.5%			Internal- CIO Non-Capital Project Total	0.5%	
Software Licenses	0.4%			Business Workstations	0.4%	
Infrastructure Security	0.4%	Estimates	0.4%			
SAP Training	0.4%			SAP User Count	0.4%	
Freedom of Information	0.3%			Blend- OM&A / CapEx	0.3%	
IT Architecture	0.3%			LAN IDs	0.3%	
Finance Support Work Program	0.3%			Internal- Finance Total	0.3%	
IT Strategy	0.2%	Estimates	0.2%			Estimates to Stations
Telecom- Administration	0.2%	Historical	0.2%			Historical to Stations
CIO GROUP- NON-CAPITAL PROJECTS						
Non-Capital Projects	7.7%	Specific / Estimates	7.7%			Specific / Estimates to Stations
	100.0%		36.8%		63.2%	

OPG CENTRALIZED SUPPORT AND ADMINISTRATIVE COSTS
COST ALLOCATION METHODOLOGY REVIEW
SUMMARY OF DISTRIBUTIONS

-		DISTRIBUTION TO BUSINESS UNITS				HYDROELECTRIC
		Direct Assignment		Allocation		Regulated / Unregulated
DEPARTMENT / Activities	Activity % of Dept.	Method	BU Direct Assign %	Cost Driver	BU Allocation %	Applies to Direct Assignment
ENERGY MARKETS GROUP						
Portfolio Management	26.1%	Estimates	26.1%			Estimates to Stations
Trading	19.2%	Specific	19.2%			N/A
Planning & Analysis	18.8%	Estimates	18.8%			Estimates to Stations
Energy Markets Support	10.4%			Internal- Energy Markets Various	10.4%	
Fossil Fuels Procurement	9.8%	Specific	9.8%			N/A
Energy Markets Programming	8.1%	Estimates	8.1%			Estimates to Stations
Electricity Sales Vice President's Office	2.7%			Internal- Portfolio Management & Trading Total	2.7%	
Energy Markets Senior Vice President's Office	4.9%			Internal- Energy Markets Total	4.9%	
	100.0%		82.0%		18.0%	
REAL ESTATE GROUP- REAL ESTATE SERVICES						
Rent & Utilities- Nuclear Facilities	59.3%	Specific	59.3%			N/A
Labor Costs	13.4%	Estimates	13.4%			> Blend- OM&A / CapEx > Internal- Various
Rent & Utilities- OPG Head Office	12.6%	Service Fees	12.6%			N/A
External Purchase Services	6.1%	Specific / Estimates	6.1%			> Blend- OM&A / CapEx > Internal- Various
Rent & Utilities- Wesleyville	3.3%			Square Footage	3.3%	
Rent & Utilities- Fossil Facilities	2.0%	Specific	2.0%			N/A
Rent & Utilities- OSL Plant Group	2.0%	Specific	2.0%			Internal- OSL Common Support Total
Rent & Utilities- Kipling Site	1.3%	Service Fees	1.3%			N/A
	100.0%		96.7%		3.3%	

OPG CENTRALIZED SUPPORT AND ADMINISTRATIVE COSTS
COST ALLOCATION METHODOLOGY REVIEW
SUMMARY OF DISTRIBUTIONS

		DISTRIBUTION TO BUSINESS UNITS				HYDROELECTRIC
-		Direct Assignment		Allocation		Regulated / Unregulated
DEPARTMENT / Activities	Activity % of Dept.	Method	BU Direct Assign %	Cost Driver	BU Alloc-ation %	Applies to Direct Assignment
REAL ESTATE GROUP- BUSINESS SERVICES						
Business Services- Corporate	35.8%			FTEs	35.8%	
Business Services- Nuclear	26.8%	Specific	26.8%			N/A
Office Services- Graphics & Printing Costs	20.9%	Historical	20.9%			FTEs
Office Services- Corporate Wide Costs	16.5%			FTEs	16.5%	
	100.0%		47.7%		52.3%	
REAL ESTATE GROUP- FACILITY SERVICES						
OPG Head Office	38.1%	Service Fees	38.1%			N/A
Nuclear Sites	23.0%	Specific	23.0%			N/A
Kipling Site	20.2%	Service Fees	20.2%			N/A
Projects & Administration Costs	11.5%	Specific	2.3%	Internal- CSA Total (excl. Centrally Held Costs)	9.2%	N/A
Wesleyville Site	3.6%			Square Footage	3.6%	
Bruce Power Site	3.5%	Specific	3.5%			N/A
	100.0%		87.2%		12.8%	
REAL ESTATE GROUP- FLEET SERVICES						
Fleet Services	100.0%			FTEs	100.0%	
	100.0%		0.0%		100.0%	
REAL ESTATE GROUP- VICE PRESIDENT						
Real Estate Vice President's Office	100.0%			Internal- Real Estate Total	100.0%	
	100.0%		0.0%		100.0%	

