EB-2010-0008

IN THE MATTER OF the *Ontario Energy Board Act*, 1998, S.O. 1998, c. 15, Schedule B;

AND IN THE MATTER OF an Application by Ontario Power Generation Inc. pursuant to section 78.1 of the *Ontario Energy Board Act, 1998* for an order or orders determining payment amounts for the output of certain of its generating facilities.

COMPENDIUM OF DOCUMENTS FOR CROSS-EXAMINATION

CANADIAN MANUFACTURERS & EXPORTERS ("CME")

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Tab No.

1. Business Planning and Budgeting Process [Exhibit A2, Tab 2, Schedule 1]

2. 2010-2014 Business Planning Instructions dated June 3, 2009 [Exhibit A2-2-1, Attachment 1]

3. Memorandum of Agreement [Exhibit A1-4-1, Attachment 2]

4. Undertaking [JT1.11], together with February 23, 2005 Ministry of Energy Backgrounder [JT1.11 Attachment]

5. Hydro Generation Business Plan 2010 to 2014 [Exhibit F1-1-1, Attachment 1]

6. Nuclear Operations 2010-2014 Business Plan [Exhibit F2-1-1, Attachment 1]

7. Article entitled "OPG Starts Energy Board Rate Application Process *If granted, rate increase would be the second since 2005*" dated March 29, 2010

8. CCC IR#001 (Non-Confidential Version) [Issue 1.3, Exhibit L, Tab 4, Schedule 001]

9. *Globe and Mail* article entitled "Ontario utilities told not to bother with requests for rate increases" dated May 6, 2010

10. Article entitled "OPG Resumes Energy Board Rate Application Process *Lower rate request reduces impact on ratepayers*" dated May 26, 2010

11. *The Star* article entitled "OPG trims proposed hydro rate increase by 32%" dated May 26, 2010

12. CME IR #010 [Issue 1.3, Exhibit L, Tab 5, Schedule 010]

13. Mitigation of Payment Amount Increases [EB-2007-0905, Exhibit K1, Tab 1, Schedule 2]

14. Typical Residential Consumer Impact Assessment [EB-2007-0905, Exhibit K1, Tab 1, Schedule 3, Table 1]

15. Annualized Residential Consumer Impact Assessment [Exhibit I1, Tab 1, Schedule 2, Table 1]

16. Order in Council No. 437/2010, together with Minister's Directive

17. Article entitled "Taking a Deep Breath on Wind Power" by Michael Trebilcock dated March 2, 2010

18. CME IR #019 [Issue 6.11, Exhibit L, Tab 5, Schedule 019]

19. CME IR #023 [Issue 6.11, Exhibit L, Tab 5, Schedule 023]

20. CME IR #026 [Issue 6.11, Exhibit L, Tab 5, Schedule 026]

21. CME IR #028 [Issue 6.11, Exhibit L, Tab 5, Schedule 028]

22. CME IR #029 [Issue 6.11, Exhibit L, Tab 5, Schedule 029], together with Forecast Information (as of Q3/2004) for Facilities Prescribed under O. Reg 53/05 [Attachment 1]

23. CME IR #032 (Non-Confidential Version) [Issue 6.11, Exhibit L, Tab 5, Schedule 032]

24. CME IR #033 [Issue 6.11, Exhibit L, Tab 5, Schedule 033]

25. CME IR #036 [Issue 6.11, Exhibit L, Tab 5, Schedule 036]

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TAB 1

BUSINESS PLANNING AND BUDGETING PROCESS

1.0 PURPOSE

This evidence presents an overview of OPG's business planning and budgeting process.

2.0 OVERVIEW

OPG's business planning and budgeting process is relevant to this Application because the revenue requirement requested for the regulated hydroelectric and nuclear facilities is based on OPG's 2010 – 2014 Business Plan.

Section 3.0 provides an overview of the business planning and budgeting process. Section 4.0 sets out the business planning guidelines for the 2010 – 2014 Business Plan and section 5.0 sets out how expenditures are classified, the objectives of OPG's investment programs and how project portfolios are developed across the company's business units. Section 6.0 describes the business case requirements for project release and section 7.0 describes the post-implementation review process following the completion of a project.

3.0 BUSINESS PLANNING AND BUDGETING – PROCESS OVERVIEW

OPG's business planning and budgeting process is a decentralized annual process undertaken within a consistent corporate framework of strategic objectives, resource guidelines, and costing assumptions. The key elements of this corporate framework are identified to the business units through business planning instructions provided by Finance. Within this framework, the individual business units develop their specific strategic and performance objectives, and then identify and plan the work required to achieve these objectives.

The key elements of the business planning process are as follows:

- The communication of the planning context.
- The identification of key operating, economic and other planning assumptions to be used in development and costing of plans, including:
  - Forecast escalation rates and burden rates for labour costing.

- Foreign exchange rate forecasts.
- Interest rate forecasts.

- The communication of the business planning framework is as follows:
  - Communication of the business planning schedule including key timelines, milestones and activities, through business planning instructions typically issued by Finance during the second quarter.
  - Communication of the regulatory framework, including variance and deferral accounts, pricing structures, and any incentive mechanisms.

- Development of a consolidated revenue, sales and production forecast by OPG's Energy Markets business unit, along with associated scenarios and sensitivities. This forecast incorporates key production and reliability parameters from the nuclear and hydroelectric business units.

- The preparation of a consolidated financial outlook by Finance, based on inputs received from across the organization. Business units provide their planned OM&A, capital and provision-funded expenditures. Finance develops a comprehensive financial outlook by supplementing this information with the following elements:
  - Forecast depreciation expense based on existing assets and forecasts of new additions to the asset base.
  - Forecast borrowing requirements and associated financing costs, which are reviewed with OPG's Treasury department.
  - Nuclear liabilities, which are based on the lifecycle cost estimates for nuclear waste management and decommissioning programs, and the associated required decommissioning and used fuel fund contributions.
  - Income taxes payable which are forecast in conjunction with the Taxation department.

- Each business unit's plan also identifies key risks to forecast results and mitigation initiatives.

- Depending on the operational and/or financial issues facing OPG at the time, alternative planning scenarios may be identified and modelled once the base case forecast has been established.

- Individual business unit plans are reviewed with the President and Chief Executive Officer ("CEO") and Chief Financial Officer ("CFO") through a series of presentations, usually during September and early October. Business units incorporate feedback and redirection from these sessions into updated submissions, typically in early November.

- The draft consolidated business plan, based on these updated submissions, is reviewed by OPG senior management. The plan is also reviewed with shareholder representatives. The 2010 – 2014 Business Plan was finalized for submission to the OPG Board in November 2009 for approval.

3.1 2010 - 2014 Business Planning Objectives

The 2010 - 2014 Business Planning Instructions, issued on June 3, 2009, are provided in Attachment 1. In setting the context for the planning process, the Instructions recognized the significant challenges facing OPG as it enters a transition phase for much of its generation, and the challenges its customers face in terms of significant economic turmoil. Major initiatives that impact OPG's regulated operations include: the Darlington Refurbishment Project (see Ex. D2-T2-S1), the Pickering B Continued Operations initiative (see Ex. F2-T2-S3) and incorporating a "gap-based" approach to business planning in Nuclear (see Ex. F2-T1-S1).

In response to the financial environment, business units were directed to be aggressive in managing their costs while maintaining their critical performance objectives. Specifically, the business planning guidelines for 2010 required an $85M reduction in OM&A, compared to previously planned levels for that year. Management's commitment to this reduction helped offset the loss in revenue resulting from the deferral of the rate application.

Guidelines for subsequent years in the plan recognized the need to maintain strict expenditure control, and included:

- The continuation, into future years, of the 2010 cost reductions implemented by Nuclear.
- A direction to all corporate support groups that they freeze their future years' expenditure at 2010 levels.

OPG's business units responded by submitting plans that have met the financial targets. The cost reduction targets set by Finance are expected to be exceeded, with estimated savings across all business units of $278M in 2011 - 2012, compared to the previous business plan. At the same time, OPG faced a number of cost increases for new initiatives, including increased expenditures on Pickering B Continued Operations. These increases total $150M during 2011 - 2012, with the result that in 2011 - 2012, the total business unit expenditures are forecast to be $128M lower than in OPG's previous business plan. Lower burden rates, primarily due to lower pension and Other Post-Employment Benefits ("OPEB") expense resulting from more favourable economic conditions, contribute an additional $193M reduction to business unit costs over the two years.

4.0 BUSINESS UNIT ACTIVITIES

Business planning within the business units starts in the spring of the year prior to the period covered by the business plan with internal reviews of the current planning framework and confirmation and updating of business objectives and priorities. The business units also review the status of operational and performance plans and related capital and OM&A expenditures, as well as identification of emerging issues. This process is supplemented by additional planning direction identified at the corporate level. For example, as noted previously, the 2010 - 2014 corporate business planning guidelines identified a requirement to reduce 2010 OM&A by $85M compared to the levels established in the previous plan. Out of this process, business unit objectives and priorities are determined.

Over the course of the early summer, initial plant and site business plans are developed. Business unit management reviews these proposals and prioritizes projects and expenditures to establish a preliminary business unit plan. Further details regarding business planning and budgeting processes within the business units are provided in Ex. F1-T1-S1 and Ex. F2-T1-S1.

The business units present their preliminary plans to the CEO and CFO in late September or early October. These presentations identify key assumptions, operational or functional objectives, key risks and uncertainties, resource requirements and analyses of year-over-year changes in requirements, as well as changes from previous plans. During these sessions, the CEO or CFO provides redirection on these plans as required.

Business units then resubmit their plans, typically in October or early November, and plans are consolidated into a final draft corporate plan. The updated corporate plan is then presented to the OPG Board for approval.

5.0 INVESTMENTS/PROJECTS

5.1 Classification of Expenditures

Expenditures on investments or projects are classified in accordance with Canadian GAAP ("GAAP") as capital, OM&A, or charges against a previously established liability. Previously established liabilities include the liability for fixed asset removal and nuclear waste management (as discussed in Ex. C2-T1-S1).

Expenditures that are classified as capital are recorded as either fixed or intangible assets. Specifically, OPG capitalizes the following types of expenditures:

- Acquisition and construction of new assets: expenditures related to the purchase, design, development, construction or commissioning of a new asset that will provide benefits beyond the current year and meet or exceed the defined materiality threshold are capitalized.
- Rehabilitation/improvement/maintenance of existing assets: expenditures related to existing assets must meet all of the following criteria to be capitalized:
    - The benefits must extend beyond the current year.
    - The level of expenditure must meet or exceed the materiality threshold.
    - The expenditure must either extend the life or increase the output of the asset.

- Replacement: expenditures for the replacement of a significant component/complete capital asset are capitalized when the expenditures are expected to provide benefits beyond the current year and meet or exceed the materiality threshold.

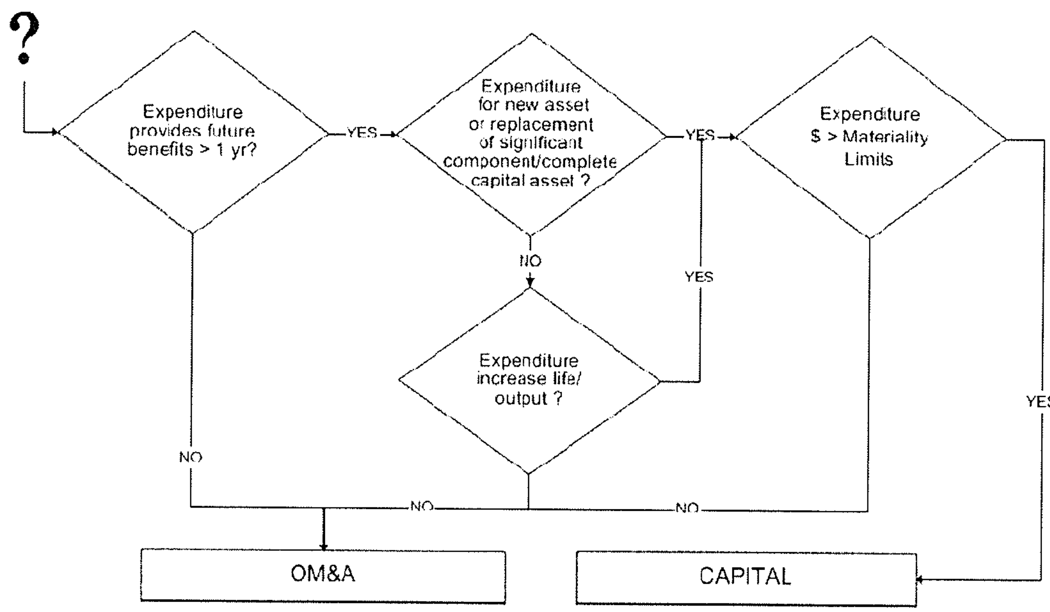
OPG capitalizes only those overhead costs that are directly attributable to the acquisition or construction of an asset. Overhead costs that are not directly attributable to the acquisition or construction of an asset such as the costs of the OPG Board, senior management, and most of the costs of support functions including finance, legal, office management and administration, and human resources, are expensed as incurred.

Expenditures that relate to a previously established liability are applied against the liability as incurred. The most significant example of such expenditures relates to nuclear decommissioning and used fuel management.

OM&A expenditures include general maintenance, repairs (up to and including major disassembly/overhaul), operating costs and other expenditures that do not meet the criteria for capitalization and do not relate to previously established liabilities. In addition, project development costs incurred prior to the date that an alternative is selected for implementation are charged to OM&A. The only exception is that payments to obtain an option to acquire property, plant, and equipment are capitalized when the option is exercised. Subject to the capitalization criteria above, project development costs are capitalized once the preferred alternative for a new capital asset or capital improvement to an existing asset is selected.

OPG's capitalization policy is summarized in the decision tree below:

CAPITALIZATION DECISION TREE



OPG applies the following thresholds for the materiality assessment included in the decision tree:

• Generating Asset Classes	$200k per generating unit
• Administrative/Service Buildings	$ 25k per building
• Telecom Equipment	$ 25k per item
• Minor Fixed Assets*	$ 25k per item
• Software	$200k per application

*Minor fixed assets include portable assets used in OPG's administrative, construction, transport or maintenance/service activities unless they are used directly for the generation of energy or form integral components of a building.

Materiality thresholds are applied on individual items rather than on an aggregated basis. Projects and/or work orders cannot be aggregated to qualify for capitalization. The exception to this principle applies to aggregated identical items purchased for a single generating unit, or items that are part of a capital project where the project as a whole is evaluated against the materiality threshold.

Following the adoption of CICA Handbook Section 3064 effective January 1, 2009, OPG reclassified certain items previously considered to be fixed assets to intangible assets. These items primarily included computer software. These intangible assets continue to be included in OPG's rate base (Ex. B1-T1-S1) and as a result, this reclassification has no impact on OPG's proposed revenue requirement.

5.2 Asset Management

OPG's investments and initiatives are targeted at programs that will result in increased generating capacity, extended service lives, improved performance, and reduced long-term operations and maintenance costs.

In addition to improving performance of its existing assets, OPG also evaluates development initiatives with respect to its regulated facilities which can include plant life extensions, plant redevelopments or new supply developments. These development initiatives are typically larger in size, have higher risk profiles and longer time horizons than the projects held within the business unit portfolios. These potential investments are subject to more rigorous internal evaluations and scrutiny during the approval process and, often, external third party reviews, prior to the decision to proceed. Examples for the regulated facilities include Darlington Refurbishment, Pickering Continued Operations, and the Niagara Tunnel.

5.3 Project Portfolios and Supporting Documentation

As part of the business planning process, business units submit project lists that have been prioritized to maximize value and address regulatory requirements while considering risks, corporate business objectives, asset management processes, and preliminary funding guidelines. All projects necessary to meet work program requirements and having cash flows within the business plan time horizon are listed. The total cost of the projects must be within the preliminary funding guidelines.

The project list is a snapshot of the project work intended to be done over the business plan horizon. As time progresses, priorities may be re-set and the project list may change as dictated by the needs of the business. Details regarding the prioritization process are provided later in this schedule.

5.3.1 Planning Business Cases

"Planning" business cases, or project screening forms in nuclear, are required for major projects (projects with cash flows of at least $1M during the budget year and/or at least $4M in any of the future years of the business planning horizon) that are planned to commence over the first two years of the plan. Inclusion of a project in the business plan does not constitute approval to proceed with the project. Request for project approval and release of funds to commence work on a project is a separate process and requires a more comprehensive business case summary ("BCS"). Business case requirements for project release are discussed later in this schedule. Planning business cases are a preliminary and usually more condensed version of the full BCS.

Planning business cases are prepared by the project sponsor[1], with assistance and review provided by the local controller. The extent of information provided in planning business cases is commensurate with the nature of the project, the level of expenditure, and its stage of development (and thus the level of information availability) at the time of inclusion in the project listing.

Key information requirements for planning business cases include:

- need for the project
- the project's contribution to meeting OPG's business objectives
- results to be delivered
- quantifiable benefits
- alternatives considered

[1] Project sponsor is the individual responsible for issuing a project charter, managing and communicating the on-going business requirements related to the project and ensuring that a post implementation review is conducted as required.

- cash flow requirements
- impacts of not proceeding/deferrals
- other considerations that can be used to establish a relative ranking and to facilitate investment trade-offs as needed

5.3.2 Project Categorization

Investments must also be categorized according to the type of benefit they are expected to produce. Investments fall within the following three categories established by OPG:

- Value Enhancing – Discretionary investments that promise value creation or strategic opportunities, such as added revenues, reduced costs, increased efficiencies, or new business opportunities.
- Regulatory – Expenditures required to satisfy environmental, safety or other requirements in law or regulation to allow the continued operation of existing facilities.
- Sustaining – Required to maintain existing infrastructure and facilities at their current performance level.

5.3.3 Project Prioritization Process

As the business units compile their project lists, the total cost of all initially identified work may exceed funding guidelines and/or the unit's capacity to undertake the work during the planning period. Prioritization processes are then applied to assist with the selection of the highest priority projects while remaining within the funding guidelines and resource capabilities. Since business units manage different assets, prioritization approaches are also unique to each business unit. The approach for regulated hydroelectric facilities is presented in Ex. D1-T1-S1 and that for nuclear projects is presented in Ex. D2-T1-S1. However, business unit prioritization approaches have common elements such as value, consideration of risks, and regulatory compliance.

Business unit funding guidelines are established based on corporate strategies and priorities. Corporate prioritization of specific projects is undertaken only if there are corporate constraints with respect to spending or borrowing, or if the funding guidelines are exceeded in the business unit plan submissions. The information submitted by the business units (e.g., planning BCSs, business unit prioritized project listings, business plan presentations) generally provide sufficient information to allow trade-offs at the corporate level should the need arise.

6.0 BUSINESS CASE REQUIREMENTS FOR PROJECT RELEASE

Approval is required for the release of funds to undertake project work. The documentation for seeking approval consists of a BCS, which provides a detailed analysis of alternatives and the rationale for the recommended alternative.

Requests for releases of funds are approved in accordance with the OPG Organizational Authority Register ("OAR"), which is provided in Attachment 2. The OAR sets out delegated authorities within OPG, and defines approval limits for decisions made on behalf of the corporation. Approval requirements for capital and OM&A projects are based on the amount of funds being released, with more restrictive requirements for projects of a strategic nature or unplanned work (projects not identified in the project portfolio during business planning). The OAR also specifies authorities for approval of variances for previously released projects, and for superseding releases where projects must be reconsidered due to significant scope and/or cost changes.

There is also a process for functional review of a BCS to ensure that it meets the criteria for the quality and completeness of the information required to enable an informed decision on approval of the project release. The functional review is required where there is a significant impact on the function or its deliverables. For example:

- Projects with substantial IT requirements should be reviewed by the Chief Information Officer's ("CIO") Department.
- Projects with significant legal or contractual issues should be reviewed by Law Division.
- Projects involving real estate transactions or leasing of office spaces should be reviewed by Corporate Real Estate.
- Projects with significant labour relations or health and safety issues should be reviewed by Human Resources.

Business Case Summaries are prepared using the format established in OPG's BCS Guidelines to ensure a consistent approach to developing investment proposals. The BCS Guidelines establish the discount rates for OPG's economic evaluations for regulated assets. The discount rate is currently 7 per cent, which is based on the OEB's approved formula for determining the cost of capital and the deemed capital structure approved by the OEB in EB-2007-0905 as well as OPG's long term view of the financial markets.

OPG uses a number of measures to assess development initiatives. As an initial screening tool, a Levelized Unit Energy Cost ("LUEC") is developed for the investment and compared to the LUEC of other investment options. A LUEC expresses all the future costs of a generation option on a per unit of energy basis and is typically expressed as ¢/kWh in constant dollars for a given year. The use of LUECs allows for comparison across different investment options.

To assess an investment's value in the context of the overall Ontario electricity system, its cost is evaluated against the estimated value to the electricity system of the additional capacity and energy expressed on $/MWh basis - the system economic value ("SEV"). OPG's develops the SEV based on a number of inputs including forecast demand, fuel prices, CO2 offset cost, cost of new generation (typically combined cycle and simple cycle gas plants) and publicly available information on committed generation plans in Ontario (e.g., OPA contracts). OPG also considers relevant environmental legislation and policies (e.g., air emission limits on SO2, NOx, particulates, mercury).

To test sensitivities, high and low values of the inputs are used to produce a range of forecast SEV. OPG's SEV forecasts are benchmarked against those developed by external agencies as part of the internal validation process.

7.0 POST IMPLEMENTATION REVIEW PROCESS

The post implementation review ("PIR") process is used by OPG on a corporate-wide basis to assess achievements following completion of capital and OM&A projects. Specifically, a PIR is an appraisal process designed to evaluate whether planned results of a given investment have been met following project completion. The two main objectives of the PIR process are to verify whether the benefits stated in the project business case were realized, and to capture the lessons learned from each project so that they can be applied to improve future projects and investment decisions.

Post implementation reviews follow a simplified or comprehensive format depending on the size and scope of the investment involved.

7.1 Simplified PIR

Focuses on validating if the stated benefits/results are realized as presented in the business case for the project. All projects greater than $200k must undergo a simplified PIR as specified in the PIR plan, ideally within six months of the project being completed. Exclusions are those projects that have been earmarked by senior management to undergo a comprehensive PIR because of high value (greater than $25M) or due to other factors.

7.2 Comprehensive PIR

A comprehensive PIR is an independent and broad review of a completed project. It is an intensive exercise requiring a multi-disciplinary team, ideally independent from the project team, to review all phases of a project. It provides detailed feedback on how the project was developed, planned, and executed to help gather lessons for future investments. It is only performed on a small number of projects due to the high resource requirements.

LIST OF ATTACHMENTS

TAB 2

2010 – 2014 Business Planning Instructions

Issued by:
Corporate Business & Investment Planning
Corporate Finance

June 3, 2009

ONTARIO POWER GENERATION

CONTACT INFORMATION	
If you require further information on business planning assumptions, schedules, or requirements, please contact:	
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Regarding OEB Regulatory processes and requirements:	
Barb Reuber – Director, Ontario Regulatory Affairs	592-5419

1.0 INTRODUCTION

This year's Business Planning process is occurring against a backdrop of unique financial circumstances. Ontario has been particularly hard hit by the global financial meltdown and the restructuring of the domestic automobile industry. At the same time, 2010-2014 Business Plan will span a critical period for OPG, during which we will see dramatic changes in our operations and assets, as we reshape the generation portfolio to meet future needs. Key elements of this transition include:

- [redacted]
- Extending the "Continued Operations" program at Pickering B, intended to confirm the feasibility and enhance confidence in being able to operate that plant beyond its current nominal service life.
- Establishing the plans and approval milestones for refurbishing Darlington
- Continuing to build the infrastructure required to support the new nuclear build project
- Ongoing pursuit of medium and large-scale hydro-electric developments
- [redacted]

The challenges associated with planning and executing these initiatives would be daunting at any time; the fact that this year's process is occurring during a period of unprecedented economic turmoil, compounds our task this year. The fact that many Ontario businesses are fighting for survival, and ratepayers are facing economic hardship, means that we can expect unprecedented pressure to aggressively manage our costs, while maintaining safe and prudent operations.

The objective of the 2010 -2014 planning process is to develop a 5-year consolidated business plan that:

- Establishes medium term (2010-2014) operational and financial targets, and resource requirements, consistent with OPG's strategic objectives.
- Establishes the budget and accountability base for the first year (2010).
- Documents OPG's medium-term financial and operational outlook to be shared with financial stakeholders (e.g., shareholder, banks, credit rating agencies, regulators) in order to maintain access to capital markets.

Once approved by the OPG Board of Directors, the 2010-2014 Business Plan will form the basis of our application to the Ontario Energy Board (OEB) for the determination of new rates for the output from OPG's regulated facilities for the January 1, 2011 to December 31, 2012 period.. Corporate Finance and Regulatory Affairs will continue to integrate business planning and regulatory information requirements.

Recognizing the scope and complexity of the challenges we face this year, a number of changes are being made to the business planning process. These improvements include:

- Earlier roll out of process instructions
- Two step process for top-down establishment of OM&A targets
- Improving the transparency of plans – eg through benchmarking and gap analyses
- Increased management oversight during the process
- Earlier approval of the corporate plan (to facilitate preparation of the OEB application)

The overall timing of key elements of the business planning process is as follows:

- Early May – Instructions issued, 2010 OM&A targets set
- June – status reports on BU business plan development; OM&A targets for 2011 and beyond set
- Early September – BU business plan submissions provided to Corporate Finance
- Late September -- Senior Management reviews of BU plans
- Mid October - Updated submissions to Finance
- November – OPG Board approves 2010-2014 plan

Post Approval Activities (OEB related)

[redacted]

A more detailed schedule is shown is section 2.5.

2.0 PLANNING CONTEXT

Contact: David Halperin

2.1 VISION, CORE BUSINESS AND STRATEGY

Over the last five years, OPG has established itself as a performance-driven company and has regained the confidence of its Shareholder. Today, OPG is seen as a responsible and credible generator, an important contributor to the economy of Ontario, and a positive force in the communities in which it operates. This perception is backed up by strong performance across a number of areas, including:

- consistently strong safety results;
- high levels of hydroelectric availability;
- [redacted]
- better environmental performance;
- continuing world class performance at Darlington and ongoing improvements at Pickering A&B; and
- higher levels of net income - although a number of challenges remain on the road to financial sustainability.

These accomplishments reflect a successful execution of the vision that has guided OPG over the last five years. Looking forward, OPG's mandate is to cost-effectively produce electricity from its diversified generating assets, while operating in a safe, open, and environmentally responsible manner.

> ***OPG's goal is to be a leader in clean energy generation and to have a major role in leading Ontario's transition to a more sustainable energy future.***

To achieve this goal, OPG is focused on three corporate strategies

- performance excellence;
- generation development; and
- developing and acquiring talent

Performance Excellence

Performance excellence is essential to OPG. Every business segment and corporate function exhibits our commitment to generation, safety, the environment, and fiscal performance. It is through our focus on performance excellence that OPG is able to efficiently and reliably provide electricity to the province and deliver value to its Shareholder.

Nuclear Generating Assets

Performance excellence for OPG nuclear means safe, efficient and cost effective operations, with prudent investments to improve reliability. Programs and initiatives have been implemented that will continue to:

- improve safety performance; increase equipment reliability to reduce generation interruptions;
- plan and execute outages more efficiently to realize optimal generation potential;
- mitigate technological risks through essential and effective inspection and testing programs; and
- address workforce planning issues.

These initiatives, combined with ongoing cost control efforts, are expected to result in lower production unit energy costs.

Hydroelectric Generating Assets

Performance excellence at OPG's hydroelectric generating assets is defined as improving production in a cost-effective and efficient manner. Programs and initiatives are underway to replace aging equipment such as turbines, generators and transformers.

- OPG plans to increase the capacity of existing stations by 87 MW over the next five years by replacing existing turbine runners with more efficient equipment. The replacement of control equipment will also improve efficiency and accommodate market dispatch requirements. Aging civil structures will be repaired, rehabilitated or replaced.

- The hydroelectric business segment is strengthening its relationships with First Nations and local communities.
- OPG is meeting the demographic challenges faced by its hydroelectric business unit by training staff to perform new roles and by hiring new staff, including graduate trainees.

Fossil-Fuelled Generating Assets

[redacted]

Safety

OPG's safety culture is rooted in the belief that zero injuries can be a reality. OPG is committed to achieving performance excellence in employee, contractor and public safety through continuous improvement in its safety management systems and risk control programs and a corporate commitment to achieving the goal of zero injuries in the workplace. OPG strives for continuous improvement through visible leadership and commitment to safety, a strong safety culture where employees take personal responsibility for safety, and maintaining effective safety management systems. To improve OPG's AIR going forward and to strive for zero injuries, OPG is committed to reducing the number of workplace injuries through targeted risk reduction programs.

Environmental Performance

OPG's Environmental Policy states that "OPG will strive to continually improve its environmental performance", and commits OPG to meet all legal requirements and voluntary commitments, with the objective of exceeding those standards where appropriate and feasible. Other goals include integrating environmental factors into business planning and decision-making, and maintaining environmental management systems which improve transparency in monitoring and reporting of OPG's environmental performance. OPG monitors emissions into the air and water and regularly reports the results to regulators that include the Ministry of the Environment, Environment Canada and the CNSC, as well as the public. OPG also continues to address historical land contamination through its voluntary land assessment and remediation program.

Financial Sustainability

OPG's financial priority, operating as a commercial enterprise, is to achieve a sustainable level of financial performance. Inherent in this priority are the objectives of: earning an appropriate return on OPG's regulated assets; receiving market prices for production from unregulated assets; identifying and exploring efficiency improvement opportunities; and ensuring that sufficient funds are available to achieve OPG's strategic objectives of performance excellence and generation development. OPG has employed a number of strategies to achieve a level of sustainable financial performance.

Generation Development

With the aging of OPG's generating fleet, it is essential that focus be placed on generation development. OPG pursues capacity expansion or life extension opportunities where it makes good business sense. Increasing the production potential of existing infrastructure reduces the environmental impact of meeting Ontario's electricity demands. Pursuing opportunities to leverage existing sites and assets will enable OPG to realize the additional benefits from these assets. OPG's ongoing and planned major projects include nuclear plant refurbishment, new nuclear generation, new hydroelectric generation and plant upgrades, [redacted]

Pickering Refurbishment Project

Work is proceeding on the feasibility study to refurbish the Pickering B nuclear generating station. This includes an assessment of the station's condition, an EA, and an Integrated Safety Review ("ISR"), which is designed to ensure safe and secure operations of the station for the proposed future period. OPG has submitted all required Safety Factor Reports to the CNSC. The CNSC continues to review these reports and OPG is providing additional information as required. OPG is preparing the final ISR for submission in late 2009.

Darlington Refurbishment Project

Planning work for the assessment of the feasibility of refurbishing the Darlington nuclear generating station began in early 2008. Planning for the plant condition assessment commenced in the second quarter of 2008 and will continue throughout 2009. In addition, a number of technical studies are underway to evaluate the condition of critical plant components in order to finalize the project's scope. In late 2008, OPG commenced the ISR process. The ISR Basis Document, which identifies the ISR scope and methodology, was submitted to the CNSC in November 2008. The ISR is expected to be completed for submission to the CNSC by late 2011.

New Nuclear Generating Units

In March 2008, the Minister of Energy announced a two-phase competitive Request For Proposal ("RFP") process to select a nuclear reactor vendor for two units of baseload generation to provide 2,000 to 3,500 MW of generating capacity to the Ontario electricity grid.

- Phase one of the RFP process assessed the ability of the invited vendors to support a successful construction licence application in compliance with Canadian regulatory requirements and to successfully deliver the overall project, as well as to ascertain their financial strength and legal position. Phase one was completed in June 2008 with Areva NP, Atomic Energy of Canada Limited, and Westinghouse Electric Company advancing to phase two.
- Phase two of the competitive RFP process was launched in June 2008 to select a nuclear reactor vendor who will design, develop, construct, and provide licensing and commissioning support, and fuel supply, to a stand-alone two-unit nuclear power plant at the Darlington site. It is expected that the preferred vendor will be announced in the late spring of 2009.

Niagara Tunnel

The progress of the tunnel boring machine continues to be slower than what was expected under the original contractor schedule, primarily due to excess overbreak of the Queenston shale in the tunnel crown. A dispute review hearing process was initiated earlier in 2008 to assess, among other things, whether the actual subsurface conditions encountered are materially different from those that were anticipated as part of the design-build contract. The Dispute Review Board issued its non-binding recommendations in late August 2008. OPG and the contractor are using the Dispute Review Board recommendations as a basis for negotiating revisions to the design-build contract. These revisions are expected to have a significant impact on the project completion schedule and the cost estimate. The negotiations are underway and are targeted for completion in the first quarter of 2009.

Upper Mattagami and Hound Chute

[redacted]

Lower Mattagami

OPG is proceeding with a development plan to increase the generating capacity of four hydroelectric [redacted]

Biomass Generation Opportunities

[redacted]

2.2 Operating Assumptions

2.2.1 Fossil Long-term Asset Strategy

[redacted]

2.2.2 Interim Nuclear Operating and Investment Decisions

Nuclear's 2010 plan assumes implementation of Pickering B Continued Operations program over the years 2009- 2013. The program is intended to ensure the plants' ability to operate through 2018. Continued operations will extend the "window" within which decisions regarding Pickering Refurbishment can be made.

Planning for the Darlington refurbishment continues to assume a 2016 date for the initial refurbishment outage.

2.3 Support Function Review

Contact: David Halperin

The dispositioning process for SFR opportunities was completed during 2008, and there are no specific business plan-related reporting or analytical requirements. Business plans will reflect benefits from opportunities implemented during the last two planning cycles.

2.4 Regulatory Requirements

Contact: Barb Reuber

The 2010-2014 Business Plan will form the basis of OPG's next rate submission to the OEB, which is planned for March 2010 and will cover rate years 2011-2012. In preparing their plans and submissions, business units should review issues raised in last summer's hearing and subsequent OEB decision (November 3, 2008) as they develop performance objectives and expenditure plans. [redacted]

If you require additional information regarding requirements for preparation of the OEB application, please call Barb Reuber at 416-592-5419.

2.5 SCHEDULE

As noted earlier, the business planning process features a number of changes this year in response to the planning challenges we are facing. Key changes and new elements include the following;

- Approval of the business plan is targeted for November 2009, one month earlier than in previous years, to facilitate preparation of the corresponding OEB rate submission for filing on March 15, 2010. This entails compressing activities at the back end of the schedule and will have little impact on BU schedules.
- Business plan instructions are being issued earlier than in previous years and expenditure guidelines for OM&A are being established.
- There will be a mid-process status report due to the Chief Financial Officer and Vice-President, Business and Investment Planning, due late in June, to communicate the status of each Business Units' business plan development.
- The Executive Committee will review and approve 2011 OM&A guidelines in July after consideration of planning progress and issues

Date	Business Planning Activities
March 31	• Executive Committee approves 2010-2014 Business Planning Process proposal and confirms 2010 OM&A targets
May (early)	• Business Plan instructions issued
May (mid)	• Preliminary Energy Production Plan released • Board approves Fossil Asset Strategy (coal unit shutdown schedules)
June	• **BU status updates provided to Senior Management (details to be provided)** • Updated Energy Production Plan reflecting May Board decision regarding Fossil Asset Strategy)
July	• Executive Committee approves 2011 OM&A targets
June – August	• Continuing site and BU plan development
September	• Initial submissions to Finance Sept 8 • **CEO/COO/CFO reviews Sept 21 – Oct 9** • Potential Status report to OPG Board (Sept. 30)
October	• Revised revenue & energy plan Oct 15 • Revised submissions to Finance Oct. 15 • **EC review Oct. 27**
November	• EC review Nov. 3 (if necessary) • Board mail out Nov 11 • **Board approval Nov 19**

Following the OPG Board's approval of the plan, completion of submission templates and other evidence for the 2011-2012 rate submission will commence, [redacted]

3.0 SPECIFIC BUSINESS PLANNING & BUDGETING INSTRUCTIONS

3.1 INFORMATION SUBMISSIONS

Contact: Sandra Radcliffe

Business Plan Submissions are required from each business unit, and consist of two primary elements:

- A quantitative resource and financial submission package, submitted through BPS, and accompanied by supporting analysis material; and
- Business Plan power point presentations, to be made to senior management starting in the second half of September, and which must be provided to Corporate Business and Investment Planning in advance of the review with senior management.