OPG CENTRALIZED SUPPORT AND ADMINISTRATIVE COSTS
COST ALLOCATION METHODOLOGY REVIEW
SUMMARY OF DISTRIBUTIONS

-		DISTRIBUTION TO BUSINESS UNITS				HYDROELECTRIC
		Direct Assignment		Allocation		Regulated / Unregulated
DEPARTMENT / Activities	Activity % of Dept.	Method	BU Direct Assign %	Cost Driver	BU Alloc- ation %	Applies to Direct Assignment
CENTRALLY HELD COSTS						
Pension / OPEB- Amortization of Deferred Costs	56.9%			Pension / OPEB Costs	56.9%	
Employee Incentives	12.9%	Historical	12.9%			> Labor Costs > Internal- Various
Cost of Services Provided to Bruce Power	9.4%	Specific	9.4%			N/A
Fiscal Calendar Payroll Adjustment	(8.8%)			Labor Costs	(8.8%)	
Rate Regulation Expenses	5.5%			Regulated Revenue Requirement	5.5%	
Subsidiaries and Joint Ventures	5.1%	Specific	5.1%			N/A
Labor Costs Escalation Provision	4.5%	Specific	4.5%			Specific to Stations
Cost of Goods Sold- Other Business	4.4%	Specific	4.4%			N/A
Provincial Fee- CNSC	2.8%	Specific	2.8%			N/A
Indemnification Fee	1.8%			Net Assets	1.8%	
Vacation Accrual	1.8%			Labor Costs	1.8%	
PST Self-assessment	1.5%			M&S / External Purchase Services Expenditures	1.5%	
Bad Debts Provision	1.1%			Revenue	1.1%	
Insurance Escalation Provision	1.1%			Insurance Costs	1.1%	
	100.0%		39.1%		60.9%	

OPG CENTRALIZED SUPPORT AND ADMINISTRATIVE COSTS
COST ALLOCATION METHODOLOGY REVIEW
SUMMARY OF DISTRIBUTIONS

-		DISTRIBUTION TO BUSINESS UNITS				HYDROELECTRIC
		Direct Assignment		Allocation		Regulated / Unregulated
DEPARTMENT / Activities	Activity % of Dept.	Method	BU Direct Assign %	Cost Driver	BU Allocation %	Applies to Direct Assignment
HYDROELECTRIC BUSINESS UNIT COMMON SUPPORT COSTS						
Hydroelectric Development	38.4%	Specific	38.4%			Estimates to Hydro Regulated / Hydro Unregulated
Engineering Services	28.2%	Specific	28.2%			> Specific to Stations > Internal- Hydro Various
Water Resources and Aboriginal Affairs	9.8%	Specific	9.8%			Base OM&A
Business Support and Regulatory Affairs	6.0%	Specific	6.0%			Base OM&A
Supply Chain	5.6%	Specific	5.6%			Estimates to Stations
Environment	4.7%	Specific	4.7%			Base OM&A
Dam Safety and Emergency Preparedness	4.3%	Specific	4.3%			Base OM&A
Executive Vice President's Office	3.0%	Specific	3.0%			Internal- Hydro Total
	100.0%		100.0%		0.0%	
OTTAWA-ST. LAWRENCE COMMON SUPPORT COSTS						
Asset Management & Technical Support Services	43.0%	Specific	43.0%			Estimates to Stations
Project Management	23.3%	Specific	23.3%			Base OM&A- OSL
HR & Support Services	16.9%	Specific	16.9%			Base OM&A- OSL
Business Support	10.6%	Specific	10.6%			Base OM&A- OSL
Plant Group Management	6.2%	Specific	6.2%			Base OM&A- OSL
	100.0%		100.0%		0.0%	

OPG CENTRALIZED OPERATING AND ADMINISTRATIVE COSTS
TEMPLATE FOR USE BY CSA DEPARTMENTS
DEPARTMENTAL COST DISTRIBUTIONS

COA Department Name

		DISTRIBUTION TO BUSINESS UNITS									
		Direct Assignment							Allocation		
Activities	Activity % of Dept.	Method	Nuclear %	Hydro %	Fossil %	Energy Markets %	Other	Other %	Allocator	%	SUM
(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)	(J)	(K)	(L)
Activity 1	10.0%	Specific	10.0%								10.0%
Activity 2	15.0%	Specific	10.0%						FTEs	5.0%	15.0%
Activity 3	20.0%	Specific			10.0%		HR	10.0%			20.0%
Activity 4	8.0%	Estimate		4.0%					MWh Generation	4.0%	8.0%
Activity 5	7.0%	Estimate		2.0%	2.0%					3.0%	7.0%
Activity 6	10.0%	Estimate				4.0%	Finance	1.0%	Blend- OM&A / CapEx	5.0%	10.0%
Activity 7	8.0%	None							FTEs	8.0%	8.0%
Activity 8	17.0%	None							Blend- OM&A / CapEx	17.0%	17.0%
Other Activities	5.0%								Overall Departmental Labor	5.0%	5.0%
	100.0%		20.0%	6.0%	12.0%	4.0%		11.0%		47.0%	100.0%