The initial *resource and financial submission packages* are due to Financial Planning on September 8 and consist of the following elements:

- Resource and financial information, including OM&A, non-electricity revenues and costs, capital, minor fixed assets, staff, and provision expenditures, which are to be submitted with work program and resource type/cost element detail through the Business Planning System (BPS). Monthly detail is required for 2010 and 2011. Summarized quarterly detail is sufficient for the remaining years, and may be submitted by email by October 15; this information must reconcile to the annual information contained in BPS.
- Interest capitalization, removal costs and in-service addition forecasts are required, consistent with capital project plan details submitted in BPS and Project listings, (see Section 3.6). Quarterly details for the all years must be submitted on September 8
- BU's are reminded of the importance of appropriate forecasts for working capital items, including fuel inventory and material and supplies inventory.
- Cost allocation – Business units must allocate all their costs to the station level, within regulated and non-regulated OPG. See section 3.4.2 following.
- An accompanying analysis package which addresses significant changes in resources and performance from both plan-over-plan and year-over-year perspectives. Changes of $5 million or 10% in business plan resources (OM&A, capital, fuel, and non-electricity revenues) should be addressed, as well factors influencing year over year performance. As in the past, this analysis should be provided to Financial Planning through an email, Excel (preferred) or Power Point file.

Similar to previous years, the *Business Plan Presentations* should identify objectives, performance targets, resources, key initiatives, and risks and mitigation strategies. Comparisons to the current business plan, with analyses of changes in resources and targets, are required. The presentations must also specifically address two new information requirements, intended to promote greater transparency in our operational plans:

Operational Benchmarking

- Business units are to indicate how benchmarks/benchmarking have been utilized in assessing operational performance, and their consideration in establishing performance objectives and/or cost targets. Where relevant or comparable benchmarks may not exist, businesses should indicate what other externally-based references are utilized to assess performance and identify potential improvements.

Marginal Resource Analysis

- Budget guidelines incorporate the targeted $85 million reduction for 2010. Business plans also need to provide a marginal resource analysis that indicates the impact of having to reduce planned in 2010 and 2011 by a further 5% below guidelines. The analysis for each year should be done separately. The analysis can be provided on a layered basis, eg "the first 1% or $X million would impact programs abc....., the next 2% would require the deferral of xyz, etc". Implications of program reductions or project deferrals are to be identified.

3.2 RESOURCE AND PERFORMANCE PLANNING GUIDELINES

The OPG Board's approval in February of the 2009-2013 Business Plan incorporated a deferral of the next rate application from 2010 to 2011. Management committed at that time to reduce 2010 OM&A by $85 million from levels in the current plan in order to ameliorate the financial impact of deferring the application. The resulting OM&A guidelines for 2010, as endorsed by the Executive Committee, are shown in the following table.

Guidelines for 2011 OM&A expenditures will be established and approved by the Executive Committee in June. The decision on guidelines will be made after considering a number of factors, including:

- The progress BUs are making on meeting their 2010 expenditure targets, and
- The continuing need to prudently reduce or defer expenditures, to reduce ratepayer costs

Until guidelines for 2011 and beyond are set, the interim guidelines are the planned OM&A levels for 2011-2013 as approved in the 2009-2013 business plan, as indicated in the table below.

OM&A - $Millions	2009 Business Plan*		2010		2011	2012	2013
	2009	2010	Reduction	Guideline	Interim Guideline		
Nuclear Operations	1,610	1,679	(40)	1,639	1,578	1,617	1,764
NGD and NNB	77	11	-	11	15	23	31
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Hydro	217	237	(5)	232	236	233	238
BS & IT	232	232	(12)	220	244	251	258
Finance	91	93	(1)	92	95	99	100
Human Resources	56	58	(1)	57	60	62	63
Corporate Affairs & Energy Markets	53	53	-	53	51	51	54
ESLA	31	31	-	31	25	25	26
Business Unit OM&A	2,818	2,832	(79)	2,753	2,730	2,804	2,976
Corporately Held Costs	170	185	(6)	179	256	330	460
Total OM&A	2,988	3,017	(85)	2,932	2,986	3,134	3,436

* before reductions

3.3 COSTING ASSUMPTIONS

Services provided to others and associated revenues should be identified and held at the business-level along with direct costs through Cost of Goods Sold.

Financial Planning is accountable for obtaining and/or developing forecasts for the following financial items:

- Interest expense, depreciation costs and income taxes – based on input from businesses. ***It is critical that BU's provide accurate interest capitalization and realistic, trended in-service addition details for capital projects, to facilitate this.*** For hydroelectric, the split between regulated and non-regulated assets must be carefully reviewed. The forecasts for regulated assets will form the basis for submission to the OEB, and therefore both the estimates, and the trending must be defensible.
- Energy revenues and [redacted] will be forecast by Energy Markets.
- Bruce Lease revenues will be forecasted and held at the corporate level; however, provision of services to Bruce Power outside of those included in the lease should be provided at the BU level.
- The non-current pension and OPEB components of the Payroll Burden Rate for regular staff will be kept at the corporate level.
- Guarantee fee on nuclear liability will be calculated and held at the corporate level.

While these items are consolidated at a corporate level, they will each continue to be allocated to sites and lines of business for purposes of segmented and management reporting.

Escalation and other economic indices required for calculating expenditures can be found by taking the following link to the Business Planning / Economic outlook web page. Q3 2008 forecasts are currently posted and these will be updated for the March 2009 outlook once it is available, expected to be early May.

[redacted]

Interest capitalization rates are assumed to be 6% pa for the business planning horizon.

3.4 Instructions for Use of BPS *Contact: Ram Iyer*

In order to isolate labour and burden rate impacts, there will be three versions of BPS available to business units, similar to last year's process. W01 will use current BP09-13 rates, W02 will use new labour rates with old burden rates, and W03 will use new labour and new burden rates. Please coordinate submissions with Karen Mooney. Financial Planning will extract W03 details on September 8, 2009 in order to consolidate the business plan.

- Work Program and Projects should be trended on a monthly basis for 2010 and 2011 which will be picked up through BPS;
- Under-spending trends indicate that planned hiring lag and project initiation assumptions require continuing refinement. Business units **must** ensure that their assumptions in this area reflect actual experience and realistic expectations. Assumptions in this area, and comparison to historical trends are to be highlighted in accompanying analyses.
- Total labour requirements **must** be balanced to total labour supply in the Labour Planning Module of BPS.
- BPS will be locked on the submission days to allow consolidation of data by Financial Planning.

3.4.1 Labour Costs and Staffing

Businesses must use the BPS system for budgeting labour costs:

- The BPS system currently contains labour rates, burden rates and job families. Escalation for Society and PWU are as per the current agreements, and should have been reflected in your 2009 plan. Work is currently underway re the annual review of any necessary changes to job families, and other factors, including the impacts of the new PWU agreement, that will affect rates by job family. Updated rates will be available for review in BPS by early July, and will be finalized by the end of July.

  NOTE: Development of updated labour rates in July requires the timely submission of regular and non-regular staff forecasts, as identified in section 3.8.

  Controllers will be required to verify and agree to the rates. Corporate burden rates will be updated by the end of July, and will be available in W03. For the final submission, payroll burden rates MAY be updated again in October, if there are material changes in staff levels and/or actuarial assumptions.

- Direct costs relating to Goal-sharing and AIP incentive plans will be budgeted at the corporate level.

- As a result of the transition to IFRS, costs charged to capital projects are required to include a SAVH component related to internal labour costs. Effective January 1, 2010, Nuclear, Fossil and BS&IT, will applied a SAVH component to both capital and OM&A projects, Hydroelectric will apply the charge only to capital projects. Business Units are responsible for developing their SAVH costs to be charged to projects. The resulting decrease in OM&A will be reflected in a corresponding change in business unit OM&A guidelines. (Contact: Tom Staines)

3.4.2 Cost Allocations *Contact: Paul Chabot*

As a result of the automation of the BUS allocation process, there will now be a requirement to load a complete set of P/L financial statement for each year of the Business Plan 2010-14 into BPS. Corporate groups will still required to supply their rationale on management estimates for allocations. A template for this information will be provided by the end of May and will be expected to be submitted one week after the September corporate submission). Preliminary accountabilities for input to BPS are:

- Electricity Generation Revenue (Energy Markets)

[redacted]

- Regulatory account (Regulatory Accounting group)
- Fuel and Fuel-related (Business Units)
- Non-electricity generation (Business Units)
- Cost of Goods Sold (Business Units)
- OM&A (Business Units)
- Centrally held costs (Corporate Support grp)
- Accretion & Earnings (Financial Planning)
- Depreciation & Amortization (Financial Planning)
- Property Tax (Property Tax grp)
- Capital Tax (Financial Planning)
- Interest (Financial Planning)
- Income Tax (Financial Planning)

The Corporate Support group will work with individual groups to transition the input to BPS.

3.4.3 New Resource Classification Detail — *Contact: Dave Bell*

External Purchased Services Classifications

Segregated information on consultant spending will now be required for both planning and reporting purposes. Currently one resource type (RT), is used to capture a number of expenditures under RT 310.

Current definition:

> *Contracts for a specifically defined project or service where the consultant establishes a level of resources required to complete, and assumes financial risks associated with successful delivery of project.*
>
> This very broad definition would include managed types of task services, professional services, such as audit and legal, and general support services.

The objective for the new definition is to isolate only services pertaining to advice or guidance in a separate RT. The new resource classification for consultants has been established in BPS as **RT 300**. The new/revised definitions for external purchased services to be used for this planning process are as follows:

Consulting Services --RT 300:

- All costs related to the use of a consultant including labour and non labour related items where the risks associated with successful delivery are with OPG. The nature of this pertains to advice/ guidance/ recommendations with respect to management of a business function. Typically the engagement is self managed by the consultant. (Examples: Studies, Reviews, E&Y or PWC consultant work in an advisory capacity, support function or operational review)

Managed Task Services/Contract Services --RT 310:

- The tasks/services are incremental to the work force capacity and are normally performed on site by a contractor who has the liability to perform. It includes all materials supplied as part of a fixed price contract; material supplied on Time & Material contracts are charged to the materials resource type. These also include professional, operations, maintenance, and general support services. (Examples:

Construction & Engineering services such as design work and construction associated with Master Services Agreements, professional services for legal and audit work and general operation & maintenance activities provided such as lawn care, snow removal, janitorial, equipment repairs, etc.).

Augmented Staff-- RT 320

- External labour cost for work under OPG supervision and on OPG premises. Includes rental staff paid by Accounts Payable, but excludes temporary staff paid through payroll. The risks associated with successful delivery are with OPG.

3.5 BUDGETING FOR SERVICE PROVIDERS — *Contact: Lovleen Bassan*

Businesses should work closely with service providers, such as Business Services & Information Technology (BS&IT), Real Estate & Services, Supply Chain, etc., to jointly agree on service requirements and associated costs. The costs should be adequately reflected in the service provider's plan. As per the cost model, all OM&A and capital resources (including MFA) will generally be held by the service providers on behalf of the businesses. Please ensure that there are no duplications in budgets between the business-levels and service providers.

Information technology (IT) requirements should be identified to the BS&IT Office. Generally speaking, they plan for all business-related IT needs, IT projects, and IT components of larger business initiatives where they are identified to them. There are a number of IT expenditures not currently captured in the BS&IT plan. These include:

- Process control hardware and software in Nuclear, Fossil & Hydro generation.
- Engineering tools hardware and new software in Nuclear. (Annual maintenance for most existing software is covered.)
- Engineering tools hardware and software in Fossil & Hydro generation.
- .

Where feasible, requirements for these items should be clearly identified to the BS&IT Office for inclusion in its plan. Where the business is asking the BS&IT Office to assume budget accountability for existing items (e.g., annual maintenance contracts), a list of the items and their related costs should form part of the information provided. Businesses are also reminded that under the OPG OAR, only the BS&IT Office has requisitioning authority for IT services and materials (hardware and software). If there is uncertainty as to whether or not a particular contract is identified in the BS&IT plan, one of the contacts listed below should be consulted.

BS&IT however will continue to plan for the replacement of network printer devices for situations where an MFP device is not justified (typically where only a network printer is required and there is no copier to be replaced).

BS&IT has established a number of joint IT and business Asset Investment Screening Committees (AISC) to prioritize and plan IT project proposals. There are currently more Business Unit requests for IT project funding than the budget envelope and the AISC approach will allow OPG to prioritize projects across the company for inclusion in the five year business plan. The

BS&IT has identified points of contact for each business as follows:

- Nuclear Customer Relationship Manager – Chris Woodcock
- Hydroelectric Customer Relationship Manager – Howard Mintz
- [redacted]
- Energy Markets – Howard Mintz
- Corporate Groups Customer Relationship Manager – Howard Mintz

- Darlington Nuclear New Build and Refurbishments – John Witherspoon

Accommodation requirements (e.g. new leases, lease renewals, facility enhancements/modifications, new furniture, etc.) outside the generating stations should be identified to Real Estate & Services. Real Estate & Services generally plans for all accommodation costs in accordance with an overall leasing strategy and will identify any costs to be charged to the businesses.

Businesses are reminded that under the OPG OAR, only Real Estate & Services has requisitioning authority for the acquisition, leasing and disposal of real estate.

Real Estate & Services has identified the following contacts by service area:

- Real Estate Services – Sony Lim (x1818 at 700U)
- Facility & Project Services – Don Seedman (x3289 at 700U)
- Business Services – Barb Smith (x7790 at 700U)
- Fleet Services – Joe Werb (416-231-4111 x6048 at Kipling)

3.5.1 WORK FOR OTHERS — *Contact: Tom Staines*

The Cost Transfer Model states that organizations are to budget for all of the resources that they control. During the 2010-14 business plan period, Support Groups may be requested to provide dedicated services to Darlington New Nuclear, or Nuclear Refurbishment. It has been agreed that for these specific projects, that an exemption will be made to the Cost Model, to allow for direct attributed labour costs to be transferred out to these projects. *Accounting will provide direction on the cost that can be classified as directly attributed costs.* Head counts will remain in the support group.

The support groups must reach agreement and obtain concurrence with Finance on the costs being transferred, prior to their business plan submission. For presentation purposes, both originating and receiving groups will show the gross and net costs and head-counts associated with these transfers. This will ensure that there are no duplications in budgets between the project and service providers

3.6 CAPITAL AND OM&A PROJECTS — *Contact: Dorothy Lau Barton*

This section specifies the requirements and the schedule for submission of the 2010-2014 capital and OM&A project portfolio listing and supporting Planning Business Cases (BCSs). Business Units are requested to provide their project information before **August 31, 2009 to Jack Fong** in Corporate Business & Investment Planning.

Section 3.6.1 specifies the listing requirements for the project portfolios. Section 3.6.2 provides the criteria for projects requiring Planning BCSs and the information requirements for Planning BCSs. Questions on these requirements should be directed to Dorothy Lau Barton (access 400, extension 4580) or Jack Fong (access 400, extension 4655).

3.6.1 Prioritized List of Capital and OM&A Projects

Business Units are requested to identify all capital and OM&A projects having cash flows within the Business Plan time horizon (2010-2014). The submitted projects must be prioritized to maximize value, while considering risks and OPG's business objectives as well as alignment with business unit strategies and facility Life Cycle Plans (as applicable).

The listing format and full information requirement are provided in the Project Listing Template, available on Corporate Finance's Business Planning Webpage. Definitions and explanations for the various fields in the template are provided in the worksheet called Guidelines. To facilitate corporate review, consolidation and reporting, it is essential that Business Units provide all information and in the format specified in the listing template.

To support the development of a 10 year integrated staff resourcing plan and an affiliated analysis underway related to skilled craft from the construction trades, an additional categorization of projects has been added to this year's project listing template. This categorization is being used to identify the type and number of skilled craft we will need from the various construction trades. For additional information on these categorizations, and how this information will be used, please contact Donna Rees (access 400, extension 4942).

In cases where the portfolio listing of projects do not add up to the total requested funding envelope, separate justification for the planned level of expenditures should be provided – e.g., benchmarking, historical spending, etc.

3.6.2 Planning Business Cases

Business Units are required to submit Planning BCSs for **unreleased** projects listed in their portfolio and meeting the following criteria:

- Projects planned for release in 2010 with cash flow greater than $1M
- Projects planned for release in 2010 or 2011 with total project cost greater than 4M

For the purpose of these instructions, **unreleased** projects include:
- Projects with no previous releases
- Projects with developmental (preliminary) and/or partial releases but the project has not been fully committed
- Previously released projects that are forecasting significant changes in scope/cost (greater of 10% or $1M) and the change has not been approved

The information requirements for Planning BCSs are specified in the Planning BCS Template and Regulatory Planning BCS Template. Additional information and explanation are also provided in the BCS Procedure. The BCS templates are available on the Finance Business Planning Webpage.

While the Planning BCS template sets out the minimum information requirements, BU will often have existing documents (e.g. Nuclear AISC Form B) that more than meets the specified information requirements. When such documents are available and up-to-date, they can be submitted in place of the Planning BCS.

Planning BCSs are typically less than two pages in length, but the extent of information should be commensurate with the nature of the project, the level of expenditure and its stage of development at the time of submission. Among others, key information requirements for Planning BCSs include: the need for the project, its contribution to meeting OPG business objectives, quantifiable benefits, cash flow requirements. impact of deferring or not proceeding, key project risks and other considerations that can be used to establish a relative ranking. This is to ensure the optimum use of resources and maximum return to the Corporation.

Planning BCSs will need to include a preliminary evaluation of alternatives to illustrate the likely merit of the proposed alternative. If the project scope or cost estimate is highly uncertain due to timing, the use of range estimates is encouraged. For the purpose of setting budgets and evaluating the economics of alternatives, the expected value should be used.

All Planning BCSs should be reviewed and signed-off by the appropriate project sponsor (i.e., Asset Manager, Engineering Director, etc.) and the local Controller.

3.6.3 BCS Preparation Assistance

For assistance with BCS preparation, please contact your local Controller or Business Support group. In addition, BCS training sessions can be arranged between June and August of each year. The 2009 training calendar is posted on the Corporate Finance Website under BCS Toolkit. For registration, please contact Banty Tezazu of Corporate Business and Investment Planning (access 400, extension 5817).

3.7 BUSINESS UNIT RISK SELF ASSESSMENT ("BURSA") *Contact: Lloyd Komori*

Introduction

The unprecedented number and complexity of strategic objectives that OPG faces in the near future requires the company to enhance its risk management processes. At the organizational level, Risk Services is responsible for creating a robust methodology or framework capable of facilitating the identification, assessment, monitoring and reporting of key threats, risks and uncertainties faced by OPG. This framework, together with a number of underlying processes, provides the critical evidence that supports the organization's ability to execute a holistic and enterprise view of key threats and risks within the context of OPG's strategic objectives.

One of the key elements of this framework is the BURSA template which has been recently enhanced in order to generate greater insight into key threats and risks that endanger the achievement of corporate business plan objectives. The collective output of these templates will be a key component of OPG's strategy to respond to challenges and increased scrutiny by stakeholders in the near future.

For this business planning period, the following business units will submit a completed BURSA template to the Risk Services Group by Friday June 12, 2009: Nuclear, Fossil, Hydroelectric, Finance, Energy Markets, BS&IT, Human Resources, Corporate Affairs and Law. Templates are to be submitted to Jody Hamade, Director - Operational & Market Risk, with copies to David Halperin.

While this timing represents a significant advance compared to previous planning cycles, it is necessary to support an enhanced consolidated risk assessment process, in which the Executive Risk Committee will be reviewing and prioritizing corporate risks during July/August. This timing, now in advance of business plan reviews, will provide senior management improved context for assessing the adequacy of business plans' responses to key risks.

In support of this earlier deadline, Risk Services staff are available to assist each business unit with the completion of the enhanced BURSA template, including pre-population of key risks. Furthermore, the staff will also provide ongoing input and assistance with respect to the regular reporting requirements that are also part of the underlying methodology.

Overview of the 2010 BURSA template

The template is designed to help each business unit identify, assess and rank their threats, risks and uncertainties based on their individual capacity to endanger the achievement of a specific business unit objective. The template records a point in time analysis of nature of the threat in relation to a specific goal, a detailed description of planned mitigation activities, commentary on how such mitigation will be continually evaluated for effectiveness, followed by identification of possible remediation actions if mitigation activities fail or prove to be ineffective. For each of these thought processes the template records key assumptions as well as applicable metrics.

Completing the BURSA template

Each business unit will use the template to generate two (2) groups of (up to*) five (5) most significant or "top" threats, risks or uncertainties. The first group of 5 captures quantifiable impacts on "measurable" goals relating to costs and revenues. Rankings based on impact on revenue or costs will be required.

The second group of 5 captures more qualitative impacts on "strategic" goals such as corporate performance in relation to safety, environmental stewardship or corporate reputation. This list of candidates will not require ranking as with the first group.

Using the template, each business unit will then submit their two "top" lists of (up to) 5 to Risk Services who will collate all the submissions. For the purpose of completing the template, the business units should use the context of one calendar year (i.e. 2010). However, there is some latitude for up to 2 years forward under limited circumstances.

** There is no need to identify a minimum of 5. Five represents the maximum number of components.*

The BURSA process

This methodology will create two groups of key or top threats, risks or uncertainties, one in relation to measurable objectives and the other in relation to strategic goals. Risk Services will evaluate these lists and validate any outstanding issues with specific business units. Once this process is complete, the contents of both lists will be presented as "candidates" for the "top" list for OPG to the Executive Risk Committee ("ERC") at the upcoming annual summit meeting scheduled for late June / early July.

At that time, the ERC will determine which threat, risk or uncertainty is a "top" priority for OPG at the enterprise level. Once this "top" list is created, each component will then be the subject of close monitoring and reporting as well as quarterly re-evaluation. The output of these re-evaluations will be contained in the quarterly Enterprise wide Risk Management report which is presented to the Audit/Risk Committee of the Board by the Chief Risk Officer.

In addition to the "top" list for OPG, Risk Services will create a supplementary list known as the "monitored" list. This list will contain those candidates for "top" list that were not selected but were nonetheless, identified as threats, risks or uncertainties sufficient to warrant quarterly monitoring.

Ongoing requirements

In the event that circumstances or developments cause a significant change* to any component of either the "top" or "monitored" list, the business unit will be responsible for reporting such developments to the Risk Services group who will then facilitate presentation of the issue to the ERC. The ERC will continue to re-confirm the appropriateness of the composition of the "top" list with their review of the Enterprise wide Risk Management report that is submitted to the Audit/ Risk Committee every quarter.

Composition of both the "top" and "monitored" list could change in the following circumstances:

i) proposal to move a threat, risk or uncertainty from the "top" list to the "monitored" list due to reduction or decrease in the nature or degree of the threat or risk (i.e. "re-allocation")*

ii) proposal to move a threat, risk or uncertainty from the "monitored" list to the "top" list due to increase in the nature or degree of the threat or risk ("re-allocation")

iii) proposal to remove a threat, risk or uncertainty from either the "top" or "monitored" list due to elimination or substantial elimination of nature or degree of threat or risk ("removal")

iv) proposal to insert into either the "top" or the "monitored" list a new threat, risk or uncertainty not previously identified ("addition")

** These terms are referenced to the Enterprise wide Risk Management report*

A revised (June 2009) BURSA template can be accessed on the Business Planning website.

Additional information on the BURSA process can be accessed on the Risk Services website.

3.8 INTEGRATED STAFF PLANNING INFORMATION REQUIREMENTS *Contact: Donna Rees*

Human Resources is developing a 10 year integrated staff resourcing plan, which will take a comprehensive look at how work is resourced within OPG, including regular and temporary staff plans, as well as purchased services for base and project work. The first 5 years of this 10 year plan will be based on the 2010 business plan, with remaining years obtained through a separate process including consultation with business units.

A resourcing template has been created to capture the information requirements related to staffing and non-project (or base) purchased services. The project related information needed will be collected through the existing project listing templates, and simply requires each project to be categorized. Please refer to the instructions provided for the project listing template for more information.

The resourcing template contains 3 parts:

Part A: Regular Staff complement and demand (excluding apprentice, trainee & seasonal staff)
Part B: Apprentice, Trainee, Seasonal & Temporary complement and demand
Part C: Non-Project External Purchased Services ($)

A preliminary submission is due on Jun 30, capturing Part A of the template.

The full template (Part A, B & C) is to be completed & submitted with your final business plan submission.

Note that for both the preliminary and final submissions, business units may utilize the Business Planning System (BPS) in lieu of this template for Parts A & B. However, Part C of the template must be completed for all business units, by planning unit. *Please note that punctual submission of this preliminary Schedule A information in June is critical to developing a timely update of pay and burden rates.*

Organization-specific templates will be available on the web, or through Donna Rees (access 400 extension 4942). The organization specific templates will have actual headcount information and data from the approved 2009 budget pre-populated in the template.

For Project Instructions:

To support the development of a 10 year integrated staff resourcing plan and an affiliated analysis underway related to skilled craft from the construction trades, an additional categorization of projects has been added to this year's project listing template. This categorization is being used to identify the type and number of skilled craft we will need from the various construction trades. For additional information on these categorizations, and how this information will be used, please contact Donna Rees (access 400, extension 4942).

The template for each business unit is available on-line at the Business Planning Website.

For copies of the nuclear template, please contact Donna Rees.

3.9 CORPORATE SAFETY GUIDELINES

Contact: Cathy Catton

OPG has achieved excellent safety performance with a strong safety culture and robust safety management systems. The Business Planning Guidelines for Corporate Safety, to be available shortly, include Strategic Objectives and Directions from our five year Strategic Plan that clearly define OPG's continuous improvement objective and and will drive OPG's breakthrough to the next level of excellence in safety performance including maintaining top quartile safety performance. The Guidelines will include details of planned initiatives associated with meeting these goals as well as a description of regulatory issues and an assessment of their impact on OPG. These must be considered by the Businesses in development of their plans.

The Safety Business Planning Guidelines are posted on the Human Resources website under "Safety"

3.10 FIRST NATIONS INITIATIVES

Contact: Bob Yap

OPG's Aboriginal Relations Policy, approved in November 2007, has the following primary objectives:

- A commitment to deal with aboriginal communities in a respectful way;
- A commitment to resolving past grievances;
- A willingness by OPG to enter into commercial partnership with aboriginal communities;
- A commitment to building relationships with aboriginal communities including community outreach, capacity building, employment and contracting opportunities.

All affected business units and support functions are required to develop programs in support of this Aboriginal Relations Policy. Program implementation is being staged over five years to facilitate an initial focus on the most critical areas. For this business planning period, the Fossil Business Unit is being added to the list of Business Units that are being requested to prepare an Aboriginal Relations Program. Programs should be developed with a view to reporting results to the First Nation Steering Committee on periodic basis.

For this Business Planning period, the following Business Units will develop programs consistent with the guidelines:

- Hydro - including the Development Group
- Fossil
- Nuclear New Build and Pickering Refurbishment projects
- Other Line Organizations that have regular contact with Aboriginal Communities

Nuclear Operations will be expected to develop First Nations Programs in future plans based on experiences gained from the organizations listed above.

For further guidance on program requirements, please visit the Hydroelectric web-site:
[redacted]

3.11 ENVIRONMENT / SUSTAINABLE DEVELOPMENT (ENV/SD) PLANS

Contact: Rob Lyng

Ontario Power Generation's Environmental Policy identifies the sustainable development policy framework within which all OPG business plans are to be developed. The Environment/Sustainable Development business plan input is an important part of Ontario Power Generation's environmental management.

The following instructions outline the requirements that business units are expected to consider and document in their Environment/Sustainable Development plans. These are plans to be submitted to the Vice President, Sustainable Development by September 30th, 2009.

Questions regarding these instructions should be directed to Rob Lyng, (416) 592-3193, rob.lyng@opg.com

PLANNING ASSUMPTIONS

- The regulation of greenhouse gas emissions is expected to begin during the business planning period, most likely in 2010 and no later than 2012. Reporting of greenhouse gas emissions will be required for all sites emitting greater than 25,000 tonnes of greenhouse gases per year.
- The Federal Framework for conventional air pollutants SO_2, NO_x, particulate and mercury, if implemented, will have no effect on OPG operations.
- Definition of best management practices for fish entrainment and impingement at nuclear and fossil plants began in 2008-2009. Implementation of these BMP must be initiated within the business planning period.
- The Ontario Endangered Species Act 2007 will come into effect as proposed and the planned lists of endangered species will be produced during the business planning period.

REQUIREMENTS

The following is a synopsis of Environment/Sustainable Development Business Plan reporting requirements. Additional detail is available on the Sustainable Development website:

- Corporate Sustainable Development 2010–2014 Business Planning Guidelines web page
- Environment SD Business Plan Instructions 2010-2014:
- In addition, a template is available on the Sustainable Development website, that may be used to submit the Env/SD Plan. Businesses are free to use their own format as long as all the relevant information is provided. This template is available on the Environment website under Environmental Planning Guidelines.

- **All business units and functions** are to identify planned activities and programs to fulfill relevant elements of the Environmental Policy and support **Operations** in fulfilling the policy. Include reference to planned initiatives to enhance environmental awareness for new and current employees as appropriate.
- **Nuclear, Fossil, Hydroelectric, NWMD, and Real Estate** businesses will identify planned activities and programs to fulfill relevant elements of the OPG Greenhouse Gas Management Plan policies as they apply to their respective operations:
  - Nuclear, Hydroelectric, NWMD, Real Estate plans should include description of programs or operational control measures to address:
    - Non-renewable CO_2 emission management;
    - Heat rate management/improvement;
    - Hydroelectric conversion efficiency; and/or
    - Internal energy efficiency.
  - [redacted]
  - Nuclear, Fossil, Hydroelectric, NWMD, Real Estate must include plans to document, for each site, inventories of greenhouse gas emissions expressed in CO_2e based on global warming potentials. Business plans should assume that all sites emitting greater than 25,000 tonnes CO_2e per year will have to report 2010 emissions in 2011 and annually thereafter.
- **Nuclear, Fossil, Hydroelectric, NWMD, and Real Estate** businesses should identify planned activities and programs to fulfill relevant elements of the following Ontario Power Generation policies as they apply to their respective operations:

Biodiversity Policy

Policy on Land Assessment and Remediation

Policy for Use of Ozone-Depleting Substances

Policy for Management of Polychlorinated Biphenyls (PCB's)

- **Nuclear, Fossil, Hydroelectric, NWMD, and Real Estate** plans should address the following in their Environment/Sustainable Development plans:
  - Changes in Significant Environmental Aspects (SEA).
  - "Other Requirements" such as Wildlife Habitat Certification or other environmental commitments that the plant / plant group have adopted.
  - Programs or operational control initiatives aimed at continued improvement of management of one or more SEA or element of the environmental management system (EMS).
  - Objectives and targets to be used by the business unit to assess program delivery and overall environmental EMS effectiveness.
- **Nuclear, Fossil, and Hydroelectric** are expected to have programs to manage fish impingement/entrainment in order to satisfactorily manage the regulatory risk of the Fisheries Act. Environment/Sustainable Development plans should include a description of these programs.
- **Nuclear** is expected to have programs to reduce tritium emissions and the quantity of low and intermediate solid radioactive waste produced. Environment/Sustainable Development plans should include a description of these programs.

3.12 EMERGENCY MANAGEMENT PLANS *Contact: Gian Di Giambattista*

Business Units are to provide the following information directly to Gian Di Giambattista, by September 15, 2009.

- Nuclear, Hydro, Fossil and Energy Markets are to identify staff and funding towards the Emergency Preparedness Market Rules compliance requirements, including, training, Key Facilities Critical Components testing (NPCC and Black Start requirements), developing and participating in workshops and exercises, reviewing standards and other drills to test emergency, business and operational continuity plans.
- All Business Units are to identify staff and funding for the review and update of their pandemic documents including findings from the H1N1 outbreak in order to maintain pandemic readiness. This will include conducting drills, participating in CMCC Pandemic exercises and planning meetings.
- Business are to identify any specific funding required as part of ongoing mitigation of risks associated with supply chain dependencies, or other identified continuity of operations vulnerabilities.
- Business Units are to identify staff and funding in 2010 for assessing their emergency preparedness/business continuity plans against the CSA Z1600 Standard using the Gap Assessment tool.
- Hydro and Fossil are to identify funding and staff requirements for the implementation of WebEOC and Mir3 software for their respective Emergency Operations Centres (EOC) in 2010. If there are no benefits for implementing these programs, it should be stated and not included in their submission.

Questions regarding these instructions should be directed to Gian Di Giambattista, Director Emergency Management (416 592-8460) , g.digiambattista@opg.com .

TAB 3

Memorandum of Agreement

BETWEEN

Her Majesty the Crown In Right of Ontario (the "Shareholder")
And
Ontario Power Generation ("OPG")

Purpose

This document serves as the basis of agreement between Ontario Power Generation Inc. ("**OPG**") and its sole Shareholder, Her Majesty the Queen in Right of the Province of Ontario as represented by the Minister of Energy (the "**Shareholder**") on mandate, governance, performance, and communications. This agreement is intended to promote a positive and co-operative working relationship between OPG and the Shareholder.

OPG will operate as a commercial enterprise with an independent Board of Directors, which will at all times exercise its fiduciary responsibility and a duty of care to act in the best interests of OPG.

A. Mandate

1. OPG's core mandate is electricity generation. It will operate its existing nuclear, hydroelectric, and fossil generating assets as efficiently and cost-effectively as possible, within the legislative and regulatory framework of the Province of Ontario and the Government of Canada, in particular, the Canadian Nuclear Safety Commission. OPG will operate these assets in a manner that mitigates the Province's financial and operational risk.

2. OPG's key nuclear objective will be the reduction of the risk exposure to the Province arising from its investment in nuclear generating stations in general and, in particular, the refurbishment of older units. OPG will continue to operate with a high degree of vigilance with respect to nuclear safety.

3. OPG will seek continuous improvement in its nuclear generation business and internal services. OPG will benchmark its performance in these areas against CANDU nuclear plants worldwide as well as against the top quartile of private and publicly- owned nuclear electricity generators in North America. OPG's top operational priority will be to improve the operation of its existing nuclear fleet.

4. With respect to investment in new generation capacity, OPG's priority will be hydro- electric generation capacity. OPG will seek to expand, develop and/or improve its hydro- electric generation capacity. This will include expansion and redevelopment on its existing sites as well as the pursuit of new projects where feasible. These investments will be taken by OPG through partnerships or on its own, as appropriate.

5. OPG will not pursue investment in non-hydro-electric renewable generation projects unless specifically directed to do so by the Shareholder.

6. OPG will continue to operate its fossil fleet, including coal plants, according to normal commercial principles taking into account the Government's coal replacement policy and recognizing the role that fossil plants play in the Ontario electricity market, until government regulation and/or unanimous shareholder declarations require the closure of coal stations.

7. OPG will operate in Ontario in accordance with the highest corporate standards, including but not limited to the areas of corporate governance, social responsibility and corporate citizenship.

8. OPG will operate in Ontario in accordance with the highest corporate standards for environmental stewardship taking into account the Government's coal replacement policy.

B Governance Framework

The governance relationship between OPG and the Shareholder is anchored on the following:

1. OPG will maintain a high level of accountability and transparency:

   - OPG is an *Ontario Business Corporations Act* ("OBCA") company and is subject to all of the governance requirements associated with the OBCA.
   - OPG is also subject to the *Freedom of Information and Protection of Privacy Act*, the *Public Sector Salary Disclosure Act* and the *Auditor General Act*.
   - OPG's regulated assets will be subject to public review and assessment by the Ontario Energy Board.
   - OPG will annually appear before a committee of the Legislature which will review OPG's financial and operational performance.

2. The Shareholder may at times direct OPG to undertake special initiatives. Such directives will be communicated as written declarations by way of a Unanimous Shareholder Agreement or Declaration in accordance with Section 108 of the OBCA, and be made public within a reasonable timeframe.

C. Generation Performance and Investment Plans

1. OPG will annually establish 3 –5 year performance targets based on operating and financial results as well as major project execution. Key measures are to be agreed upon with the Shareholder and the Minister of

Finance. These performance targets will be benchmarked against the performance of the top quartile of electricity generating companies in North America.

2. Benchmarking will need to take account of key specific operational and technology factors including the operation of CANDU reactors worldwide, the role that OPG's coal plants play in the Ontario electricity market with respect to load following, and the Government of Ontario's coal replacement policy.

3. OPG will annually prepare a 3 – 5 year investment plan for new projects.

4. Once approved by OPG's Board of Directors, OPG's annual performance targets and investment plan will be submitted to the Shareholder and the Minister of Finance for concurrence.

D. <u>Financial Framework</u>

1. As an OBCA corporation with a commercial mandate, OPG will operate on a financially sustainable basis and maintain the value of its assets for its shareholder, the Province of Ontario.

2. As a transition to a sustainable financial model, any significant new generation project approved by the OPG Board of Directors and agreed to by the Shareholder may receive financial support from the Province of Ontario, if and as appropriate.

E. <u>Communication and Reporting</u>

1. OPG and the Shareholder will ensure timely reports and information on major developments and issues that may materially impact the business of OPG or the interests of the Shareholder. Such reporting from OPG should be on an immediate or, at minimum, an expedited basis where an urgent material human safety or system reliability matter arises.

2. OPG will ensure the Minister of Finance receives timely reports and information on multi-year and annual plans and major developments that may have a material impact on the financial performance of OPG or the Shareholder.

3. The OPG Board of Directors and the Minister of Energy will meet on a quarterly basis to enhance mutual understanding of interrelated strategic matters.

4. OPG's Chair, President and Chief Executive Officer and the Minister of Energy will meet on a regular basis, approximately nine times per year.

5. OPG's Chair, President and Chief Executive Officer and the Minister of Finance will meet on an as needed basis.

6. OPG's senior management and senior officials of the Ministry of Energy and the Ministry of Finance will meet on a regular and as needed basis to discuss ongoing issues and clarify expectations or to address emergent issues.

7. OPG will provide officials in the Ministry of Energy and the Ministry of Finance with multi-year and annual business planning information, quarterly and monthly financial reports and briefings on OPG's operational and financial performance against plan.

8. In all other respects, OPG will communicate with government ministries and agencies in a manner typical for an Ontario corporation of its size and scope.

F. Review of this Agreement

This agreement will be reviewed and updated as required.

Dated: the 17th day of August, 2005

On Behalf of OPG:

Jake Epp
Chairman
Board of Directors

On Behalf of the Shareholder:

Her Majesty the Queen in Right of the Province of Ontario as represented by the Minister of Energy, Dwight Duncan

TAB 4

UNDERTAKINGS

Undertaking

To provide copies of Ministry of Energy backgrounder document.

Response

Attached is the February 2005 Ministry of Energy Backgrounder.

Backgrounder/ Document d'information

Ontario

Ministry of Energy   Ministère de l'Énergie

February 23, 2005

ONTARIO GOVERNMENT ANNOUNCES PRICES ON ELECTRICITY FROM ONTARIO POWER GENERATION

The Ontario government has established prices for electricity produced by Ontario Power Generation (OPG) effective April 1, 2005. These prices are designed to:

- Better reflect the true cost of producing electricity
- Ensure a reliable, sustainable and diverse supply of power in Ontario
- Protect Ontario's medium and large businesses by ensuring rates are stable and competitive
- Provide an incentive for OPG to contain costs and to maximize efficiencies
- Allow OPG to better service its debt while earning a rate of return that balances the needs of customers and ensures a fair return for taxpayers
- Relieve taxpayers of the burden of a financially unsustainable rebate program.

Prices on Output of OPG's Regulated Assets

- Under Bill 100, the Electricity Restructuring Act, the government is obliged to set a price for the output of OPG's regulated assets. These assets include the Adam Beck and Decew hydro stations at Niagara, the R.H. Saunders hydro station near Cornwall, and the Pickering and Darlington nuclear stations. These assets provide much of the province's baseload generation, and operate on a nearly constant basis to provide Ontario's homes and businesses with power.

- Regulating the price of OPG's baseload nuclear and hydroelectric assets will reduce price volatility and have a stabilizing effect on electricity prices, which will be of benefit to all consumers.

- Ontario Power Generation's regulated assets represent approximately 60 per cent of OPG's annual output, and approximately 40 per cent of the total generation in Ontario.

- Under the regulation announced today, OPG's baseload hydroelectric generation will be set at 3.3 cents per kilowatt hour, and the price for OPG's nuclear generation will be set at 4.95 cents per kilowatt hour. An average price of 4.5 cents per kilowatt hour is projected for the weighted forecast output for the hydroelectric and nuclear generation combined.

- The prices on OPG's regulated assets are based on projected costs of operation, plus a five per cent return on equity (ROE). While the standard ROE for North

American utilities is ten per cent, a five per cent ROE will generate revenue to service the OPG debt held by the Ontario Electricity Financial Corporation, while putting significant discipline on OPG to contain costs and improve overall operating efficiencies.

- The new prices will stay in effect until the Ontario Energy Board (OEB) develops mechanisms for setting prices for OPG's regulated assets as stipulated in the Electricity Restructuring Act, 2004, no later than March 31, 2008. Transferring the authority to the OEB to set prices for electricity generated from OPG is consistent with the government's commitment to ensure politics are taken out of electricity pricing in the province.

Prices on Output of OPG's Unregulated Assets

- As a result of a ministerial directive, OPG's revenues on most of the output of its unregulated assets (non-baseload hydroelectric, coal and gas-fired stations), which represents approximately 33 per cent of all generation in Ontario, will be temporarily set at an upper limit of 4.7 cents per kilowatt hour. Ontario Power Generation will pay a rebate on revenues over this amount.

- This revenue limit will temporarily be in place from April 1, 2005 to April 30, 2006. It replaces the Market Power Mitigation Agreement (MPMA) implemented by the previous government when it attempted to open Ontario's electricity market in May 2002.

- The revenue limit on OPG's unregulated assets is designed to ensure continued pressure on OPG to contain costs and enhance performance, while acting as a transitional measure to protect consumers as they adjust to the new prices. It is also designed to ensure that OPG has the incentive to respond to market signals and limit OPG's market power.

- The recent Request for Proposals (RFP) which will result in almost 400 megawatts of new renewable energy supply, together with the current RFP for 2,500 megawatts of new clean energy supply, demand response and energy conservation initiatives, both clearly demonstrate that the McGuinty government is taking decisive steps to close the looming gap between electricity supply and demand in the province.

Effect on Consumers

- The new pricing takes effect on April 1, 2005, and will have an immediate impact on the approximately 55,000 large industrial and commercial electricity customers across Ontario who use more than 250,000 kilowatt hours per year.

- To provide some recent historical comparisons on the likely price impacts, commodity prices that large consumers will pay starting April 1 are expected to be 1.5 per cent higher than the prices which prevailed in 2002/2003, the first year of market opening. The prices will be about 5 per cent higher than 2003 prices, and between 8 to12 per cent higher than the unusually soft prices in 2004 (in part, the result of extremely moderate weather in both the summer and winter peak demand periods).

- It is important to look at today's announcement in the broader context of price trends over a number of years, rather than just looking at comparisons to any one specific period where, for example, unusual weather patterns could be a key driver in setting overall price levels.

- It is also important to look at today's announcement in the context of commodity price increases that have also recently taken place or have been announced in key U.S. jurisdictions, as well as in Quebec and Manitoba, two of the lowest cost electricity jurisdictions in North America. By April 1, 2005, for example, it is forecast that Quebec (which relies almost exclusively on hydroelectric power) prices for all classes of customers will have increased by about 7 per cent over the period 2004/2005. In addition, on August 1, 2004, Manitoba (another major hydroelectric jurisdiction) introduced new general rates which represented an average increase of 5 per cent for all customer classes.

- Even with the removal of the MPMA, electricity costs for large industrial and commercial users in Ontario will continue to match neighbours with whom we compete such as Michigan and Illinois, and in fact will be lower than such jurisdictions as New York, Masssachusetts and Pennsylvania.

- In order to help large customers cope with the realities of increasing electricity prices, while adding needed new electricity supply to Ontario, the McGuinty government has also announced that it is appointing an industrial co-generation facilitator to actively encourage industrial cogeneration projects in the province (see accompanying backgrounder). Co-generation opportunities can significantly reduce electricity costs for large industrial users, resulting in enhanced operational efficiencies and improved overall competitiveness.

- While residential, small business and designated consumers will not be affected immediately the Ontario Energy Board's new regulated price plan (RPP) will take effect no later than May 1, 2005. The board will blend the various prices paid to generators into a fixed price that consumers will pay under the RPP. That price will be stable but still reflect the true cost of producing electricity.

<u>History of the Market Power Mitigation Agreement</u>

- The MPMA was put in place by the previous government when it tried to open Ontario's electricity market in May 2002, in order to prevent OPG from exploiting its dominant position as the majority supplier of Ontario's electricity. The MPMA structure was intended to be a temporary measure consistent with the previous government's policy of selling OPG's generation assets.

- Since its inception, the MPMA has cost OPG approximately $100 million per month and approximately $3.3 billion in total. As a result, OPG has suffered poor financial performance over the last three years, and the government and taxpayers have not been able to realize any financial benefit from OPG.

- Under the MPMA, all customers who use more than 250,000 kilowatt hours per year receive a rebate if the annual average Ontario electricity price exceeds 3.8 cents per kilowatt hour. This rebate applies to half of the electricity they consume.

- Due to the MPMA, electricity prices for consumers have been effectively subsidized by taxpayers, and OPG has not been able to recover the cost of generating the electricity it produces. This has severely compromised the company's ability to improve its overall financial performance.

-30 -

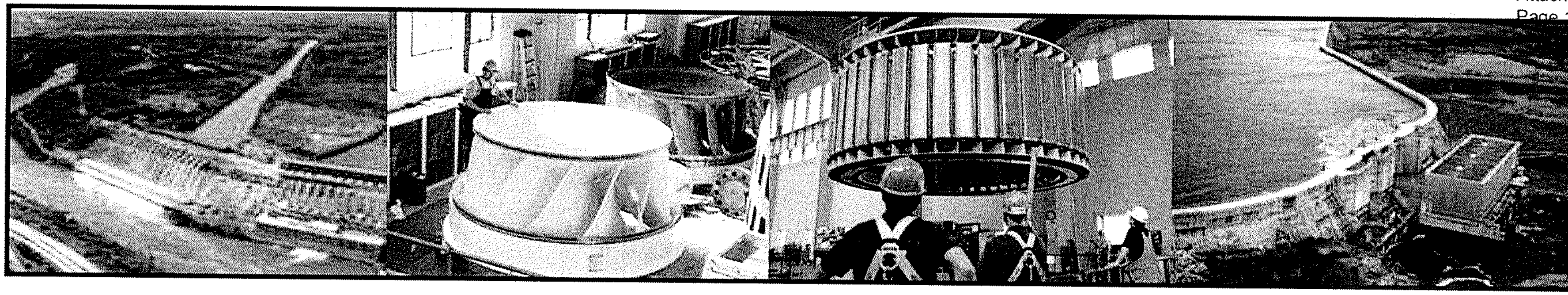
Contact:
Angie Robson
Minister's Office
416-327-6747

Ted Gruetzner
Communications Branch
416-327-4334

Disponible en français

www.energy.gov.on.ca

TAB 5



Hydro Generation Business Plan 2010 to 2014

Presentation to OPG Board of Directors

November 19, 2009

John Murphy
EVP Hydro

ONTARIO POWER GENERATION

Business Plan Outline

1. Setting the Context
   - The Assets
   - Age Profile & Re-Investment Frequencies
2. Major Initiatives
3. Performance and Cost Summary
4. Plan Over Plan Changes - OM&A & Capital
5. Hydroelectric Development Plan
6. Project Expenditures to Maintain and Improve Existing Assets
7. Project Expenditures – Safety and Environmental Programs
8. Runner Upgrade Program
9. Energy Production Plan
10. Reliability
11. Aboriginal Program
12. Demographics and Staffing Strategy/Plan
13. Benchmarking – OM&A Unit Energy Cost and Reliability
14. Key Business Risks

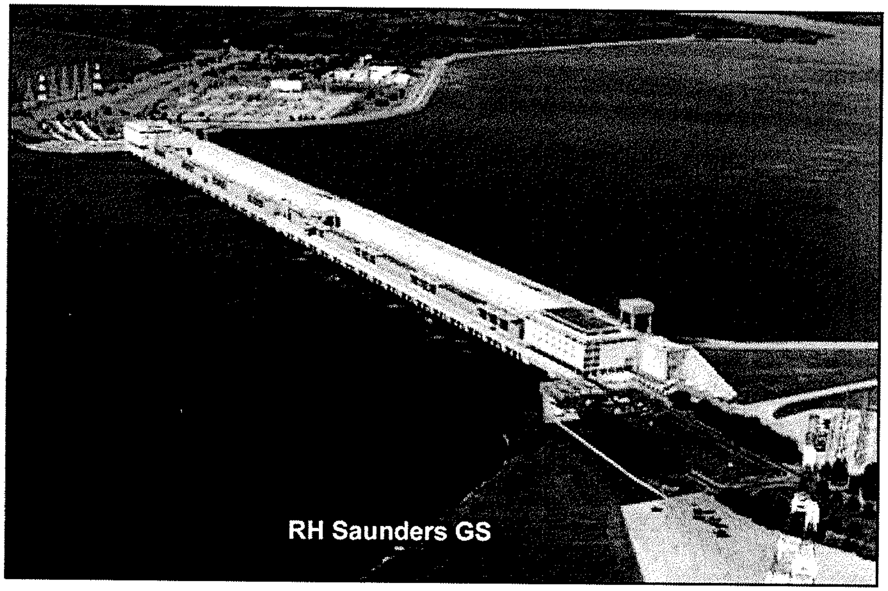
Appendix A – Additional Information

- Station Statistics
- Portfolio Classification and Project Prioritization System
- Capital Expenditures - History and Future
- Hydro Revenue, Cost, Staffing and Other Performance Information
- Year Over Year Changes
- Capacity Changes During Planning Period
- Energy Production Forecast – Impacts of Surplus Baseload Generation (Details)

Appendix B - Regulated Asset Information

Appendix C - Unregulated Asset Information

The Assets

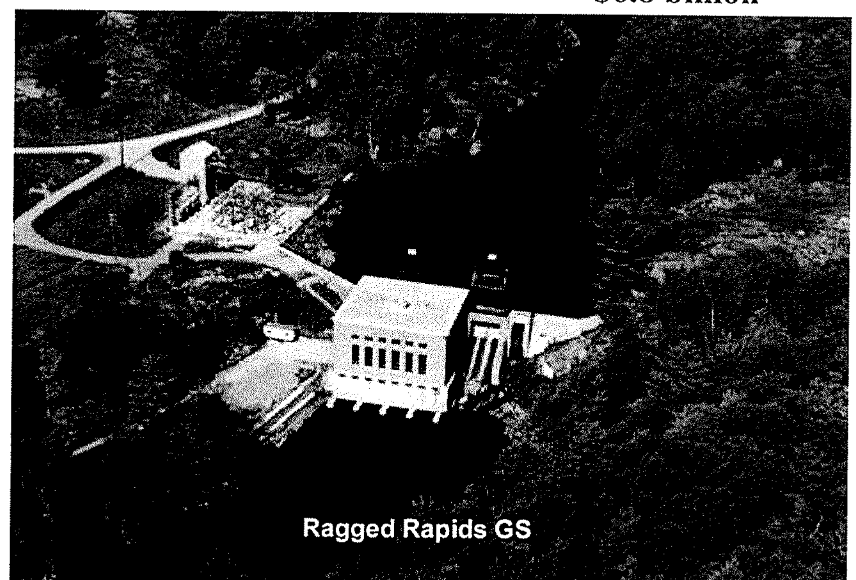


PEOPLE / WORK CENTRES / LAND

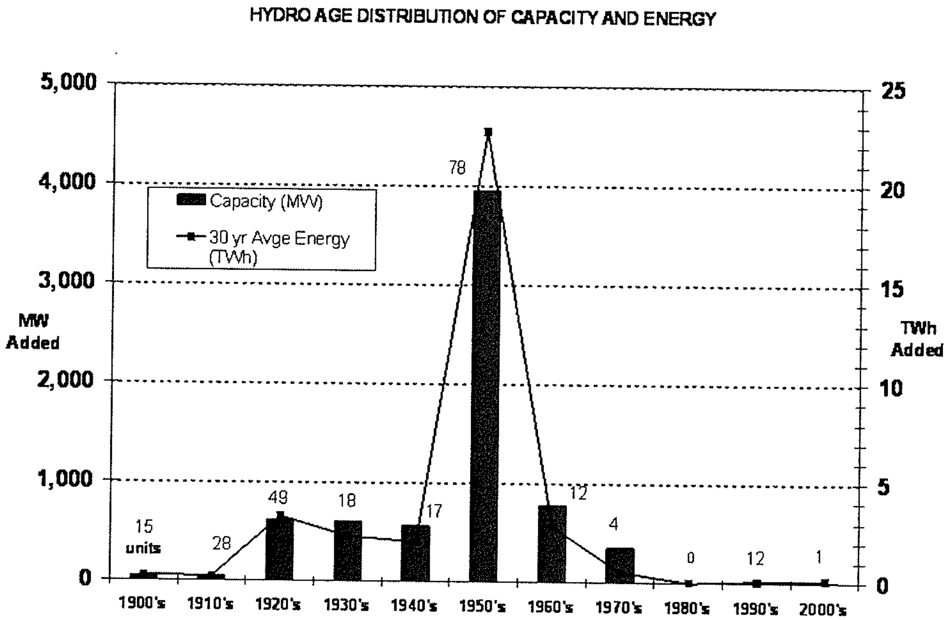
PLANT GROUPS	5
WORK CENTRES	22
CONTROL CENTRES (includes ICD)	7 (was 18 pre-1999)
TOTAL STAFF	~1060
OPERATORS	~100 (was 200 pre-1999)
NO. OF RIVER SYSTEMS	24
HYDRO OWNED LAND	~17,000 hectares
LEASED LAND (flooded)	~800, 000 hectares

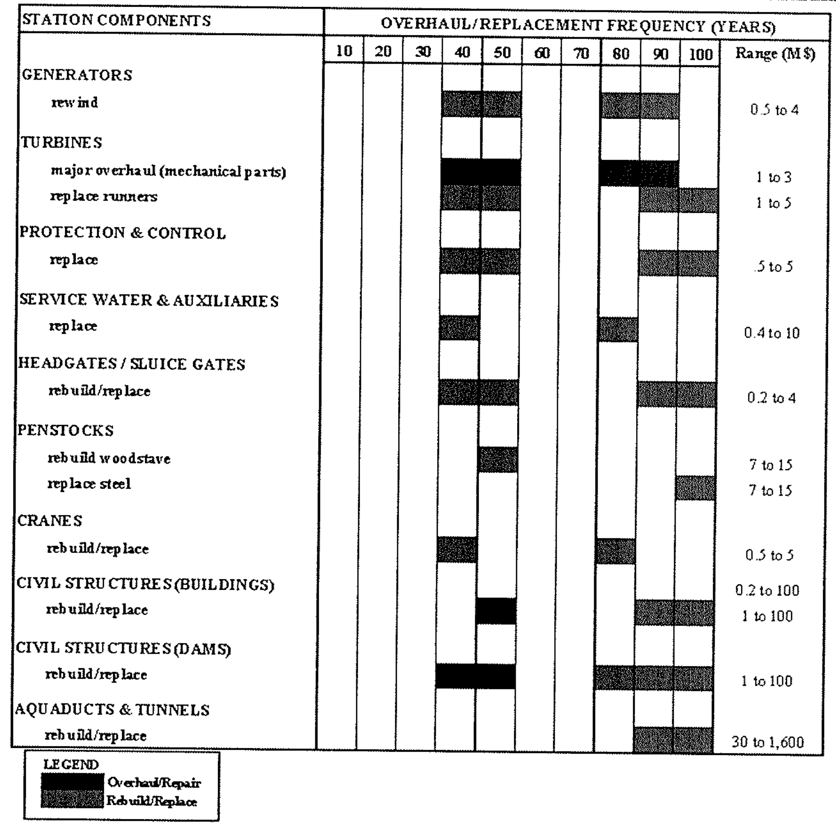
STATIONS PROFILE

NO. OF STATIONS	65 (4 stations being redeveloped)
AVERAGE ENERGY	34.7 TWh
CAPACITY	6943 MW
AVERAGE AGE	70 yrs
NO. OF GENERATING UNITS	230
SMALLEST / LARGEST UNIT	1 MW / 137 MW
NO. OF DAMS	231
BOOK VALUE	$6.8 billion



The Assets: Age Profile & Re-Investment Frequencies





- Average age of stations is 70 years.
- 70% of Hydro capacity built during the 1950's and 1960's.
- Equipment service lives range between 30 to 50 yrs.
- Structures such as dams, penstocks, powerhouses, canals, etc. typically require repairs every 25 to 50 years. Replacement of some civil components is required every 40 to 75 years (eg, wood stave penstocks, stop-logs, etc).
- There is risk of deteriorating performance and safety without significant continued re-investment (due to demographics of portfolio, and large number and variability of stations/units/equipment).
- Re-investment levels of about 1% to 3% per yr of "replacement cost" are considered reasonable by industry experts. Hydro has invested approximately 0.5% to 1.5% per yr of "replacement cost" in the past 10 years (excludes new facilities). Determination of appropriate investment levels should consider station/fleet age and condition, type of equipment, station role (peaking vs base), past investment strategy (eg, harvesting), reliability targets, etc.
- The Business Plan addresses the need to sustain and improve the existing assets for long term per the Hydro mandate. Plant Condition Assessment/Life Cycle Plans and Portfolio Approach to Asset Management used to determine and prioritize investments (Appendix A).

Major Initiatives

- **Invest in New Hydroelectric Developments per Government Mandate**
  - ✓Continue with construction of Niagara Tunnel, Upper Mattagami/Hound Chute and Healey Falls projects.
  - ✓Obtain approvals and start construction of Lower Mattagami project, [redacted]

- **Re-invest in existing assets to maintain/improve their condition, reliability and efficiency**
  - ✓Availability will range from 91.0% to 92.8%.
  - ✓EFOR target is 1.5% (proposed stretch target is 1.4%).
  - ✓Continue replacement/refurbishment civil infrastructure including dams, penstocks, and building envelopes.
  - ✓Continue rehabilitations/upgrades at major stations.
  - ✓Continue runner upgrade program (additional 66 MW of capacity and 144 GWh from 2010 to 2014).
  - ✓Increase/advance reinvestment in small hydro plants (eg, replace aging penstocks, gates, etc) to ensure continued long term safety and performance.

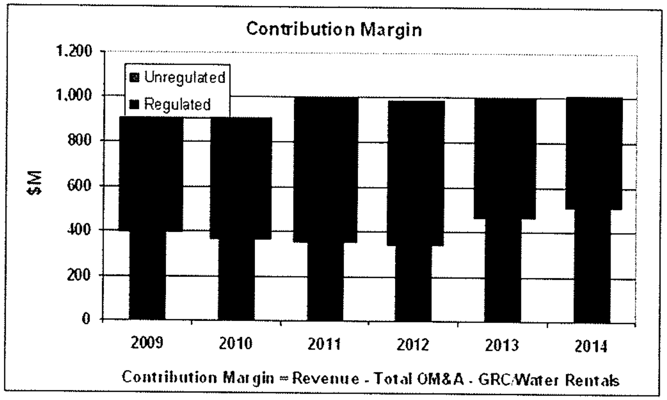
- **Improve Dam and Public Safety through investments and improved processes:**
  - ✓Rehabilitate/upgrade/repair civil works and maintain/improve safety of dams to address deterioration and deficiencies in ageing structures and sluice gates.
  - ✓Improve public safety through the addition of safety booms, fencing, signs, cameras, special structures at certain sites, and enhancement/integration of existing procedures.
  - ✓Increase Dam Safety Surveillance as per the recommendations of Independent Dam Safety Panel.
  - ✓Continue to participate in, and influence, the development of provincial regulations with the MNR.
  - ✓Develop and implement Geographic Information System (GIS).

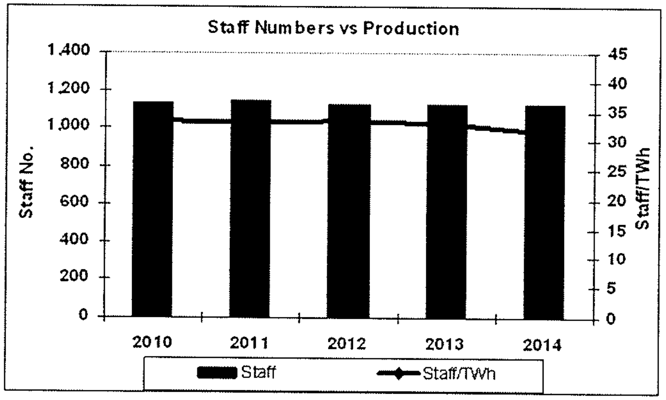
Major Initiatives (cont'd)

- **Invest In People**
  Continue rejuvenation and training of Hydro workforce to address ageing demographics and new work associated with development projects and changing regulatory and internal governance requirements.
- Improve Accident Severity Rate and All Injury Rate and maintain registration in OHSAS 18001.
- Maintain/improve environmental performance in the area of spills risk management and containment testing, and maintain registration in ISO 14001
- **Strengthen relationships with First Nations and Metis**
  Build relationships, consult and partner with First Nations on new developments, and continue activities to support the Aboriginal Relations Policy
- Maintain/improve relationships with provincial and federal government agencies and community stakeholders (to maintain our rights to the "fuel" on the watersheds).
- Improve project planning and execution through enhancement of Project Management processes, systems, training and oversight.

[redacted]

Performance and Cost Summary





	2009 (Proj'n)	2010	2011	2012	2013	2014
PERFORMANCE MEASURES - OPERATIONS						
Capacity (MW)	6,943	6,995	7,000	6,966	7,228	7,484
Energy (TWh)	36.1	34.1	34.4	33.8	34.4	36.0
Availability (%)	93.1	91.0	92.4	92.6	92.3	92.8
Scheduled Outage Factor (%)	5.7	7.8	6.4	6.2	6.5	6.0
EFOR (%)	1.5	1.5	1.5	1.5	1.5	1.5
Spill Losses (Forced + Planned Outages) (GWh)	293	320	200	200	199	201
REVENUE ($M) *	[redacted]					
RESOURCES						
Base OM&A - Operations($M)	[redacted]					
Project OM&A - Operations ($M)						
OM&A - Hydroelectric Development ($M)						
TOTAL OM&A ($M)						
Capital - Operations ($M)						
Capital - Niagara Tunnel ($M)						
Capital - Upper Mattagami & Hound Chute ($M)						
Capital - Lower Mattagami ($M)						
Capital - Little Jackfish ($M)						
Capital - Other New Developments ($M)						
TOTAL CAPITAL ($M)						
Staff	1,077	1,138	1,144	1,130	1,131	1,132
GROSS REVENUE CHARGE/WATER RENTALS	365	353	358	357	353	347
CONTRIBUTION MARGIN ($M)	[redacted]					
PRODUCTION COSTS						
OM&A UEC ($/MWh)						
GRC/Water Rentals UEC ($/MWh)	10.1	10.3	10.4	10.6	10.3	9.6
PUEC ($/MWh)	[redacted]					
ENVIRONMENT	Meet all Environmental Regulatory Limits & Targets					
HEALTH & SAFETY	Meet all Health and Safety Targets (ASR=4.5 & AIR=3)					

* HESA Revenues for Lac Seul, Upper Mattagami, Healey Falls and Lower Mattagami Developments are included.

Highlights

- Increased capacity and energy from new development projects and runner upgrades.
- Average availability of 92.2% lower than 2009 due additional major planned outages, but still significantly better than external benchmarks.
- OM&A stable during business plan period (average of [redacted] per year).
- Capital costs increase due to new development projects (average of [redacted] per year).
- Revenue lower in first three years of plan with expected upside in 2013/2014 due to increased production and increased energy prices.
- OM&A Unit Energy Cost and Production Unit Energy Cost improves over the planning period.

OM&A - Plan Over Plan

Major Changes

- Some lower risk OM&A projects have been deferred from 2010 to later in planning period. Consulting and discretionary costs have been reduced to meet Cost Reduction Challenge.
- Modest staff additions to address demographics, additional project and regulatory requirements in operations, and increased dam safety surveillance.
- Central Hydro Plant Group organization will be strengthened and improvements will be made to managed systems, public safety, and project and maintenance management.
- NEPG and NWPG support staff added to assist in construction and ultimate operation of the Upper and Lower Mattagami projects.
- Niagara Bridge Divestiture Strategy: OPG has legal obligations to maintain and replace certain bridges at the end of their life. OPG will pay municipalities to replace these bridges and turnover all responsibility to the municipalities. This will eliminate future cost and legal liabilities associated with these bridges.
- Increases in Geographic Data System data acquisition (flight surveys and LIDAR) and mapping system costs.
- Reductions due to IFRS accounting changes (transfer SAVH from OM&A to Capital).
- Labour and payroll burden rates have been reduced.

OM&A - Plan Over Plan	2009 Proj'n	2010	2011	2012	2013
Last Year's Approved Plan ($M)	[redacted]				
Changes					
Corporate Reduction Challenge		-5.0			
Mechanical, Civil, Electrical Work Program (Reprioritization & Scope Change	1.2	-2.7	-5.6	-1.0	-1.5
Additional New Hires, Apprentices and Operators - Demographics		0.8	0.4	0.5	0.3
Plant Group Operations Support for Upper Mattagami, Lower Mattagami, Healey Falls and Little Jackfish		[redacted]			
New Hydro Development Project Increases (includes Pumped Storage)					
Niagara Bridge Replacement/Divestiture Program	4.0	1.8	6.9	0.0	0.0
Public Safety Increases (Signs, Fencing, Booms, etc)		1.5	0.6	0.6	0.6
Dam Safety Surveillance Inspection Increases (per Independent Panel)		1.0	1.0	1.0	1.0
Central Hydro PG (Strengthen Organizatio/Due Diligence & Improve Maintenance)	0.2	1.4	1.6	1.8	1.9
Re-investment in the Small Hydro Fleet (Project Changes)		[redacted]			
Niagara Joint Works Changes (NYPA cost increases)		1.2	0.5		
Geographic Information System (GIS) Implementation		1.8	0.2	0.2	0.2
Shoreline Remediation/Erosion Protection Projects (First Nations)	-2.9	0.7			
Miscellaneous Changes	-5.1	0.6	3.7	1.4	-0.5
OM&A Submission (before labour rate & payroll burden reduction)	[redacted]				
SAVH Transferred to Capital		-1.7	-1.7	-1.7	-1.7
Labour Rate & Burden Reduction		-9.1	-9.7	-11.6	-11.4
OM&A Submission	[redacted]				
Change in OM&A From Last Year's Plan					

ONTARIOPOWER GENERATION

Capital - Plan Over Plan

Major Changes

- Project costs on both the operations side of business and new developments have been increased to reflect actual contract bids, and latest material/ equipment/contracting cost information.
- Replacement of old wood stave and steel penstocks at small hydro plants (eg, South Falls, Matabitchuan) have been advanced. DeCew Falls 1 steel penstock to be replaced in 2009 to 2011.
- Niagara Tunnel in-service date and cost has been changed to December 2013 and $1.6 billion, respectively.
  Cash flows and energy production assumptions for the tunnel are aligned with this in-service date.
- Pre-concept phase costs for new development projects and initiatives such as pumped storage added.
- Lower Mattagami total cost increased to [redacted] and schedule per latest contractor estimates.

Capital - Plan Over Plan	2009 Proj'n	2010	2011	2012	2013
Last Year's Plan ($M)	[redacted]				
Operations Changes					
SAB1 G10,3,5,4 Upgrade changes (Runner Upgrade/Rewind)	-2	-10	-10	-5	-3
Civil Project Changes	2	6	9	0	-3
Major Mechanical, Electrical & P&C Equipment Replacements (Reprioritization & Scope Changes)	-5	3	4	2	5
Equipment Cost Increases	2	4	0	0	0
Operations Projects deferred to align with Hydro Development projects	[redacted]				
Penstock Replacement Changes and Cost Increases	1	-2	15	4	0
Small Hydro Re-Investment	[redacted]				
New Development Changes					
Niagara Tunnel Project	49	7	145	197	214
Lower Mattagami	[redacted]				
Upper Mattagami and Hound Chute					
Mattagami Lake Dam					
Healey Falls					
Little Jackfish					
Hydro Development Project and Other Changes (Timing)					
Capital Submission					
Change in Capital From Last Year's Plan					

ONTARIOPOWER GENERATION

Hydroelectric Development Plan

	Capacity MW	Pre-2009	2009 $M	2010 $M	2011 $M	2012 $M	2013 $M	2014 $M	Bal $M	Total $M
Projects In-Progress										
Niagara Tunnel Project (from NTP Info Sheet)		434.5	222.7	241.8	288.0	199.0	214.0	0.0	0.0	1,600
Upper Mattagami & Hound Chute	[redacted]									
Healey Falls										
Subtotal (Projects In-Progress)										
Projects In Definition Phase										
Lower Mattagami										
Mattagami Lake Dam										
Little Jackfish										
Subtotal (Definition Phase)										
Projects in Concept/Pre-Concept (Corporate Provision)										
Ranney Falls	[redacted]									
Newpost Creek										
Long Lake Dam										
South Falls										
OPG Control Dams										
Lake Gibson										
Moose River Basin (Greenfield)										
Albany River (Hat & Chard)										
Northern Rivers										
Calabogie										
Maynard Falls										
Concept/Pre-Concept - Corp. Provision										
Total (Projects In-Progress, In Definition Phase & Pre-Def'n Phase)										

[redacted]

General

- Costs for projects presently in execution and definition phases are included in this business plan.
- Timing of execution phase for projects presently in definition phase will be dependent on government directives, HESA's (from OPA), agreements with First Nations, EA approvals, etc (timing of phases for each project shown on next page).