Instructions

1) Enter values or names in blue cells.
2) Columns C-K are for Distribution of costs to Business Units.
3) List activities or resouces in Column A and portions of department budget in Column C; must total 100%.
4) For Direct Assignments, indicate in Column C if Specific, Estimate or Historic, and enter values in Columns D-I.
5) Use Columns H-I for Other Business Units or assignments to COA groups or departments.
6) For Allocations, enter cost driver in Column J. Colummn L should equal 1 - Column B.
7) Total of Columns D-I is shown in Column L; must equal totals in Column B.
8) Columns M-P are for Distribution of costs to Stations.
9) It is assumed same cost driver is used for all Business Unit to Stations allocations; enter cost driver in Column N- All.
10) If Business Unit to Station cost driver is different, enter Business Unit in Column O and cost driver in Column P.
11) For any Direct Assignments, indicate "Direct" in Column M.

OPG CENTRALIZED OPERATING AND ADMINISTRATIVE COSTS

DEPARTMENTAL COST DISTRIBUTIONS

COA Department Name

Activities	Activity % of Dept.		DISTRIBUTION TO STATIONS Allocators			
			Direct Assign	All	Other- Name	Other- Allocator
(A)	(B)		(M)	(N)	(O)	(P)
Activity 1	10.0%					
Activity 2	15.0%					
Activity 3	20.0%					
Activity 4	8.0%					
Activity 5	7.0%					
Activity 6	10.0%					
Activity 7	8.0%					
Activity 8	17.0%					
Other Activities	5.0%					
	100.0%					

OPG CENTRALIZED SUPPORT AND ADMINISTRATIVE COSTS
COST ALLOCATION METHODOLOGY REVIEW
2006 BUDGET

DEPARTMENT / Activities	2006 Budget C$000s	2006 Budget % of Total	Distribution to Business Units-Direct Assign %
Human Resources Group	47,284	6.8%	61.0%
Corporate Center Group			
Executive Office	8,403	1.2%	
Law	9,999	1.4%	100.0%
Sustainable Development	2,771	0.4%	69.3%
Corporate Secretariat	3,023	0.4%	
	24,196	3.5%	
Nuclear Waste Manegement Group	5,086	0.7%	100.0%
Finance Group			
Controllership	41,361	5.9%	44.2%
Treasury	33,129	4.7%	77.7%
Risk Services	8,707	1.2%	51.4%
Supply Chain	5,354	0.8%	58.0%
Financial Planning & Taxation	4,360	0.6%	
CFO Office	686	0.1%	
	93,597	13.4%	55.1%
Corporate Affairs Group			
Public Affairs	11,705	1.7%	65.4%
Regulatory Affairs / Strategic Planning	5,708	0.8%	38.1%
SVP Office	1,178	0.2%	38.1%
	18,591	2.7%	55.3%
CIO Group	167,873	24.0%	36.8%
Energy Markets Group	22,713	3.2%	82.0%
Real Estate			
Real Estate Services	15,042	2.1%	96.7%
Business Services	18,134	2.6%	47.7%
Facilities Services	15,693	2.2%	87.2%
Fleet Services	337	0.0%	
Vice President's Office	298	0.0%	
	49,504	7.1%	74.5%
Total CSA Costs (excluding Hydroelectric Common Support Costs)	**428,844**	**61.2%**	**52.5%**
Centrally Held Costs	271,500	38.8%	39.1%
Total (excluding Hydroelectric Common Support Costs)	**700,344**	**100.0%**	**47.3%**
Hydroelectric Common Support Costs			
Hydroelectric Business Unit Common Support Costs	23,400	81.3%	100.0%
Ottawa-St. Lawrence Common Support Costs	5,400	18.8%	100.0%
Total	**28,800**	**100.0%**	**100.0%**
Total (including Hydroelectric Common Support Costs)	**729,144**		

ONTARIO POWER GENERATION INC.
TORONTO, ONTARIO

REVIEW OF THE ONTARIO POWER GENERATION INC. DEPRECIATION REVIEW PROCESS

REPORT ON THE REVIEW CONDUCTED BY

GANNETT FLEMING INC.

March 2007

Gannet Fleming
Valuation and Rate Division

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March 1, 2007

Lubna Ladak
Controller, Regulatory Finance
Ontario Power Generation Inc.
700 University Avenue
Toronto, Ontario M5G

Ms. Ladak:

Pursuant to your request, we have conducted a review of the processes, procedures and methods used by Ontario Power Generation Inc., as a rate regulated utility, to review its depreciation expense. Our report presents a description of the methods used in our review, the findings of our review and our recommendations for future depreciation reviews conducted by Ontario Power Generation Inc.

Gannett Fleming has found that the processes, procedures and methods followed by Ontario Power Generation Inc. adequately meet regulatory objectives regarding depreciation generally accepted by Canadian regulatory authorities. These processes, procedures and methods should also lead to a reasonable and appropriate calculation of depreciation expense for inclusion in the revenue requirement for ratemaking purposes. Gannett Fleming makes certain recommendations, which in our view, would further enhance the extent to which these regulatory objectives are being met by Ontario Power Generation Inc.