Pumped Storage

- Extensive review of historical information and international pumped storage installations completed and [redacted] OPG sites [redacted] have been identified as being the most desirable for addition of pumped storage. As well, preliminary review of expansion of the existing Sir Adam Beck PGS reservoir has been conducted.
- [redacted]

Project In-Service Dates

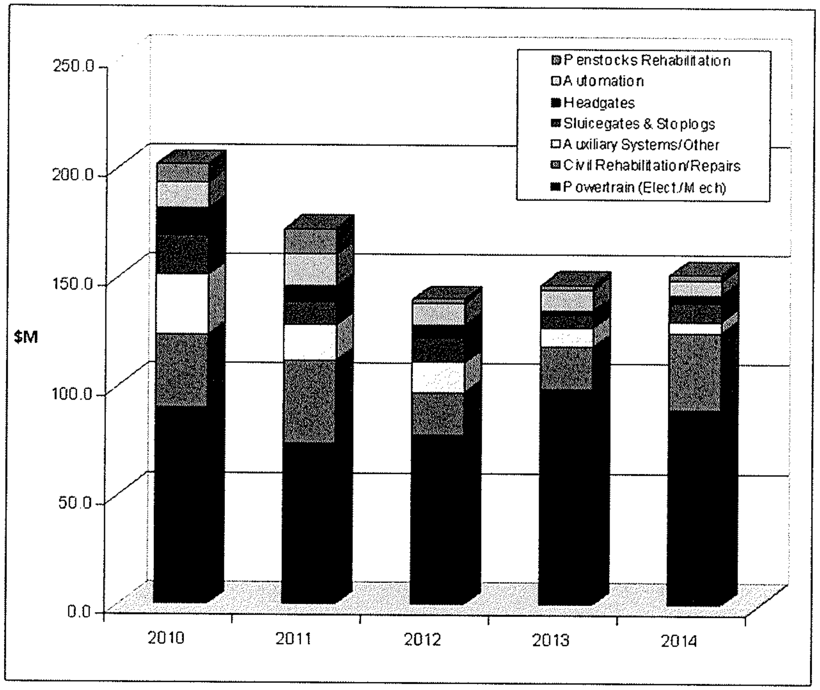
- Healey Falls: [redacted]
- Upper Mattagami/Hound Chute: [redacted]
- Niagara Tunnel: December 2013
- Mattagami Lake [redacted]
- Lower Mattagami: [redacted]

Hydroelectric Development Plan (Project Phases/Timelines)

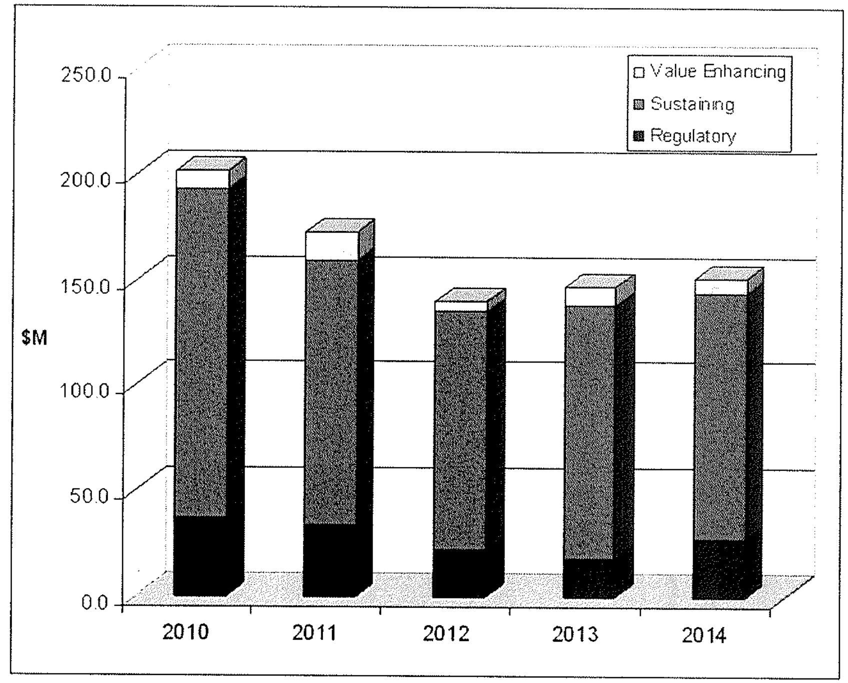
[redacted]

Project Expenditures To Maintain and Improve Existing Assets

By Discipline/Component



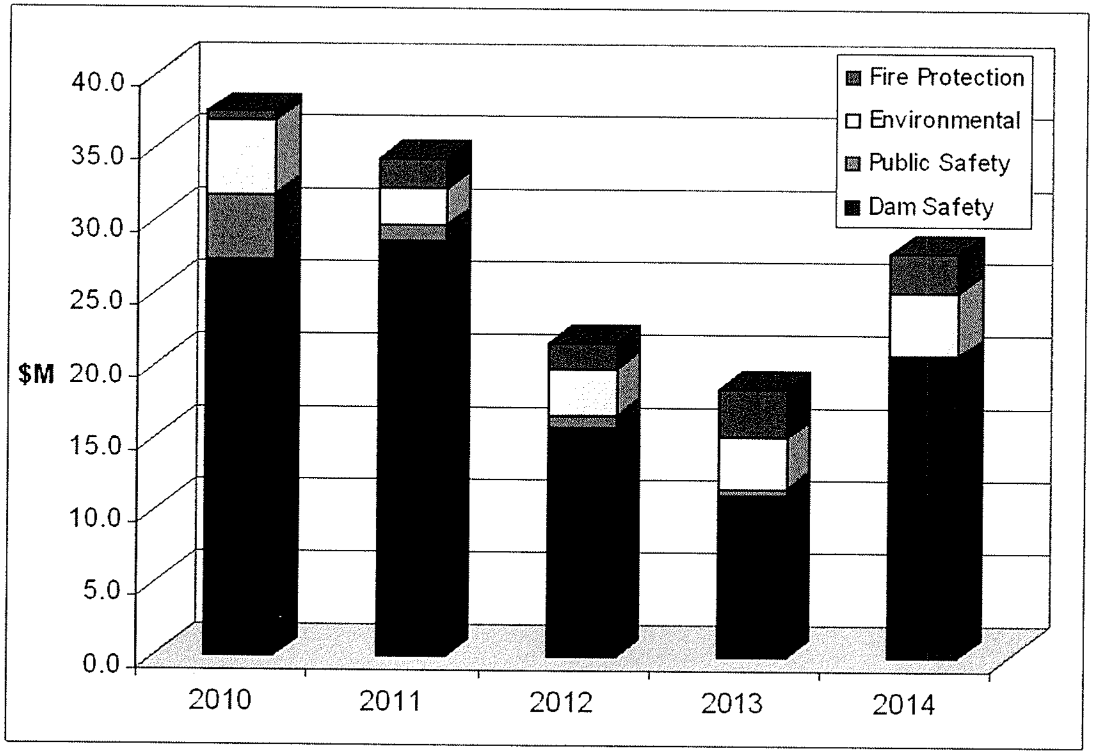
By Regulatory/Sustaining/Value Enhancing



Continued re-investment, averaging [redacted] per year in Capital and OM&A project expenditures, will be required to sustain and improve the existing assets per our mandate. Major investments will include:

- replacement of ageing "power train components" such as turbines, generators, transformers
- replacement of control equipment (automation) to improve efficiency and accommodate market dispatch requirements
- repairs, rehabilitation or replacement of ageing civil structures including powerhouses, penstocks, dams, sluiceways and bridges
- replacement and refurbishment of headgates and sluicegates
- runner upgrades/replacements
- investment in small hydro facilities

Project Expenditures - Safety and Environmental Programs

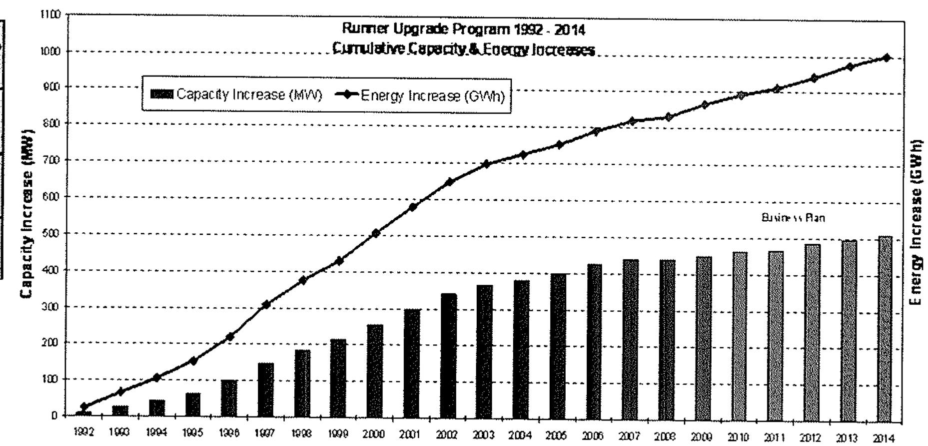


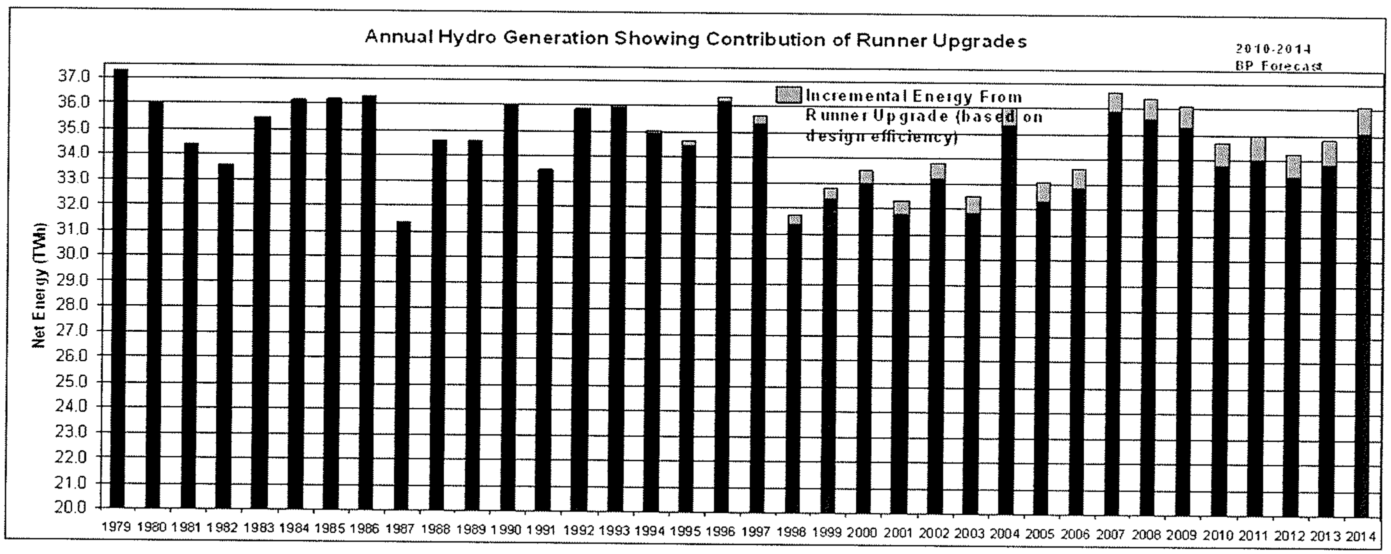
Project expenditures for safety and environmental programs during planning period:

- Public Safety (safety booms, fencing, signs, video cameras, special structures, etc) (5% of total safety and environmental project costs).
- Dam Safety (sluicegate & headgate refurbishments/additions, dam upgrades/ restoration)(74%).
- Environment (oil containment, turbine pit/sump improvements, underground piping remediation) (14%).
- Fire Protection (life safety projects). Program to be completed during planning period. (7%).

Runner Upgrade Program

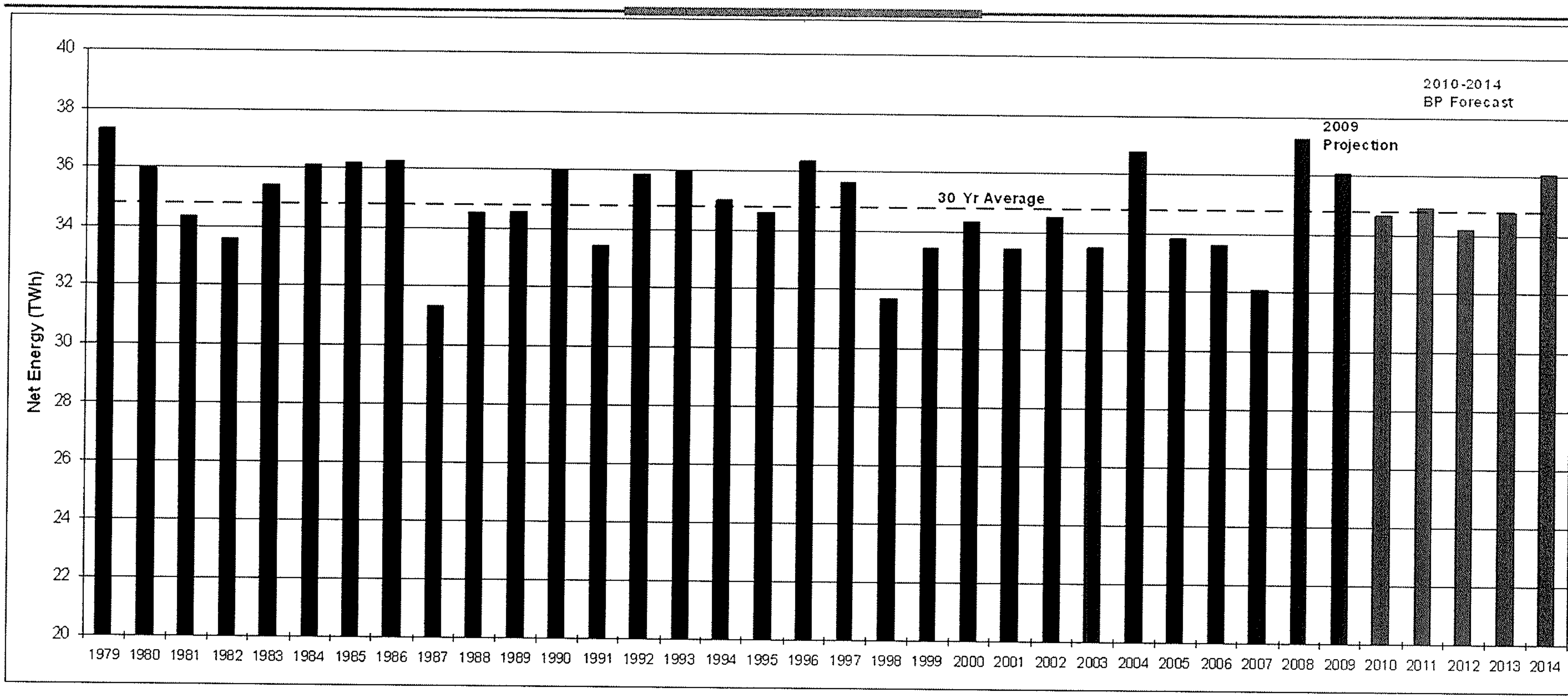
	Completed 1992 to 2008	2009	2010	2011	2012	2013	2014	Total (2010 to 2014)
CAPACITY (MW)	439	11	13	4	19	18	12	66
ENERGY (GWh)	831	35	26	25	29	38	27	144
TOTAL CAPITAL COST (M$)	167	15	9	14	8	12	7	51





- In 2009, Hydro is adding 11.2 MW of capacity & 35.3 GWh of energy. During the planning period runner upgrades will add 65.9 MW and 144 GWh.
- Execution of remaining program will continue as quickly as practical. A business case will be developed for each project before proceeding (LUEC's presently estimated to be between 3 and 10 cents/kWh depending on project).
- The speed of execution may be impacted by IESO constraints, consideration of outage spill losses, coordination with other major work, resource availability (internal resources and external contractors) & coordination with development projects (at existing sites - LMD).

Energy Production Plan



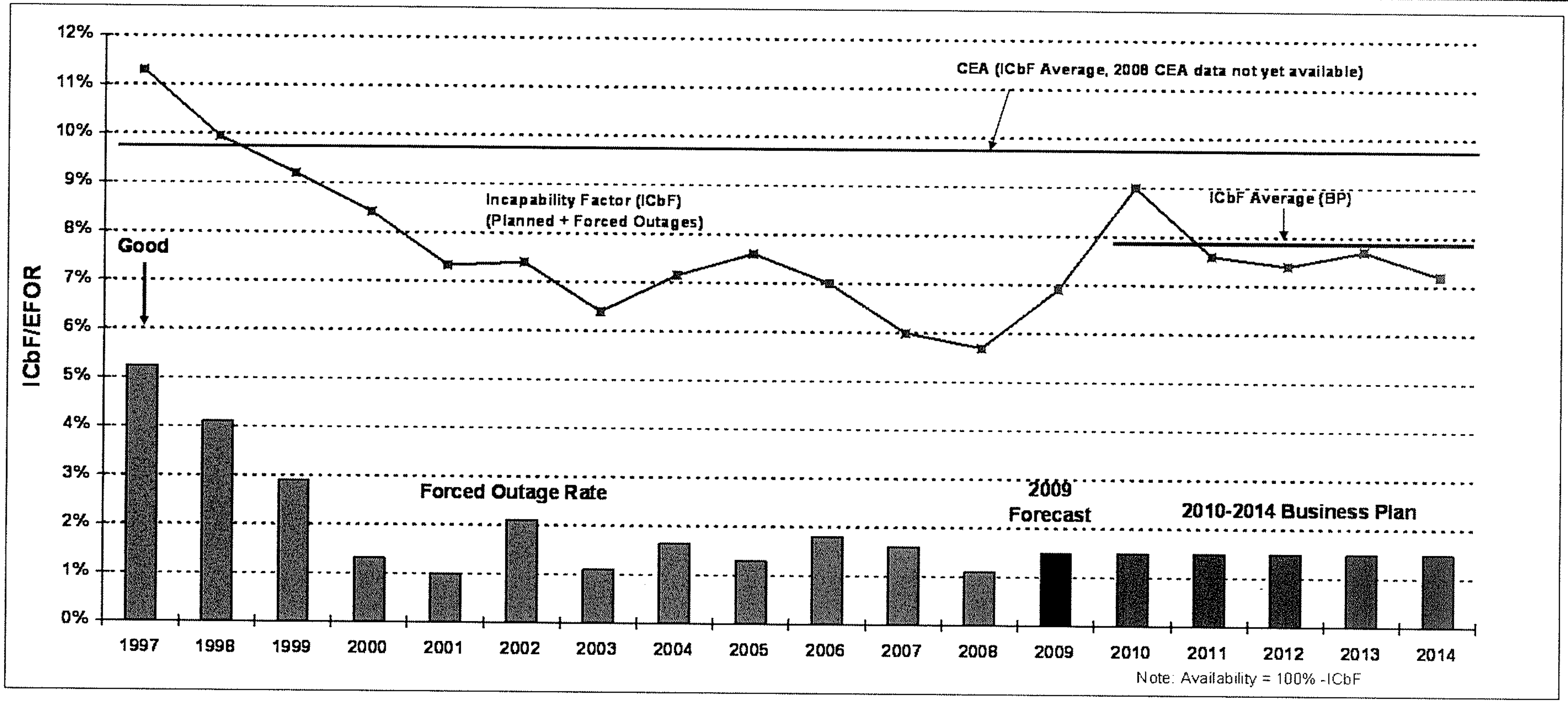
- Base 2010 to 2014 energy forecast assumes median water levels and Surplus Baseload Generation (SBG) spill losses included per Energy Markets forecast (see graph)
- Major energy increases during business plan period include:
  - 2013: Niagara Tunnel Energy (1.6 TWh in 2014)
  - 2010:Upper Mattagami [redacted]
  - 2013/2014: Lower Mattagami [redacted]

[redacted]

ONTARIOPOWER GENERATION

OPG Confidential

Reliability



- Availability will average 92.2% (ICbF=7.8%) during the business planning period. This is significantly better than the CEA average.
- In 2010 to 2014, availability will be lower than the 2009 projection due to additional/long outages required for major rehabilitations and upgrades at several stations (eg, Sir Adam Beck 1 Units 9,10, 3, 4 & 5, Mountain Chute Unit 2, Des Joachims, Otter Rapids, Lower Notch, Little Long, Harmon, Abitibi Canyon (full station outage), Otto Holden, Pine Portage, Whitedog Falls, Alexander Falls.
- EFOR is assumed to average 1.5% during the business planning period. This is also significantly better than the CEA average. A stretch target of 1.4% is proposed for EFOR.
- EFOR & Availability may be negatively impacted by additional dispatches and stops/starts associated with SBG situation.

Aboriginal Program

	2009 Actual	2010	2011	2012	2013	2014
Community Relations and Outreach (M$) Community Support	1.0	1.1	1.1	0.6	0.6	0.6
Capacity Building Support (M$) Educational Partnership Scholarships/Bursaries Mentoring Project Participation	1.6	4.3	4.1	3.6	3.6	3.6
Employment Opportunities (M$) New hires - regular/PT/Students	0.8	1.3	0.6	0.5	0.5	0.5
Contracting Opportunities (M$) Contracts	0.3	0.8	0.1	0.0	0.0	0.0
Other Initiatives (M$)	0.0	0.7	0.0	0.0	0.0	0.0
Total	3.8	8.3	5.9	4.7	4.7	4.7

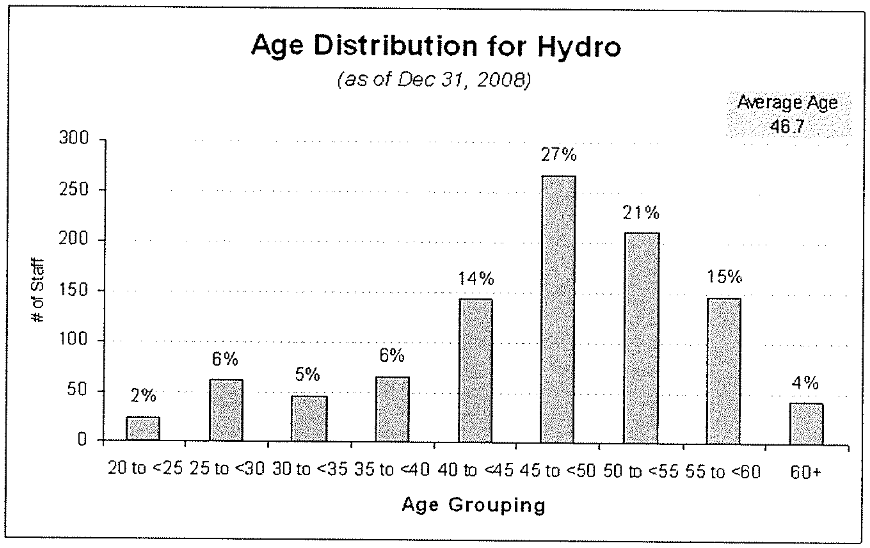
- Program includes both operations and hydroelectric development initiatives.
- Program covers 30 First Nations and Metis.
- Hydroelectric Development costs include support to First Nations for:
  - Commercial agreements
  - Technical studies/assistance
  - EA consultants
  - Employment training

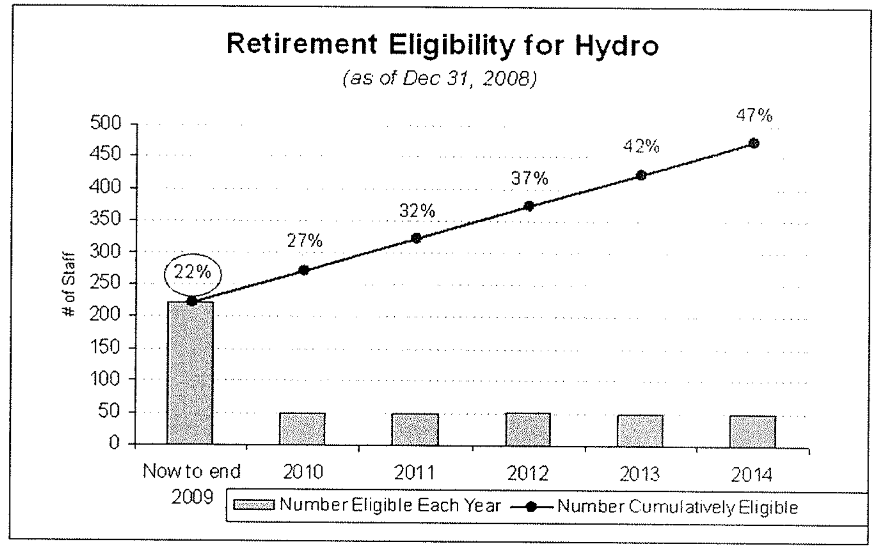
Notes
1. Above costs are already included in Business Plan, either in base OM&A for the Plant Groups or Hydroelectric Development project costs.
2. Above table does not include past grievance settlement costs and remediation work (eg, Long Lac #58 shoreline remediation and Whitesand erosion repairs).
3. Above table does not include Plant Group and Aboriginal Affairs Division staffing costs to manage and carry out the aboriginal program.

Demographics

- During 2008 and 2009, significant progress has been made to reduce this risk through external hiring strategy (apprentices, Hydroelectric Operating Trades Trainee's, and Engineering/Professional Trainees).

- Demographics have marginally improved since 2008, but 22% of staff are still eligible to retire by end of 2009 and 47% by end of 2014. Thus, it is important to continue hiring and training strategy which was initiated in 2008 (see next page).



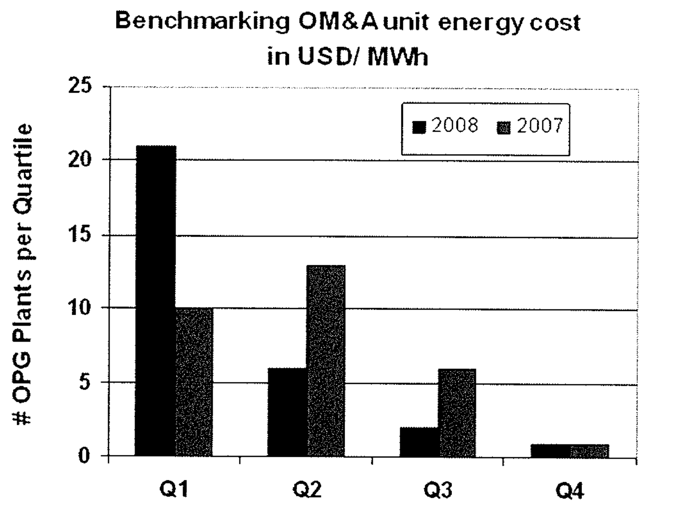


Staffing Strategy/Plan

- Aggressive hiring strategy to attract skilled ("journey person") trades external to the company.
- Apprenticeship Program – hiring and training apprentices to replace retiring skilled trades.
- "Strategic Complement" – Strategy of "over hiring" to account for unexpected attrition, high turnover, and long lead times required to hire staff.
- Succession Management – succession planning for leadership roles down to FLM level is formally underway.
- Knowledge Transfer – overlap new hires with anticipated retirements to ensure knowledge transfer.
- Re-establish Graduate Engineering Trainee Programs.
- Leadership/Supervisory Development Program.
- Reduce temporary staff, contract staff and consultants as regular staff complement increases.

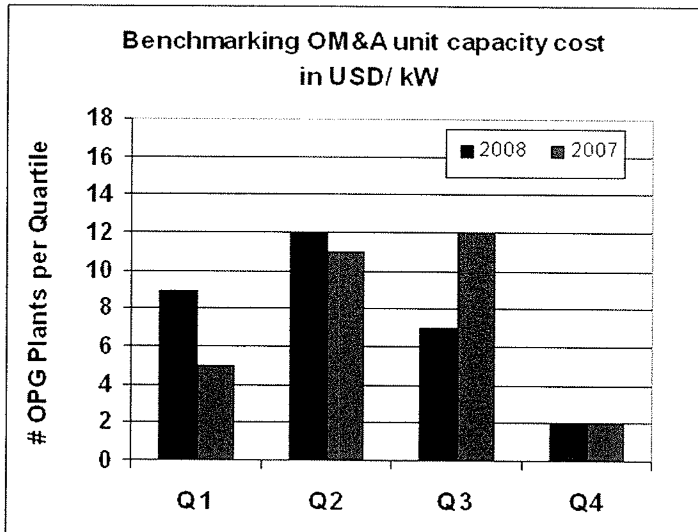
Regular Staff - Plan Over Plan	2009 Proj'n	2010	2011	2012	2013
Last Year's Plan (Staff)	[redacted]				
Changes					
Maintenance Staff Changes including Apprentices (Journeyperson Mechanical/Electrical Maintainers)					
Operations & Maintenance Support (engineering, project management, environment, public safety, regulatory support, public affairs, etc)					
Hydroelectric Development Staff Increases for Concept Phase Work and Project/Construction Management					
Plant Group Operations Support for New Development Projects (Upper Mattagami, Lower Mattagami, Little Jackfish)					
Central Hydro Plant Group (Organizational Reinforcement)					
Hydro Staff BP Submission					
Change in Total Staff From Last Year's Plan					

Benchmarking of OM&A Costs – EUCG (2008)



2008 EUCG survey: OPG 30 out of 241 plants

	2008 OPG Plant Distribution				total
	Q1	Q2	Q3	Q4	
USD/ MWh	1.0 - 8.7	8.7 - 17.6	17.6 - 44.0	44.0 - 1,132	
# plants	21	6	2	1	30
TWh	33.1	3.8	0.3	0.1	37.3
% TWh	89%	10%	0.9%	0.4%	100%



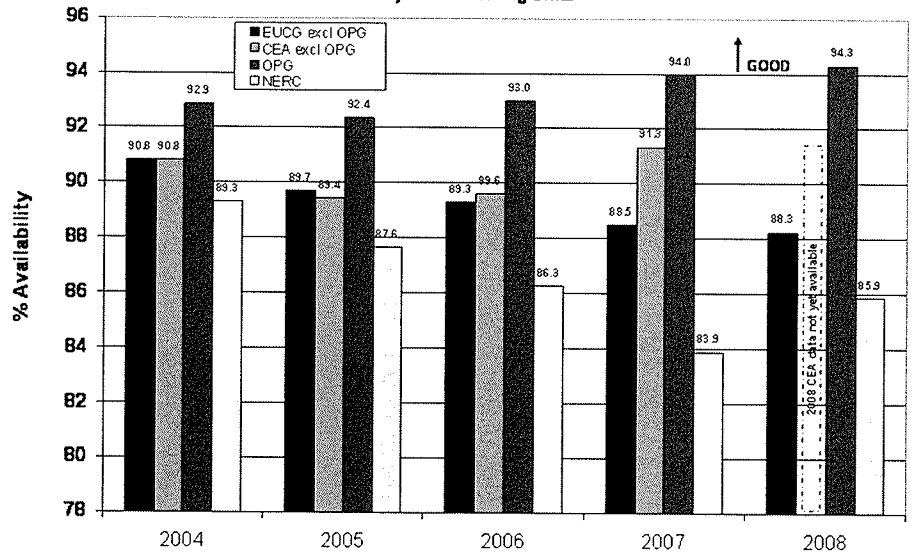
2008 EUCG survey: OPG 30 out of 241 plants

	2008 OPG Plant Distribution				total
	Q1	Q2	Q3	Q4	
USD/ kW	7.2 - 24.0	24.0 - 44.3	44.3 - 96.4	96.4 - 1,860	
# plants	9	12	7	2	30
MW	4,206	2,038	650	42	6,935
% MW	61%	29%	9%	0.6%	100%

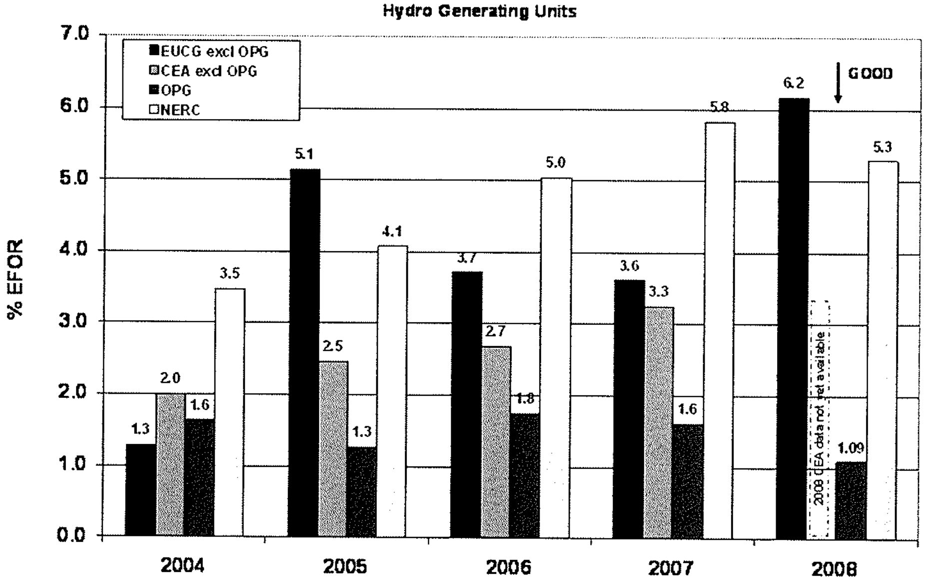
- OM&A costs continue to be competitive with other EUCG participating utilities (99% of Hydro generation is in top two quartiles.
- Most of our large stations (eg, Saunders, Sir Adam Beck 2 and Des Joachims) are in the top quartile.

Benchmarking of Reliability (2004 – 2008)

Availability Factor Trend
Hydro Generating Units



Forced Outage Rate Trend
Hydro Generating Units



- Hydro Availability and EFOR continues to benchmark better than EUCG and NERC participants.

- Availability (EUCG Benchmarking)
  - 10 Hydro plants are in the top quartile.
  - 19 plants are better than the median. This accounts for 71% of Hydro capacity.

- Forced Outage Rate (EUCG Benchmarking)
  - Hydro has 18 plants that are better than the median. This accounts for 52% of Hydro capacity.

Notes:

1) 30 OPG Hydro stations are included in the benchmarking. Benchmarking studies do not include small stations/units

2) CEA benchmarking data for 2008 is not yet available.

Key Business Risks

- Niagara Tunnel Project – Delays in schedule, increase in project cost and geological risk.

- Hydroelectric development project risks associated with project management capability, availability of qualified contractors and skilled labour, cost escalation, EA approvals, First Nations support/partnerships, obtaining PPA's or HESA's from OPA.

- Cost escalation risk - Hydro Operations:
  - Construction and rehabilitation activity in power sector and other infrastructure continues to be robust, leading to increased demand for equipment, materials, labour, and consulting and contracting services.
  - This could significantly increase costs for repair, rehabilitation and replacement projects.

- Demographic risk, especially in the engineering and skilled trades areas.

- Dam Safety (New Regulation risk) and Public Safety risks. Potential upgrade costs are not included in plan.

- Aboriginal Past Grievances - Cost of future settlements and additional claims may be higher than current provision.

- Ageing Plants: Asset integrity, reliability and safety at risk without continued re-investment.

- Structural and operational risks associated with:
  - Alkali Aggregate Reaction (AAR) induced concrete growth at Otto Holden, Saunders, Manitou Falls, Pine Portage, Chats Falls and Frederickhouse Dam.
  - Ageing wood stave and steel penstocks at Nipissing GS and Matabitchuan GS.

- Environmental risk associated with Ontario Endangered Species Act and Federal Species at Risk Act (compliance may require mitigation costs and impacts on production/revenue)

- Risks/impacts on Hydro production and reliability (generating equipment and sluice gates) of increasing Surplus Baseload Generation (SBG) situation in Ontario

The above risks are mitigated through programs, prudent asset management strategies and managed systems incorporated in this Business Plan. The risk profile of Hydro has not significantly increased due to new development projects. Project risks are mitigated by implementation of rigorous planning and project management systems/controls and revenue certainty from financial contracts (HESA's).

Appendix A
Additional Information

Station Statistics

HYDROELECTRIC PLANT LISTING BY PLANT GROUP

Niagara Plant Group	No. of Units	Capacity (MW)	30 Yr Avg Energy (GWH)	Age In 2009 (Years)	Capacity Factor
Decew Falls ND1	4	23	107	111	54
Decew Falls NF23	2	144	1,037	65	82
Sir Adam Beck I	8	417	2,162	87	59
Sir Adam Beck II	16	1,499	9,568	55	73
Sir Adam Beck PGS	6	174	-121	52	7
TOTAL	36	2,257	12,753	74	65
CNP Payback & Water Transfers			-500		
TOTAL (after CNP/WT)			12,253		62

NUMBER OF DAMS & SPECIAL STRUCTURE 25

Note: Units 1 & 2 at SAB 1 are deregistered in April 2009 (were 25 Hz units)

Northeast Plant Group	No. of Units	Capacity (MW)	30 Yr Avg Energy (GWH)	Age In 2009 (Years)	Capacity Factor
Abitibi Canyon	5	349	1,340	76	44
Harmon	2	141	632	44	51
Hound Chute	0	0	0	0	Redev.
Indian Chute	2	3	16	85	63
Kipling	2	157	633	43	46
Little Long	2	133	555	46	48
Lower Notch	2	274	400	38	17
Lower Sturgeon	0	0	0	0	Redev.
Matabitchuan	4	10	52	99	62
Otter Rapids	4	182	707	48	44
Sandy Falls	0	0	0	0	Redev.
Smoky Falls*	4	52	377	85	82
Wawaitin	4	11	51	97	54
TOTAL	31	1,312.1	4,763	51	41

NUMBER OF DAMS IN PLANT GROUP 41

Ottawa-St. Lawrence Plant Group	No. of Units	Capacity (MW)	30 Yr Avg Energy (GWH)	Age In 2009 (Years)	Capacity Factor
Arnprior	2	82	147	33	21
Barrett Chute	4	176	302	67	20
Calabogie	2	5	21	92	52
Chats Falls	4	96	531	78	63
Chenaux	8	144	734	59	58
Des Joachims	8	429	2,264	59	60
Mountain Chute	2	170	298	42	20
Otto Holden	8	243	1,153	57	54
R.H. Saunders	16	1,045	6,844	51	75
Stewartville	5	182	308	61	19
TOTAL	59	2,570.9	12,603	60	56

NUMBER OF DAMS IN PLANT GROUP 45

Northwest Plant Group	No. of Units	Capacity (MW)	30 Yr Avg Energy (GWH)	Age In 2009 (Years)	Capacity Factor
Aguasabon	2	51	291	61	65
Alexander	5	68	428	79	72
Cameron Falls	7	90	530	88	67
Caribou Falls	3	91	515	51	64
Ear Falls	4	17	115	79	77
Kakabeka Falls	4	25	143	103	66
Manitou Falls	5	73	392	53	61
Pine Portage	4	142	791	59	64
Silver Falls	1	48	214	50	51
Whitedog Falls	3	68	392	51	66
Lac Seul	1	12	52	1	49
TOTAL	39	684	3861	61	64

NUMBER OF DAMS IN PLANT GROUP 54

Central Hydro Plant Group	No. of Units	Capacity (MW)	30 Yr Avg Energy (GWH)	Age In 2009 (Years)	Capacity Factor
Auburn	3	2	10	98	63
Big Chute	1	10.0	51	16	58
Big Eddy	2	8.0	37	68	53
Bingham Chute	2	1.0	4	86	48
Coniston	3	4.6	19	104	47
Crystal Falls	4	8.4	43	88	58
Elliot Chute	1	1.6	5	80	37
Eugenia Falls	3	6.1	23	94	43
Frankford	4	2.6	14	96	61
Hagues Reach	3	3.6	20	84	64
Hanna Chute	1	1.4	8	83	65
Healey Falls	3	11.8	72	96	70
High Falls	3	2.7	15	89	63
Lakefield	1	1.8	7	81	47
McVittie	2	2.8	11	97	47
Merrickville	2	1.7	6	94	39
Meyersberg	3	5.2	34	85	75
Nipissing	2	1.8	9	100	58
Ragged Rapids	2	8.3	40	71	55
Ranney Falls	3	10.4	52	87	57
Seymour	5	5.7	32	100	65
Sidney	4	4.4	25	98	66
Sills Island	2	1.8	9	109	54
South Falls	3	5.0	26	102	60
Stinson	2	5.4	23	84	49
Trethewey Falls	1	1.8	9	80	60
TOTAL	65	119.8	607	87	58

NUMBER OF DAMS IN DIVISION 66

Total Capacity (MW)	**6,943**
Average Energy (TWh)	**34.7**
Total Number of Plants	**65**
Total Number of Dams	**231**
Avg. Age of Plants(yr)	**70**
Number of Units	**230**

ONTARIO POWER GENERATION

"Portfolio Approach" to Asset Management

- Large portfolio of Hydro stations/units of varying vintage, technology and design makes it a challenge to prioritize maintenance and investments
- Portfolio of hydroelectric assets classified into 5 asset classes:
  1) Flagship
  2) Workhorse
  3) Middle of the Pack
  4) Small Plants
  5) Marginal Plants
- Stations in each asset class have similar characteristics/attributes & priorities.
- Provides asset management framework for:
  1) Determination of business priorities
  2) Assignment of risk tolerance
  3) Allocation of investment resources
  4) Determination of maintenance priorities (LEM)
- Economic value vs risk was used to classify stations into each asset class (risks include operational/environmental, condition, future investment, etc)

Prioritization Matrix - Projects and Maintenance Activities

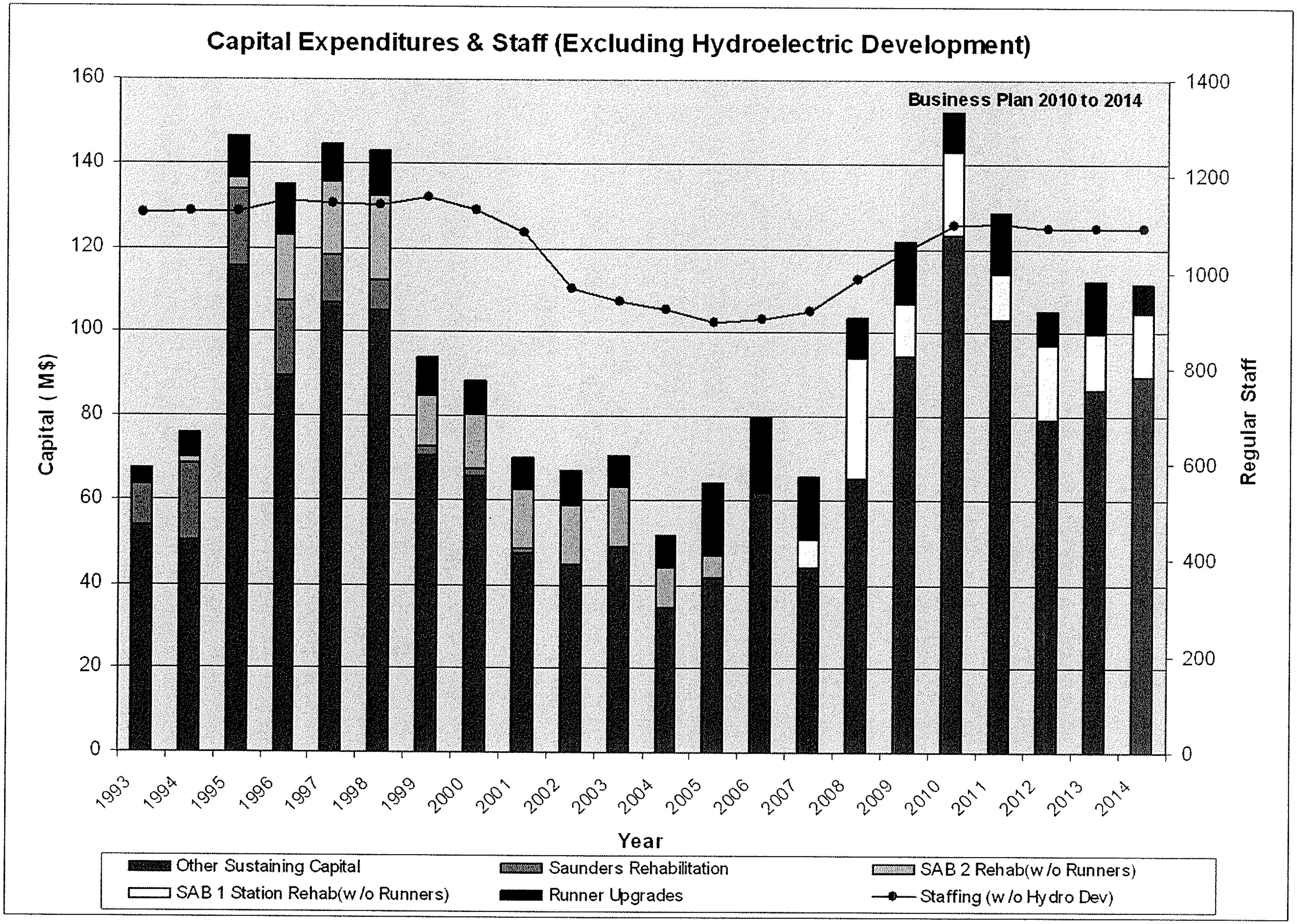
		Business Objectives (Work Categories)				
		Regulatory and Obligations (See Note 2)	Maintain Condition (MC)			Value Enhancing or Improvement
Asset Class	**Stations**		Asset Protection	Production	Non-production	
Flagship	SAB II, R.H. Saunders, Des Joachims, SAB 1	1	2	3	8	NPV, IRR & PAYBACK
Workhorse	Abitibi Canyon, DeCew NF23, Otto Holden, Otter Rapids, Pine Portage, Lower Notch, Kipling, Chenaux, Harmon, Little Long, Mountain Chute, SAB PGS, Caribou Falls, Stewartville, Whitedog, Silver Falls, Aguasabon	1	2	4	9	NPV, IRR & PAYBACK PERIOD
Middle of the Pack	Barrett Chute, Chats Falls, Alexander, Manitou Falls, Cameron Falls, Smoky Falls, Arnprior, Lac Seul, Kakabeka Falls, DeCew ND1, Ear Falls	1	2	5	10	NPV, IRR & PAYBACK PERIOD
Small Plants	Healey Falls, Big Chute, Ragged Rapids, Matabitchuan, Ranney Falls, Big Eddy, Sidney, Meyersberg, Seymour, South Falls, Crystal Falls, Indian Chute, Eugenia, Frankford, Trethewey Falls, Hagues Reach, High Falls, Hanna Chute, Sills Island, Auburn, Stinson, McVittie, Coniston, Merrickville, Lakefield	1	6	7	13	NPV, IRR & PAYBACK PERIOD
Marginal	Hound Chute, Calabogie, Wawaitin, Lower Sturgeon, Sandy Falls, Bingham Chute, Elliott Chute, Nipissing	1	11	12	14	NPV, IRR & PAYBACK PERIOD

1. Projects are assigned a priority in the Work Program Catalogue/Project Listing by applying this matrix in order to establish the relative importance of projects.
2. Regulatory/Obligations category includes expenditures required to satisfy contractual obligations, dam safety requirements, health and safety regulations, environmental regulations, and corporate policy. It is expected that all projects in this category will be funded or corrective action be taken.
3. Value enhancing or Performance Improvement projects, are to be assessed on an individual basis and must meet corporate financial guidelines.
4. Refer to the " Business Objectives/Work Categories - Definitions" for a description of what is included in each category.
5. Plants highlighted in red are being redeveloped.

ONTARIO POWER GENERATION

OPG Confidential

Capital Investments (Past, Present & Future)



Hydro Revenue, Cost, Staffing and Performance Summary

HYDRO TOTAL	2009 Forecast	2010	2011	2012	2013	2014
Energy TW.h	**36**	**34.1**	**34.4**	**33.8**	**34.4**	**36.0**
Total Revenue (M$)	[redacted]					
OM&A (M$)	[redacted]					
- Base	[redacted]					
- Projects (Totals from project listings)	[redacted]					
Capital & MFA (M$)	[redacted]					
- MFA	[redacted]					
- Projects (Totals from project listings)	[redacted]					
Total Regular Staff at YE	**1077**	**1138**	**1144**	**1130**	**1131**	**1132**
- PWU	697	729	733	720	723	722
- Society	285	306	307	306	304	306
- Management Group	95	103	104	104	104	104
Temporary Staff FTEs	**12**	**16**	**16**	**16**	**16**	**16**
Fuel/GRC & Other Water Rentals (M$)	**365**	**353**	**358**	**357**	**353**	**347**
Total Gross Labour ($M)	**145**	**154**	**161**	**169**	**173**	**179**
- Total Gross Regular	143	152	159	167	171	177
- Total Gross Temporary & Other	2	2	2	2	2	2
- Overtime	7	7	8	8	8	9
- Overtime (% of Gross labour)	5	4.9	4.9	4.9	4.9	5.0
Availability Factor %	**93.1**	**91.0**	**92.4**	**92.6**	**92.3**	**92.8**
Equivalent Forced Outage Rate (EFOR) %	1.5	1.5	1.5	1.5	1.5	1.5
Scheduled Outage Factor (SOF) %	5.7	7.8	6.4	6.2	6.5	6.0
Incapability Factor %	6.9	9.0	7.6	7.4	7.7	7.2
OM&A UEC ($/MW.h)	[redacted]					
FUEC ($/MW.h) (GRC+Water Rentals)	[redacted]					
PUEC ($/MW.h) (Operations)	[redacted]					
Contribution Margin (M$)	[redacted]					
Capacity (MW)	**6943**	**6995**	**7000**	**6966**	**7228**	**7484**

OM&A And Capital - Year Over Year Changes (2009 to 2010)

[redacted]

Capacity Changes During Planning Period

Hydro Capacity Summary	2009	2010	2011	2012	2013	2014	Change (2010 to 2014)
TOTAL CAPACITY AT BEGINNING OF YEAR (MW)	6,961	6,943	6,996	7,000	6,966	7,228	
Runner Upgrade Program	11.2	12.6	4.4	18.8	18.0	12.1	65.9
SAB 1 G7 Conversion (25 Cycle to 60 Cycle-does not incl. runner upgrade portion)	54.6						0.0
SAB 1 (Decommissioning of 25 cycle system - G1 & G2)	-92.0						0.0
Lake Gibson	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Upper Mattagami Redevelopment	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Sandy Falls	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Lower Sturgeon	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Wawaitin	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Hound Chute	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Lower Mattagami Redevelopment	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Little Long	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Harmon	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Kipling	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Smoky Falls	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Mattagami Lake Dam	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Newpost Creek	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Healey Falls	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Ranney Falls	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Lac Seul GS	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Long Lake	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Little Jackfish	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Lake Gibson	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
South Falls	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
TOTAL CAPACITY AT END OF YEAR (MW)	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]

Energy Production Plan (Impacts of Surplus Baseload Generation)

Business Plan 2010-2014 Energy Production Forecast with SBG

PLANT GROUP	2010 TWh	2011 TWh	2012 TWh	2013 TWh	2014 TWh
Niagara Plant Group Total	12.99	13.23	13.21	13.27	14.14
Group SBG	0.18	0.46	0.80	0.34	0.75
Niagara PG Adjusted SBG Group Total	12.81	12.77	12.41	12.93	13.39
OSPG Group Total	12.56	12.61	12.61	12.53	12.56
Group SBG	0.00	0.02	0.05	0.02	0.03
OSPG Adjusted SBG Group Total	12.56	12.60	12.55	12.51	12.54
Northeast Plant Group Total	[redacted]				
Group SBG					
NEPG Adjusted SBG Group Total					
Northwest Plant Group Total					
Group SBG					
NWPG Adjusted SBG Group Total					
Central Hydro Plant Group Total					
Group SBG					
CHPG Adjusted SBG Group Total					
HYDROELECTRIC TOTAL					
Total SBG					
ADJUSTED SBG HYDROELECTRIC TOTAL					

[redacted]

Appendix B
Regulated Asset Information

Hydro Regulated Asset Performance & Cost Summary

Regulated Hydro (Includes Hydro Central Office Allocations)	2009 Forecast	2010	2011	2012	2013	2014
Energy TW.h	**19.5**	**19.3**	**19.4**	**19.0**	**19.6**	**20.3**
Total Revenue (M$)	**733**	**713**	**741**	**730**	**804**	**837**
OM&A (M$)	**67**	**67**	**78**	**72**	**71**	**76**
- Base	59.7	61.9	68.7	62.2	63.7	67.0
- Projects (Totals from project listings)	6.9	5.3	9.7	10.0	7.7	8.7
Capital & MFA (M$)	**41**	**54**	**40**	**37**	**32**	**29**
- MFA	0.2	0.2	1.2	0.3	0.3	0.3
- Projects (Totals from project listings)	40.5	53.3	38.7	36.5	31.6	28.4
Total Regular Staff at YE	**313**	**319**	**318**	**307**	**309**	**309**
Temporary Staff FTEs	**0.7**	**0.7**	**0.7**	**0.7**	**0.7**	**0.7**
Fuel/GRC & Other Water Rentals (M$)	**263**	**266**	**269**	**269**	**267**	**260**
Total Gross Labour ($M)	**42**	**43**	**45**	**47**	**47**	**49**
- Total Gross Regular	40.9	42.3	44.3	46.2	46.2	48.3
- Total Gross Temporary & Other	0.8	0.3	0.3	0.3	0.4	0.4
- Overtime	2.2	2.2	2.4	2.5	2.5	2.6
- Overtime (% of Gross labour)	**5.4**	**5.2**	**5.3**	**5.4**	**5.4**	**5.3**
Availability Factor %	**93.8**	**90.3**	**90.8**	**90.7**	**91.7**	**92.0**
Equivalent Forced Outage Rate (EFOR) %	**1.4**	**1.3**	**1.3**	**1.3**	**1.3**	**1.3**
Scheduled Outage Factor (SOF) %	5.1	8.7	8.1	8.3	7.3	6.9
Incapability Factor %	6.2	9.7	9.2	9.3	8.3	8.0
OM&A UEC ($/MW.h)	**3.4**	**3.5**	**4.0**	**3.8**	**3.6**	**3.7**
FUEC ($/MW.h) (GRC+Water Rentals)	**13.5**	**13.7**	**13.9**	**14.1**	**13.6**	**12.8**
PUEC ($/MW.h)	**16.9**	**17.2**	**17.9**	**17.9**	**17.3**	**16.5**
Contribution Margin (M$)	**403**	**380**	**393**	**390**	**465**	**502**
Capacity (MW)	**3302**	**3312**	**3312**	**3315**	**3320**	**3322**

Niagara Plant Group

Niagara Plant Group	2009 Forecast	2010	2011	2012	2013	2014
Energy TW.h	**12.4**	**12.4**	**12.4**	**12.1**	**12.7**	**13.4**
Total Revenue (M$)	**465**	**457**	**474**	**463**	**519**	**551**
OM&A (M$)	**45.8**	**44.4**	**53.4**	**46.3**	**47.7**	**50.1**
- Base	40.6	40.3	46.7	40.3	41.4	43.9
- Projects	5.2	4.0	6.7	6.0	6.3	6.3
Capital & MFA (M$)	**28.0**	**36.2**	**30.7**	**30.9**	**25.3**	**25.2**
- MFA	0.2	0.2	1.2	0.3	0.3	0.3
- Projects	27.8	36.0	29.5	30.6	25.0	24.9
Total Regular Staff at YE	**243**	**251**	**250**	**239**	**241**	**241**
Temporary Staff FTEs	**0**	**0**	**0**	**0**	**0**	**0**
GRC & Other Water Rentals (M$)	**167**	**172**	**175**	**174**	**173**	**166**
Total Gross Labour ($M)	**33**	**34**	**35**	**37**	**37**	**38**
- Total Gross Regular	31.9	33.4	35.0	36.5	36.2	37.9
- Total Gross Temporary & Other	0.7	0.3	0.3	0.3	0.3	0.4
- Overtime	1.9	1.9	2.0	2.1	2.2	2.2
- Overtime (% of Gross labour)	**6.0**	**5.7**	**5.8**	**5.8**	**6.0**	**5.8**
Availability Factor %	**89.5**	**88.2**	**89.5**	**88.3**	**90.0**	**89.1**
Equivalent Forced Outage Rate (EFOR) %	1.5	1.8	1.8	1.8	1.8	1.8
Scheduled Outage Factor (SOF) %	9.3	9.9	9.0	10.2	8.5	9.5
Incapability Factor %	10.5	11.8	10.5	11.7	10.0	10.9
OM&A UEC ($/MW.h)	**3.7**	**3.6**	**4.3**	**3.8**	**3.8**	**3.7**
GRC UEC ($/MW.h) (GRC+Water Rentals)	**13.5**	**13.9**	**14.1**	**14.4**	**13.7**	**12.4**
PUEC ($/MW.h)	**17.2**	**17.4**	**18.4**	**18.3**	**17.5**	**16.1**
Capacity (MW)	**2257**	**2267**	**2267**	**2270**	**2275**	**2277**

Key Programs & Issues

- Major rehabilitation/upgrade of SAB1 G9 in 2009/2010, G10 in 2013, G3 in 2012.
- Civil rehabilitation projects for SAB1 continue through planning period (e.g. concrete restoration, roof replacement, tailrace bridge and piers, etc.)
- DeCew Falls ND1 G8 scheduled for overhaul in 2011. Penstock replacement 2009 to 2011. Station Protection and control upgrades scheduled for 2011/2012.
- SAB PGS Unit rehabilitation on G2-5 planned for 2011-2014. PGS Unit transformers also scheduled for replacement 2009-11. Unit breakers and governors planned for replacement 2011-13.
- SAB 2 Station Service System Replacement 2010/2011 and Governor system upgrade 2013/2014
- Development and implementation of Niagara Bridge program including maintenance, divestment and investment ongoing. Divestiture of four bridges being pursued.
- Optimization Initiative – Niagara Optimization Working Group
- Continue to build and improve public franchise.
- Manage risks of equipment failures:
  - PGS Reliability & Turbine Leakage.
  - PGS Transformer failure. Replacement planned in 2010/11.

Saunders GS

Saunders GS (includes OSPG Support Costs)	2009 Forecast	2010	2011	2012	2013	2014
Energy TW.h	**7.1**	**6.9**	**7.0**	**7.0**	**7.0**	**7.0**
Total Revenue (M$)	**268**	**255**	**267**	**267**	**285**	**286**
OM&A (M$)	**16.2**	**13.6**	**16.0**	**17.6**	**15.4**	**16.7**
- Base	14.6	12.4	13.1	13.6	14.0	14.3
- Projects (Totals from project listings)	1.7	1.2	3.0	4.0	1.4	2.4
Capital & MFA (M$)	**12.7**	**17.3**	**9.2**	**5.9**	**6.6**	**3.4**
- MFA	0.0	0.0	0.0	0.0	0.0	0.0
- Projects (Totals from project listings)	12.7	17.3	9.2	5.9	6.6	3.4
Total Regular Staff at YE (Saunders Only)	**71**	**68**	**68**	**68**	**68**	**68**
Temporary Staff FTEs	**0.0**	**1**	**1**	**1**	**1**	**1**
GRC & Other Water Rentals (M$)	**96**	**94**	**94**	**94**	**94**	**94**
Total Gross Labour (M$)	**9**	**10**	**10**	**11**	**11**	**11**
- Total Gross Regular	8.6	9.8	10.2	10.7	11.0	11.4
- Total Gross Temporary & Other	0.1	0.0	0.0	0.0	0.0	0.0
- Overtime	0.4	0.3	0.3	0.3	0.4	0.4
- Overtime (% of Gross labour)	**4.2**	**3.2**	**3.1**	**3.1**	**3.2**	**3.2**
Availability Factor %	95.5	93.7	94.2	96.1	96.3	98.9
Equivalent Forced Outage Rate (EFOR) %	1.1	0.4	0.4	0.4	0.4	0.4
Scheduled Outage Factor (SOF) %	3.6	6.0	5.5	3.6	3.4	0.8
Incapability Factor %	4.5	6.3	5.8	3.9	3.7	1.1
OM&A UEC ($/MW.h)	**2.3**	**2.0**	**2.3**	**2.5**	**2.2**	**2.4**
FUEC ($/MW.h)	**13.6**	**13.5**	**13.5**	**13.5**	**13.5**	**13.5**
PUEC	**15.8**	**15.5**	**15.8**	**16.1**	**15.7**	**15.9**
Capacity (MW)	**1045**	**1045**	**1045**	**1045**	**1045**	**1045**

Key Programs & Issues

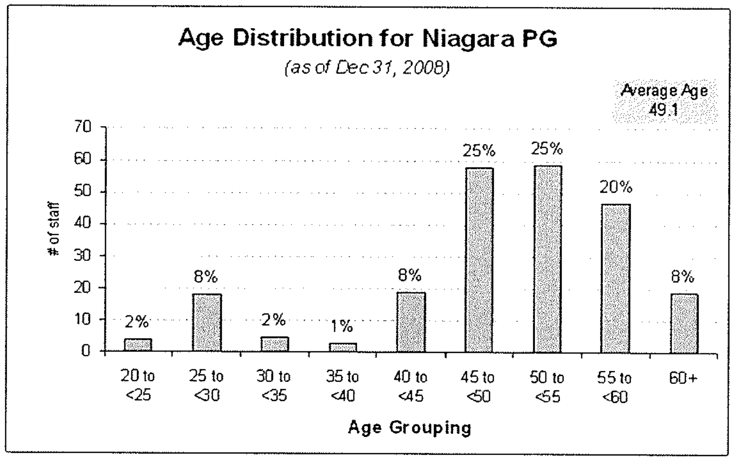
- Protection and Controls replacement project (2009 to 2011).
- St. Lawrence Power Development Visitor Centre to be completed in 2010 (part of Saunders GS capital costs)
- Barnhardt Island Bridge Repainting – Joint Works (NYPA Project) in 2012
- Ice Sluices Deck and Steel Support Beam Rehabilitation in 2011
- NYPA Joint Works including the Barnhardt Island Bridge repairs, inspection of Long Sault Dam and crane lead abatement totals $5.5M

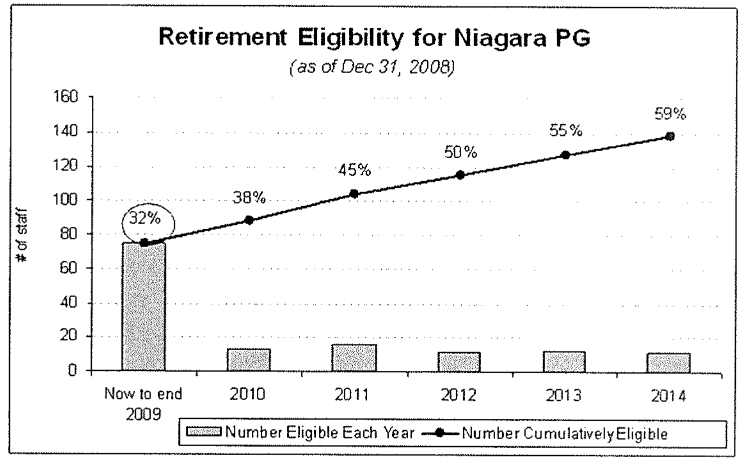
Issues/Risks:

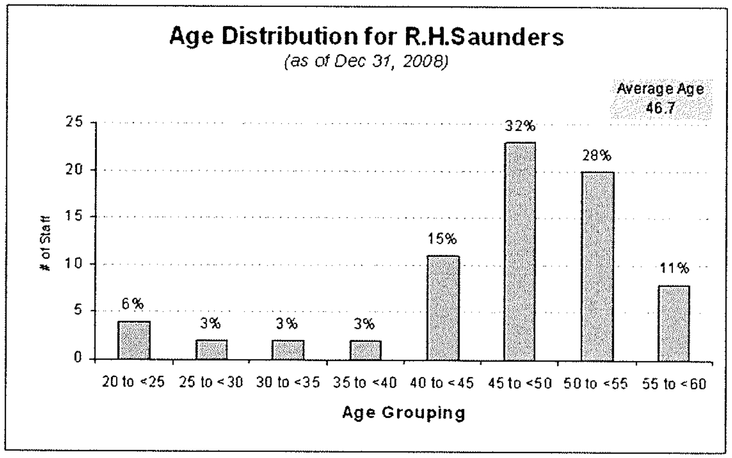
- American eel mitigation funding included at ($540-$685k per year). Improved Eel Ladder was installed in 2009.
- Saunders concrete growth rate faster than expected. Monitoring continues. Could require re-slotting in 3 to 8 yrs.

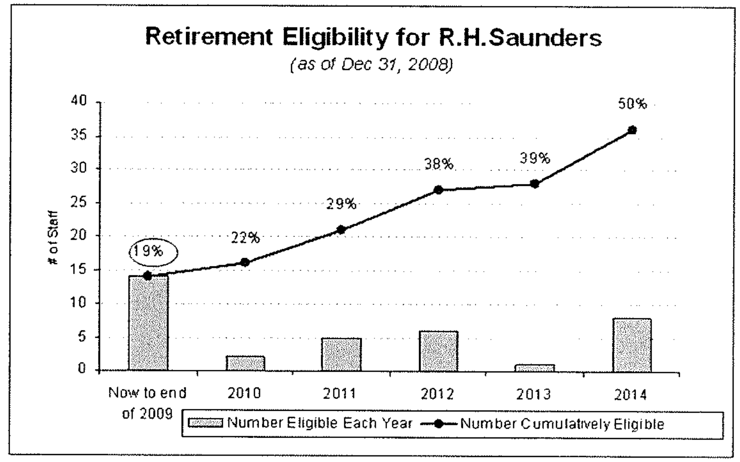
Human Resources – Demographics (Regulated Plants)

- 32% of Niagara staff are eligible to retire by end of 2009 and 59% by end of 2014. Demographics and retirement eligibility at R.H. Saunders are better than Niagara, but still an issue.









- Due to the staff shortages in engineering / project support and some trades areas, it has been a challenge to complete the planned 2009 work program in Niagara.
- To address the demographic issue, Niagara is adding apprentices and operating trainees, as well as engineers and contract monitors. The apprentices will overlap with experienced trades staff for training and knowledge transfer. Staff complement at Niagara will increase from 243 in 2009 to 250 in 2011, and decline to 241 in 2013/4.

TAB 6

ONTARIO POWER GENERATION

Nuclear Operations
2010-2014 Business Plan

OPG Board Of Directors
November 19, 2009

Accountability at OPG means we deliver committed actions that achieve the desired results.
Say it, Do it

Wayne Robbins
Chief Nuclear Officer

ONTARIO POWER GENERATION

Executive Summary

OPG Nuclear will continue to deliver on its mission of proudly generating clean, safe, low-cost electricity through dependable performance. This business plan outlines Nuclear's operational and financial performance targets for the next 5 years and the plan to meet this commitment.

With the use of external benchmarking, aggressive yet balanced targets have been set by the CNO under the 4 Cornerstones areas of Safety, Reliability, Human Performance and Value for Money:

- Nuclear will continue to target better than industry Safety performance.
- Reliability metrics currently in the lowest quartile will improve significantly, while maintaining top quartile performance in others.
- Plan over plan costs will be reduced by $423 million (or $293 million with investment in Pickering B Continued Operations).
- Generation will increase in 2010 to 2013 by .5 TWh (reduced by 2.6 TWh with Continued Operations).
- This plan incorporates net staff reductions of 791 from 2009 to 2014.

Using a fleet-wide peer team approach, Nuclear has developed an action plan to address the gaps between targets and current performance levels. 7 key initiatives have been identified that will drive significant performance improvement.

ONTARIO POWER GENERATION

Planning Assumptions

- Pickering B's investment in Continued Operations will extend the life of Units 5 and 6 to 2018 and Units 7 and 8 to 2020. Investment in Continued Operations is included in this business plan.
- Pickering A derate of 3% concludes in 2009 and the plant's end of life is consistent with Pickering B's end of life.
- Darlington begins refurbishment in October 2016.
- The 5 year generation plan does not assume demand will be effected by market conditions or future stakeholder decisions.
- Project portfolio investments align with end of life assumptions at all 3 sites.

ONTARIO POWER GENERATION

Nuclear Cornerstones for Excellence

Safety Cornerstone

- Strong Nuclear Safety Culture
- Zero Injuries
- ALARA
- Environmental Stewardship

Human Performance/ Leadership Cornerstone

- Event-Free Behaviours
- Performance Improvement
- Training to Improve Performance
- Model of Accountability

PICTURE OF EXCELLENCE

• Zero Injuries • No Events • Breaker to Breaker Runs • Low Cost •

TO BE THE BEST PERFORMING NUCLEAR FLEET IN THE WORLD

Reliability Cornerstone

- System Health Focused
- Preventive Maintenance Bias
- Low Backlogs
- Strategic Investments

Value for Money Cornerstone

- Simplified Processes
- Effective Resource Utilization
- Excellent Outage Performance
- Excellence in Project Execution

ACCOUNTABILITY
Say it. Do it.

TEAMWORK, COMMITMENT, INTEGRITY, RESPECT

ONTARIO POWER GENERATION

Gap Based Business Planning Methodology

Nuclear Cornerstones

Benchmarking	Target Setting	Closing the Gap	Resource Planning
✓ 2008 Performance Benchmarks	✓ Strengths & Challenges ✓ Major Program Areas/ Objectives ✓ 5 year Generation Targets ✓ 2014 Performance Targets	✓ Reliability Targets and Initiatives ✓ Safety Targets and Initiatives ✓ Human Performance Targets and Initiatives ✓ Value for Money Targets and Initiatives	✓ Cost Plan ✓ Staff Plan ✓ Investment Plan ✓ Risks to the Plan

ONTARIO POWER GENERATION

2008 Performance Benchmarks

Metric	NPI Max	Best Quartile *	Median *	Pickering A	Pickering B	Darlington
Safety						
All Injury Rate		[redacted]	[redacted]	0.73	0.96	1.04
2-Year Industrial Safety Accident Rate	0.20	0.05	0.09	0.14	0.07	0.04
2-Year Collective Radiation Exposure (man-rem per unit)	80.00	62.15	81.84	44.2	95.81	72.83
Airborne Tritium (TBq) Emissions per Unit		48.0	101.0	101.0	50.7	40.0
Fuel Reliability (microcuries per gram)	0.000500	0.000001	0.000165	0.00059	0.00159	0.00025
2-Year Reactor Trip Rate (# per 7,000 hrs)	0.50	0.00	0.33	1.22	0.26	0.00
3-Year Auxiliary Feedwater System Unavailability	0.0200	0.0014	0.0020	0.0119	0.0040	0.0017
3-Year Emergency AC Power Unavailability	0.0250	0.0024	0.0076	0.0081	0.0091	0.0020
3-Year High Pressure Safety Injection Unavailability	0.0200	0.0001	0.0037	0.0012	0.0001	0.0001
Reliability						
WANO NPI (Index)		96.19	62.46	60.84	60.93	95.67
2-Year Forced Loss Rate (%)	1.00	0.68	3.79	37.90	18.19	0.93
2-Year Unit Capability Factor (%)	92.00	90.97	84.31	56.8	73.17	91.99
2-Year Chemistry Performance Indicator (Index)	1.01	1.00	1.01	1.13	1.25	1.00
1-Year Online Elective Maintenance (work orders/unit)		218	278	425	695	313
1-Year Online Corrective Maintenance (work orders/unit)		4	7	14	28	8
Value for Money						
3-Year Total Generating Costs per MWh ($/Net MWh)		28.66	32.31	92.27	58.68	30.08
3-Year Non-Fuel Operating Costs per MWh ($/Net MWh)		18.06	21.28	82.62	50.95	25.10
3-Year Fuel Costs per MWh ($/Net MWh)		5.02	5.37	2.64	2.68	2.62
3-Year Capital Costs per MW DER**($/MW)		32.79	46.22	32.07	32.44	18.79

*Panel used for WANO quartile and median data was All COG CANDU
**DER - Design Electrical Rating

Green = best quartile performance/max NPI points achieved if applicable
White = 2nd quartile performance
Yellow = 3rd quartile performance
Red = lowest quartile performance

Safety

- All 3 nuclear plants perform well against industry Safety metrics.
- Pickering A had 2 reactor trips in 2008 with no occurrences in 2009.
- Pickering B has seen improvement in both Collective Radiation Exposure and Fuel Reliability since 2008.

Reliability

- Reliability suffered in 2008 due to a high number of forced outages caused by equipment and human performance events at the Pickering stations.
- Darlington's reliability performance is excellent. Darlington has also made considerable strides towards reducing backlogs from 2004 to 2008.

Value for Money

- Fuel costs are at industry best quartile due to technology differences.
- Capital costs are difficult to compare due to OPG's higher capitalization threshold; Total Generation Costs is a better indicator of performance as it is independent of these differences.
- Non-Fuel Costs per MWh for the Pickering stations are a factor of lower generation and higher operating costs relative to industry benchmarks.

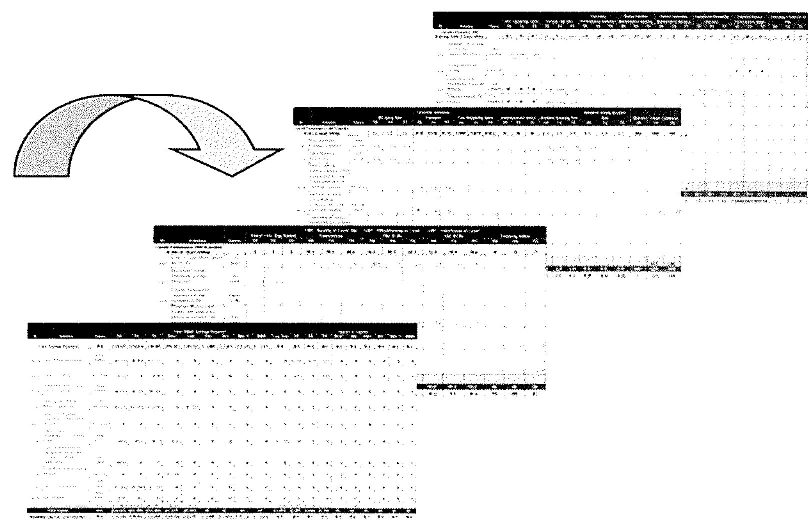
ONTARIO POWER GENERATION

2014 Target Setting and Closing the Gap

- Benchmarking data was used to set top down targets for the next 5 years.
- By considering OPG Nuclear's strengths and challenges as well as its major focus areas and objectives, a solid action plan was developed to address the gaps between current and targeted performance.
- Over a period of 8-10 weeks, fleet-wide peer teams developed initiatives that closed the gaps.
- Through prioritization and resource management, an initial list of 150 initiatives was narrowed to 33 (listed below by cornerstone). 7 of these initiatives (bolded below and detailed in the supporting materials section) are expected to bring stepped improvement to nuclear operations.
- Each initiative was quantified as to its impact on the gap between current and targeted performance.

Safety 1. IS-01 – Musculoskeletal Disorder Prevention 2. RP-26 – Area Mapping 3. EN-03 – Improve Fuel Reliability Index 4. RP-10 - Detritiation of Reactor PHT 5. IS-02 – Safety Behaviours Assessment 6. IS-03 – Review Incident Counting Practices 7. IS-04 – Constrain Training Qualifications 8. RP-05 – Optimize Reactor Face Shielding 9. RP-09 – Improve Fuel Machine Filtration	**Human Performance** 1. **OP-05 – Human Performance Improvement Program (contains OP-01)** 2. PI-01 – CAP Improvement Program 3. PI-02 – Implement Human Performance Rapid Response 4. PI-03 – CAP is Core 5. TR-02 – Computer Based Training Increase 6. TR-04 – Initial Authorization Training Program
Reliability 1. **EN-01 – Work Order Readiness (contains MA-02 and TR-07)** 2. **OU-02 – Outage Improvement Strategy (contains OU-01, OU-02, OU-04, OU-05, OU-06, OU-07, TR-06)** 3. **ER-01 – Standard Equipment Reliability Program** 4. **ER-02 – Improve PM Program** 5. ER-03 – Critical Spares/Obsolescence 6. MA-01 – Improve FIN Effectiveness 7. OP-02 – Work Management Performance Improvement Plan 8. MA-07 – Leverage DN OEMB Process 9. WM-01 – Backlog Reclassification	**Value for Money** 1. **EN-02 – Engineering Value for Money** 2. **MA-08 – Day Based Maintenance** 3. MS-02 – Inventory Management 4. MS-03 – Strategic Sourcing 5. MA-04 – Centralized Measurement and Test Equipment (give to facilities) 6. MA-06 – Maintenance "Helpers" 7. MA-09 – Single Source Laundry (Give to M&S) 8. FS-03 – Offer Fire Training (Revenue Opportunity) 9. FP-02 – Labour Cost Reduction

Bold initiatives are the identified high priority initiatives



ONTARIO POWER GENERATION

Major Objectives/Focus Areas

- Implement key fleet-wide and site specific initiatives to drive and sustain significant performance improvements:
    - Execute Continued Operations work at Pickering B to sustain base load generation until 2020 and during the refurbishment of Darlington.
    - Continue to improve plant reliability at Pickering A to achieve its potential.
    - Improve outage execution (readiness, scope, duration and costs) to make our plants more effective and efficient.
    - Improve inventory management and costs through better planning and getting work ready.
- Combine Pickering A and Pickering B into one station to leverage fleet advantages and capitalize on economies of scale.
- Execute Pickering Vacuum Building Outage successfully in terms of safety, scope, duration and costs.
- Implement accountability model across Nuclear through leadership courage, leadership presence and management effectiveness.