Gannett Fleming gratefully acknowledges the access to Ontario Power Generation Inc. personnel and information in the completion of the review.

Respectfully submitted,

GANNETT FLEMING INC.
VALUATION AND RATE DIVISION

LARRY E. KENNEDY
Director, Canadian Services

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PART I. INTRODUCTION

ONTARIO POWER GENERATION INC.
TORONTO, ONTARIO

DEPRECIATION REVIEW PROCESS

PART I – INTRODUCTION

SCOPE

This report sets forth the results of a review conducted by Gannett Fleming Inc. (“Gannett Fleming”) to assess the adequacy of the Ontario Power Generation Inc. (“OPG”) depreciation review processes, procedures and methods (the “Depreciation Review Process”) to meet generally accepted depreciation objectives for rate regulated companies. OPG retained Gannett Fleming to provide an opinion on the degree of adequacy to which the Depreciation Review Process used by OPG achieves those objectives that are generally accepted by Canadian regulatory authorities, and to specifically provide comment on the ability of OPG’s process to result in an appropriate amount of depreciation expense as a component of the revenue requirement. This report is based on the objectives of a well defined depreciation review process and the ability of OPG’s current Depreciation Review Process to adequately meet these objectives.

In completion of this assignment Gannett Fleming developed a set of generally accepted depreciation objectives for rate regulated companies and assessed the degree to which OPG’s processes, procedures and methods meet these objectives. The degree to which OPG meets these regulatory objectives was evaluated based on information gained from on-site interviews with representatives of OPG Management, Operating, and Engineering staff as well as with the Chair and members of OPG's Depreciation Review Committee (the "DRC"). Additionally, Gannett Fleming reviewed OPG's documentation related to its depreciation policies and the DRC's report and working papers.

SUMMARY OF FINDINGS

The development and administration of depreciation policy currently occurs within the Finance Group of OPG. Ultimately, the Chief Financial Officer ("CFO") of the company is responsible for approving depreciation policy. The review of the average service life indications of OPG's regulated plant is completed through the work of a multi-departmental DRC. The DRC is accountable for providing a formal engineering, technical and financial review of the service lives of OPG's fixed assets. Based on our review of the DRC report and working papers for the 2006 DRC recommendations, Gannett Fleming confirms that the processes, procedures and methods used by the DRC as part of OPG's Depreciation Review Process are sufficient to address generally accepted depreciation objectives for rate regulated companies. Additionally, OPG's current practices should result in a reasonable determination of average service lives and a reasonable and appropriate amount of depreciation expense to be included in OPG's revenue requirement request. It should be noted that Gannett Fleming did not perform a review of the actual average service lives of the regulated assets. Rather, Gannett Fleming reviewed the adequacy of OPG's Depreciation Review Process to achieve generally accepted regulatory objectives related to depreciation.

Gannett Fleming makes recommendations regarding two main areas, as follows:

- <u>Independence from Bias</u> – While Gannett Fleming did not find any instances of a lack of impartiality impacting OPG's Depreciation Review Process, Gannett Fleming makes the following two recommendations in order to ensure that the impartiality of the process is not compromised and any external perception of potential bias is removed:

- Establishment of a Depreciation Approvals Committee or similar appropriate internal governance structure whose mandate would be to approve the DRC report and OPG's depreciation review policies; and
- Where appropriate, increased use of benchmarking of average asset service life estimates to a peer group of North American utilities.

- Transparency and Understandability – Gannett Fleming recommends that, for use in the regulatory context, the DRC report be re-structured to better outline OPG's depreciation policies and objectives with respect to depreciation and the DRC process, and to include additional detail for explanations and justification of the average life estimates contained in the report.

In making the recommendation that OPG establish a Depreciation Approvals Committee or other appropriate internal governance structure within the company, Gannett Fleming suggests that this committee be charged with the specific responsibility of approving depreciation review policies and procedures and have the ultimate responsibility for the recommendations contained within the DRC report. Gannett Fleming is of the view that the current DRC should be provided with specific criteria regarding its composition and selection of asset accounts to review and further should receive specific direction with regard to review procedures directly from the committee or other governance structure. Additionally, the DRC should file its report with, and seek approval of the average service life estimates from this committee or governance structure.

Currently, the responsibility for depreciation rests within the Finance Group, which sets accounting policy, calculates depreciation expense, and coordinates the annual review of service lives through the DRC process. Gannett Fleming notes that the DRC process does rely to a significant extent on the input from the lines of business with respect to the selection of assets for review and the actual estimates of average service lives. The recommendations of the DRC are approved by the CFO and the heads of OPG's lines of business. Establishing a Depreciation Approvals Committee or other appropriate internal governance structure, which would include members from outside of the Finance Group, would provide further independence and increased structure to the Depreciation Review Process. Gannett Fleming notes that its review did not yield any evidence that the current DRC process lacks impartiality.