ONTARIO POWER GENERATION

Generation Plan

		2010	2011	2012	2013	2014	Delta
TWh	2010-2014 OPG Submission	46.2	48.9	50.0	48.1	49.3	
	Additional Site performance target	2	2	2	2	2	
	2010-2014 Nuclear Submission	48.1	50.9	52.0	50.1	51.3	
	2009-2013 Nuclear BP	48.6	52.1	52.8	50.2	0.0	
	Variance	***-0.5***	***-1.3***	***-0.7***	***-0.2***	***N/A***	***-2.6***
	Variance to 2009-14 Nuclear BP	***-0.2***	***0.1***	***-0.1***	***0.7***		***0.5***
	Variance - Continued Ops Impact	***-0.3***	***-1.3***	***-0.7***	***-0.9***		***-3.2***
Planned Outage	2010-2014 Nuclear Submission	554.8	372.3	312.5	400.2	364.8	
	2009-2013 Nuclear BP	513.8	267.3	249.5	373.2		
	Variance	***41.0***	***105.0***	***63.0***	***27.0***	***N/A***	***236.0***
	Variance to 2009-14 Nuclear BP	***13.0***	***-6.0***	***7.0***	***-44.0***		***-30.0***
	Variance - Continued Ops Impact	***28.0***	***111.0***	***56.0***	***71.0***		***266.0***
Forced Loss Rate	2010-2014 Nuclear Submission	3.5%	3.2%	2.8%	2.8%	2.5%	
	2009-2013 Nuclear BP	3.6%	3.2%	2.8%	2.8%		*(average)*
	Variance	***0.0%***	***0.0%***	***0.0%***	***0.0%***	***N/A***	***0.0%***
	Variance to 2009-14 Nuclear BP	***0.0%***	***0.0%***	***0.0%***	***0.0%***		***0.0%***
	Variance - Continued Ops Impact	***0.0%***	***0.0%***	***0.0%***	***0.0%***		***0.0%***

- Reduction of 30 planned outage days contributes to a plan-over-plan generation increase (excluding continued operations) of 0.5 TWh.
- Investment in Continued Operations requires an additional 266 planned outage days resulting in a 3.2 TWh loss, but translates into a long-term benefit to base load generation for Ontario in the next decade.
- 2010 - additional planned outage days are required for replacing vacuum building risers; 2012 - additional days are required at Pickering B for feeder replacements; all additional days are mitigated by reduced scope required under Life Cycle Management Plans and weld overlay implementation at Darlington in 2012.

Filed: 2010-05-26
EB-2010-0008
Exhibit F2-1-1
Attachment 1

ONTARIO POWER GENERATION

5 Year Performance Plan

Metric	2008 Pickering A	2008 Pickering B	2008 Darlington	2014 Pickering A	2014 Pickering B	2014 Darlington
Safety						
All Injury Rate	0.73	0.96	1.04	1.2	1.2	1.2
2-Year Industrial Safety Accident Rate	0.14	0.07	0.04	0.15	0.15	0.15
2-Year Collective Radiation Exposure (man-rem per unit)	44.2	95.81	72.83	125	82	66
Airborne Tritium (TBq) Emissions per Unit	101.0	50.7	40.0	81.1	36.5	27.0
Fuel Reliability (microcuries per gram)	0.00059	0.00159	0.00025	0.0005	0.0005	0.0005
2-Year Reactor Trip Rate (# per 7,000 hrs)	1.22	0.26	0.00	0.50	0.50	0.50
3-Year Auxiliary Feedwater System Unavailability	0.0119	0.0040	0.0017	0.0200	0.0200	0.0200
3-Year Emergency AC Power Unavailability	0.0081	0.0091	0.0020	0.0250	0.0250	0.0250
3-Year High Pressure Safety Injection Unavailability	0.0012	0.0001	0.0001	0.0200	0.0200	0.0200
Reliability						
WANO NPI (Index)	60.84	60.93	95.67	70.9	81.3	99.1
2-Year Forced Loss Rate (%)	37.90	18.19	0.93	4.00	4.00	1.25
2-Year Unit Capability Factor (%)	56.6	73.17	91.99	84.3	81	93.3
2-Year Chemistry Performance Indicator (Index)	1.13	1.25	1.00	1.04	1.04	1.01
1-Year Online Elective Maintenance (work orders/unit)	425	695	313	278	300	214
1-Year Online Corrective Maintenance (work orders/unit)	14	28	8	9	15	4
Value for Money						
3-Year Total Generating Costs per MWh ($/Net MWh)	92.27	58.68	30.08	70.81	64.80	36.75
3-Year Non-Fuel Operating Costs per MWh ($/Net MWh)	82.62	50.95	25.10	60.07	52.47	28.82
3-Year Fuel Costs per MWh ($/Net MWh)	2.64	2.68	2.62	6.01	7.45	5.43
3-Year Capital Costs per MW DER**($/MW)	32.07	32.44	18.79	34.73	34.67	20.37

- Continue to lead industry in overall conventional and nuclear safety performance.
- Increase fuel reliability.
- Strengthen equipment reliability and human performance to reduce reactor trips.
- Focus on work order readiness, reducing backlogs, improving maintenance effectiveness, and work management.
- Reduce base and outage operating costs to improve fleet-wide total generating costs per MWh. Darlington becomes industry leader in costs. Pickering A and B narrow gaps.

2014 WANO indicator targets are set to provide maximum NPI points only. 2014 Cost Targets are above 2008 due to expected cost escalation of Median and Best Quartile Costs per EUCG panel historical trend. 2010-2014 values represent annual targets. Actuals will be calculated based on rolling average definitions.

ONTARIO POWER GENERATION

Safety Cornerstone
Targets and Gap Closure through Initiatives

ID	Initiative	Owner	All Injury Rate			Collective Radiation Exposure			Fuel Reliability Index			Environmental Index			Accident Severity Rate			Industrial Safety Accident Rate			Airborne Tritium Emissions		
			DN	PA	PB	DN	PA	PB	DN	PA	PB	DN	PA	PB	DN	PA	PB	DN	PA	PB	DN	PA	PB
Current Performance (2009 Projection at date of Target Setting)			1.3	1.3	1.3	78.50	147.00	103.45	0.0005	0.0028	0.0012	85	80	80	4.75	4.75	4.75	0.15	0.15	0.15	4000	12000	7000
IS-01	Musculoskeletal Disorders Prevention	Greg Jackson	0.10	0.10	0.10										0.64	0.64	0.64	0.04	0.03	0.04			
IS-02	Safety Behaviours Assessment	Greg Jackson	0.10	0.10	0.10										0.64	0.64	0.64	0.04	0.03	0.04			
RP-05	Reduce collective radiation exposures (CRE) during reactor face work through optimization of reactor face shielding	Tom Wong				6.40	15.80	5.40															
RP-10	Detritiation of Reactor PHT & Moderator Systems to reduce the source term radiation	Tom Van Horne				✓	2.00	2.00														525	1050
RP-09	Optimization of Fueling Machine Filtration at Sites to minimize Co-59 injection and buildup of Co-60	John Pinnegar				1.90	5.90	1.00															
EN-03	Improved Fuel Reliability Index	M. O'Neill							✓	0.0023	0.0007												
Site Contribution to Gap Closure Identified by Functional Teams						6.80	15.00	6.30				5	0	0								6125	2100
2014 TARGET			1.2	1.2	1.2	66.00	125.00	82.00	0.0005	0.0005	0.0005	80	80	80	3.30	3.30	3.30	0.15	0.15	0.15	4000	6000	5400
Remaining Gap			(0.1)	(0.1)	(0.1)	(2.60)	(16.70)	6.75	0.0000	0.0000	0.0000	(10)	0	0	0.17	0.17	0.17	(0.08)	(0.06)	(0.08)	0	(125)	(500)

✓ = impacts metric, enabler for performance but not quantified for gap closure
italics = initiative has impact in another cornerstone
Bold = Key initiative (See Appendix)

IS-03, IS-04 and RP-26 are not included in table above as planning is still under development.

ONTARIO POWER GENERATION

Reliability Cornerstone
Targets and Gap Closure through Initiatives

ID	Initiative	Owner	Unit Capability Factor			Forced Loss Rate			Chemistry Performance Indicator			Online Elective Maintenance Backlog			Online Corrective Maintenance Backlog			Equipment Reliability Indicator			Planned Outage Performance (Days)			Criticality 1 Deferral of PMs		
			DN	PA	PB	DN	PA	PB	DN	PA	PB	DN	PA	PB	DN	PA	PB	DN	PA	PB	DN	PA	PB	DN	PA	PB
Current Performance (2009 Projection at date of Target Setting)			86%	79%	87%	2.0%	11.5%	6.2%	1.01	1.08	1.10	311	425	685	8	14	28	67	45	52	171.7	106.5	135.3	7	20	15
ER-03	Implement Critical Spares and Proactive Obsolescence Program	Paul Vonhatten	0.125%	0.125%	0.125%																					
OU-02	*Outage Improvement Strategy*	*Jim Woodcroft*																			✓	✓	✓			
ER-01	**Implement a Fleet Standardized Equipment Reliability**	**Paul Vonhatten**	✓	✓	✓	0.3%	1.88%	0.8%										15.0	26.0	14.0						
ER-02	**Implement Improved PM Program**	**Paul Vonhatten**	✓	✓	✓	0.08%	0.75%	0.2%							3	5	13	7.0	11.0	6.0						
OP-05	***Human Performance Improvement Plan (Contains PI-04)***	***Granville, Henderson, Guglielmi***	✓	✓	✓	0.38%	2.70%	1.1%																		
OP-02	WM Performance Improvement	Dave Walsh										✓	✓	✓	✓	✓	✓									
MA-01	Improve FIN Team Effectiveness	Jim Whyte				✓	✓	✓				✓	52	120												
MA-07	Leverage Darlington OEMB Process Across Fleet	Chris Johnston											95	265												
EN-01	**Work Order Readiness**	**Steve Woods**										*96												* 5	*11	*11
Site Contribution to Gap Closure Identified by Functional Teams			0%	0%	0%		1.1%		0.01	0.06	0.10	0	0	0	0	0	0									
2014 TARGET			93%	84%	81%	1.25%	4.0%	4.0%	1.01	1.04	1.04	215	278	300	5	9	15	89.0	82.0	72.0	80.8	89.0	225.0	2	9	4
Remaining Gap			7%	5%	(6%)	0.0%	1.1%	0.1%	(0.01)	(0.02)	(0.04)	0	0	0	0	0	0	0.0	0.0	0.0	Commitment to Meet Plan			0	0	0

✓ = impacts metric, enabler for performance but not quantified for gap closure
italics = initiative has impact in another cornerstone
Bold = Key initiative (See Appendix)

WM-01 is not included in table above as planning is still under development.

ONTARIO POWER GENERATION

Human Performance Cornerstone
Targets and Gap Closure through Initiatives

ID	Initiative	Owner	Event Free Day Resets			CAP - Quality of Level 1&2 Evaluations			CAP - Effectiveness of Level 1&2 SCRs			CAP - Timeliness of Level 1&2 SCRs			Training Index		
			DN	PA	PB	DN	PA	PB	DN	PA	PB	DN	PA	PB	DN	PA	PB
Current Performance (2009 Projection at date of Target Setting)			8	4	8	80.0	80.0	80.0	50.0	80.0	60.0	92.0	90.0	58.0	70	70	75
PI-03	CAP is Core	Tom Smart				10.0	10.0	10.0	30.0	7.5	22.5	2.4	3.8	28.0			
PI-02	Implement Human Performance Rapid Response	Tom Smart	2	0.0	2												
OP-05	***Human Performance Improvement Plan***	***Station DOMs***	2	2	2												
PI-01	Program efficiency and quality, and additionally reduce associated FLM administrative burden	Tom Smart						1.1	10.0	2.6	7.6	0.8	1.2	9.2			
TR-02	Computer Based Training Development to Reduce Classroom Training Resources	Gord Haverluck													5.0	5.0	3.75
OU-02	**Outage Improvement Strategy**	**Jim Woodcroft**													5.0	5.0	3.75
Site Contribution to Gap Closure Identified by Functional Teams																	
2014 TARGET			**4**	**2**	**4**	**90.0**	**90.0**	**90.0**	**90.0**	**90.0**	**90.0**	**95.0**	**95.0**	**95.0**	**90**	**90**	**90**
Remaining Gap			0	0	0	0.0	0.0	(1.1)	0.0	(0.1)	(0.1)	(0.2)	0.0	(0.2)	(10)	(10)	(8)

✓ = impacts metric, enabler for performance but not quantified for gap closure
italics = initiative has impact in another cornerstone
Bold = Key initiative (See Appendix)
TR-04 included in the Value for Money slide .

ONTARIO POWER GENERATION

Value for Money Cornerstone
Targets and Gap Closure through Initiatives

ID	Initiative	Owner	Total OM&A Savings Required										Impact to Capital								
			DN	PA	PB	NP&T	E&M	PINO	NSC	IM&CS	NWM	Safety	DN	PA	PB	NP&T	E&M	PINO	NSC	IM&CS	NWM
Total 5 Yr Savings Required		N/A	$ 77,760	$ 53,000	$ 55,000	$102,953	$ 26,757	$ 1,000	$ 7,014	$ 17,733	$ 3,411	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
MA-08	**Days Based Maintenance**	**Doug Radford**	($4,323)	($8,468)	($13,125)	$0	$0	$0	$0	$0	$0	$0	$1,500	$775	$775	$0	$0	$0	$0	$0	$0
MA-04	Centralize M&TE	Jim Whyte	($788)	$0	($788)	$0	$0	$0	$0	$0	$0	$0	$350	$0	$350	$0	$0	$0	$0	$0	$0
MA-09	Implement Single Source Laundry Supplier	Doug Radford	($4,000)	($3,200)	($4,800)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
EN-02	**Engineering Value for Money Improvement**	**Fred Dermarkar**	($3,510)	($15,005)	($15,005)	$0	($5,200)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
IS-04	Safety Training Qualifications to Capability Profiles	Greg Jackson	($660)	($417)	($579)	($105)	$0	$0	$0	$0	$0	($1,743)	$0	$0	$0	$0	$0	$0	$0	$0	$0
FS-03	Revenue Opportunity by Opening the Wesleyville location to external organizations	Don Trylinski	($500)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
TR-04	Initial Authorization Training Program	Silviu Idita	$0	$0	$0	$11,498	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
FP-02	Labor Cost Reductions	Cathy Treacy	($1,900)	($1,340)	($2,100)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
RP-26	Area Mapping	Robin Manley	$100	$50	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
N/A	Summary of Other Initiatives	N/A	($17,962)	($15,609)	($18,987)	$6,582	$160					$380	$1,035	$1,035	$1,035		$0				
Estimated Savings from Initiatives			**($33,543)**	**($43,989)**	**($55,384)**	**$17,975**	**($5,040)**	**$0**	**$0**	**$0**	**$0**	**($1,363)**	**$2,885**	**$1,810**	**$2,160**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**
Gap closed in Site and Support Group Plans			$77,760	$53,000	$55,000	$79,879	$26,757	$1,000	$7,014	$ 29,533	$3,411	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Final Gap to Initial Savings Target			$0	$0	$0	$23,074	$0	$0	$0	($11,800)	$0	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A

✓ = impacts metric, enabler for performance but not quantified for gap closure
italics = initiative has impact in another cornerstone
Bold = Key initiative (See Appendix)

Site and support groups were asked to meet financial targets though a combination of fleet-wide savings initiatives (above) and site specific initiatives (in supporting site presentations).

MS-02, MS-03 and MA-06 are not included in table above as planning is still under development.

ONTARIO POWER GENERATION

Nuclear's Gap Based Business Planning Results

Nuclear's gap-based process has resulted in a business plan that reflects our objective of improved operational and financial performance across the fleet.

ScottMadden Inc., a general consulting firm, was retained by OPG management to undertake a benchmarking study comparing its nuclear financial and non-financial performance with industry peers. In the final benchmarking report, ScottMadden reported the following:

"It is our opinion that OPGN has undertaken the actions necessary to successfully pilot a gap-based business planning process as originally envisioned. These actions include: (a) fairly benchmarking the company's operational and financial performance to external peers, (b) using the benchmarking results to establish performance improvement targets that will achieve, or significantly drive the company closer to, top quartile industry performance, and (c) developing and implementing a gap-based business planning process that identified the improvement initiatives best able to close the identified performance gaps."

ONTARIO POWER GENERATION

Cost Plan - OM&A Cost Savings

Nuclear Operations 2010-2014 Business Plan

($ millions)	2010	2011	2012	2013	2014	Total
Total OM&A - 2009-2013 Approved BP	$1,679	$1,579	$1,617	$1,764		
Targeted Reductions (Note 1)	-$40	-$53	-$61	-$87		
Additional Expenditures (Note 2)	$14	$17	$20	$21		
Additional Savings (Note 3)	-$58	-$58	-$68	-$68		
Nuclear Operations OM&A Plan-over-Plan Reduction	**-$84**	**-$94**	**-$110**	**-$135**		**-$423**
Nuclear Operations OM&A 2010-2014 Submission	**$1,595**	**$1,485**	**$1,507**	**$1,629**		
Corporate Planning Guidelines 2010-2014	**$1,639**	**$1,579**	**$1,617**	**$1,764**		
Nuclear Operations Savings above Guidelines	**-$44**	**-$94**	**-$110**	**-$135**		
Pickering B Continued Operations Investment		$51	$42	$37		
Pickering A P2/P3 Project Timing	$9					
Total OM&A Submission 2010-2014	**$1,604**	**$1,535**	**$1,549**	**$1,666**	**$1,673**	

Note 1:	2010	2011	2012	2013
Pickering A	-$6.0	-$13.0	-$10.0	-$12.0
Pickering B	-$9.0	-$9.0	-$9.0	-$14.0
Darlington	-$9.0	-$9.0	-$11.2	-$21.4
Nuclear Programs & Training	-$10.0	-$14.4	-$20.8	-$25.4
Nuclear Supply Chain	-$0.5	-$0.5	-$0.5	-$2.0
Engineering & Modifications	-$2.0	-$3.5	-$5.2	-$7.0
Nuclear Waste Management	-$0.2	-$0.3	-$0.4	-$0.6
Inspection Maintenance & Commercial Services	-$2.3	-$2.9	-$3.9	-$4.3
Performance Improvement & Nuclear Oversight	-$0.2	-$0.2	-$0.2	-$0.2
CNO Office	-$1.0	$0.0	$0.0	$0.0
Targeted Reductions - Base and Outage	-$40.2	-$52.8	-$61.2	-$86.9

Note 2:	2010	2011	2012	2013
2010 Vacuum Building Outage	$14.0			
2011/2012 Turbine Work - PA		$7.2	$8.2	
Underfunded OM&A Project Portfolio		$5.0	$5.0	$10.0
NPT Shortfall on Targeted Reductions		$4.3	$6.3	$10.8
Additional Expenditures	$14.0	$16.5	$19.5	$20.8

Note 3:	2010	2011	2012	2013
Impact of Lower Labour Burden Rate	-$38.0	-$38.5	-$48.7	-$47.5
Impact of New Labour Rates	-$12.4	-$13.0	-$12.7	-$13.8
SAVHO Reallocation to Capital Projects	-$5.4	-$5.0	-$4.7	-$3.8
Continued Operations	-$2.0			
IM&CS Savings		-$1.3	-$2.1	-$3.3
Additional Savings	-$57.8	-$57.8	-$68.2	-$68.4

ONTARIO POWER GENERATION

Financial Plan

	Business Plan 2010-2014					Plan-Over-Plan			
($ Millions)	2010	2011	2012	2013	2014	2010	2011	2012	2013
OM&A Base and Outage Expenditures									
Pickering A	260.1	236.5	235.0	240.7	259.1	(17.3)	(18.1)	(15.7)	(26.0)
Pickering B	371.9	369.5	366.5	373.8	392.8	(13.9)	11.9	5.0	(0.2)
Darlington	398.2	362.6	372.1	471.6	426.9	(17.5)	(23.2)	(28.5)	(39.3)
Engineering & Modifications	68.4	63.9	63.8	66.8	66.9	(11.2)	(14.5)	(16.3)	(16.9)
Nuclear Programs & Training	234.1	249.7	253.9	255.9	264.3	(30.4)	(18.5)	(24.9)	(24.6)
Nuclear Supply Chain	68.6	68.4	69.1	69.3	70.5	(3.3)	(3.4)	(3.8)	(5.2)
Inspection Maintenance & Commercial Services	32.5	32.9	33.2	33.5	33.5	(7.6)	(9.0)	(10.8)	(12.2)
Nuclear Waste Management	4.3	4.4	4.6	5.4	4.3	(0.3)	(0.4)	(0.5)	(0.7)
PINO	9.1	9.2	9.4	9.6	10.0	(0.6)	(0.6)	(0.7)	(0.7)
CNO Office / Other	22.6	9.9	13.1	11.7	11.9	13.4	0.3	0.3	0.3
Total Base & Outage	**1,470.0**	**1,407.0**	**1,420.8**	**1,538.3**	**1,540.4**	**(88.8)**	**(75.3)**	**(96.0)**	**(125.5)**
OM&A Portfolio Projects	111.7	108.3	111.2	115.7	121.2	6.7	11.9	11.2	15.7
OM&A PB Continued Operations	1.8	19.9	17.0	11.9	11.3	(2.0)	19.9	17.0	11.9
OM&A P2/P3 Projects	20.6	0.0	0.0	0.0	0.0	9.1	0.0	0.0	0.0
Total OM&A	**1,604.1**	**1,535.1**	**1,549.0**	**1,665.9**	**1,672.9**	**(75.0)**	**(43.5)**	**(67.8)**	**(97.9)**
Fuel & Waste Provision Expense									
Fuel (Uranium & Combustion Turbine Unit)	178.9	209.1	233.2	232.5	238.6	(0.5)	(14.6)	(17.9)	(16.6)
Fuel Provisions	23.5	25.7	27.2	27.9	29.9	(1.3)	(1.2)	(1.4)	(10.3)
Total - Fuel & Waste Provisions	**202.4**	**234.8**	**260.5**	**260.4**	**268.5**	**(1.7)**	**(15.7)**	**(19.3)**	**(27.0)**

ONTARIO POWER GENERATION

Financial Plan

($ Millions)	2010	2011	2012	2013	2014
Projects - Capital & OM&A and MFA					
OM&A Portfolio Projects	111.7	108.3	111.2	115.7	121.2
OM&A Pickering B Continued Operations	1.8	19.9	17.0	11.9	11.3
Capital Portfolio Projects	172.0	172.0	172.0	172.0	172.0
Total Portfolio and Other Projects	**285.5**	**300.2**	**300.2**	**299.6**	**304.5**
OM&A P2/P3 Projects	20.6	0.0	0.0	0.0	0.0
Capital P2/P3 Projects	8.8	0.0	0.0	0.0	0.0
Total P2/P3 Projects	**29.5**	**0.0**	**0.0**	**0.0**	**0.0**
Minor Fixed Assets	**20.2**	**19.7**	**19.5**	**19.6**	**19.7**
Total OM&A and Capital Projects and MFA	335.1	319.9	319.7	319.2	324.3

ONTARIO POWER GENERATION

Staff Plan

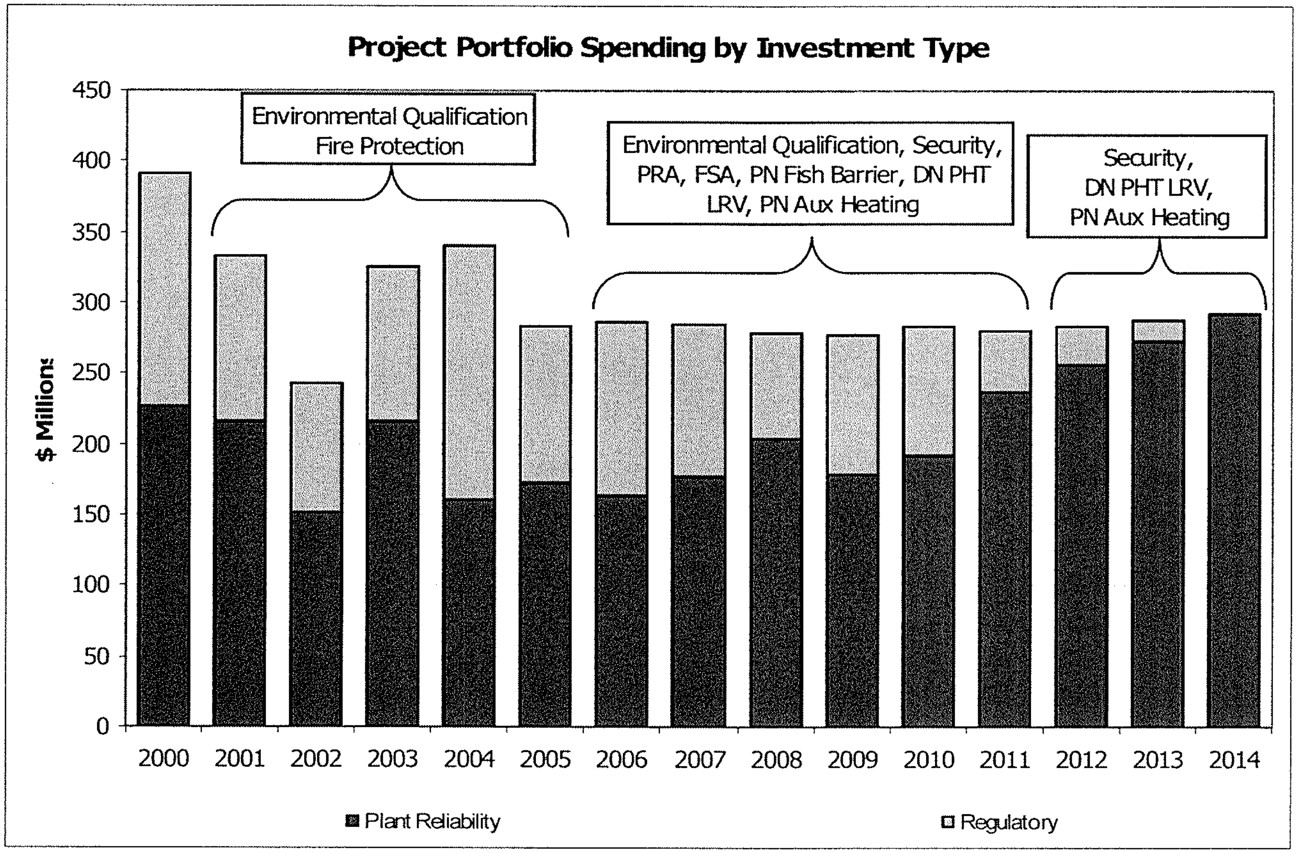
MAJOR DEPARTMENTS	Headcount	Full Time Equivalent					Variance from BP 2009-2013				
Regular Staff	2009 Year-End	2010	2011	2012	2013	2014	2009 YE	2010	2011	2012	2013
Pickering A	1,266	1,129	998	987	986	982	(12)	29	10	9	8
Pickering B	1,608	1,636	1,606	1,558	1,554	1,523	2	77	66	24	10
Darlington	1,703	1,693	1,667	1,663	1,647	1,654	(51)	(25)	(20)	(19)	(24)
Engineering & Modifications	674	667	626	606	576	568	(3)	0	(12)	(23)	(34)
Nuclear Programs & Training	976	1,027	988	973	961	968	6	(15)	(39)	(69)	(66)
Nuclear Supply Chain	380	370	362	353	347	343	(18)	7	3	3	(3)
Performance Improvement & Nuclear Oversight	57	57	57	57	57	57	-	(1)	-	-	-
Inspection Maintenance & Commercial Services	589	545	484	439	406	373	(6)	(1)	(63)	(108)	(141)
Nuclear Waste Management	312	310	307	307	307	307	(1)	(3)	(6)	(6)	(6)
CNO Office	2	2	2	2	2	2	-	-	-	-	-
Regular Staff Total	**7,567**	**7,435**	**7,095**	**6,945**	**6,842**	**6,776**	**(83)**	**68**	**(61)**	**(189)**	**(256)**

Plan-Over-Plan Major Business Reason for Regular Staff Variance from BP 2009-2013	2009 YE	2010	2011	2012	2013
Pickering A - Unit 2/3 Long Term Provision hires offset by staff reductions in major departments	(17)	9	10	9	8
Pickering B - Reductions in staff are attributable to Fleet and Station Initiatives	2	4	(40)	(68)	(72)
Pickering B - Staff hires for turbine crew funded from purchased services		19	19	19	19
Pickering B - Continued Operations Staff	-	54	87	73	63
Darlington - Staff Reductions in Operations, Maintenance, Fuel Handling, Engineering, Projects Support and MSSP	(62)	(25)	(20)	(19)	(24)
Engineering & Modifications - Staff Reductions in major departments	(3)	-	(12)	(23)	(34)
Nuclear Programs & Training - Staff Reductions in Nuclear Programs and Nuclear Integration	1	6	(26)	(46)	(37)
Nuclear Supply Chain - Staff Hires offset by reductions in major departments	(18)	7	3	3	(3)
Performance Imp. & Nuclear Oversight - Eliminate 1 Engineering Position from VP's Office	-	(1)	-	-	-
Inspection Maintenance & Comm. Serv. - Discontinuing Service Agreements with Bruce Power	(6)	(4)	(65)	(110)	(143)
Nuclear Waste Management - Planned reductions in Used Fuel Ops. and Engineering Staff offset by hires in Waste Ops	(1)	(3)	(6)	(6)	(6)
Other Contributing Variances	21	2	(11)	(21)	(27)
TOTAL REGULAR STAFF REQUIREMENTS - PLAN-OVER-PLAN	**(83)**	**68**	**(61)**	**(189)**	**(256)**

FTE #'s do not reflect changes due to reorganization of Nuclear Operations and Nuclear Refurbishment, Projects and Support.
FTE #'s do not include Security.

ONTARIO POWER GENERATION

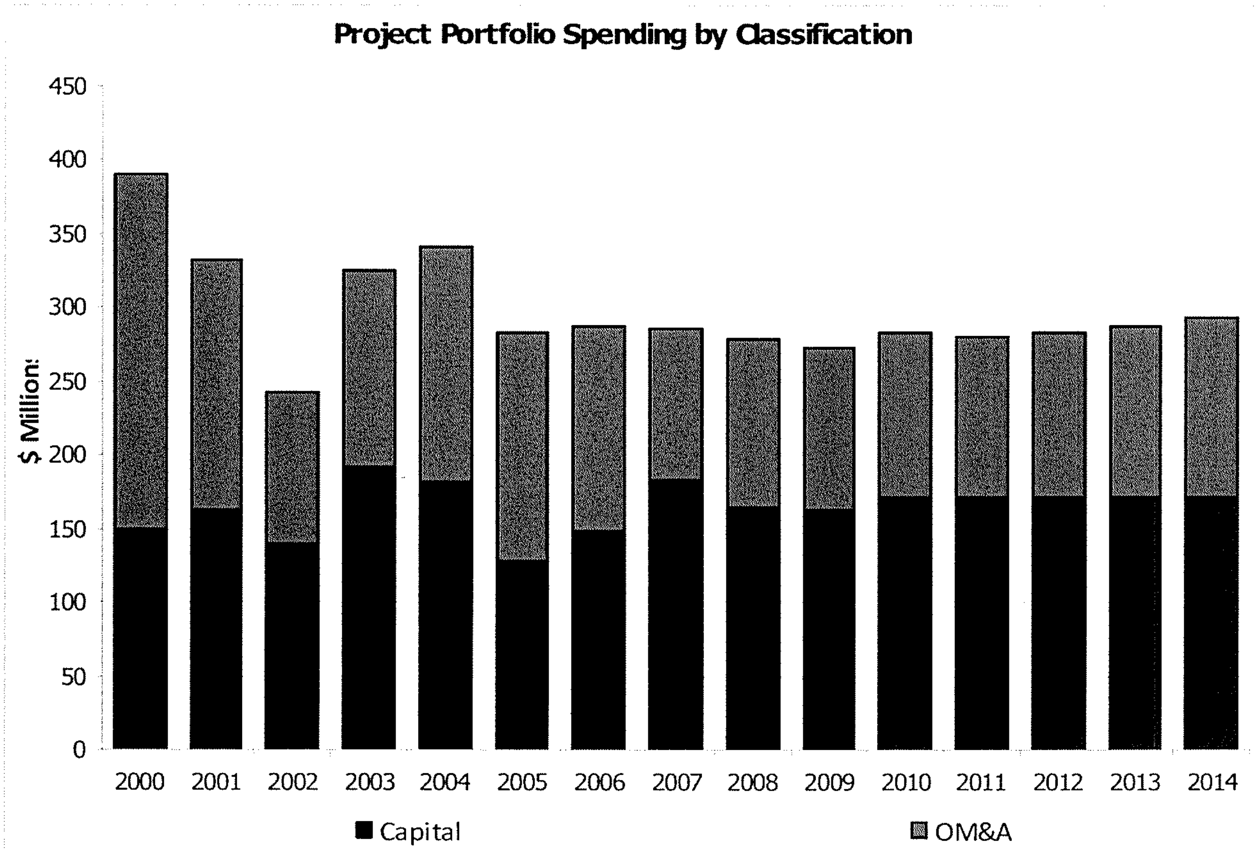
Investment Plan



- Known regulatory projects end in the planning period but history shows new regulatory projects continuously emerge.
- Previous decreases in portfolio funding are not sustainable.
- Benchmarking capital expenditures is difficult due to OPG's higher capitalization threshold; however, it is believed that OPG spends less on plant reliability investment due to high regulatory capital requirements than industry benchmark.

ONTARIO POWER GENERATION

Investment Plan



- SAVH has been re-allocated to capital and OM&A project portfolio.
- Capital expenditures in 2010-2014 business plan ceiling maintained at $172 million.
- Nuclear labour rate savings have been re-allocated to OM&A project portfolio in the amounts of $5 million (2011-2012); $10 million (2013) and $15 million (2014).

ONTARIO POWER GENERATION

Risks to Business Plan

Safety

- Darlington Heat Transport System Aging impact on adequate operating margins determined by safety analysis limits. MEDIUM
- Environmental Qualification of Darlington Nuclear by 2010 to meet licensing condition. LOW

Human Performance

- Human Performance trending indicates challenges with: Procedure Use & Adherence, Work Protection and rework. The risk impact on the business is not achieving zero human performance consequential events in the areas of Nuclear Safety and Worker Safety (including Radiological safety). STRATEGIC

Value for Money

- Implementation of initiatives using the same staff which are involved in day-to-day operations and maintenance. MEDIUM

Reliability

- Replacement of Feeder Pipes in Nuclear Stations due to thinning: Thin spots at Graylocs at Darlington; and "Blunt flaws" under welds and feeder bend thinning rates unknown at Pickering A. LOW
- End of Life Determination: The medium risk in the confidence level of attaining the planned effective full power hours (EFPH) for Darlington and Pickering B units is insufficient for effective business planning. STRATEGIC
- Corrosion of Pickering A Calandria Vault: The corrosion of structural components and cooling systems is being caused by moisture in the vault atmosphere and radiolysis forming nitric acid which attacks the carbon steel components in the reactor vault. STRATEGIC

ONTARIO POWER GENERATION

Darlington
2010-2014 Business Plan

"Beyond Sustainability"

Say it, Do It

ONTARIO POWER GENERATION

Major Objectives/Focus Areas

Darlington's objective for the 2010-2014 plan is to continue to focus on achieving top operational performance in the nuclear industry and position the station for refurbishment and beyond.

- The plan proposes a significant improvement in contribution margin with cost reductions achieved through:
  - Peer team and site specific initiatives
  - The challenge and prioritization of work programs
  - Cost control and productivity improvements
  - Continued optimization of the feeder replacement program

- Plan-over-Plan 2010-2013 costs are reduced by $108.6 million and revenues are increased by $22.2 million.

- Funds for newly identified life cycle management programs have been accommodated in the plan.

ONTARIO POWER GENERATION

Pickering B
2010-2014 Business Plan

"Delivering on our Commitment to Achieve Continued Operations for OPG"

Say it, Do It

ONTARIO POWER GENERATION

Major Objectives/Focus Areas

The objective of the 2010-2014 Pickering B plan is to deliver on the commitment to improve the operational performance of the station and extend the life of Pickering B to 2020. The Plan includes:

- Extending the life of Pickering B through the "Continued Operations" program and providing the Province of Ontario and OPG with a highly valued source of base load generation through the next decade, as well as, a source of generation during the potential refurbishment of Darlington
- Additional investments will also be required to ensure plant equipment operates as intended to 2020
- Significant improvements in cost performance totaling $55 million in OM&A reductions – reducing the overall OM&A impact of Continued Operations

ONTARIO POWER GENERATION

Continued Operations

Program Background

- Pickering B Continued Operations is a work program consisting of inspections, physical work and Research & Development with the objective of extending the operating life of the Pickering B units from their current nominal end of life of 2014/2016 by four years to 2018/2020.
- This requires incremental investments in plant equipment and increases in outages over the next few years. In addition to extending the Pickering B station life, it provides greater assurance of the extended operation of Pickering A Units 1 and 4 to 2020 due to the technical interdependencies between the two stations.
- The achievement of Continued Operations would also benefit the Ontario electricity system by providing additional nuclear base load generation during a period of planned intensive nuclear unit refurbishment in Ontario.

Risks

- A number of technical and regulatory issues will need to be managed to ensure acceptability of Pickering B Continued Operations.
- This plan identifies funding requirements and generation impact for all 5 years of the plan ($190 million in outage costs and 266 days or approximately 3.2 TWh in generation).

ONTARIO POWER GENERATION

Pickering A
2010-2014 Business Plan

"Achieving Our Potential "

Say it, Do it

ONTARIO POWER GENERATION

Major Objectives/Focus Areas

The objective of the 2010–2014 Pickering A plan is to reduce Forced Loss Rate, increase Capability Factor and decrease Total Generating Cost over the five year period. We are working to "Achieve Our Potential" by:

- Continuing to improve the material condition of the plant
- Maximizing the operating time at 100% Full Power
- Restoring margins
- Maintaining continuous improvement in Safety, Reliability, Human Performance and Value for Money with a focus on achieving industry standards
- Improving accountability and focus on results

  Plan-over-Plan Changes:

  Cost = -$77.1 million

  Generation = +0.17 TWh or $9.2 million in additional revenue

ONTARIOPOWER GENERATION

Appendix

OPG Nuclear Operations - Top 7 Initiatives

Initiative		Description
EN-01	**Work Order Readiness** Steve Woods	Redevelop the process, procedures, organizational accountabilities, reporting relationships, authorities, metrics, and stakeholder support organizations, (specifically design engineering, procurement engineering, maintenance assessing and supply chain buyers) so that work orders are efficiently and effectively assessed, parts are available and tasked are scheduled to allow maintenance to execute work more efficiently. Four sub-initiatives will be executed to complete this improvement: EN 1.1 Implementation of an Accountability Model EN 1.2 Pro-Active Assessing Improvements EN 1.3 Establish Fleet EFIN Formal Process and Organizational Structure EN 1.4 Timely Holds Resolution Improvements
OU-02	**Outage Improvement Strategy** Jim Woodcroft	Review and implement fleet contractor management procedure (how contractor work is managed, what work is performed, when the work is scheduled, what support is available, standards for scope change/approval, revise strategic planning of contract work). Drive toward consistent use of contractors across the fleet and improve contractor efficiency, simplify resource planning, improve oversight and quality of contractor function. Improve the execution rate - the amount of work done per day. Review standard durations on critical path and look for opportunities to reduce/improve. Utilize gap analysis outage over outage and identify and implement opportunities for improvement. Integrate the scoping process of MA-0013, MA-0036, AS-0043. Make changes to the scoping process to improve timely identification and assessing prior to scope freeze milestone (PO-12). The result will be an improved scope at scope freeze milestone. Review and implement fleet standards for minimum OCC staffing requirements for best in fleet organizational structure. Ensure OCC staff involvement during outage planning phase. Develop future Outage Managers. Modify this year's lessons learned process and MA13 improvement / realignment session into OPGN's outage program by updating N-PROC-MA-0013 to allow the stations to exchange key learnings from previous years and tackle issues across the fleet. Take over running and maintenance of all outage metrics to support continuous improvement.

OPG Nuclear Operations - Top 7 Initiatives

Initiative		Description
ER-01	**Standard Equipment Reliability** Paul VonHatten	Specify and implement industry standard ER program. Standardize existing elements across the fleet for efficiency and effectiveness. Establish roles and accountabilities for ER at the station and corporate level. Establish an ER peer team. Specify and implement supporting IT structure to improve ER program effectiveness and to reduce costs.
ER-02	**PM Program Improvement** Paul VonHatten	Comprehensive implementation and improvement of the Preventative Maintenance Program across the fleet. The elements of this plan include: 1. Implementation of the revised criteria for classification of component criticality. This is an enabler to the PM program effectiveness in improving equipment reliability while improving cost performance. 2. Validation and implementation of the new PM templates developed through the AP913 process. 3: Establishing methodologies to establish PM budgets linked to improved ER performance, and a focused review of the top 5 systems/components contributing to FLR and the Top 5 systems contributing to high levels of EM/CM work, and the Top 5 systems from a PM cost perspective. Although all 3 sites are currently executing various local and shared initiatives design to improve their PM Program. 4. Implementation of a robust PM feedback and review process. 5. Improvements to the PM program efficiency and effectiveness. 6. Establishing a Graded approach to Non-Critical Component Technical Basis.
EN-02	**Engineering Value for Money Improvement** Fred Dermarker	Site and central engineering groups are conducting an overall cost and efficiency evaluation aimed at staff reductions as a result of organizational realignment and a close examination of products and services. Several functions will be centralized and roles may shift between Engineering and Maintenance as well from Reactor Safety to Operations.

OPG Nuclear Operations - Top 7 Initiatives

Initiative		Description
OP-05	**Human Performance Improvement** Sean Granville Tom Henderson Frank Guglielmi	Accelerate and sustain fleet Performance Improvement through the establishment of a formal Fleet initiative. Improved organizational recognition, control and response to pre cursor events; reduction in frequency and significance of events and accelerated response to performance/behavioral underlying contributors. OPGN has been criticized for not having an obvious Fleet improvement model and leveraging the common strengths/weaknesses of the sites. Adoption of the INPO document 05-005 Guidelines for Performance Improvement at Nuclear Power Stations provides the PI model, with three main areas of PI: performance monitoring; analyzing problems, identifying and planning solutions; and implementing solutions. Sites need to take full advantage of lower level events or trends to be predictive and take corrective action to mitigate risk. Staff engagement is not fully leveraged since the results of adverse condition reporting at low levels are not quickly evident. External groups are critical of our ability to resolve underlying trends. Trending at OPGN needs to intrusive and critical, and not limited to binning. Effective implementation of solutions remains a challenge. Staff behaviors are not always guided or corrected through the use of supervisor/management oversight and intervention.
MA-08	**Days Based Maintenance** Doug Radford	OPG has a long standing practice of performing maintenance around the clock on a shift basis. This is not the industry practice. Approximately 45% of the total maintenance compliment at each site for Control and Mechanical functions are assigned to shift. The necessary work required on a 24/7 basis is estimated to be 3 FTEs for Control and 0 FTEs for Mechanical. The sole reason these staff remain on shift is to provide emergency response functions. Many of the emergency response functions they provide could be automated with currently available technology. In order to staff these functions 24/7 we require 5 staff of which only 2 are present at site in any 24 hour period. This means at any one period in time 30% of our Control and Mechanical functions are away from the stations. Studies of the productivity of shift versus day maintenance indicate days-based maintenance is more effective (regardless of working 8 or 12 hours). In addition shift premiums result in a 17% escalation in wage costs. A move towards a days-based maintenance operation will require introduction of new technology for radiation data gathering (currently done manually) and changes to the Shift Minimum Compliment document (regulatory approval required). Based on reducing current maintenance shift compliment to 25 (5 x 5 crews), the savings in shift differential would be approximately $3M per year (moving from a current shift compliment of 250 to a compliment of 75.

TAB 7

ONTARIOPOWER GENERATION
700 University Avenue Toronto, Ontario M5G 1X6

News
from Ontario Power Generation
Tel: 416-592-4008 or 1-877-592-4008 Fax: 416-592-2178
www.opg.com

March 29, 2010

OPG STARTS ENERGY BOARD RATE APPLICATION PROCESS
If granted, rate increase would be the second since 2005

[Toronto]: Ontario Power Generation (OPG) will be seeking its second rate increase since 2005 when it submits an application to the Ontario Energy Board (OEB) in April. Any new rates stemming from this application would not go into effect until January 2011 and would remain in effect for two years.

Tom Mitchell, OPG's President and CEO, noted that last year, in recognition of the economic downturn, the company did not seek a rate increase and looked for internal cost saving measures instead.

"We deferred our rate application once but we must go to the OEB this year to make a request for an increase in our regulated rates. We continue to look for internal savings on top of the $85 million we've saved to date," said Mitchell. "We look forward to validating our rate proposal before the regulator."

The proposed increase, if accepted by the OEB, would result in modest increases on the average residential bill of about $2.75 per month starting in 2011.

The final decision will be made by the OEB after it examines OPG's case for a rate increase. The OEB operates as an adjudicative tribunal and carries out a public hearing to review the rate application.

KEY FACTS

- OPG is the only generating company in the province whose rates are set through a public process, and its net income remains in the Province of Ontario.

- The application is for the rate OPG receives for the output from its Darlington and Pickering stations and from its hydroelectric plants at Niagara and Cornwall. These plants produce about 70 per cent of the electricity produced by OPG.

- In 2009, OPG received 5.5 cents a kWh for its nuclear output, and 3.7 cents a kWh for its regulated hydroelectric output.

- OPG's prices are below those received by most other generating companies. Thus OPG's prices help to hold down the overall costs for electricity that are paid by consumers.

- The current commodity price for residential and other small volume consumers under the Regulated Price Plan of the OEB is 5.8 cents per kWh. This applies to the first 1,000 kilowatt hours used in a month. After the first 1,000 kilowatt hours, the price rises to 6.7 cents per kWh.

- OPG began stakeholder information sessions today. Public hearings are expected to take place later this year.

- 30 –

For more information contact
Ontario Power Generation
Media Relations
(416) 592-4008 or 1-877-592-4008

TAB 8

CCC Interrogatory #001
(NON-CONFIDENTIAL VERSION)

Ref: Ex. A1-T7-S1

Issue Number: 1.3
Issue: Is the overall increase in 2011 and 2012 revenue requirement reasonable given the overall bill impact on consumers?

Interrogatory

On March 29 and April 1, 2010 OPG held two stakeholder information sessions regarding its proposed Application. At that time the proposed payment amounts inclusive of riders was $36.25/MWh for Hydroelectric and $62.22/MWh for Nuclear. Please provide the following information:

a) All correspondence between OPG and its shareholder between April 1, 2010 and May 26, 2010, regarding OPG's Application;

b) All presentations or reports made to the OPG Board of Directors during that period;

c) A detailed description of the process OPG followed in terms of revising its budgets that flowed from the initial budgeting process;

d) A chart explaining the differences between the amounts proposed on April 1 and the budgets now contained in the evidence in support of the Application. Where specifically did OPG make changes?

Response

a) See Attachment 1. OPG's reply to the letter in Attachment 1 is provided in Attachment 2.

b) The requested presentations and reports provided to OPG's Board of Directors ("OPG Board") in relation to OPG's payment amounts application are privileged and OPG objects to their production. The requested materials were prepared for the purpose of litigating the payment amounts application. The materials contain a discussion of matters that are related to OPG's strategy for litigating the application including in relation to settlement, issue analysis, regulatory risks and anticipated positions of other parties. Production of these materials, even on a confidential basis, will impact the ability of management to candidly discuss the application with the OPG Board, undermine the OPG Board in carrying out its important governance and oversight roles, and effectively compromise OPG's ability to litigate the application.

Further, the requested materials are not relevant to the OEB's determination of just and reasonable payment amounts. The application has been prepared on a cost of service basis and must be considered by the OEB as such. OPG's internal assessment of its application, prospects for settlement etc. as described above can have no impact on the OEB's responsibility to independently assess the application and objectively decide it based on the evidentiary record.

Even if the requested materials were relevant, and not privileged, their probative value is outweighed by the prejudicial effect on OPG and the regulatory process in general. In order to perform their respective roles of managing and governing OPG, management and directors must be able to speak freely and directors must be fully informed of both the risks and benefits of management proposals. In addition to the prejudice to OPG discussed above, the inevitable impact of production would be to reduce the level of detail in information and analysis presented to the OPG Board and reduce the level of oversight that the directors bring to bear on management's proposals. OPG submits that this result is not a desirable one for the company or Ontario ratepayers.

c) There have been no changes to OPG's planned budgets between the stakeholder sessions and filing of the application. The information discussed in the stakeholder information sessions and the rate proposal submitted on May 26, 2010 are based on the same assumptions regarding work requirements, work programs, resource requirements, and performance objectives that were included in the business plans approved by OPG's Board at their November 2009 meeting.

d) The payment amounts discussed during the stakeholder sessions cannot fairly be characterized as proposed. OPG was explicit that these figures were preliminary and subject to confirmation before the submission was finalized. That said, only two factors materially impacted the payment amounts inclusive of riders between the preliminary figures discussed at the stakeholder sessions and the final figures in OPG's application:

The recovery period for the tax loss variance was extended from 24 to 46 months.

The period for clearing all other variance account balances was shortened from 24 to 22 months due to the change in implementation date from January 1, 2011 to March 1, 2011.

Ministry of Energy
and Infrastructure

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OFFICE OF THE
PRESIDENT & CEO

MAY 07 2010

Ontario

Filed: 2010-08-12
EB-2010-0008
L-04-001
Attachment 1

MAY - 5 2010

MC-2010-1610

Mr. Tom Mitchell
President and CEO
Ontario Power Generation
700 University Avenue
Toronto ON M5G 1X6

Dear Mr. ~~Mitchell~~: Tom

I am writing in regard to Ontario Power Generation's (OPG) planned rate application to the Ontario Energy Board.

As you are aware, the Province of Ontario has keenly felt the impact of the recent recession, and this has been reflected in the government's 2010 budget. We are aggressively pursuing internal cost savings to meet our fiscal targets. At the same time we are committed to ensuring government agencies and Crown corporations across the public sector are equally focused on delivering cost savings that are under their control.

Bearing that in mind, I would request OPG carefully reassess the contents of its rate application prior to filing with the Ontario Energy Board. I would like OPG to demonstrate concerted efforts to identify cost saving opportunities and focus your forthcoming rate application on those items that are essential to the safe and reliable operation of your existing assets and projects already under development.

Also, as part of OPG's efforts to mitigate rate pressures and consistent with the government's policy on the introduction of the harmonized sales tax (HST), I would request that OPG commit to returning to ratepayers the full cost reduction impact of input tax credits from items that were previously subject to the Retail Sales Tax (RST).

I am confident that OPG and the Ministry of Energy and Infrastructure can continue working together to provide good value to Ontario electricity customers.

Sincerely,

Brad Duguid
Minister

ONTARIOPOWER GENERATION

Tom Mitchell
President & Chief Executive Officer

Filed: 2010-08-12
EB-2010-0008
L-04-001
Attachment 2

700 University Avenue, H19 A24 Toronto, ON M5G 1X6

Tel: 416-592-2121 Fax: 416-592-2174
tom.mitchell@opg.com

June 24, 2010

The Honourable Brad Duguid
Minister of Energy and Infrastructure
4th floor, Hearst Block
900 Bay Street
Toronto, Ontario
M7A 2E1

Dear Minister Duguid,

Thank you for your letter of May 5th, 2010 requesting that OPG carefully re-assess the contents of its rate application. I can assure you that OPG shares your desire to see that Ontario electricity consumers are provided with good value and highly reliable service.

Since our last rate decision in 2008 OPG has been focused on finding additional cost efficiencies in its business. This has included a decision to advance the shut down of four coal fired units to October 2010, a one year deferral in filing our rate application with the Ontario Energy Board (OEB), and a much more aggressive approach to business planning. In fact, OPG's business plan for 2010-2014 placed significant emphasis on reducing OM&A expenses compared to the previous year's plan through aggressive target setting, efficiencies and other cost reduction measures. As a result of those efforts, OPG has removed in excess of $600 million over the period 2010 to 2013.

OPG's rate application is based on the 2010-2014 business plan and therefore reflects a good portion of the $600 million in savings mentioned above. For example, the application presents OPG's use of benchmarking to support our cost control activities and to drive performance improvement at our nuclear and hydroelectric facilities. In nuclear, an extensive benchmarking effort has led to the development of challenging five-year operational and financial performance targets. Based on initiatives and other cost control measures developed in response to this benchmarking activity, the application includes more than $200 million in nuclear OM&A cost savings in the rate period of 2011-2012.

OPG's corporate groups have also embarked on significant cost saving initiatives. Here we have been able to hold overall spending levels to an increase of just over one percent per year on average over 2007-2012. One of the key contributors has been our ability to control Information Technology costs. We have been able to reduce our Information Technology costs by achieving lower service provider costs, leveraging existing applications, and increasing the standardization and simplification of our information technology environment.

The rate application also includes expenditures related to the refurbishment of our Darlington generating station and our plans to continue to operate the units at the Pickering B station. Both of these initiatives are important in helping the Government achieve its objective of providing the people of Ontario with a clean, reliable and cost effective supply of electricity.

Your letter specifically references the need to return to ratepayers the savings that result from the introduction of the harmonized sales tax (HST). I can confirm that this is part of OPG's plan. The introduction of the HST produces a small net benefit for OPG, and the rate application includes the savings for ratepayers that are attributed to our regulated assets.

As you know, in response to the building public concern over electricity prices, OPG determined in mid-April that it would defer the filing of its application to allow us to consider alternatives that would further reduce the impact on customers. As a result of the work that we have done since then, I can assure you that OPG's revised rate application fully meets the requirements of your May 5th letter.

OPG's revised application extends the period over which we would recover some costs relating to our last OEB decision. This extension reduces the average increase in rates to approximately 6.2% from the previously indicated 9.6%. Given that our last rate increase was awarded in 2008, this new increase is equivalent to about 2% per year over the 2008-2011 period. In terms of consumer impact, a 6.2% increase would result in an estimated increase of $1.86 per month on the bill of a typical residential consumer.

As you may know, at its meeting of May 20, 2010, OPG's Board of Directors approved OPG's revised rate application and on May 26, 2010 the application was filed with the OEB. Under separate cover, OPG's Board Chair has submitted a revised 2010-2014 Business Plan that reflects the new proposed rates to you and to the Minister of Finance for concurrence, as per our Memorandum of Agreement.

[redacted]

Please let me know if you require any additional information.

Tom Mitchell
President & Chief Executive Officer

cc. David Lindsay, Deputy Minister, Ministry of Energy and Infrastructure

TAB 9

THE GLOBE AND MAIL

May 6, 2010

Ontario utilities told not to bother with requests for rate increases

By Karen Howlett
Globe and Mail Update

Government steps in to prevent backlash over soaring hydro costs

The Ontario government has taken the highly unusual step of ordering the province's Crown-owned electricity utilities to cancel their requests for hydro rate increases, amid worries of a consumer backlash over soaring power costs.

The government's 11th-hour intervention in a rate-setting process that is designed to take the politics out of electricity pricing follows revelations that residential customers in Ontario are already facing increases of $300 more a year on average to keep the lights on by the end of 2011.

Three days before Hydro One was set to go to the province's energy regulator in mid-March, government officials told the company not to file its application, according to industry sources. Months of preparation that had gone into applying for the new rate suddenly ground to a halt, including the printing of hundreds of thousands of pages of documents.

The magnitude of the increase Hydro One was seeking - 22 per cent over two years, according to industry sources - left many of its largest customers in shock. Ontario Power Generation's (OPG) intention to ask for a 9.6 per cent rate increase effective next January - equivalent to about $2.75 a month for the average household - paled in comparison. But unlike Hydro One, OPG publicly announced its plans last March 29, and it was the negative reaction that prompted government officials to step in, the sources said.

Energy Minister Brad Duguid said government officials are scrutinizing any request for a price increase to determine whether it is, in fact, necessary.

"We're looking very closely at all increases in the system to ensure that we're standing up for consumers, to ensure that they're getting value for their money," he said in an interview on Thursday. "We are scrutinizing any impacts on rates very closely."

Opposition members say the McGuinty government is to blame for mismanaging the electricity system.

"This is more about politics than anything else," said Progressive Conservative energy critic John Yakabuski. "They don't want to deal with the negative push back from the consumer."

Energy consultants say several factors account for the $300 annual increase, or 25 per cent, consumers are facing next year, including green-energy investors the government is luring with the promise of generous long-term contracts. The figure does not include the increases sought by Ontario Hydro and OPG.

Industry sources said they were surprised the utilities had withdrawn their requests, because they typically seek the green light from government before proceeding to the Ontario Energy Board. This time around, both utilities had already spent two days meeting with large customers last March, explaining the need for rate increases, before suspending their applications.

Hydro One spokeswoman Daniele Gauvin said the utility, which owns the province's electricity transmission system, is now reviewing its application to look for areas where it can reduce costs by deferring work.

"In the current economic times, we are mindful of the impact of rate increases on our customers," Ms. Gauvin said. She would not confirm how much of an increase Hydro One was seeking.

OPG planned to file its application on April 15. But that same day, Andrew Barrett, OPG's vice-president of regulatory affairs, sent an e-mail to large customers, saying the date had been pushed back to late May.

"During this time, OPG will review our application to identify ways to further lessen the impact of our request on ratepayers," he said.

OPG spokesman Ted Gruetzner denied that it was Mr. Duguid who directed the utility to withdraw its application.

OPG generates about two-thirds of the province's electricity output and is the only producer whose rates are set through public hearings. The utility has not had a rate increase since 2008. It receives 5.5 cents a kilowatt hour for power from its nuclear reactors and 3.7 cents from its hydroelectric plants - well below what other producers receive.

TAB 10

ONTARIOPOWER GENERATION

700 University Avenue Toronto, Ontario M5G 1X6

News

from Ontario Power Generation

Tel: 416-592-4008 or 1-877-592-4008 Fax: 416-592-2178
www.opg.com

May 26, 2010

OPG RESUMES ENERGY BOARD RATE APPLICATION PROCESS
Lower rate request reduces impact on ratepayers

[Toronto]: Ontario Power Generation (OPG) is proceeding with a lower rate application to the Ontario Energy Board (OEB).

The proposal, if accepted by the OEB, would result in an increase to the average residential bill of about $1.86 per month. OPG delayed filing its application last month so that it could find a way to lower its requested rate by more than 30 per cent.

"We wanted to do more to reduce the impact of our request on ratepayers," said Tom Mitchell, OPG's President and CEO. "Last year, we found $90 million of internal savings and deferred our application. This year, we sharpened our pencils to shave our current rate application while still allowing OPG to produce safe, clean, reliable, low-cost electricity for Ontario."

Any new rates stemming from this application would not go into effect until March 2011 and would remain in effect until the end of 2012.

The final decision will be made by the OEB following public hearings that allow stakeholders to examine OPG's case for a rate increase. The OEB operates as an independent tribunal and will carry out a public hearing to review the rate application.

KEY FACTS

Last year, OPG generated 92.5 billion kilowatt hours of electricity to power two thirds of Ontario's homes and businesses.

The rate increase would pay for work that includes but is not limited to:

- Maintaining and operating its nuclear generation units – including Darlington, which are consistently among the best operating CANDU units in the world -- and its heritage hydroelectric plants, which are among the best operating plants in North America. OPG's nuclear and hydro plants are also the backbone of Ontario's emission-free electricity system.

- Undertaking detailed planning for Darlington refurbishment that would allow it to operate for an additional 30 years. Darlington supplies about 20 per cent of Ontario's electricity.

- Pursuing continued operations at Pickering B to about 2020 -- which will generate approximately 65 billion kilowatt hours of electricity over the four-year period of continued operation.

- Rehabilitating and getting more electricity from heritage hydroelectric assets. Hydro is the lowest-cost and one of the cleanest forms of electricity available to Ontarians.

- Continuing contributions to a fund to pay for the storage of nuclear waste so as not to burden future generations.

- Continuing the licensing and environmental assessment work for new nuclear to be ready for the future.

During the 2011-2012 period, OPG's forecast production from these valuable baseload assets is 137.3 billion kilowatt hours.

OPG is the only generating company in the province whose rates are set through a public process, and its net income remains in the Province of Ontario.

- 30 –

For more information contact
Ontario Power Generation
Media Relations
(416) 592-4008 or 1-877-592-4008

TAB 11

Back to OPG trims proposed hydro rate increase by 32%

OPG trims proposed hydro rate increase by 32%

May 26, 2010

John Spears

Ontario Power Generation has reduced a proposed rate increase by 32 per cent after coming under pressure from Energy Minister Brad Duguid – but opposition critics say consumers are still paying "exorbitant prices."

OPG is now proposing new rates that would increase a typical householder's bill by about $1.86 a month, down from its original proposal of $2.75 a month.

The new rates, which must be approved by the Ontario Energy Board, would come into effect next March.

Duguid had asked OPG and Hydro One, both owned by the province, to keep their increases "to a minimum." Hydro One scaled back its proposed increase last week by more than 25 per cent.

OPG produces two-thirds of Ontario's electricity. The price of about 70 per cent of that output, which comes from its biggest hydro-electric stations and nuclear plants, is regulated by the energy board.

OPG is now proposing a 6.2-per-cent price increase for its regulated output, instead of the 9.6 per cent increase it had first requested, said spokesman Ted Gruetzner.

The company says it needs money to maintain and operate its nuclear units; to plan for refurbishing the Darlington nuclear plant and plan for new nuclear units; and to cover the cost of nuclear waste storage.

If the proposal is approved, OPG will get 3.7 cents a kilowatt hour for the output of its big hydro stations, and 5.3 cents a kilowatt hour for its nuclear output.

To shave money from its original proposal, Gruetzner said OPG will shut down four coal-burning units ahead of schedule.

Two units at its Lambton power station, and two at Nanticoke, will close in October. The province has committed to closing all units by 2014.

In addition, OPG will not jack up rates to recover what were in effect tax overpayments made in previous years.

OPG's proposed increase is one of many putting pressure on power prices.

The province has approved a host of new bids from companies producing electricity from renewable sources such as wind and sunshine. Those generators are being paid prices ranging from 13.5 cents a kilowatt hour for wind, to 80 cents a kilowatt hour for solar.

The HST will boost rates 8 per cent, and time-of-use rates, which charge users higher prices during periods of peak usage, will also mean higher bills for many consumers.

Opposition MPPs decried the proposed increase.

"This is no break to the consumer," said John Yakabuski of the Ontario Conservatives, pointing to array of factors pushing up the price. "Consumers are still paying exorbitant prices."

"All you've got to do is look at what the forecasters say will happen based on the commitments this government is making, based on high-cost power."

New Democratic Party critic Peter Tabuns said OPG's plans for spending much of the increase on nuclear plants are misguided.

"OPG should be supporting a transition to an efficiency and conservation-led utility, not one that's focused on nuclear power," he said.

TAB 12

CME Interrogatory #010

Ref: Ex. A1-T3-S1, page 3
Ex. F4-T4-S1, pages 4-5
Ex. I1-T1-S2

Issue Number: 1.3
Issue: Is the overall increase in 2011 and 2012 revenue requirement reasonable given the overall bill impact on consumers?

Interrogatory

The Board's Distribution Rate Handbook implies that consumers cannot be expected to tolerate an average annual total bill increase in excess of 10%. Hydro One had planned to file its application for increases in transmission rates on or about April 1, 2010. On March 29, 2010, OPG announced its plan to submit an application to the OEB in April and began stakeholder sessions. Hydro One did not file its application for transmission rate increases on or about April 1, 2010 as initially planned. On May 6, 2010, an article appeared in the *Globe and Mail*. The article notes the magnitude of the increases being requested by Hydro One and OPG. The article suggests that the government considered the combined bill impacts of the pending applications of Hydro One and OPG. On May 26, 2010, OPG announced it was proceeding with a lower rate application to the OEB. In an article appearing in *The Toronto Star* on May 26, 2010, the article indicates that OPG reduced its proposed increase by 32% and indicates that spokesperson Ted Gruetzner suggested that OPG will not increase its rates to recover what were in effect tax overpayments made in previous years. In its first payment amounts application, OPG proposed mitigation related to tax losses in an amount of $228M. In the context of these developments, please provide the following information:

a) Produce, in confidence if necessary, all documents and other information presented to OPG's Board of Directors, including any information provided to OPG by its shareholder, that led to the decision to revise the application OPG intended to file in mid-April.

b) Compared to the application OPG planned to file in mid-April 2010, what is the amount that OPG decided to refrain from claiming from ratepayers?

c) What criteria were applied by OPG's Board of Directors to cause them to conclude that a portion of the amount reflected in the application that was to have been filed in mid-April should not be claimed?

d) Assume that OPG's spending plans, in combination with the impacts of transitioning to more and more renewable energy sources, are likely to produce total bill increases for a typical or average residential consumer in an amount that exceeds, on average, 10% per year over five years. Under this assumption, does OPG have any suggestions as to what the OEB should do to constrain the total bill impacts on a typical residential customer to an amount that does not exceed, on average, 10% per year over the next five years?

Response

a) Please see response to the interrogatory in Ex. L-4-001, parts a) and b).

b) The impact of delaying the implementation of new payment amounts from January 1, 2011 to March 1, 2011 is estimated to be $16M assuming that OPG's request is fully approved.

c) Please see response to the interrogatory in Ex. L-4-001, part b).

d) No. The focus of OPG's activity before the OEB is on matters that relate to the determination of just and reasonable payment amounts for the prescribed facilities or directly impact OPG operations.

TAB 13

MITIGATION OF PAYMENT AMOUNT INCREASES

OPG's revenue requirement forecast as presented in Ex. K1-T1-S1 summarizes the revenue and expense evidence for OPG's 21 month test period for the nuclear and regulated hydroelectric facilities. OPG recognizes that the revenue requirement increase over the current payment amounts is significant and will have an impact on electricity consumers. OPG proposes to mitigate this impact by crediting the benefit associated with certain tax losses accumulated over the interim period to consumers in the test period.

As detailed in Ex. F3-T2-S1, the regulatory taxable income calculation for the years 2005 - 2008 results in tax losses for those years. OPG has used the accumulated tax losses at the end of 2008 to reduce the regulatory taxable income for 2009 to nil. The projected remaining balance of regulated tax losses is $503.2M at the end of 2009.

Absent any mitigation, OPG would propose to carry forward this balance to reduce regulatory taxable income in future years until no tax loss balance remained. To mitigate the increase in payment amounts in this application, OPG proposes to accelerate the application of the available tax losses to reduce the test period revenue requirement. This mitigation approach results in the application of the associated tax loss balance multiplied by the 2009 income tax rate of 32 percent (see Ex. F3-T2-S1 Table 7) to revenue requirement in the test period. This results in a reduction to the revenue requirement of $228M. This mitigation approach results in a 14.8 percent increase in the payment amounts, as opposed to an 19.0 percent increase without mitigation.

OPG proposes to apply the mitigation associated with the tax loss carry forward balance to its nuclear and regulated hydroelectric payment amounts to achieve a consistent payment amount increase across the two technologies. This application results in a reduction of regulated hydroelectric revenue requirement of $90.1M and a reduction in the nuclear revenue requirement of $137.9M. The offset in revenue requirement associated with mitigation is used in the calculation of the regulated hydroelectric and nuclear payment amounts as presented in Ex. K1-T2-S1 and Ex. K1-T3-S1, respectively.

TAB 14

Numbers may not add due to rounding.

Table 1
Typical Residential Consumer Impact Assessment
Test Period April 1, 2008 to December 31, 2009

Line No.	Description	Test Period Regulated Hydroelectric	Nuclear	Total
		(a)	(b)	(c)
1	**Typical Residential Consumer Usage (KWh/Month)**[1]	1,000.0	1,000.0	1,000.0
2	**Gross-up for Line Losses**[2]	1.0522	1.0522	1.0522
3	**OPG Portion**[3]	11.4%	31.9%	43.3%
4	**Residential Consumer Usage of OPG Generation (KWh/Month)**	119.8	336.0	455.8
	(line 1 * line 2 * line 3)			
	IMPACT OF RECOVERY OF REVENUE REQUIREMENT DEFICIENCY:			
5	**Test Period Deficiency ($M)**	241.2	784.6	1,025.8
6	**Less: Mitigation ($M)**[4]	90.1	137.9	228.0
7	**Required Recovery ($M)** (line 5 - line 6)	151.1	646.7	797.8
8	**Forecast Production (TWh)**[5]	31.5	88.2	119.7
9	**Required Recovery ($/MWh)**[6] (line 7 / line 8)	4.80	7.33	6.66
10	**Typical Monthly Consumer Bill Impact ($)**	0.58	2.46	3.04
	(line 4 * line 9)			
11	**Typical Monthly Residential Consumer Bill ($)**[7]	111.63	111.63	111.63
12	**Percentage Increase in Consumer Bills**	0.52%	2.21%	2.72%
	(line 10 / line 11)			

Notes:
1 OPG has used consumption information reflected in the consumer rate impact analysis in the rate model developed by the OEB to establish rates for Ontario's electric distributors. This information can be accessed at: http://www.oeb.gov.on.ca/html/en/consumers/understanding/bill_comparison.htm
2 OPG has used the adjustment factor for line losses data reflected in the consumer rate impact analysis in the rate model developed by the OEB to establish rates for Ontario's electric distributors. This information can be accessed at: http://www.oeb.gov.on.ca/html/en/consumers/understanding/bill_comparison.htm
3 Total based on OPG's forecast production divided by the weather normal IPSP energy forecast for 2008 and 2009. Reg. Hydro. and Nuclear portions determined based on energy production.
4 Inclusion of tax losses applicable to future periods as described in Ex. K1-T1-S2
5 From Ex. K1-T1-S1 Table 3
6 Recovery amount is expressed in $/MWh and does not reflect the structure of the payment amount which includes a fixed payment amount for Nuclear.
7 OPG has used the average electricity distributors bill included in the consumer rate impact analysis in the rate model developed by the OEB to establish rates for Ontario's electric distributors. This information can be accessed at: http://www.oeb.gov.on.ca/html/en/consumers/understanding/bill_comparison.htm

TAB 15

Table 1
Annualized Residential Consumer Impact Assessment
Test Period January 1, 2011 to December 31, 2012

Line No.	Description	Notes	Test Period Regulated Hydroelectric	Test Period Nuclear	Test Period Total
			(a)	(b)	(c)
1	**Typical Residential Consumer Usage (kWh/Month)**	1	800.0	800.0	800.0
2	**Gross-up for Line Losses**	2	1.0728	1.0728	1.0728
3	**OPG Portion**	3	13.5%	34.9%	48.4%
4	**Residential Consumer Usage of OPG Generation (kWh/Month)**		116.2	299.1	415.3
	(line 1 x line 2 x line 3)				
	IMPACT OF RECOVERY OF REVENUE REQUIREMENT DEFICIENCY:				
5	**Revenue Requirement Deficiency Requested for Recovery ($M)**	4	25.4	218.0	243.4
6	**Recovery of Variance and Deferral Account Amounts ($M)**	5	(86.8)	459.9	373.1
7	**Amount to be Recovered From Customers ($M)** (line 5 + line 6)		(61.3)	677.8	616.5
8	**Forecast Production (TWh)**	6	38.4	98.9	137.3
9	**Required Recovery ($/MWh)** (line 7 / line 8)		(1.60)	6.85	4.49
10	**Typical Monthly Consumer Bill Impact ($)**		(0.19)	2.05	1.86
	(line 4 x line 9)				
11	**Typical Monthly Residential Consumer Bill ($)**	7	109.40	109.40	109.40
12	**Percentage Increase in Consumer Bills**		-0.17%	1.87%	1.70%
	(line 10 / line 11)				

Notes:

1 OPG has used consumption information reflected in the consumer rate impact analysis in the rate model developed by the OEB to establish rates for Ontario's electric distributors. This information can be accessed at:
http://www.oeb.gov.on.ca/OEB/Consumers/Electricity/Your+Electricity+Utility/All+Electricity+Utility+Bills

2 OPG has used the adjustment factor for line losses data reflected in the consumer rate impact analysis in the rate model developed by the OEB to establish rates for Ontario's electric distributors. This information can be accessed at:
http://www.oeb.gov.on.ca/OEB/Consumers/Electricity/Your+Electricity+Utility/All+Electricity+Utility+Bills

3 Total based on OPG's forecast production divided by normal weather energy demand forecast for 2011 and 2012. Energy forecast for 2011 is from IESO 18-Month Outlook Update for March 2010 to August 2011, Table 3.1, which can be accessed at:
http://www.ieso.ca/imoweb/pubs/marketReports/18MonthOutlook_2010feb.pdf
Energy forecast for 2012 is assumed equal to 2011 forecast (141.9 TWh).
Reg. Hydro. and Nuclear portions determined based on energy production.