Gannett Fleming also recommends that OPG benchmark the average service lives of certain generation assets to those of a peer group of North American utilities in order to identify asset groups that may require more detailed assessment and to provide additional basis for assessing the reasonability for OPG's depreciation expense included in the revenue requirement proposal. Finally, Gannett Fleming recommends that the DRC report be enhanced to better outline the company's policies, objectives and average service life justifications with respect to depreciation and the DRC process. The purpose of this recommendation is to increase the transparency and understandability of OPG's depreciation policies and Depreciation Review Process for the benefit of ratepayers, the regulator, and other external stakeholders in the regulatory process. Alternatively, OPG may consider preparing a separate document to accompany the existing DRC report.

PART II
REVIEW

PART II – REVIEW

DEPRECIATION IN A REGULATED ENVIROMENT

Depreciation, in public utility regulation, is the loss in service value not restored by current maintenance, incurred in connection with the consumption or prospective retirement of utility plant in the course of service from causes which are known to be in current operation and against which the utility is not protected by insurance. Among causes to be given consideration are wear and tear, deterioration, action of the elements, inadequacy, obsolescence, changes in the art, changes in demand, and the requirements of public authorities.[1]

Development of an appropriate and reasonable level of depreciation requires the development of depreciation policies, practices and detailed procedures, which are consistent with generally accepted regulatory objectives. One aspect of the practices and procedures is a depreciation review process, part of which includes the selection of the estimated service life for each of the assets or asset classes. In circumstances where group accounting practices are followed, the depreciation review process determines an average service life and, where appropriate, a retirement dispersion pattern for a class of assets. In circumstances where the utility follows a site or asset accounting practice, a depreciation review process will determine an average service life estimate for each depreciable asset or asset type.

REGULATORY OBJECTIVES RELATED TO DEPRECIATION

The review of depreciation and average service lives is undertaken to establish a depreciation expense for inclusion in the proposed revenue requirement that is reasonable in the circumstances (i.e., to enable the regulator to meet its statutory obligation to establish just and reasonable rates). A reasonable level of depreciation expense will properly recognize the consumption of the service value of a utility's assets

[1] Federal Energy Regulatory Commission, code of Federal Regulations, Part 101, Uniform System of Accounts Prescribed for Public Utilities and Licensees Subject to the Provisions of the Federal Power Act.

and will provide the appropriate level of rate base upon which the company earns a regulated return.

Regulators balance the level of precision required to enable them to determine that rates are just and reasonable against the costs of achieving increased levels of precision. For regulated utilities, the depreciation review process must evolve to meet the objectives and requirements of the regulator.

The following generally accepted regulatory objectives impact the depreciation review process and the depreciation amounts included in the revenue requirement of a regulated utility:

1) **Effectiveness**
   Ensure that the depreciation method and depreciation review techniques provide a reasonable degree of assurance that the depreciation amount included in the revenue requirement is appropriate.[2] The depreciation method should also be reliable and systematic, as consistent with the requirements outlined by Generally Accepted Accounting Principles ("GAAP") in Canada governing depreciation.[3]

2) **Efficiency**
   Ensure that the depreciation method results in positive net benefits (i.e., the depreciation method should not drive the design and implementation of asset management systems, rather the chosen depreciation method should benefit from and utilize whatever systems management considers necessary to provide efficient utility service). Incremental system and process requirements necessary to support the regulator's determination of just and reasonable rates should be developed based on the assessment of both the benefits and the incremental costs of implementation and operation.[4,5]

3) **Transparency and Understandability**
   Ensure that sufficient, appropriate information is provided to facilitate the review of the utility's depreciation method and the unique utility circumstances that the method has been designed to address. [6,7]

[2] As stated in the National Energy Board of Canada, Uniform Accounting Regulations
[3] As stated in the Canadian Institute of Chartered Accountants Handbook, Section 3061.28
[4] As stated in Alberta Energy Board Decision 2004-066, relating to a 2004 Distribution Tariff Application by ENMAX Power Corporation
[5] As stated in Alberta Energy Board Decision 2006-002, relating to a 2005 Distribution Tariff Application by ENMAX Power Corporation
[6] Ibid footnote 2
[7] As discussed in Ontario Energy Board Decision RP-1998-0001, relating to a Transitional Rate Order for Distribution Rates for Ontario Hydro Services Company, dated April 1, 1999, pages 68 and 69

4) **Intergenerational Equity**
Ensure that the depreciation method provides a reasonable alignment between the recovery of costs in rates and the benefits derived by ratepayers from the consumption of the service value of the assets.[8,9]

5) **Capital Attraction**
Ensure that the depreciation method enables a utility's investors to recover their capital investment.[10]

6) **Independence from Bias**
Ensure that the development and review of the depreciation policies and rates occurs in an impartial manner and free from any overriding bias from the company to arrive at predetermined conclusions.[11]

CURRENT OPG PROCESSES, PROCEDURES AND METHODS

OPG reviews the average service life of its regulated plant through the work of a multi-departmental DRC. The DRC is accountable for providing a formal engineering, technical and financial review of the service lives of fixed assets. The DRC includes representatives from the lines of business and other corporate functions who are responsible for operating and maintaining the fixed assets, in addition to representatives having experience in finance, planning, regulation and accounting. The DRC recommendations are documented in an annual report which is submitted to the CFO and line of business Executive Vice Presidents ("EVPs") for approval. Following approval, the DRC recommendations are normally implemented on January 1 of the following year. Generally, the DRC process includes the following steps:

- Nomination of members of the DRC by line of business and functional area leaders
- Initial meeting of the DRC to discuss high level team objectives and to establish key contacts in the organization

[8] Ibid footnote 1
[9] As stated in the Canadian Institute of Chartered Accountants Handbook, Section 3061.29
[10] Ibid footnote 2
[11] Ibid footnotes 2, 7

- Selection of assets for review based on principles established by the DRC at the outset of the review
- Assessment of services lives of selected asset classes by operational experts and documentation of the related facts and conclusions in the Depreciation Review Assessment Asset Class record (the "Technical Report"). Technical Reports provide a description of assets included in the class, a summary of operating experience and other factors (such as asset condition assessments or external data) impacting the service life estimate, and the overall recommendation regarding the service life estimate by operational experts.
- Review of the Technical Reports by the DRC
- Development of the draft recommendations and report by the Chair of the DRC
- Review and approval of the report by the DRC
- Submission of the DRC recommendations to OPG's CFO and line of business EVPs

Implementation of recommendations on January 1 of the following year based on approval by the CFO and line of business EVPs

The regulated assets of OPG are studied by the DRC in combination with the non-regulated assets. The regulated assets include a large hydroelectric generating plant group (the "Niagara" plant group) and a large hydroelectric generating plant (the "Saunders" plant). The Niagara plant group is comprised of five sites in the Niagara region of Ontario and includes 38 generating units. The Saunders plant in the Cornwall area of Ontario comprises 16 units.

The regulated assets also include three nuclear generating plants (the "Darlington", "Pickering A" and "Pickering B" plants). The Darlington plant includes four generating units while the two Pickering plants include eight units (of which two units are currently being placed in safe storage). The depreciation rates for these regulated hydroelectric and nuclear plants are developed as part of the DRC review of OPG's generation facilities, which also include approximately 60 non-regulated hydroelectric sites, five fossil sites, and one additional nuclear plant (the "Bruce" plant) that is leased to and operated by an independent third party. The DRC also reviews the service lives of non-generation fixed assets, such as buildings and computer systems.

ASSESSMENT OF OPG'S PROCESSES

Overview

In order to determine the degree to which OPG's depreciation review processes, procedures and methods meet the regulatory objectives related to depreciation, Gannett Fleming's review assessed the following:

- OPG's process for the determination and administration of depreciation policy;
- OPG's process for establishing average service lives;
- The 2006 DRC documentation related to its purpose, structure and operation, including the asset selection process;
- The 2006 DRC documentation and processes, procedures and methods related to its review of hydroelectric generation assets;
- The 2006 DRC documentation and processes, procedures and methods related to its review of nuclear generation assets;
- The 2006 DRC documentation and processes, procedures and methods related to its review of non-generation assets; and
- The process related to the review and approval of the DRC report.

To the extent that Gannett Fleming determined that OPG's practices warranted enhancement to address generally accepted regulatory objectives related to depreciation, the Gannett Fleming review incorporated a review of OPG's practices against commonly used methods for the review of average service life estimates and depreciation rates by regulated utilities throughout North America. The intent of the review was to identify options available to improve the capability of OPG's depreciation review practices to achieve specific regulatory objectives. The current state of OPG's systems, records and procedures was then considered to assess the cost and implementation challenges for each option.

Review of OPG's Processes

The following discussion provides a brief overview of the extent to which OPG's current depreciation review processes, procedures and methods meet each of the regulatory objectives described in the earlier section of this report.

Effectiveness OPG's Depreciation Review Process adequately meets this regulatory objective and should result in an appropriate depreciation expense amount for inclusion in the revenue requirement. A review of average service lives by trained and experienced internal experts, who are knowledgeable about the condition of the assets and the company's intentions with respect to their use, is an effective and valid technique for performing depreciation reviews, particularly for generation utilities. While statistical analysis of retirement data and benchmarking are other common methods for depreciation reviews used by energy companies, electricity generation utilities tend to have specialized, location specific economic asset life considerations and thus tend to have limited retirement experience that is meaningful to facilities at other locations, either within the company or at other electricity generation companies. This has particular relevance to OPG's nuclear assets, which are operated using CANDU nuclear technology. It should be noted that OPG depreciates its nuclear asset classes on a straight-line basis over the shorter of the classes' and the applicable nuclear facilities' estimated useful lives.

CANDU technology is currently used by only two other generation utilities in North America, both of which are Canadian, thus providing only a limited population against which to benchmark the service lives of OPG's nuclear facilities. However, selective benchmarking of service lives of certain nuclear asset subgroups to a peer group of North American utilities may have some benefit insofar that differences in technology are appropriately considered. For instance, benchmarking information can be used for average life estimates of certain equipment, such as radiation monitoring systems, nuclear training simulators, and other accessory station equipment, and the conventional components of nuclear plants, such as system transformers and rotors. OPG's ability to benchmark the overall service lives of its nuclear facilities is limited by the fact that nuclear generation utilities in the United States consider the term of their operating licenses as a primary indicator for determining useful lives of their facilities. The duration of operating licenses is not a factor considered by OPG in establishing useful lives for nuclear facilities because the Canadian Nuclear Safety Commission issues licenses for significantly shorter terms. These terms are not reflective of the economic or operational lives of the nuclear facilities.