4 From Ex. I1-T1-S1 Table 4.

5 From Ex. H1-T2-S1 Table 1.

6 Reg. Hydro production from Ex. E1-T1-S1 Table 1
Nuclear production from Ex. E2-T1-S1 Table 1

7 OPG has used the average electricity distributors bill included in the consumer rate impact analysis in the rate model developed by the OEB to establish rates for Ontario's electric distributors. This information can be accessed at:
http://www.oeb.gov.on.ca/OEB/Consumers/Electricity/Your+Electricity+Utility/All+Electricity+Utility+Bills

TAB 16

Ontario
Executive Council
Conseil des ministres

Order in Council
Décret

On the recommendation of the undersigned, the Lieutenant Governor, by and with the advice and concurrence of the Executive Council, orders that:

Sur la recommandation du soussigné, le lieutenant-gouverneur, sur l'avis et avec le con- sentement du Conseil des ministres, décrète ce qui suit:

WHEREAS it is desirable to achieve reductions in electricity consumption and reductions in peak provincial electricity demand.

AND WHEREAS the Minister may, with the approval of the Lieutenant Governor in Council, issue directives under section 27.1 of the *Ontario Energy Board Act, 1998* in order to direct the Board to take steps to promote energy conservation, energy efficiency, load management or the use of cleaner energy sources, including alternative and renewable energy sources.

AND WHEREAS the Minister may, with the approval of the Lieutenant Governor in Council, issue directives under section 27.2 of the *Ontario Energy Board Act, 1998* in order to direct the Board to establish conservation and demand management targets to be met by distributors and other licensees.

NOW THEREFORE the Directive attached hereto is approved and shall be and is effective as of the date hereof.

Recommended: ______________________
Minister of Energy and Infrastructure

Concurred: ______________________
Chair of Cabinet

Approved and Ordered: MAR 3 1 2010
Date

____
Lieutenant Governor

O.C./Décret 437/2010

MINISTER'S DIRECTIVE

TO: THE ONTARIO ENERGY BOARD

I, Brad Duguid, Minister of Energy and Infrastructure, hereby direct the Ontario Energy Board pursuant to sections 27.1 and 27.2 of the *Ontario Energy Board Act, 1998*, as described below.

The Board shall take the following steps in order to establish electricity conservation and demand management ("CDM") targets to be met by licensed electricity distributors ("distributors") within the timeframe specified herein:

1. Subject to paragraph 5, the Board shall, without a hearing and in accordance with the requirements of this Directive, which relate to the conservation and demand-management targets to be met by distributors and other licensees including the OPA, amend each distributor's licence to add a condition requiring the distributor to achieve reductions in electricity consumption and reductions in peak provincial electricity demand through the delivery of CDM programs ("CDM Programs") by the amounts specified by the Board (the "CDM Targets"), over a four-year period beginning January 1, 2011.

2. In establishing CDM Targets for each distributor, the Board shall:

    (a) ensure that the total of the CDM Targets established for all distributors is equal to 1330 megawatts (MW) of provincial peak demand persisting at the end of the four-year period and 6000 gigawatt hours (GWh) of reduced electricity consumption accumulated over the four-year period;

    (b) specify for each distributor, a CDM Target for the reduction of provincial peak electricity demand and a CDM Target for the reduction of electricity consumption, each of which must be greater than zero; and,

    (c) have regard to information obtained from the Ontario Power Authority ("OPA"), developed in consultation with distributors, regarding the reductions in provincial peak electricity demand and electricity consumption that could be achieved by individual distributors through the delivery of CDM Programs.

3. The Board shall amend the licence of each distributor as follows:

    (a) by adding a condition that specifies each distributor must meet its CDM Targets through:

        (i) the delivery of Board approved CDM Programs delivered in the distributor's service area ("Board-Approved CDM Programs");

(ii) the delivery of CDM Programs that are made available by the OPA to distributors in the distributor's service area under contract with the OPA ("OPA-Contracted Province-Wide CDM Programs"); or,

(iii) a combination of (i) and (ii)

(b) by adding a condition that specifies that the distributor must deliver a mix of CDM Programs to all consumer types in the distributor's service area, whether through Board-Approved CDM Programs, OPA-Contracted Province-Wide CDM Programs or a combination of the two, as far as is appropriate and reasonable having regard to the composition of the distributor's consumer base;

(c) by adding a condition that requires the distributor to comply with rules mandated by a code issued by the Board.

4. The Board shall amend licenses of distributors to ensure that:

(a) distributors utilize the same common Provincial brand (which includes any mark or logo that the Province has used or is using, created or to be created by or on behalf of the Province, and which will be identified to the Board by the Ministry as a provincial mark or logo for its conservation programs) with all Board-Approved CDM Programs;

(b) that the brand identified in (a) shall be the same brand utilized by the OPA and distributors for OPA-Contracted Province-Wide CDM Programs, once those programs have been created; and,

(c) that the brand shall be used by distributors in conjunction with or co-branded with distributor's own brand or marks.

and the Board shall, upon receipt of written direction from the Ministry, which may be issued from time to time, and as a condition of license, require any one or more distributors to cease using the Provincial brand described in this paragraph at such time or in such way as may be specified in such direction.

5. The Board shall not amend the licence of any distributor that meets the conditions set out below:

(a) with the exception of embedded distributors the distributor is not connected to the Independent Electricity System Operator (IESO)-controlled grid; or,

(b) the distributor's rates are not regulated by the Board.

6. The Board shall issue a code that includes rules relating to the reporting requirements and performance incentives associated with CDM Programs and to the planning, design, approval, implementation and the evaluation, measurement and verification ("EM&V") of Board-Approved CDM Programs and to such other matters as the Board considers appropriate.

In developing such rules, the Board shall have regard to the following objectives of the government in addition to such other factors as the Board considers appropriate:

(a) that Board-Approved CDM Programs shall not duplicate OPA-Contracted Province-Wide CDM Programs that are available from the OPA at the time of Board approval;

(b) that the Board shall encourage opportunities for coordinating CDM Programs between the distributor and other relevant entities such as other electricity distributors, natural gas distributors and the OPA;

(c) that the Board shall not preclude consideration of CDM Programs or funding for CDM Programs on the basis that a distributor's CDM Targets have been or are expected to be exceeded;

(d) that a tiered performance incentive mechanism shall be available to distributors for verified electricity savings with incentives beginning to accrue once a distributor meets 80% of each CDM Target; performance incentives shall not be offered for electricity savings achieved beyond 150% of each CDM Target;

(e) that Board approval for funding of any given Board-Approved CDM Program shall correspond to the period in which the Board-Approved CDM Program is offered, provided that the period is no longer than the period for which CDM Targets are established;

(f) that the Board shall require distributors to use OPA cost-effectiveness tests, as modified by the OPA from time to time, for assessing the cost-effectiveness of Board-Approved CDM Programs;

(g) that the Board shall require distributors to use the OPA protocol process and third-party vendor of record list, as modified by the OPA from time to time, when conducting EM&V of Board-Approved CDM Programs;

(h) that the Board shall consider the definition of CDM to be inclusive of load reduction from initiatives, such as geothermal heating and cooling, solar heating and fuel switching, but exclusive of initiatives that are associated with the OPA Feed-in Tariff Program and the OPA Micro Feed-in Tariff Program; and,

(i) that all Board-Approved CDM Programs shall utilize the same common provincial brand (which includes any mark or logo that the Province has used or is using, created or to be created by or on behalf of the Province, and which will be identified to the Board by the Ministry as a provincial mark or logo for conservation) used for OPA-Contracted Province-Wide CDM Programs, once such programs are created, and used in conjunction with or co-branded with any brand or mark used by the distributor.

7. The Board shall not approve CDM Programs until OPA-Contracted Province-Wide CDM Programs have been established.

8. The Board shall, in approving Board-Approved CDM Programs, continue to have regard to its statutory objectives, including protecting the interests of consumers with respect to prices.

9. The Board shall conduct, or cause to be conducted, targeted audits of EM&V carried out by the distributor or third-parties on behalf of the distributor, as necessary.

10. The Board shall annually review and publish the verified results of each individual distributor's CDM Programs and the consolidated results of all distributor CDM Programs, both Board-Approved CDM Programs and OPA-Contracted Province-Wide CDM Programs and take steps to encourage distributors to improve CDM Program performance.

11. The Board shall permit distributors to meet a portion of their CDM Targets through the delivery of CDM Programs targeted to low-income consumers.

12. The Board shall have regard to the objective that lost revenues that result from CDM Programs should not act as a disincentive to a distributor.

Minister of Energy and Infrastructure

TAB 17

March 2, 2010

TAKING A DEEP BREATH ON WIND POWER

Michael Trebilcock

The current Ontario government's headlong rush into massive subsidization of various forms of renewable energy, including wind power and solar energy, is likely to reveal the law of unintended consequences from these precipitous policies unless we take a deep breath and calmly and rigorously re-evaluate these policies before committing billions more dollars from consumers and taxpayers to them.

Such a re-evaluation would sharply focus on three key factors: a) the costs of renewable energy; b) its contributions to reducing CO2 (greenhouse gas) emissions; and c) its contributions to creating jobs in the province. Much of the current government's renewable energy focus has been on the promotion of industrial wind turbine-generated electricity, and hence I focus on these three factors as they relate to industrial wind power.

a) Economic Effects

First, as to the cost of wind-generated electricity, the feed-in tariff for on-shore wind turbines in Ontario provided for under the *Green Energy Act* is 13.5 cents per kWh (and higher for smaller projects), which is more than twice prevailing rates for electricity on the spot market in Ontario (less than 6 cents per KWh). Solar power qualifies for an 80 cents per KWh feed-in tariff. These cost increases will be fed through to industrial, commercial, and residential consumers through various additional charges on their electricity bills. In addition, further expenditures are required in order to enhance and extend the transmission grid to accommodate these projects. A recent study by London Economics Consultancy, "Examining the Potential Costs of the *Ontario Green Energy Act 2009* (April 30, 2009), estimates that the higher costs of green power will add hundreds of dollars to average electricity bills of households throughout Ontario. A recent article in the *Globe and Mail*, "The High Cost of Green Power," January 8, 2010, quotes Adam White, President of the Association of Major Power Consumers of Ontario, as stating: "The situation is not sustainable because it will leave companies paying higher rates than competitors in other jurisdictions." Toronto energy lawyer, Peter Murphy, is quoted as stating: "The government is sitting on a political time bomb." Recent studies of wind power in Denmark,[1] Germany,[2] and the UK,[3] reach similar conclusion about the impacts of renewable energy on electricity costs in these three jurisdictions. The Ontario government's estimate of an increase in electricity costs per year from its renewable policies of 1 percent a year seems to lack any justification or credibility.

b) Environmental Effects

The contributions of industrial wind power to reducing CO2 (greenhouse gas) emissions, which might be thought to justify the additional cost of renewable energy, are in fact at best marginal. Most wind turbines run at only about 25 percent of nameplate capacity, so that generating any substantial amount of electricity from wind power requires massive numbers of wind turbines. In addition, because of their intermittency and unpredictability (like solar power), they require the availability of back-up generation, especially for peak-load capacity, which has entailed in Denmark, Germany, the UK, and now Ontario the construction of additional fossil fuel plants (typically natural gas plants) to provide reliability. This dramatically reduces the net contributions of wind power to CO2 abatement, which come at an extremely high cost relative to

[1] Centre for Policy Studies (CEPOS), *Wind Energy: The Case of Denmark*, Copenhagen, Denmark, September 2009.
[2] Christoph M. Schmidt, *Economic Impacts from the Promotion of Energies: The German Experience* (RWI, Essen, Germany, 2009).
[3] John Etherington, *The Wind Farm Scam: An Ecologist's Evaluation* (Stacey International, 2009), chapter 4.

other abatement strategies (such as real-time pricing of electricity).[4] In the case of base load electricity, most of this is provided in Ontario by carbon-clean hydro and nuclear power so that, to the extent that wind power is used to provide base load electricity, it simply displaces lower cost hydro and nuclear power with no effects on CO2 emissions (or results in exports of surplus power, often at give-away prices).

In October 2007, the Ontario Power Authority (OPA) – the government's own agency, tasked with planning Ontario's power system and now entering into long-term contracts with renewable energy producers – published its Integrated Power System Plan, where it analyzed a "high wind power" scenario for the province, and concluded: "Since wind generation has an effective capacity of 20 percent compared to 73 percent for hydroelectric generation, additional generation capacity with better load-following characteristics would need to be installed. This needed capacity will likely have to be obtained by installing additional gas fired generation. Thus, in addition to incurring further capital costs for the gas generation installation, higher gas usage would be expected to make up for the reduced amount of renewable energy from wind compared to that from hydroelectric generation or this alternative. Therefore, this alternative would result in higher greenhouse gas emissions." The OPA concluded: "Wind and solar power will never be more than a niche supplier of power in Ontario."

What did the OPA see as the better alternative? Renewable hydro power sites in northern Ontario (which it identified). The OPA stated: "The hydroelectric generation developments included in the plan are cost effective compared to developing additional wind generation; this comparison includes the cost of transmission reinforcements. In conclusion, development of major hydroelectric generation north of Sudbury, with major reinforcement of the transmission

[4] Donald Dewees, "The Price Isn't Right: The Need for Reform in Consumer Electricity Pricing," C.D. Howe Institute Backgrounder, No. 124, January 2010.

north of Sudbury, is the preferred alternative compared to developing additional renewable generation in southern Ontario and other parts of northern Ontario."

This begs the obvious question, what has changed in two years? Beyond these sites in northern Ontario, in the medium to longer term there is enough northern Canadian hydro power in Manitoba, Quebec and Labrador to satisfy Ontario's needs for decades. If Boston and New England can depend on northern Canadian hydro power, why not Toronto? Moreover, prior demand projections for electricity need to be revised downwards to reflect not only the current economic recession (demand was down more than 6% in 2009 over 2008), but the long-term contraction in a number of Ontario's electricity-intensive heavy manufacturing industries, such as steel and automobile manufacturing.

c) Employment Effects

The potential contributions of renewable energy to the creation of jobs in the province require a heavy dose of skepticism. While the government has claimed that it plans to create 50,000 new green jobs in the province over the coming years, the additional burdens on industrial, commercial, and household consumers from higher electricity costs associated with renewable energy will kill existing jobs. Recent studies in Denmark and Germany find that very few net new jobs have been created as a result of renewable energy policies, and in the case of Denmark, have cost between US $90,000 to US $140,000 per job per year in public subsidies, and in the case of Germany, up to US $240,000 per job per year. According to a column by Randall Denley in the Ottawa Citizen of January 24, 2010, the new manufacturing jobs entailed in the massive Samsung renewable project recently announced by the Ontario government will cost $300,000 each in public subsidies.

In an SNL Financial news wire report of October 23, 2009, the Ontario Minister of Natural Resources was reported as stating that the agency had temporarily stopped accepting applications for proposed wind energy projects because it had already received 500 such applications and needed to make sure that it had appropriate processes in place before taking any more. Obviously, the massive public subsidies being offered by the Ontario government to the renewable energy sector, especially industrial wind turbines, have provoked a massive corporate feeding frenzy, but corporate enthusiasm for subsidized wind power should not be confused with the longer-term public interest. On all three of the critical factors reviewed above, wind power attracts a failing grade. Beyond these three factors, localized impacts on flora and fauna and on the character of some of Ontario's most beautiful rural communities, potentially adverse health effects on local residents from persistent exposure to low intensity turbine noise, potentially adverse impacts on local property values, and an environmental review process which the Ontario Environmental Commissioner describes as "broken,"[5] render renewable energy policy, at least as currently conceived by the Ontario government, one of the least compelling public policy options in the challenging economic environment in which the province finds itself now and for the foreseeable future.

Picking technological winners in fields such as this, and then picking winners within classes of technology (such as Samsung) are fraught with the risk of costly errors. A far better policy orientation would be first to price all sources of electricity so as to reflect environmental costs and let consumers respond accordingly, and then to subsidize breakthrough R and D in all sectors that are significant sources of carbon emissions. As Dr. Jan Carr, former CEO of the OPA from 2005 to 2008, puts it in a recent article:[6]

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[5] Gord Miller, Annual Report, 2007-2008.

[6] Jan Carr, "A Rational Framework for Electricity Policy," (2010) *Journal of Policy Engagement* 8.

> The recent rush to "green" Ontario's electricity system has produced a largely *ad hoc* approach to the selection and investment in power generation technologies that will unnecessarily increase the cost of electricity with far-reaching economic and social effects... Pricing carbon would have the advantage of continuing a century of economically rational development of the electricity system as an essential underpinning of modern society. To do other than proceed on an economic basis is to risk massive economic distortions... The alternative process of picking winners and losers in renewable energy technologies, based on perceptions and public opinion polls, puts us all at considerable risk."

Before mortgaging its long-term future by awarding hundreds more 20-year fixed-price contracts to wind developers, the province of Ontario urgently needs an independent, objective, expert investigation (perhaps by the Auditor-General) of the prospective economic, environmental, and employment effects of wind power and other renewable energy policies in the province and alternatives thereto.

TAB 18

CME Interrogatory #019

Ref: Ex. C1-T1-S1, Tables 1-7

Issue Number: 6.11
Issue: Are the amounts proposed to be included in the test period revenue requirement for other operating cost items, including depreciation expense, income and property taxes, appropriate?

Interrogatory

What is the total dollar amount OPG seeks to recover in the test period Revenue Requirement (i.e., not through deferral accounts) for payments in lieu of taxes ("PILS") for the test period?

Response

The total payments in lieu of income, capital and property taxes and municipal property taxes[1,2] amounts included in the 24-month test period revenue requirement for prescribed and Bruce facilities is $301.6M. The total municipal property taxes amount included in the 24-month test period revenue requirement for prescribed and Bruce facilities is $29.5M.

Therefore, the total PILS and municipal property taxes for the test period is $331.1M. A detailed breakdown of the components of this amount is presented in Ex. L-05-036.

[1] Municipal property taxes are included to enable amounts to be reconciled to the pre-filed evidence (which combines both Payment in Lieu of property tax paid to the OEFC and property taxes paid to municipalities) and to enable results to be reconciled to results from other CME interrogatories, which request information related to taxes generally.

[2] OPG is expected to become subject to the water taking charges during the test period. As the test period amount is only approximately $0.5M per year, it has been presented in OPG's property taxes amounts for the test period in the pre-filed evidence (refer to Ex. F4-T2-S1, section 10.5). Inclusion of WTC in this response is required to reconcile to the breakdown of taxes requested by CME at Ex. L-5-036.

TAB 19

CME Interrogatory #023

Ref: Ex. C1-T1-S1, Tables 1-7

Issue Number: 6.11
Issue: Are the amounts proposed to be included in the test period revenue requirement for other operating cost items, including depreciation expense, income and property taxes, appropriate?

Interrogatory

What amount of tax does OPG, the corporation, actually expect to pay to the Ontario Electricity Financial Corporation ("OEFC") for 2010?

Response

OPG declines to provide the requested 2010 information with respect to income and capital taxes because it has not been previously filed with the OEB, it is not publicly available and it is not relevant to this proceeding. It is not relevant because it is a forecast for OPG's company-wide operations, including unregulated operations. OPG does not make separate income or capital tax payments for its regulated operations, as the payments are made on a legal entity basis. A budget calculation for the 2010 tax expense for the regulated facilities is provided at Ex. F4-T2-S1, Table 5. OPG has filed its tax returns for 2005 – 2009, in confidence, in response to the OEB's direction in EB-2007-0905 to provide a reconciliation of prior period tax expense and the calculation of tax expense for the regulated facilities.

With respect to payments in lieu of property tax made to the OEFC, the projected amount that will be paid in cash property taxes for OPG's regulated operations (including Bruce assets), based on the 2010 – 2014 business plan, is $15.2M. Additionally, OPG expects to pay $14.8M in municipal property taxes for the regulated operations (including Bruce assets).

TAB 20

CME Interrogatory #026

Ref: Ex. F4-T2-S1, Attachment 3
Ex. G2-T2-S1
Ex. H1-T2-S1

Issue Number: 6.11
Issue: Are the amounts proposed to be included in the test period revenue requirement for other operating cost items, including depreciation expense, income and property taxes, appropriate?

Interrogatory

All taxes that OPG pays are effectively paid to its owner, the Province of Ontario. All return on equity OPG earns is either paid to or attributable to its owner, the Province of Ontario. In these circumstances, please respond to the following questions:

a) Does OPG make any effort to minimize or eliminate its tax burden? If so, then please list all of the tax reduction initiatives in which OPG engaged in each of the years 2005 to 2010, inclusive.

b) Please list whether OPG has adopted any tax planning measures for the test period to minimize the amount of taxes it will be called upon to pay to the Province of Ontario.

c) Please provide the names of any consultant(s) OPG uses to help it with its tax planning.

Response

a) Yes. As any prudent commercial taxable entity would, OPG has made and continues to make (including the period 2005 – 2010) all appropriate efforts to structure and conduct its business and operations in a tax-effective manner while operating in accordance with the rules and regulations of the *Income Tax Act* (Canada) and the *Electricity Act, 1998.* OPG considers all potentially relevant allowable tax deductions and tax credits in the filing of its tax returns in order to minimize its tax burden.

OPG's Finance department has a dedicated group of experienced tax professionals. To fulfill the objective of tax minimization and assessment of related risks, tax filing positions are taken after appropriate research into case laws and technical interpretations where available. OPG's tax professionals engage in continuing professional development training such as attending the Canadian Tax Foundation and Tax Executive Institute seminars, and participate in the Canadian Electricity Association's tax consultation group. OPG also consults with external tax advisors to optimize the tax effectiveness of its business activities.

b) As part of OPG's normal business operations, tax planning measures noted in part a) are carried out to minimize the amount of taxes OPG will be required to pay for the test period.

c) OPG engages the following consultants for tax planning, depending on the nature of the area of tax:

- PricewaterhouseCoopers LLP
- KPMG LLP
- Deloitte & Touch LLP
- Ernst & Young LLP
- Blake, Cassels and Graydon LLP
- Torys LLP

TAB 21

CME Interrogatory #028

Ref: Ex. F4-T2-S1, Attachment 3
Ex. G2-T2-S1
Ex. H1-T2-S1

Issue Number: 6.11
Issue: Are the amounts proposed to be included in the test period revenue requirement for other operating cost items, including depreciation expense, income and property taxes, appropriate?

Interrogatory

What amount does OPG, the corporation, actually expect to pay in taxes to the Province of Ontario in 2010, 2011 and 2012?

Response

OPG declines to provide the requested 2010, 2011 and 2012 information with respect to income and capital taxes because it has not been previously filed with the OEB, it is not publicly available and it is not relevant to this proceeding. It is not relevant because it is a forecast for OPG's company-wide operations, including unregulated operations. OPG does not make separate income or capital tax payments for its regulated operations, as the payments are made on a legal entity basis. A forecast of the 2010, 2011 and 2012 tax expense for the regulated facilities is provided at Ex. F4-T2-S1, Table 5.

With respect to payments in lieu of property tax made to the Ontario Electricity Financial Corporation ("OEFC") and payments for municipal property tax[1] related to OPG's regulated operations (including Bruce assets), the projected amounts, based on the 2010 – 2014 business plan, are as follows:

	2010[2]	2011	2012
Payments in lieu of property tax	$15.2M	$15.8M	$16.3M
Municipal property taxes	$14.8M	$15.8M	$16.3M

[1] Includes water taking charge as discussed in Ex. L-5-019.
[2] As discussed in Ex. L-5-023.

TAB 22

CME Interrogatory #029

Ref: Ex. F4-T2-S1, Attachment 3
Ex. G2-T2-S1
Ex. H1-T2-S1

Issue Number: 6.11
Issue: Are the amounts proposed to be included in the test period revenue requirement for other operating cost items, including depreciation expense, income and property taxes, appropriate?

Interrogatory

Were any amounts recovered from ratepayers for taxes during each of the years 2005 to 2009, inclusive? If so, then what amounts were recovered from ratepayers during each of those years?

Response

The table below sets out the requested information to the extent available.

For the period April 1, 2005 – March 31, 2008, OPG is unable to identify the amount of taxes recovered from ratepayers. Rates for that period were set by the Province of Ontario by Regulation. OPG includes the forecast tax information that was provided to the Province of Ontario on an annual basis for 2005 – 2007 for the purposes of setting these rates. This information is from a document referenced in section 5 (1) of O. Reg. 53/05 and available on the Ontario Energy Board website at: http://www.oeb.gov.on.ca/documents/cases/EB-2006-0064/forecast_facilities_opg_20070213.pdf. The document is reproduced as Attachment 1 to this response.

The amounts for 2008 and 2009 in the table below represent the amounts approved by the OEB in the EB-2007-0905 Payment Amounts Order.

<table>
<tr><th>$M</th><th>Notes</th><th>2005</th><th>2006</th><th>2007</th><th>2008</th><th>2009</th></tr>
<tr><td>Property Tax – Prescribed Assets</td><td>1, 4</td><td>22</td><td>28</td><td>29</td><td rowspan="2">22.8</td><td rowspan="2">30.7</td></tr>
<tr><td>Capital Tax – Prescribed Assets</td><td>1, 4</td><td>30</td><td>33</td><td>36</td></tr>
<tr><td>Income Tax – Prescribed Assets</td><td>1, 5</td><td>18</td><td>20</td><td>22</td><td>nil</td><td>nil</td></tr>
<tr><td>Property Tax – Bruce</td><td>2, 3</td><td>N/A</td><td>N/A</td><td>N/A</td><td>11.4</td><td>15.5</td></tr>
<tr><td>Capital Tax – Bruce</td><td>2, 3</td><td>N/A</td><td>N/A</td><td>N/A</td><td>3.3</td><td>3.6</td></tr>
<tr><td>Income Tax – Bruce</td><td>2, 3</td><td>N/A</td><td>N/A</td><td>N/A</td><td>28.3</td><td>37.7</td></tr>
<tr><td>Large Corporations Tax</td><td>1, 2</td><td>20</td><td>18</td><td>11</td><td>nil</td><td>nil</td></tr>
<tr><td>Total</td><td></td><td>90</td><td>99</td><td>98</td><td>65.8</td><td>87.5</td></tr>
</table>

<u>Notes:</u>

1. Amounts for 2005 – 2007 are annual amounts as provided to the Province of Ontario for the purposes of setting interim rates (Attachment 1, sum of Nuclear and Regulated Hydroelectric amounts for each respective year).

2. Amounts for Bruce were included in Nuclear amounts in the information provided to the Province of Ontario shown in Attachment 1.

3. Amounts for 2009 are per EB-2007-0905, Payment Amounts Order, Appendix A, Table 7, line 5 (Property Tax), line 6 (Capital Tax), and line 9 (Income Tax), column (f). For 2008, the amounts are 3/4 of those found in the above lines in Table 7, column (c) to reflect the adjustment for the period January 1, 2008 – March 31, 2008 (shown as total adjustment to Bruce net revenues on Table 7, line 15, column (c)).

4. Property and capital taxes for prescribed assets were approved by the OEB as a single amount for each of Regulated Hydroelectric and Nuclear. Amounts for 2008 are per EB-2007-0905, Payment Amounts Order, Appendix A, Table 1, line 18, column (c) and Table 2, line 18, column (c). For 2009, the amounts are per Tables 1 and 2, line 18, column (f).

5. Income tax for prescribed assets was set at Nil as per EB-2007-0905, Payment Amounts Order, Appendix A, Tables 1 and 2, line 23, columns (c) and (f).

Forecast Information (as of Q3/ 2004) for Facilities Prescribed under O. Reg 53/05

- As part of the establishment of a hybrid electricity market, the Government made Ontario Regulation 53/05 (O. Reg. 53/05) in February 2005. The Regulation prescribes Ontario Power Generation Inc.'s (OPG's) nuclear generating facilities, specifically Pickering A, Pickering B and Darlington Generating Stations, and certain hydroelectric generating facilities, specifically Sir Adam Beck I, Sir Adam Beck II, Sir Adam Beck Pump Generating Station, DeCew Falls I, DeCew Falls II and R.H. Saunders, for the purposes of section 78.1 of the *Ontario Energy Board Act, 1998* and establishes payment amounts for the output from the nuclear and regulated hydroelectric facilities.

- OPG provided forecast information to the Government in support of the development of O.Reg. 53/05. The forecast information was developed in Q3 2004 and is summarized in Table 1 below. This information was the basis upon which the Government established the payment amounts in the Regulation.

- The information in Table 1 represents OPG's forecasts as of Q3 2004 and does not represent OPG's current forecasts. For example, in Q3 2004, OPG planned to return Pickering A Units 2 and 3 to service and production from these units is included in the 2007 nuclear production forecasts in Table 1. In August 2005, OPG's Board of Directors accepted management's recommendation not to refurbish Pickering Units 2 and 3 and OPG is placing the units in a safe storage state. As a result, current forecasts of nuclear production are less than the forecasts provided in Table 1. Hydroelectric production forecasts are dependent on forecasts of water levels and outflows which can change with time.

Table 1: Forecast Information (as of Q3/ 2004) for Facilities Prescribed under O. Reg 53/05

	Nuclear			Regulated Hydroelectric		
	2005	2006	2007	2005	2006	2007
Average Rate Base ($M)	2,988	3,200	3,712	4,015	3,967	3,916
Energy Generated - TWh	45.2	50.6	53.0	18.0	18.4	18.7
Costs ($M)						
Fuel /GRC Costs	100	112	128	236	243	249
Station Service Charges	11	11	11	5	5	5
OM&A	1,769	1,805	1,889	76	81	82
Property Tax	22	28	29	0	0	0
Capital Tax	19	22	24	11	11	12
Depreciation	292	343	467	65	65	66
Interest	99	107	123	132	134	131
Current Income Taxes	8	9	11	10	11	11
Large Corporate Tax	13	12	8	7	6	3
Return on Equity at 10%	134	144	167	181	179	176
Required Revenues ($M)	**2,466**	**2,593**	**2,857**	**723**	**734**	**735**
Less:						
Bruce Lease - Earnings in Excess of Costs	85	96	117			
Revenues From:						
Ancillary Services	2	3	3	38	40	41
Other Services	21	23	23			
Net Revenue Requirement ($M)	2,358	2,472	2,714	685	694	694
Forecast Interim Rate at 10% ROE ($/MWh)	**52.2**	**48.9**	**51.2**	**38.1**	**37.7**	**37.1**

Forward looking information used in the development of the interim rates was based on planning information developed in Q3 2004 and should not be used for any other purpose.

TAB 23

CME Interrogatory #032
(NON-CONFIDENTIAL VERSION)

Ref: Ex. F4-T2-S1, Attachment 3
Ex. G2-T2-S1
Ex. H1-T2-S1

Issue Number: 6.11
Issue: Are the amounts proposed to be included in the test period revenue requirement for other operating cost items, including depreciation expense, income and property taxes, appropriate?

Interrogatory

For the years 2005 to 2009, inclusive, does the total amount for taxes in each year that OPG has either recovered or now seeks to recover from ratepayers exceed the amount for taxes actually paid by OPG, the corporation, to the Province of Ontario? If so, then what is the amount of the excess for each year and cumulatively?

Response

OPG makes payments in lieu of income, capital and property tax to the Ontario Electricity Financial Corporation ("OEFC") and property tax payments to municipalities. The table below sets out the comparison between these amounts paid for 2005 – 2009, as per Ex. L-5-027, and the amount of taxes OPG has either recovered or seeks to recover from ratepayers for those years (as per Ex. L-5-029, Ex. L-5-030 and Ex. L-5-031), to the extent information is available.

The requested comparison is not meaningful because:

- As noted in Ex. L-5-023 and Ex. L-5-027, information for income and capital taxes paid is only available for OPG as a whole, and not regulated operations separately. Therefore, the amounts paid for income and capital taxes relate to OPG's total operations while the amounts recovered relate to regulated operations (including Bruce assets) only.

- As noted in Ex. L-5-029, for the period April 1, 2005 – March 31, 2008, OPG is unable to identify the amount of taxes, if any, recovered from ratepayers through the interim rates set by the Province of Ontario. The information regarding amounts recovered for the years 2005 – 2007 presented below is based on amounts OPG submitted to the Province for the purposes of setting interim rates.

- The calculation of regulatory income and capital taxes involves the application of regulatory principles, whereas amounts paid by OPG do not.

$M	2005	2006	2007	2008	2009
OEFC – Income and Capital Taxes	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
OEFC – Property Tax	12.3	13.8	13.6	14.7	14.5
Municipalities – Property Tax	12.5	12.8	13.3	14.1	14.1
Total Tax Paid (A)	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Payment Amounts	90.0	99.0	98.0	65.8	87.5
Tax Loss Variance Account	N/A	N/A	N/A	66.3	55.9
Bruce Variance Account	N/A	N/A	N/A	(98.3)	(35.2)
Total Tax Recovered/Recoverable (B)	**90.0**	**99.0**	**98.0**	**33.8**	**108.2**
Difference = (B) – (A)	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Cumulative Difference (A > B)					[redacted]

As per the table above, there is no cumulative excess, as defined in the question.

TAB 24

CME Interrogatory #033

Ref: Ex. F4-T2-S1, Attachment 3
Ex. G2-T2-S1
Ex. H1-T2-S1

Issue Number: 6.11
Issue: Are the amounts proposed to be included in the test period revenue requirement for other operating cost items, including depreciation expense, income and property taxes, appropriate?

Interrogatory

Did the payment amounts that OPG received from ratepayers in 2010 include any amount for taxes? If so, then what is that amount?

Response

Yes, the payment amounts received in 2010 include amounts for capital and property taxes for the prescribed facilities, and capital, property and income taxes related to the Bruce facilities.

The table below sets out the requested information.

$M	Notes	2010
Property and Capital Tax – Prescribed Assets	1	30.6
Income Tax – Prescribed Assets	2	nil
Property Tax – Bruce	3	15.4
Capital Tax – Bruce	3	3.9
Income Tax – Bruce	3	37.7
Total		**87.6**

Notes:
1. Amount is calculated as 12/21 of property and capital tax amounts approved by the OEB as part of OPG's revenue requirement in EB-2007-0905 (all references are to EB-2007-0905, Payment Amounts Order, Appendix A):

	$M
Total Regulated Hydroelectric (Table 1, line 18, col. (i))	15.2
Total Nuclear (Table 2, line 18, col. (i))	38.3
Total for the period April 1, 2008 – December 31, 2009	**53.5**
Amount for 2010: 12/21 x $53.5M	**30.6**

Witness Panel: Deferral and Variance Accounts, Payment Amounts and Regulatory Treatments

2. Income tax for prescribed assets was set at Nil as per EB-2007-0905, Payment Amounts Order, Appendix A, Tables 1 and 2, line 23, columns (i).

3. As shown in Ex. L-5-031, amounts for Bruce taxes are calculated as 12/21 of amounts approved as part of OPG's revenue requirement in EB-2007-0905:

	$M
Property Tax for full year 2008	15.2
Property Tax for full year 2009	15.5
Less: Q1 2008 (1/4 x $15.2M)	3.8
Total April 1, 2008 – December 31, 2009	26.9
Amount for 2010: 12/21 x $26.9M	**15.4**
Capital Tax for full year 2008	4.4
Capital Tax for full year 2009	3.6
Less: Q1 2008 (1/4 x $4.4M)	1.1
Total April 1, 2008 – December 31, 2009	6.9
Amount for 2010: 12/21 x $6.9M	**3.9**
Income Tax for full year 2008	37.7
Income Tax for full year 2009	37.7
Less: Q1 2008 (1/4 x $37.7M)	9.4
Total April 1, 2008 – December 31, 2009	66.0
Amount for 2010: 12/21 x $66.0M	**37.7**

TAB 25

CME Interrogatory #036

Ref: Ex. F4-T2-S1, Attachment 3
Ex. G2-T2-S1
Ex. H1-T2-S1

Issue Number: 6.11
Issue: Are the amounts proposed to be included in the test period revenue requirement for other operating cost items, including depreciation expense, income and property taxes, appropriate?

Interrogatory

For the test period 2011 and 2012, what amount in the test period Revenue Requirement in each year does OPG seek to recover from ratepayers for taxes?

Response

The tax amounts for the 24-month test period for the prescribed assets included in the revenue requirement are as follows (all references are to Ex. I1-T1-S1, Table 1):

	$M
Regulated Hydroelectric Property Taxes (line 18, col. (c))	0.0
Nuclear Property Taxes (line 18, col. (f))[1]	32.6
Regulated Hydroelectric Income Tax (line 23, col. (c))	57.9
Nuclear Income Tax (line 23, col. (f))	129.8
Total Taxes for prescribed assets for 24 months 2011 – 2012	**220.3**

The tax amounts for the 24-month test period 2011 – 2012 for the Bruce assets included in the revenue requirement are as follows (all references are to Ex. G2-T2-S1, Table 5):

	$M
Bruce Property Taxes (line 2, col. (e) + col. (f))	27.7
Bruce Current Income Tax (line 10, col. (e) + col. (f))	8.6
Bruce Future Income Tax (line 11, col. (e) + col. (f))	74.5
Total Taxes for Bruce assets for 24 months 2011 – 2012	**110.8**

The combined amount of taxes for prescribed and Bruce assets included in the 24-month revenue requirement for is therefore $331.1M ($220.3M + $110.8M).

[1] Includes a water taking charge as discussed in Ex. F4-T2-S1, section 10.5, and Ex. L-5-019.