Limitations for benchmarking of OPG's hydroelectric generation assets to a peer group of North American utilities are less restrictive than those for its nuclear assets, due to the more widespread use of hydroelectric generation in Canada. Components of a typical hydroelectric generation plant also do not vary as much with the type of technology used. Therefore, where appropriate, such benchmarking is recommended for OPG's hydroelectric generation assets.

Gannett Fleming further notes that a number of OPG's generation assets, which may normally lend themselves to statistical retirement analysis, are not studied using statistical methods by OPG due, in large part, to the fact that these assets have been re-valued for financial and regulatory reporting purposes as at April 1, 1999 (the date on which OPG was formed and effectively purchased the assets from the former Ontario Hydro). As such, much of the original cost and retirement history that would be required in order to perform a statistical retirement analysis would need to be re-created. Even in the circumstances that this data could be re-created, the development of this data would be cost prohibitive, and, in the view of Gannett Fleming, would not provide sufficient additional benefit to warrant the cost associated with its development.

Gannett Fleming also notes that the implementation of the average service life estimates is performed in a reliable and systematic manner. The implementation is discussed within the DRC report that is presented for approval to the CFO of the company. The approved recommendations of the DRC are normally implemented in accordance with the plan described within the DRC report in a rational and systematic manner. The depreciation method used by OPG (predominantly straight line) is compliant with Canadian GAAP as governed by the Canadian Institute of Chartered

Accountants Handbook and is the depreciation method prescribed by the majority of Canadian regulatory authorities.

Efficiency OPG's Depreciation Review Process is efficient. The DRC is comprised of internal subject matter experts, and relies upon systems that are in place for operational and reporting purposes. The use of internal company resources in the development of the average service life estimates results in a DRC process that is cost effective to the ratepayer. Once assets are selected for review by the DRC, the process leading to the average service life recommendation is completed through internal company resources and in a manner that should lead to reasonable and appropriate average service life recommendations. The DRC process adequately meets the regulatory intention for companies to maximize the use of internal information and processes without burdening the ratepayer with significant costs associated with the implementation of new systems or processes. Gannett Fleming is of the view that the DRC process for the determination of average service lives is able to gather and process the information that is required through existing operational and accounting systems. Gannett Fleming's recommendation to introduce benchmarking of average services lives of certain assets to a peer group of utilities would not compromise the overall efficiency of OPG's Depreciation Review Process because benchmarking would focus on assets for which the necessary data is available and accessible from information published within the industry and from that which is in the public domain in regulatory forums. Once the appropriate sources of information are established, the actual collection of the data on a periodic basis would not be cost prohibitive.

Transparency and Understandability The DRC recommendations with regard to the average service life estimates are supported through the issuance of the DRC report to the CFO and line of business EVPs. The DRC report partially achieves the objective of Transparency and Understandability by including a reasonable description of the following: the scope of work performed by the DRC, the principles underlying the selection of assets to be reviewed by the DRC, recommendations and supporting rationale for average service life changes, and recommendations that should be considered in future DRC reviews.

Gannett Fleming notes that the primary purpose of the DRC report is to provide estimates of service lives for OPG's fixed assets. Given that some of OPG's assets are subject to rate regulation, additional disclosure in the report would be beneficial for complying with this regulatory objective. This would include additional detail regarding the company's depreciation policy, which is documented in OPG's Fixed Asset Accounting Procedure, additional detail regarding the Depreciation Review Process, such as specific asset selection criteria and the process for establishing the composition of the DRC, and additional detail for justification of the average service life estimates. Alternatively, Gannett Fleming notes that this information could be outlined in a separate document that can be reviewed in a regulatory proceeding by external stakeholders.

Intergenerational Equity The average service life estimates of the assets that are reviewed through the DRC process should be reasonable because internal experts who assess service lives are knowledgeable about the manner and timing of the utilization of these assets. Overall, the depreciation expense resulting from the DRC life estimates will align rate recovery established by the regulator with the receipt of the benefit of the assets in regulated service by ratepayers, as the service life estimates represent the periods of time over which the assets are used to generate electricity. Similarly, costs associated with asset retirement obligations are appropriately recovered during the service lives of related assets.

Capital Attraction The average service life estimates developed using the DRC process should result in the recovery of owner investment in a timely manner. The depreciation methods used in the application of average service lives are systematic and rational and, therefore, are appropriate to ensure a fair opportunity for the recovery of investment.

Independence from Bias The DRC review of average service life estimates is structured in a manner that relies significantly upon the professional views of internal company experts regarding the specific asset classes. In this manner, a potential bias of an internal expert may be carried through to the selection of assets for review and to the final average service life estimates. Gannett Fleming notes that three measures are commonly available to ensure that impartiality of average service life recommendations is preserved, as follows:

1. Review of specific average service life recommendations by an independent external expert;
2. Comparison of the recommended average service life estimates against peer companies; or
3. Review and approval of the specific recommendations for depreciation policies and the average service lives and procedural issues through an internal governance structure within the utility, which is responsible for the overall approval of depreciation review policies and their impact on depreciation expense.

Gannett Fleming notes that in the Ontario Energy Board (the "OEB") Decision RP-1998-0001 relating to an Ontario Hydro Services Company ("OHSC") Application, the DRC process was discussed. Generally, the OEB appeared concerned with the independence of the DRC process and recommended that:

1. "OHSC should establish a Depreciation Accounting Responsibility Center in the Finance/Accounting Division, with overall responsibility for determining depreciation accounting policies and accounting practices. The Responsibility Center would compare OHSC's depreciation policies to industry standards, engage external expertise as required for internal purposes or as deemed necessary by the Board, and set the specific practices governing the collection of data by DRC members, including the use of field inspections and surveys in setting service lives, determining dispersion patterns, etc. The role of the DRC

would be that of providing technical input as required by the Responsibility Center."

2. "OHSC should conduct appropriate bench-marking analysis of asset life as part of its depreciation study."[11]

The OEB in Decision RP-1998-0001 appeared to be primarily concerned with the governance of the DRC process and the manner in which any potential lack of impartiality be removed from the process. Gannett Fleming notes that, although the responsibility for depreciation in general falls under the mandate of OPG's CFO, the current DRC report is filed for review and approval with a number of senior executives of the company (the CFO and line of business EVPs). This approval results in a reasonable level of scrutiny of the DRC process by various stakeholders in the organization, and thus serves to promote the impartiality of the process. However, a specific Depreciation Approval Committee or other appropriate internal governance structure relating to depreciation has not been established within the company. Gannett Fleming views that an appropriately empowered, formalized Depreciation Approvals Committee or other governance structure, which would have the responsibility for overseeing the development of depreciation review policy and standards and for providing direction to the current DRC, will better meet the regulatory objective of Independence from Bias. Such a committee or governance structure would have a balanced representation from various areas of the organization, including Regulatory Affairs, Finance and the operational lines of business. It is envisioned that the DRC would receive instruction, structured criteria relating to its membership and asset selection and other guidance from this committee or other appropriate governance structure. Additionally, the committee may retain independent external expertise to assist in the development of appropriate depreciation review policy and standards and to guide the DRC in the review of the average service life recommendations, as it determines appropriate.

Increased use of benchmarking of average service lives would further serve to preserve the impartiality of the DRC process and would be consistent with the recommendations made by the OEB as part of Decision RP-1998-0001. Specific

[11] Ibid footnote 7

observations related to OPG's ability to benchmark service lives of its assets were discussed previously in this report.

Notwithstanding the observations noted above, Gannett Fleming, based on its review, has found no evidence that the current DRC process lacks impartiality and is of the view that, overall, the DRC process results in average service lives that are reasonable and establishes an appropriate level of depreciation expense in the revenue requirement.

PART III
FINDINGS AND RECOMMENDATIONS

PART III – FINDINGS AND RECOMMENDATIONS

FINDINGS AND RECOMMENDATIONS

The average service life estimates for OPG's assets are reviewed by the DRC and are approved by the CFO of the company and leaders of OPG's lines of business. Gannett Fleming finds that the current process is sufficiently adequate to address most regulatory objectives regarding depreciation, including Effectiveness, Efficiency, Intergenerational Equity, Capital Attraction and Independence from Bias. The Transparency and Understandability objective would be better met if the DRC report or a separate document that would be reviewed in the regulatory forum contained a discussion of the company's policy and overall objectives regarding depreciation and the DRC process, as well as additional detail for explanations and justification of average life estimates.

Certain aspects of OPG's Depreciation Review Process relating to the objective of Effectiveness could be refined; however, these refinements would not, in Gannett Fleming's view, have a material impact on the amount of depreciation expense or the overall adequacy of the process to meet the Effectiveness objective. The refinements relate to the inclusion of benchmarking of average service lives for certain generation assets to a peer group of utilities as part of the DRC process. The adequacy of meeting the objective of Independence from Bias could be enhanced by establishing a Depreciation Approvals Committee or other internal governance structure with the objective of overseeing the development of depreciation review policy and practices, as well as by increasing the use of benchmarking as part of the DRC process.

Notwithstanding the recommendations contained herein, Gannett Fleming does not find that the general DRC process and the 2006 DRC process and report specifically would create any concern that depreciation expense was not reasonable in the circumstances. Gannett Fleming believes that OPG's current Depreciation Review Process results in the depreciation expense component of the revenue requirement that reasonably and appropriately reflects the consumption of the average service life of OPG's regulated assets. Gannett Fleming also views that, overall, the DRC process is adequate in meeting the generally accepted regulatory objectives regarding depreciation for regulated North American utilities.